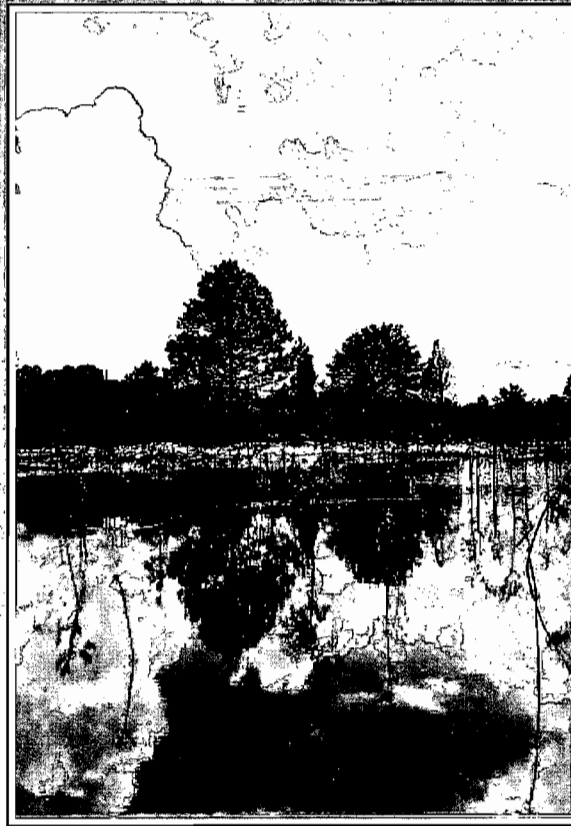


Kissimmee Utility Authority
Florida Municipal Power Agency
Cane Island – Unit 3

NEED FOR POWER APPLICATION

Volume 1A

Kissimmee Utility Authority
Florida Municipal Power Agency



Cane Island Power Park Unit 3



BLACK & VEATCH_{LLP}



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Introduction

This Site Certification Application (SCA) is being submitted jointly by Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for the addition of Unit 3 to the Cane Island Power Park, and for the existing Units 1 and 2, in accordance with the Florida Electrical Power Plant Siting Act. Cane Island Unit 3 is a proposed combined cycle unit with a nominal rating of approximately 250 MW, consisting of a F class combustion turbine, heat recovery steam generator (HRSG), and steam turbine.

The SCA is comprised of three volumes. The first volume of the application is divided into subvolumes labeled 1A, 1B, and 1C, and contains Section 1 of the SCA. These subvolumes contain the Public Service Commission Need for Power (NFP) Application portion of the SCA. The joint need for power application is based on the needs of both KUA and FMPA who are each 50 percent joint owners in Cane Island Unit 3 and existing Units 1 and 2. Subvolumes 1A, 1B, and 1C contain the following information.

- 1A - NFP information common to both participants.
- 1B - NFP information specific to KUA.
- 1C - NFP information specific to FMPA.

Volumes 2 and 3 contain information regarding all other aspects of the SCA other than the need for power, including environmental information associated with the proposed facility and existing units.

KUA was the project manager for licensing and construction of the existing Cane Island Units 1 and 2. KUA is also the operator for Units 1 and 2. Likewise, KUA is the project manager for licensing and construction of Unit 3 and will be the operator. Unit 1 consists of a simple cycle General Electric LM 6000 combustion turbine with a nameplate rating of 42 MW. Unit 2 consists of a General Electric 7EA 1 x 1 combined cycle with a nameplate rating of 120 MW.

Site certification for the proposed Unit 3 is being sought under the Florida Electrical Power Plant Siting Act, Sections 403.501-403.518, Fla. Stat., and as such, the determination of need for the proposed Unit 3 is being sought under Section 403.519, Fla. Stat.. As existing units, site certification for Units 1 and 2 is being sought under Section 403.5175, Fla. Stat.. In accordance with Section 403.5175(1), Fla. Stat., a determination of need is not required for Units 1 and 2. Notices regarding the project should be sent to KUA's attention.



Applicant's Official Names and Mailing Addresses

Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, Florida 32742-3219

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, Florida 32809

Address of Official Headquarters

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, Florida 32809

Business Entity

Kissimmee Utility Authority (KUA) is a body politic, duly organized, and legally existing as part of the government of the City of Kissimmee, engaged in the generation, transmission, and distribution of electric power to persons within the service area.

Florida Municipal Power Agency (FMPA) is a joint agency formed pursuant to the Interlocal Cooperation Act which exercises powers under the Joint Power Act. FMPA has authority to undertake and finance electric projects and, among other things, to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, extend, or otherwise participate jointly in those projects and to issue bonds or bond anticipation notes for the purpose of financing or refinancing the costs of such projects.



Name, Address, and Telephone Number of Official Representative Responsible for Obtaining Certification

A.K. Sharma
Kissimmee Utility Authority
1701 W. Carroll St.
Kissimmee, FL 34741
Ph. (407) 933-7777, ext. 1232
Fax (407) 847-0787

Site Location

Osceola County

Nearest Incorporated City

Kissimmee

Longitude and Latitude

Lat: 28 degrees, 16 minutes, 50 seconds
Long: 81 degrees, 32 minutes, 00 seconds

UTMs (Center of Site)

3,128,000 North
447,500 East

Section, Township, Range

Sec 29, 32/T25S/R28E

Location of Any Directly Associated Transmission Facilities

Osceola County



Nameplate Generating Capacity

The nameplate rating of Cane Island Unit 3 will depend upon the exact combustion turbine selected and the design of the steam turbine. It is estimated that Cane Island Unit 3 will have a nameplate gross generating capacity of approximately 270 megawatts (MW) at 59° F.

Commercial Operation Date

Cane Island Unit 3 is scheduled for commercial operation on June 1, 2001.



1A.1.0 Overview and Summary

1A.1.1 Overview

Cane Island Unit 3 will be the third unit installed at the Cane Island Power Park site located approximately 13 miles west of Kissimmee, Florida. Cane Island Unit 3 is being planned for a *nominal net* generating capacity of approximately 250 MW.

KUA and FMFA are both 50 percent joint owners of the Cane Island Unit 3 facility. This ownership arrangement mirrors the ownership arrangement of the existing Cane Island Unit 1 and Unit 2 facilities.

1A.1.2 Summary

Cane Island Unit 3 is planned to utilize a 1 x 1 configuration with an F-class combustion turbine and a 100 MW steam turbine. The estimated 2001 installed capital cost is \$117,567,000, which includes interest during construction and an associated 230 kV transmission line from Cane Island to Florida Power Corporation's Intercession City Plant. Cane Island Unit 3 is projected to have a net degraded output of 262 MW at 59° F with a higher heating value (HHV) heat rate of 6,815 Btu/kWh. Cane Island Unit 3 is planned to be equipped with evaporative inlet cooling and duct firing to increase output during the summer. Cane Island Unit 3 will be natural gas fueled and is planned to have No. 2 oil as backup fuel. Cane Island Unit 3 is also planned to be equipped with a bypass damper and stack to enable operation in simple cycle mode.





1A.2.0 Description of the Project

1A.2.1 Description of Facilities

The Cane Island Power Park (Power Park) currently includes two existing units, Units 1 and 2, and support facilities as shown on the Site Arrangement Drawing Figure 1A.2-1. Unit 1 consists of a simple cycle General Electric LM 6000 combustion turbine (CT) with a nameplate rating of 42 MW. Unit 2 consists of a General Electric 7EA 1 x 1 combined cycle with a nameplate rating of 120 MW. The proposed Unit 3 is also shown on Figure 1A.2-1, and will consist of an F-class 1 x 1 combined cycle with a nominal rating of approximately 250 MW. The actual size of Unit 3 will depend upon the combustion turbine vendor selected and the design and size of the steam turbine. Output will also vary with degradation and ambient conditions. Electricity generated by the Cane Island Units is stepped up in voltage by generator step-up transformers to 230 kV for transmission via the power grid.

The basic power generation cycle for Unit 3 consists of an F-class combustion turbine, a heat recovery steam generator (HRSG), a condensing steam turbine, and a mechanical draft cooling tower. The HRSG will be a three pressure design. Duct burners will be installed in the HRSG inlet to allow the steam turbine to be fully loaded at higher ambient temperatures. The HRSG will be provided with a bypass stack and diverter damper to accommodate operation in simple cycle mode.

Natural gas will be the primary fuel for the combustion turbine and the only fuel for the HRSG duct burners. Low sulfur (0.05 percent), No. 2 fuel oil is currently planned to be the emergency backup fuel for the combustion turbine. The Unit 1 fuel oil storage tank has a capacity of 0.3 million gallons and the Unit 2 tank has a capacity of 0.7 million gallons, for a total existing storage capacity of 1.0 million gallons. An additional 1.0 million gallon tank is currently planned to be installed to provide backup fuel oil for Unit 3. The combined storage capacity, 2.0 million gallons, will provide more than 3 days of fuel oil supply for full load operation of Units 1, 2 and 3.

Flue gas is the only byproduct of the combustion process whether burning natural gas or No. 2 fuel oil. Both are low sulfur, low ash fuels. The manufacturer guarantees full load NO_x emission levels of 12 to 15 ppm, while burning natural gas, will be attained by implementing dry low NO_x combustor technology. Therefore, installation of an SCR will not be required

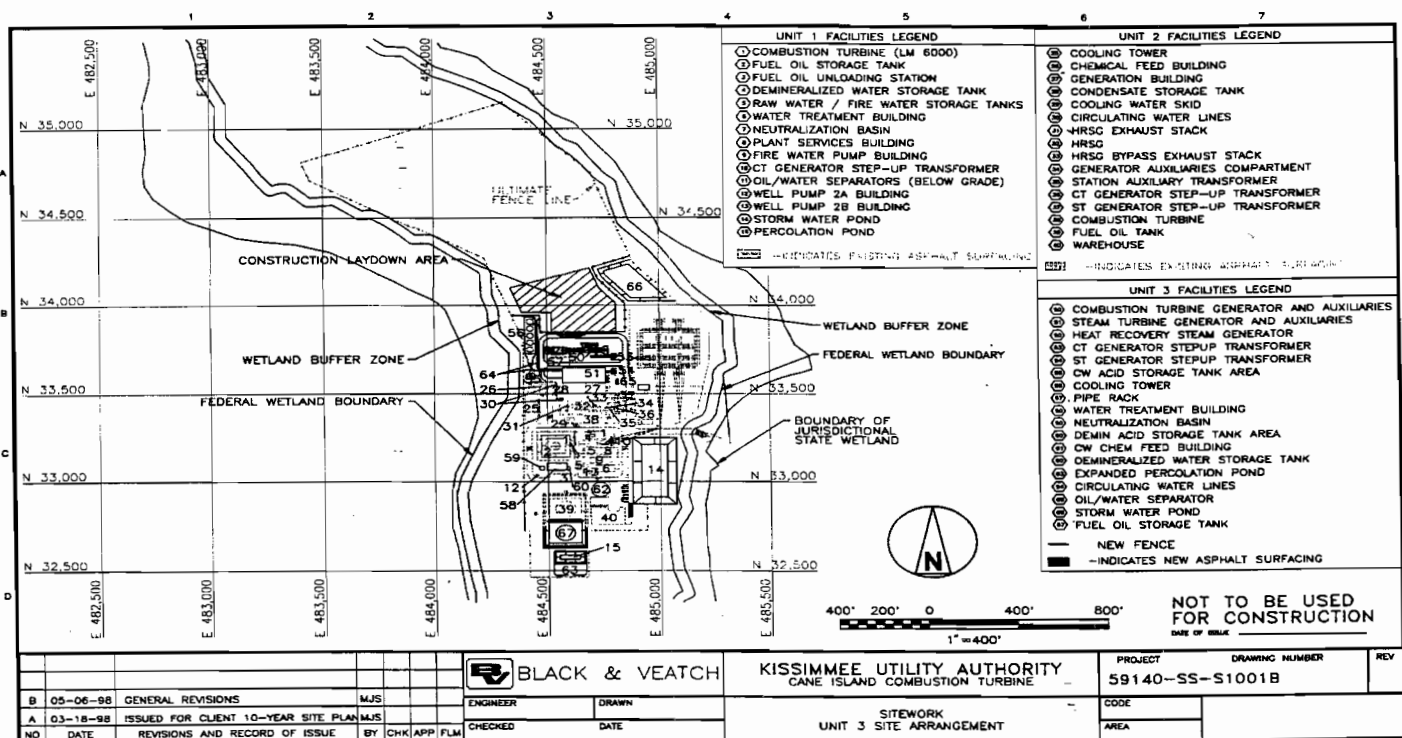


Figure 1A.2-1



for Unit 3. For air emissions, Unit 3 will be considered a major stationary emission source and will be subject to Prevention of Significant Deterioration (PSD) permitting requirements. Unit 3 will be considered a minor stationary emission source with respect to SO₂ and will be permitted under a federally enforceable annual SO₂ emission limit of 40 tons per year. Unit 3 emissions will be maintained below the 40 tons per year threshold by limiting fuel oil firing to approximately 30 days per year. Units 1 and 2 are each permitted for fuel oil firing a maximum of 800 hours per year (33 days).

Cane Island Unit 3 waste heat will be rejected to the atmosphere by a cooling cycle using a mechanical draft cooling tower. The source of cooling water makeup will be treated sewage effluent from the City of Kissimmee's effluent pipeline. Provisions will be included to utilize well water as an emergency source of cooling water makeup. It is estimated that six new wells will be required to accommodate new process uses and emergency well water demands. The estimated cooling water withdrawal rate from the City of Kissimmee's effluent pipeline for Unit 3 is 1,895,000 gpd, at full load, with the evaporative cooler operating. When the combustion turbine inlet air evaporative cooler operates, 43,000 gpd of the Unit 3 evaporative cooler blowdown will be routed to the cooling tower and will provide the balance of the Unit 3 cooling water makeup requirement.

Cane Island Unit 3 will have five major sources of wastewater. These wastes include sanitary waste, oil/water separator waste, cooling tower blowdown, chemical wastes, and boiler blowdown. Similar to the methods used for the existing units, the process wastewaters will be treated and discharged at three locations. Oil/water separator effluent will be routed to an onsite percolation pond for ground water recharge. Cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be returned to the City of Kissimmee's effluent pipeline for ultimate disposal at the Imperial Percolation Pond Site. Sanitary wastes will be routed to the existing septic tank/tile field system. For Unit 3, it is estimated that 446,000 gpd of combined wastewater from cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be returned to the City of Kissimmee's effluent pipeline.

Unit 3 will utilize an independent, distributed control system. The existing Unit 2 steam turbine building will be expanded to house the control room expansion, control equipment, and electrical equipment. Units 1-3 will be controlled from the expanded control room.



Other than combustion control measures, such as dry low-NO_x combustors, no other air pollution control techniques are required, although water injection will be required when burning No. 2 oil.

1A.2.2 Fuel Supply

Natural gas is the primary fuel at the Cane Island Power Park and is supplied via a 20 inch diameter natural gas line that is owned by Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) and operated by Florida Gas Transmission (FGT). The natural gas line was installed in 1993 and connects to an existing FGT line near the intersection of Interstate I-4 and State Road 545. The capacity of the line will support a total build out of 1,000 MW at Cane Island.

Existing fuel oil capacity at the Cane Island site is provided by two storage tanks with capacities of 0.3 million gallons and 0.7 million gallons. At ISO conditions, Units 1 and 2 can operate for four days at full load with the existing storage capacity. An additional 1.0 million gallon storage tank is planned to be installed adjacent to the existing fuel oil tanks to provide backup fuel oil to Unit 3. The expanded fuel oil capacity will enable Unit 3 to be fuel oil fired at full load for a period of three days. The tanks will be piped so that all units can draw fuel oil from any tank.

Although backup fuel oil capacity will supply Units 1-3 with the necessary fuel for operation during curtailment or outage of the gas line, the existing backup fuel oil supply has never been required. This is because the Cane Island Power Park has not experienced a gas line outage since installation of the line in 1993. Although new gas supply customers will connect to the St. Petersburg lateral, which supplies the Cane Island Power Park, FGT planning staff have stated that overall reliability of the supply is expected to remain unchanged.

1A.2.2.1 Fuel Quantities

Full load fuel consumption estimates for Units 1-3 are presented in Table 1A.2-1. Fuel usage estimates are based on the full load output of each unit at 95 F.

1A.2.2.2 Fuel Transportation

Natural gas is the primary fuel at the Cane Island Power Park and is supplied via a 20 inch diameter natural gas line that is owned by KUA and FMPA and operated by FGT.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Table 1A.2-1
Fuel Consumption Estimates (MBtu/h)¹

Unit	No. 2 Fuel Oil	Gas
Unit 1 - LM6000 ²	459.8	432.6
Unit 2 - 1x1 7EA ²	976.1	937.3
Unit 3 - 1x1 F-Class ³	1,808.0	1,736.3
Total Consumption	3,243.9	3,106.2
¹ Based on 95 F full load heat rates. ² Actual test data. ³ Includes degradation.		



The natural gas line was installed in 1993 to support the Cane Island Power Park. The line ties into an existing FGT natural gas line near the intersection of Interstate I-4 and State Road 545. The size of the line is based on a total build out of 1,000 MW at the Cane Island Power Park. A more detailed analysis and description of FGT's system is presented in Section 1A.3.3 Fuel Availability.

Number 2 fuel oil is the secondary (backup) fuel for the Cane Island Power Park. The fuel oil is delivered to the Power Park utilizing tanker trucks. Once onsite, the fuel is transferred from the tankers to onsite storage tanks.

1A.2.2.2.1 Natural Gas Delivery and Metering. Natural gas is delivered to Cane Island Power Park as described in Subsection 1A.2.2.2. A metering station was installed in 1993 with the 20 inch natural gas line to support the Cane Island Power Park. The metering station is located at the interconnection location (intersection of I-4 and State Road 545) with the FGT pipeline. This metering station will continue to meter the additional amount of natural gas utilized by Unit 3. There is a common custody grade meter at the Cane Island Power Park. Additionally, Unit 3 will have its own individual gas meter.

1A.2.2.2.2 Fuel Oil Storage and Handling. The existing No. 2 fuel oil storage consists of two aboveground tanks--one 0.3 million gallon tank for Unit 1, and one 0.7 million gallon tank for Unit 2. An additional fuel oil storage tank, with a capacity of 1.0 million gallons, is currently planned to be installed at the Cane Island Power Park for Unit 3. The locations of the storage tanks are indicated on the Site Arrangement, Figure 1A.2-1.

Fuel is delivered to the storage tanks by tanker truck. The fuel oil truck unloading station is located south of the Unit 1 storage tank as indicated on Figure 1A.2-1. Semitrailer tanker trucks enter the site at the main gate, park adjacent to the unloading station, and are connected to the unloading station. Unloading operations are coordinated between the Plant operator(s) and the truck driver and are constantly monitored by both parties.

1A.2.3 Capital Costs

The capital cost estimate is developed on the basis of the current competitive generation market. Indirect costs include the typical items of engineering, construction management, general indirect costs, and contingency. In addition, indirect costs include SCADA interface costs, spares, owner's engineer costs, permitting, training, substation costs to integrate the unit into the Cane Island substation, and costs for a 230 kV transmission line from Cane Island to Florida Power Corporation's Intercession City Plant in order to place the costs on a comparable basis with costs resulting from purchase power bids. Total capital cost is the



summation of direct and indirect cost and interest during construction for commercial operation in 2001.

The project cost for Cane Island Unit 3 is estimated to be \$117,567,000. The capital cost reflects significant savings associated with the sharing of common site utilities and equipment including the engineering costs of the buildings and associated facilities. Some of these facilities include the site access road, cooling tower makeup water supply pipeline, water treatment and wastewater disposal, and site buildings. A detailed description of capital cost components is listed in Table 1A.2-2.

1A.2.4 O&M Cost

The O&M cost estimates are based on a unit life of 25 years and baseload capacity factor. The estimates also include a 20 percent contingency. For the fixed O&M analysis, it was assumed that fixed costs will remain constant in real dollars over the life of the plant. Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Variable O&M costs include consumables, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation. The estimates of fixed and variable O&M are \$2.08/kW-yr and \$2.58/MWh (1998 \$), respectively. The O&M cost estimates were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors.
- Combustion turbine generator (CTG) maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at \$38/man-hour.
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost. These costs are included in the capital cost. The cost of the parts used in the inspections and overhauls are included in the O&M costs.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.



Table 1A.2-2
Cost Estimate
Cane Island Unit 3

Procurement Contracts	
Mechanical	53,037,311
Electrical	4,465,000
Control	1,350,000
Chemical	<u>930,000</u>
Subtotal	59,782,311
Furnish & Erect Contracts	
Structural	144,652
Mechanical	<u>1,770,000</u>
Subtotal	1,914,652
Construction Contracts	
Civil/Structural	5,318,287
Mechanical	13,273,121
Electrical/Control	2,171,823
Chemical	450,000
Construction Services	<u>712,117</u>
Subtotal	21,925,348
Total Direct Cost	83,622,311
Indirect Costs	
General Indirects	175,000
Outside Engineering	6,260,000
Construction Management	1,100,000
Transmission/SCADA/Substation	7,416,006
Spare Parts	4,821,767
Training/Permitting	1,000,000
Contingency	7,529,030
Interest During Construction	<u>5,642,841</u>
Total Indirect Cost	33,944,644
Total Project Cost	117,566,955
Total Project Cost, \$/kW	449⁽¹⁾

⁽¹⁾Based on ISO rating of 262 MW.



- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- Provision for two additional staff in 2001 are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.

1A.2.5 Heat Rate

The estimates for average net plant heat rate (NPHR) and output for Cane Island Unit 3 are listed in Table 1A.2-3. Plant heat rate and output estimates include a 2 and 4 percent degradation factor, respectively.

1A.2.6 Availability

Availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs and routine maintenance activities. Availability of the F-class Cane Island Unit 3 is estimated to be approximately 91.8 percent per year. The availability estimate includes a 4.1 percent forced outage rate and all scheduled maintenance outages as described in Section 1A.2.4.

1A.2.7 Schedule

The schedule for Cane Island Unit 3 is based on a 20-month construction period. Engineering would start 5 months before the start of construction to complete the design in advance of construction. To meet a June 1, 2001, commercial operation date, construction would start October 1, 1999 upon receiving site certification, and engineering would start May 1, 1999.

The 5-month period for engineering before construction starts includes the time required to procure major equipment and to complete the detailed foundation design. The combustion turbine, steam turbine, HRSG and transformers represent the long lead time equipment.

This project schedule is based on reasonable durations and a logical, efficient approach to the project. This approach will support completing the project on time with minimum total cost. The detailed schedule is presented in Figure 1A.2-2.



Table 1A.2-3
Net Plant Heat Rate (NPHR) HHV

Output (percent)	59 F		95 F	
	MW	NPHR Btu/kWh	MW	NPHR Btu/kWh
100	262	6,815	237 ¹	6,945 ¹
75	196	7,141	175	7,483
50	139	7,699	123	8,011
25	73	9,894	64	10,474

(1) 244 MW and 6,998 Btu/kWh with duct firing.

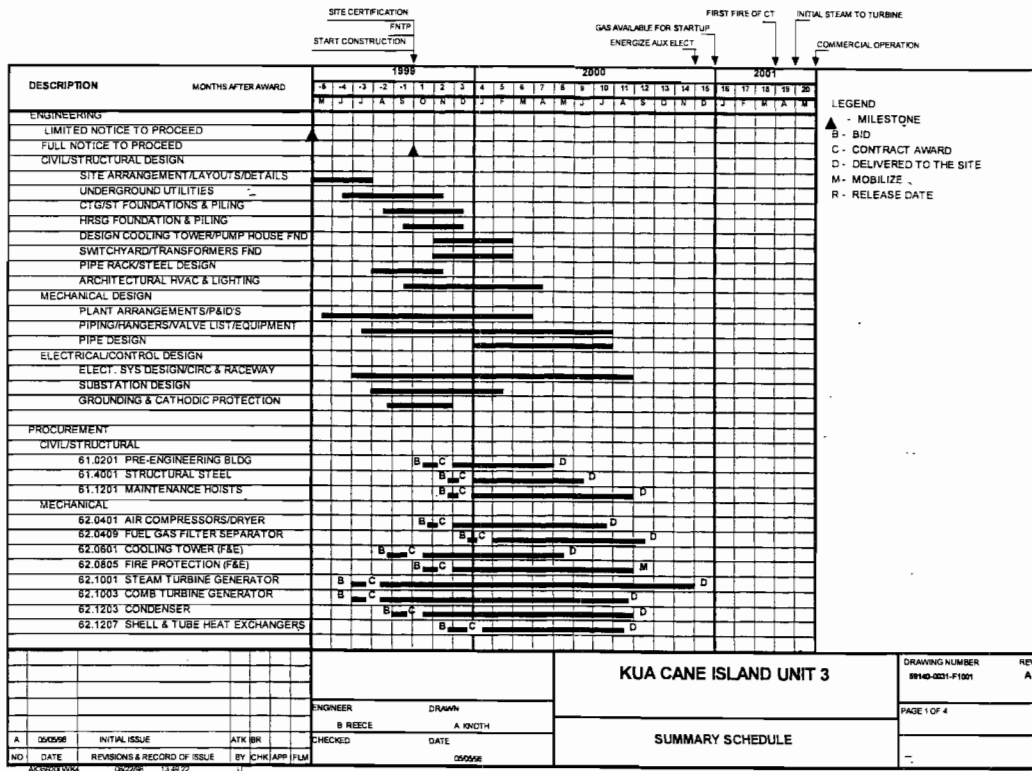


Figure 1A.2-2 (Page 1 of 4)

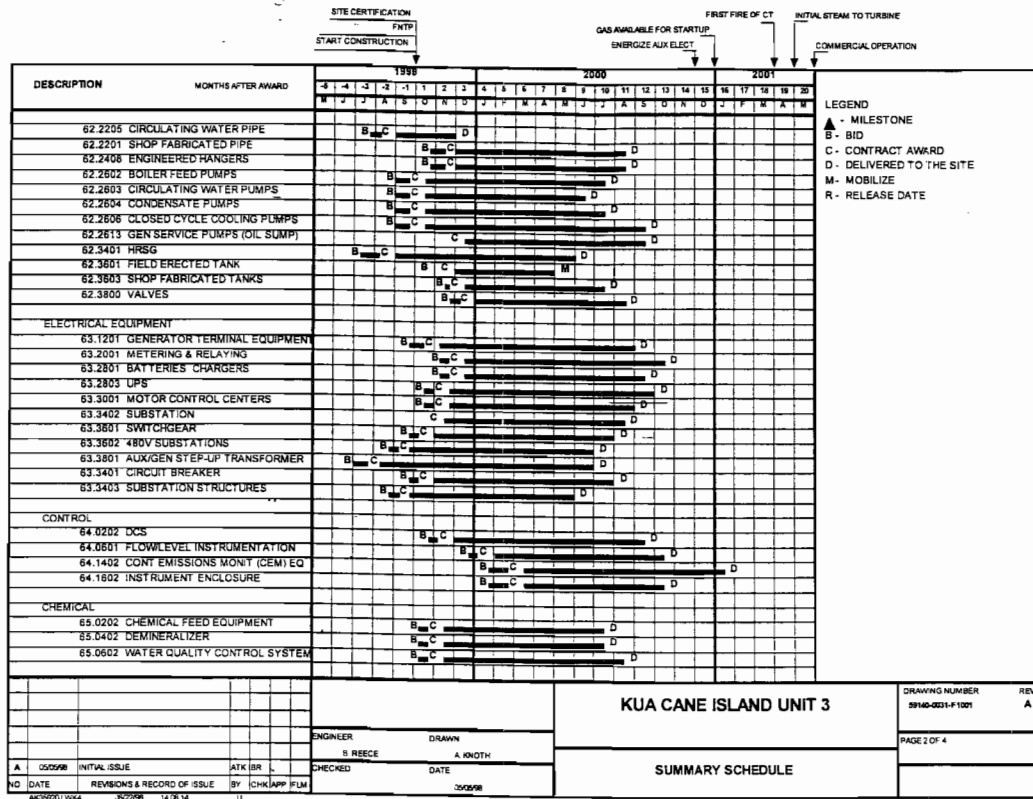


Figure 1A.2-2 (Page 2 of 4)

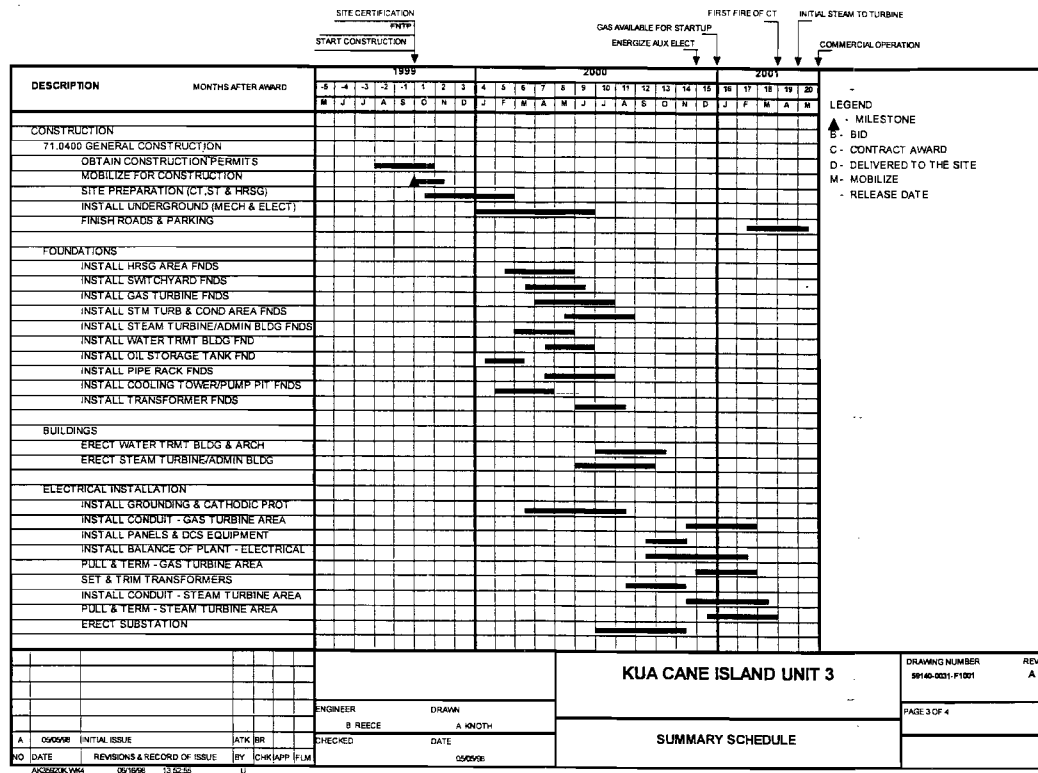
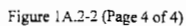


Figure 1A.2-2 (Page 3 of 4)





1A.2.8 Analysis of Clean Air Act Implications

The Cane Island Power Park is required to comply with the Clean Air Act (CAA) and the current Florida air quality requirements stemming from the Act. Section 1A.8.0 presents an analysis of the CAA implications and licensing requirements for construction of Cane Island Unit 3.

1A.2.9 Associated Transmission Line

Load flow studies using the 1998 Florida Reliability Coordinating Council (FRCC) database indicate that with the addition of Cane Island 3 during an outage of the Cane Island-Taft 230 kV transmission line, the Clay Street 230/69 kV auto transformer overloads. With the addition of a second autotransformer at Clay Street, under the same contingency, the Clay Street-Hansel 69 kV transmission line overloads, requiring reconductoring. Planning studies indicated that a new 230 kV transmission line from Cane Island to Florida Power Corporation's Intercession City Plant would solve these contingency problems at a significantly lower cost. The new 230 kV transmission line will be routed on the existing Cane Island-Clay Street transmission line towers to the site boundary and then be routed in the identified utility corridor adjacent to the CSX railroad line to the Intercession City Plant. The Intercession City Plant property directly adjoins the Cane Island site. The transmission line will be treated as an associated facility under the Florida Electrical Power Plant Siting Act.





1A.3.0 Evaluation Criteria

This section presents the assumptions used for economic parameters and projections of prices used in the need for power analysis. The assumptions stated in this section are applied consistently throughout. Section 1A.3.1 outlines the basic economic assumptions, Section 1A.3.2 discusses the fuel price projections, and Section 1A.3.3 discusses the availability of fuel at the Cane Island Power Park.

1A.3.1 Economic Parameters

1A.3.1.1 Escalation Rates

A 2.5 percent general inflation rate is assumed. A 3.0 percent annual escalation rate is used for operation and maintenance (O&M) costs. A 2.5 percent annual escalation rate is used for capital costs.

1A.3.1.2 Bond Interest Rate

The bond interest rate is assumed to be 5.5 percent.

1A.3.1.3 Present Worth Discount Rate

The present worth discount rate is equal to the bond interest rate of 5.5 percent.

1A.3.1.4 Interest During Construction

Interest during construction is assumed equal to bond interest rate of 5.5 percent.

1A.3.1.5 Fixed Charge Rate

The fixed charge rate is 8.2 percent. The fixed charge rate was developed based on a 30 year bond term including principal and interest, a 1 year debt service reserve fund, interest earnings credit based on the bond interest rate, a 2.9 percent bond issuance fee, and 1.0 percent for property insurance.



1A.3.2 Fuel Price Projections

This section presents the analysis of fuel prices and current market projections based on the Standard and Poor's Analysis of Utility Fuel Prices in the South Atlantic Region which was completed in September of 1997 by DRI. The forecast is presented in Appendix 1A.9.1. Fuel price projections are developed for coal, natural gas, nuclear, No. 6 and No. 2 fuel oil. Delivered fuel cost projections for the base, low, and high cases are presented in Tables 1A.3-1, 1A.3-2, and 1A.3-3, respectively. The forecasted fuel prices are represented graphically on Figure 1A.3-1. The first graph presents all fuel price forecasts in nominal dollars. The second graph presents a comparison of historical spot gas prices to the natural gas forecast. The historical and projected gas prices exclude transportation costs.

1A.3.2.1 Coal Price Forecast

The forecast for delivered price of coal was based on actual 1997 delivered cost of spot coal purchases for Stanton Energy Center from the Resource Data Institute (RDI) POWERdat database and Standard and Poor's Analysis of Utility Fuel Prices in the South Atlantic Region by DRI. The DRI forecast of spot coal prices was converted to 1996 dollars using DRI's implicit price deflator listed in Table 1A.3-4. The actual delivered cost of coal was then projected by applying DRI's real, annual coal price escalation in 1996 dollars plus 2.5 percent annual inflation to the 1997 actual delivered cost of spot coal purchases for Stanton Energy Center.

1A.3.2.2 No. 6 and No. 2 Oil Price Forecasts

The fuel price forecasts for No. 2 and No. 6 oil were developed based on the actual average delivered cost of No. 2 and No. 6 oil for Florida from the Energy Information Administration (EIA) Cost and Quality of Fuels and Standard and Poor's Analysis of Utility Fuel Prices in the South Atlantic Region by DRI. The DRI distillate fuel price forecast was converted to 1996 dollars using DRI's implicit price deflator listed in Table 1A.3-4. The delivered cost forecasts of No. 2 and No. 6 oil were developed by applying the resulting DRI real, annual distillate price escalation in 1996 dollars plus a 2.5 percent annual inflation rate to the 1997 Florida average delivered cost of No. 2 and No. 6 oil.



Table 1A.3-1
Delivered Fuel Price Forecast--Base Case
(\$/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas ¹
1998	1.70	2.68	4.47	0.55	2.39
1999	1.71	2.66	4.45	0.56	2.31
2000	1.74	2.75	4.59	0.57	2.22
2001	1.77	2.89	4.82	0.59	2.25
2002	1.81	3.03	5.05	0.60	2.38
2003	1.86	3.16	5.28	0.62	2.46
2004	1.90	3.31	5.52	0.63	2.53
2005	1.93	3.49	5.82	0.65	2.61
2006	1.97	3.65	6.09	0.67	2.70
2007	2.02	3.82	6.37	0.68	2.79
2008	2.06	4.00	6.68	0.70	2.92
2009	2.10	4.18	6.99	0.72	3.02
2010	2.15	4.36	7.29	0.73	3.17
2011	2.20	4.57	7.63	0.75	3.32
2012	2.23	4.78	7.98	0.77	3.45
2013	2.29	5.00	8.34	0.79	3.59
2014	2.34	5.23	8.72	0.81	3.77
2015	2.40	5.46	9.12	0.83	3.92
2016	2.46	5.70	9.52	0.85	4.09
2017	2.51	5.97	9.96	0.87	4.30

(1) Sum of commodity price, fuel charge, GRI demand surcharge, commodity charge, GRI commodity charge, AGA surcharge, unit fuel surcharge, and FGU service charge.



Table 1A.3-2
Delivered Fuel Price Forecast--Low Case
(\$/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas ¹
1998	1.64	2.58	4.30	0.53	2.30
1999	1.62	2.51	4.19	0.53	2.19
2000	1.61	2.54	4.24	0.53	2.06
2001	1.60	2.62	4.37	0.53	2.05
2002	1.61	2.69	4.49	0.54	2.13
2003	1.62	2.75	4.60	0.54	2.17
2004	1.62	2.83	4.72	0.54	2.21
2005	1.62	2.92	4.87	0.54	2.20
2006	1.62	3.00	5.00	0.55	2.25
2007	1.62	3.07	5.13	0.55	2.27
2008	1.63	3.16	5.27	0.55	2.34
2009	1.63	3.24	5.41	0.55	2.38
2010	1.63	3.31	5.53	0.56	2.44
2011	1.64	3.40	5.68	0.56	2.52
2012	1.63	3.49	5.82	0.56	2.56
2013	1.64	3.58	5.97	0.57	2.62
2014	1.64	3.67	6.12	0.57	2.70
2015	1.65	3.76	6.27	0.57	2.76
2016	1.66	3.85	6.42	0.57	2.82
2017	1.66	3.94	6.58	0.58	2.91

(1) Sum of commodity price, fuel charge, GRI demand surcharge, commodity charge, GRI commodity charge, AGA surcharge, unit fuel surcharge, and FGU service charge.



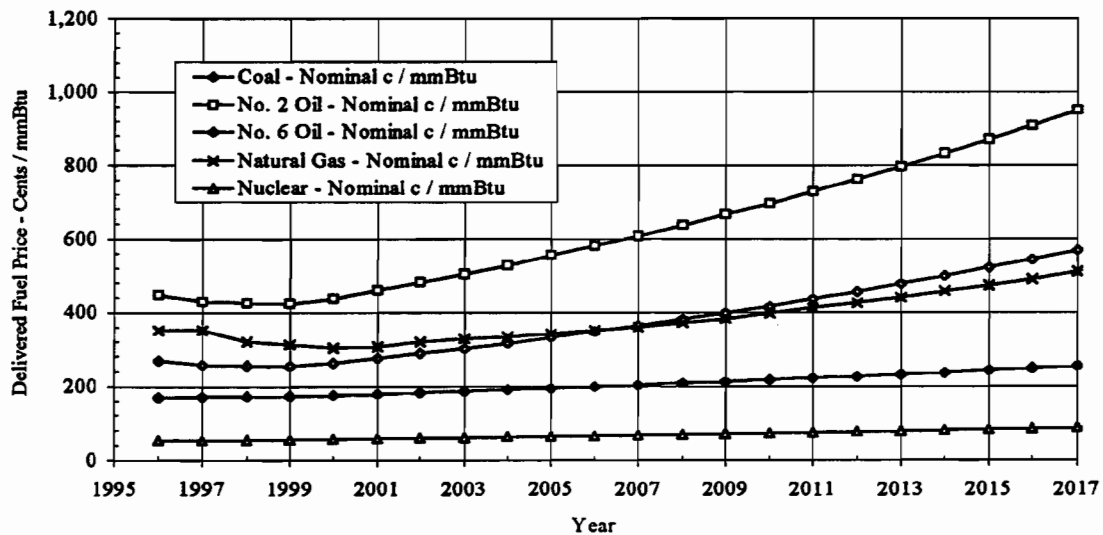
Table 1A.3-3
Delivered Fuel Price Forecast--High Case
(\$/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas ¹
1998	1.77	2.78	4.65	0.57	2.48
1999	1.82	2.82	4.71	0.59	2.45
2000	1.88	2.97	4.96	0.62	2.38
2001	1.95	3.18	5.31	0.65	2.46
2002	2.04	3.40	5.68	0.68	2.66
2003	2.12	3.62	6.04	0.71	2.81
2004	2.21	3.86	6.44	0.74	2.97
2005	2.30	4.15	6.93	0.77	3.07
2006	2.39	4.43	7.39	0.81	3.26
2007	2.49	4.72	7.88	0.84	3.41
2008	2.60	5.04	8.42	0.88	3.64
2009	2.70	5.38	8.98	0.92	3.85
2010	2.82	5.72	9.55	0.96	4.10
2011	2.94	6.11	10.20	1.01	4.39
2012	3.04	6.51	10.87	1.05	4.64
2013	3.18	6.94	11.59	1.10	4.93
2014	3.31	7.40	12.35	1.15	5.26
2015	3.47	7.88	13.16	1.20	5.59
2016	3.62	8.40	14.01	1.25	5.93
2017	3.77	8.95	14.94	1.31	6.35

(1) Sum of commodity price, fuel charge, GRI demand surcharge, commodity charge, GRI commodity charge, AGA surcharge, unit fuel surcharge, and FGU service charge.



Fuel Price Forecast Nominal Values



Historical Spot and Forecast Natural Gas Prices

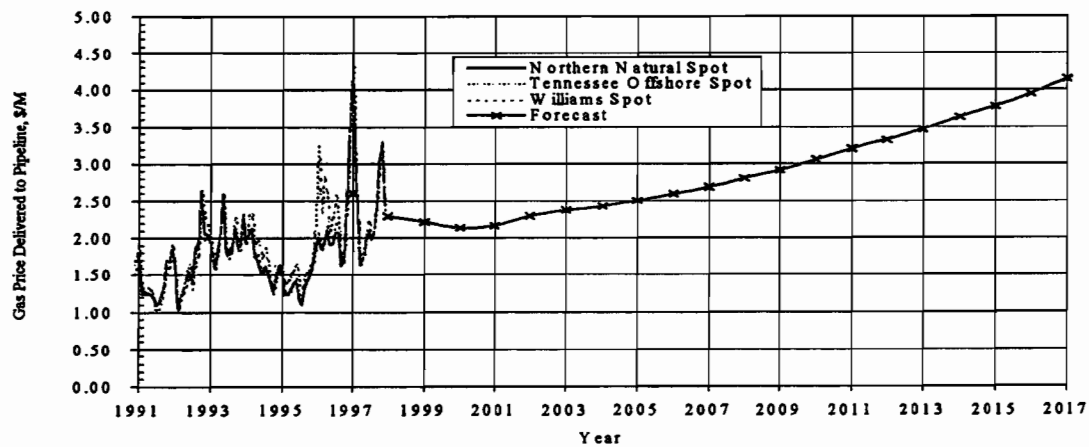
Historical and Forecast Fuel Prices
Figure 1A.3-1



Table 1A.3-4
DRI Implicit Price Deflator

Year	1992 Base	1996 Base	Annual Increase
1997	1.125	1.021	2.1
1998	1.151	1.044	2.3
1999	1.178	1.069	2.4
2000	1.207	1.095	2.5
2001	1.238	1.123	2.6
2002	1.271	1.153	2.6
2003	1.304	1.184	2.7
2004	1.340	1.216	2.7
2005	1.379	1.251	2.9
2006	1.419	1.288	3.0
2007	1.462	1.327	3.0
2008	1.507	1.368	3.1
2009	1.555	1.411	3.1
2010	1.605	1.458	3.2
2011	1.659	1.506	3.4
2012	1.718	1.557	3.4
2013	1.775	1.610	3.4
2014	1.837	1.667	3.5
2015	1.902	1.725	3.5
2016	1.970	1.788	3.6
2017	2.041	1.852	3.6



1A.3.2.3 Natural Gas Price Forecast

1A.3.2.3.1 Commodity. The natural gas commodity price forecast was developed based on Standard & Poor's Analysis of Utility Fuel Prices in the South Atlantic Region by DRI. DRI's gas price forecast is based upon normal weather, which, in combination with adequate storage and a normal output from nuclear stations, predicts moderate short-term prices. The DRI values for Henry Hub and Gulf Coast spot prices for natural gas delivered to pipelines were averaged and converted to 1996 dollars using DRI's implicit price deflator listed in Table 1A.3-4. The final commodity cost was developed by applying the resulting DRI real, annual natural gas price escalation in 1996 dollars plus 2.5 percent annual inflation rate to the average spot prices.

1A.3.2.3.2 Transportation. Natural gas transportation in Florida is supplied by Florida Gas Transmission Company (FGT). Details of FGT's system are presented in Section 1A.3.3. Natural gas transportation from FGT is supplied under two tariffs, FTS-1 and FTS-2. Rates for FTS-2 are based on FGT's Phase III expansion while rates for FTS-1 are based on the Phase II expansion. As discussed in Section 1A.3.3, the Phase III expansion was extensive and rates for FTS-2 transportation are significantly higher than for FTS-1. The Phase IV expansion will be less extensive and thus, transportation rates should be lower. While it is anticipated that Phase IV rates may be lower, the cost for the Phase IV expansion may be rolled in with the Phase III costs, and the resultant rate may not be significantly less than the current Phase III rates.

For purposes of projecting delivered gas prices, for new units it is assumed that the current Phase III transportation rates will apply. Table 1A.3-5 presents the delivered natural gas price forecast based on current FTS-2 rates. Actual rates for natural gas transportation should be less than these. However, for evaluation purposes, this forecast will be used for natural gas for new units.

Both KUA and FMPA are members of Florida Gas Utility (FGU) which is an organization of municipal utilities which manages and schedules member's transportation entitlements and purchases gas for members. The small FGU service charge is included in the forecast in Table 1A.3-5.

Table 1A.3-5
Natural Gas Price Forecast (\$/MBtu)

Year	Henry Hub	Gulf Coast	Average	Implicit Price Deflator	Deflated \$1996	General Inflation 2.5%	Fuel Charge 3.05%	Demand Reservation	GRI Demand Surcharge	Commodity Charge	GRI Commodity Charge	AGA Surcharge	Unit Fuel Surcharge	FGU Service Charge	Delivered Price
1997	2.60	2.49	2.55	1.02	2.49	2.55	0.08	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.51
1998	2.28	2.19	2.24	1.04	2.14	2.25	0.07	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.20
1999	2.20	2.11	2.16	1.07	2.02	2.17	0.07	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.12
2000	2.12	2.03	2.08	1.10	1.89	2.09	0.07	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.03
2001	2.14	2.06	2.10	1.12	1.87	2.12	0.07	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.06
2002	2.28	2.19	2.24	1.15	1.94	2.25	0.07	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.19
2003	2.36	2.27	2.32	1.18	1.96	2.32	0.07	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.27
2004	2.42	2.34	2.38	1.22	1.96	2.38	0.08	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.34
2005	2.51	2.43	2.47	1.25	1.97	2.47	0.08	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.42
2006	2.61	2.53	2.57	1.29	2.00	2.55	0.08	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.51
2007	2.71	2.63	2.67	1.33	2.01	2.64	0.08	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.60
2008	2.85	2.77	2.81	1.37	2.05	2.76	0.09	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.73
2009	2.97	2.89	2.93	1.41	2.08	2.86	0.09	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.83
2010	3.15	3.07	3.11	1.46	2.13	3.01	0.09	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.98
2011	3.32	3.24	3.28	1.51	2.18	3.15	0.10	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.13
2012	3.48	3.41	3.45	1.56	2.21	3.28	0.10	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.26
2013	3.66	3.58	3.62	1.61	2.25	3.42	0.11	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.40
2014	3.88	3.80	3.84	1.67	2.30	3.59	0.11	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.58
2015	4.07	3.99	4.03	1.73	2.34	3.73	0.12	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.73
2016	4.30	4.22	4.26	1.79	2.38	3.90	0.12	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.90
2017	4.57	4.48	4.53	1.85	2.44	4.10	0.13	0.8072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	5.11

Notes:

Forecast data is based on Standard & Poor's DRI "Analysis of Utility Fuel Prices in the South Atlantic Region," September, 1997. Implicit Price Deflator from DRI.



1A.3.2.4 Nuclear Fuel Price Forecast

The nuclear fuel price projection is based on the average of the 1996 fuel price for the St. Lucie and Crystal River Nuclear Plants from the Resource Data Institute (RDI) POWERdat database escalated at the underlying general inflation rate of 2.5 percent.

1A.3.3 Fuel Availability

DRI projects that natural gas supply increases are expected to be adequate to possibly excessive by 2000. This is because (1) reserve additions have exceeded production during the past 2 years in the United States and, (2) by 2000, pipeline capacity additions of 5 to 10 Bcf/day from Canada, the Rocky Mountains, and the deep Gulf of Mexico are expected to create a "gas-bubble" even though gas demand is projected to grow by up to 7 Bcf/day. Gas prices are expected to weaken as new supply sources are added to the US market. DRI predicts swift demand growth acting to absorb the new supplies and gas markets permitting a return to a better balance after 2000. DRI expects demand growth for 1997 to 2000 to average about 1.9 Bcf/day per year.

1A.3.3.1 Florida Gas Transmission Company

Florida Gas Transmission Company (FGT) is an open access interstate pipeline company transporting natural gas for third parties through its 5,000 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation, which in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and Sonat, Inc., one of the largest independent producers of natural gas in the United States.

The FGT pipeline system accesses a diversity of natural gas supply regions including:

- Permian Area (West Texas and New Mexico).
- Anadarko Basin (Texas, Oklahoma and Kansas).
- Fort Worth and East Texas Basins.
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana - Mississippi - Alabama Salt Basin.
- Mobile Bay.



FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 14 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

1A.3.3.2 Florida Gas Transmission Market Area Pipeline System

The FGT multiple pipeline system corridor enters the Florida panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

1A.3.3.3 Service to Cane Island Power Park

The Cane Island Power Park is served from an existing FGT system delivery point on the St. Petersburg Lateral located in Section 26, T25S, R27E in northwestern Osceola County. From the custody metering installation at the delivery point, the lateral pipeline (the Cane Island Lateral) runs south and then easterly to service the existing generation facilities at the Cane Island site. The Cane Island Lateral is a 20 inch diameter pipeline capable of providing maximum design basis hourly volumes, as limited by the design of the delivery point metering station, of up to 10,000 MBtu per hour, assuming maximum operating pressure in the St. Petersburg Lateral of 975 psig.

The Cane Island Lateral completed in 1993 is sized for the supply of natural gas at the ultimate plant development level (approximately 1,000 MW of combined cycle capacity) of the Cane Island site. However, subsequent to the completion of the lateral pipeline, a tap off



serving the Intercession City Plant of Florida Power Corporation (FPC) has been completed from the Cane Island Lateral. This sublateral, installed in 1996, is an 8 inch diameter pipeline with an estimated flow capacity of 20 to 30 million cubic feet per day at present-day FGT mainline operating pressures. Under the contractual arrangements between KUA and FPC, the service to the Intercession City Plant is on an "as available" basis and is interruptible should KUA and FMFA require the gas supply for operation of the Cane Island facilities.

The existing infrastructure of the FGT system following completion of the Phase III expansion in February 1995 allows the flexibility to accommodate a certain amount of capacity expansion by an increase of mainline compression with minor looping of lines to alleviate bottlenecks. This expansion will be accomplished as part of the FGT Phase IV expansion program discussed below.

1A.3.3.4 Florida Gas Transmission Phase IV Expansion

On August 15, 1997, FGT initiated an "open season" for a proposed expansion of mainline transmission capability to serve new markets.* This initiative was structured to gauge potential demand for the prospective FGT Phase IV expansion project with an estimated in-service date of late 1999 or early 2000; however, depending upon market needs, it was indicated that a phased-in expansion at earlier dates may be possible.

FGT has indicated that the responses received from the August-September 1997 open season were not deemed to be firm and accurate to justify the formal implementation of the Phase IV expansion of the FGT system at that time. However, FGT continues to receive inquiries and hopes to formally file for Federal Energy Regulatory Commission (FERC) approvals of the Phase IV expansion program in late 1998 as requests for additional transmission services are firmed up. Under present planning scenarios, it is envisioned by FGT that this expansion will primarily consist of additional compression capability installed

*The term "open season" refers to the industry practice of conducting a survey of future market demands for transport of natural gas prior to the design and construction of new line construction or expansion projects on existing pipeline systems. The open-market survey is employed to "test the market" by requesting that potential shippers submit non-binding expressions of interest or requests for new or additional (incremental) firm transmission services or, in some cases, for the relinquishment from existing shippers of firm transmission capacity. This process allows the pipeline developer to ascertain the need for, the extent and nature of pipeline capacity expansion capacity volumes and the overall economic feasibility of the proposed project. The open season is conducted under defined ground rules to assure the integrity of the shipper's submissions and the non-discriminatory analysis of the responses.



in the Panhandle and West Leg portions of the pipeline system and line extensions of existing lateral branchlines. Looping of existing corridors to alleviate capacity constraints is not projected as being extensive. The Phase IV expansion of the FGT system should therefore be capable of implementation at a relatively low incremental cost impact to existing and prospective customers.

1A.3.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida

Over the years a number of alternative schemes for pipeline delivery of natural gas to Peninsular Florida have been proposed to provide competition to the existing FGT system. The most notable of these initiatives is the "SunShine System" pipeline, proposed in 1993 by SunShine Pipeline Partners, a subsidiary of the Coastal Corporation, to provide natural gas from an interconnection to existing pipelines from Texas-Louisiana Gulf Coast production regions and from onshore gas processing plants located in the Mobile Bay production region. The interstate portion of the proposed system comprised approximately 143 miles of new pipeline extending from near Pascagoula, Mississippi, to delivery points in Escambia and Okaloosa Counties, Florida. A separate proposed intrastate pipeline extended from the Okaloosa delivery point eastward and then southward for a distance of about 502 miles to terminate at the Florida Power Corporation's Hines Energy Complex site northwest of Fort Meade (Polk County), Florida. The project included a 27 mile lateral line to enable deliveries to customers in the Pensacola (Escambia County) area.

The primary customer of the project was to have been Florida Power Corporation (FPC) which acquired an equity position and firm transport conditional commitment in the pipeline (January and February 1993). The project subsequently received preliminary (non-environmental) approvals for the intrastate and interstate pipelines from the Florida Public Service Commission and FERC, respectively.

The competitive threat to the established pipeline system was countered by FGT which reached agreement with FPC for gas transmission via the expanded FGT system. FPC subsequently withdrew as an equity partner in the SunShine Project (September 1994) and terminated the agreements for firm transmission service (February 1995). The project was canceled in April 1995.



The successor to the SunShine pipeline is the "Gulf Stream" pipeline which is also being promoted by the Coastal Corporation and ANR Pipeline. This pipeline would also originate in the Mobile Bay region, cross the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay) to service existing and prospective electric generation and industrial projects in south Florida. This project is in the development stage with the prognosis for ultimate completion uncertain. In any case, the proposed routing of the pipeline across peninsular Florida would appear to be too far to the south to provide economic service to the Cane Island site. Another proposal by Williams-Transco is also in the initial stage of development.

1A.3.3.6 Natural Gas Supply at the Cane Island Site

Based on discussions with FGT, the natural gas supply at the delivery point to the Cane Island lateral will be fully adequate in terms of quantity and delivery pressure to support the Cane Island Unit 3 facilities. In addition, natural gas transportation is sufficient to support the fuel requirements of the proposed Cane Island Unit 3 facilities.



1A.4.0 Consistency With Peninsular Florida Needs

The Florida Reliability Coordinating Council (FRCC) is the North American Reliability Council (NERC) Coordinating Council responsible for coordinating power supply reliability in Peninsular Florida. As part of their reliability coordination activities, the FRCC provides an annual summary and report of Peninsular Florida Ten-Year Site Plans. The annual summary is then analyzed by PSC staff and utility members during annual workshops. The most recent planning summary conducted by FRCC is the, "1997 Ten-Year Plan State of Florida." Published during 1997, this Ten-Year Plan summarizes utility loads and resources, by type of capacity, through the year 2006. The summary also includes utility load forecast data and proposed generation expansion plans, retirements, and capacity re-rates. The following sections summarize the results of FRCC's reliability analysis in the determination of future capacity requirements for Peninsular Florida.

1A.4.1 Peninsular Florida Capacity and Reliability Needs

Table 1A.4-1 presents the peak demand and available capacity for Peninsular Florida for summer and winter as presented in the 1997 Ten-Year Plan State of Florida. The available capacity consists of existing capacity, capacity which has been certified under the Florida Electrical Power Plant Siting Act, and proposed capacity changes not requiring certification under the Florida Electrical Power Plant Siting Act as presented in the 1997 Ten-Year Plan State of Florida. Figures 1A.4-1 and 1A.4-2 present peak demands and available capacity from Table 1A.4-1 in graphical form.

Table 1A.4-1 indicates that 689 MW of additional capacity is required in the winter for Peninsular Florida to maintain a 15 percent reserve margin beginning in 2000/01 and increasing to 4,808 MW by 2006/07. Additional capacity is required beginning in 2003 to maintain 15 percent reserve margin in the summer. Both needs are based on full load reductions for load management and interruptible load being implemented.

Cane Island Unit 3's capacity will help contribute to alleviating the capacity shortfall in Peninsular Florida and improve reliability beginning with its commercial operation on June 1, 2001.

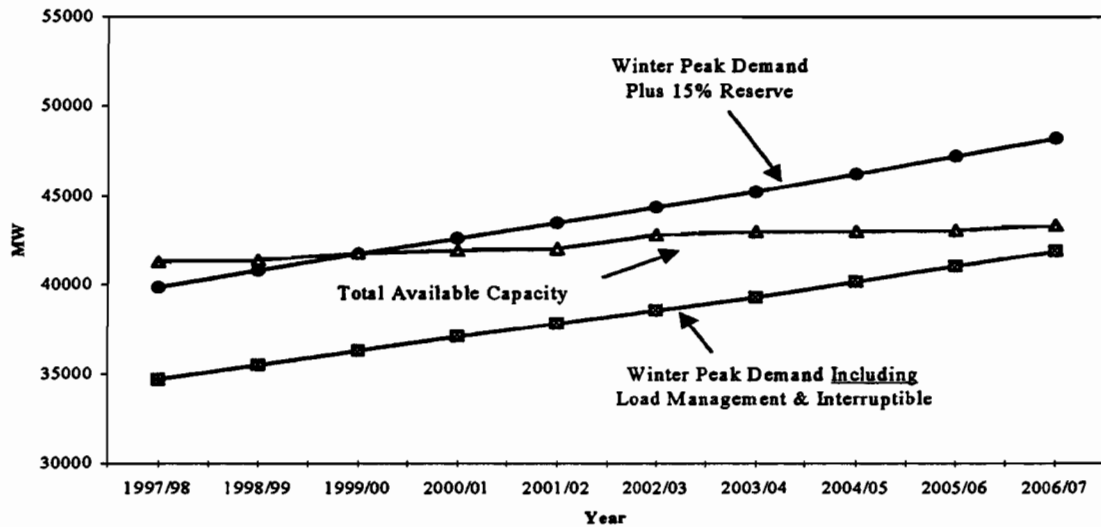


Table 1A.4-1
Peninsular Florida Peak Demand and Available Capacity

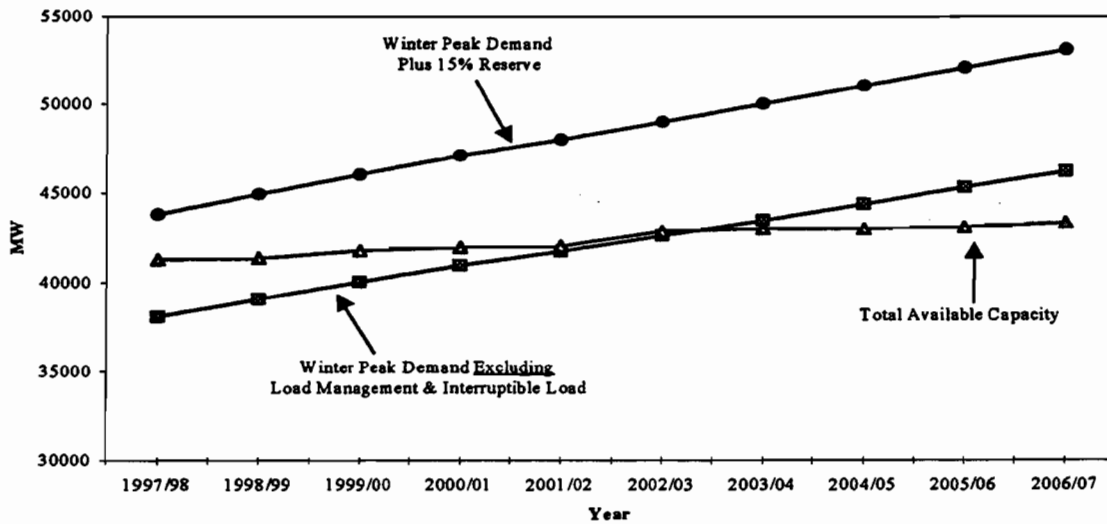
10 Year Plan Summer Peak Demand														
Calendar Year	Installed Capacity (MW)	Capacity Changes Not Requiring FPSA (MW)	Contracted Firm Interchange (net import) (MW)	Projected Firm Net to Grid from NUG (MW)	Total Available Capacity (MW)	Total Peak Demand (MW)	Reserve Margin w/o Exercising Load Management and Int.		Load Management (MW)	Interruptible Load (MW)	Firm Peak Demand (MW)	Reserve Margin with Exercising Load Management & Int.		Additional Required for 15% Reserves (MW)
							(MW)	% of peak				(MW)	% of peak	
1997	35110	60	1300	2416	38886	34566	4320	12.5%	1539	1159	31868	7018	22.0%	-
1998	35170	21	1311	2416	38918	35643	3275	9.2%	1629	1187	32826	6092	18.6%	-
1999	35191	325	1626	2531	39673	36172	3501	9.7%	1726	1241	33205	6468	19.5%	-
2000	35516	211	1714	2531	39972	37079	2893	7.8%	1823	1251	34005	5967	17.5%	-
2001	35727	64	1677	2531	39999	37894	2105	5.6%	1924	1232	34738	5261	15.1%	-
2002	35791	733	1666	2531	40721	38530	2191	5.7%	2010	1170	35350	5371	15.2%	-
2003	36524	224	1678	2531	40957	39197	1760	4.5%	2103	1168	35926	5031	14.0%	358
2004	36748	-9	1596	2531	40866	39891	975	2.4%	2162	1169	36559	4307	11.8%	1177
2005	36739	230	1607	2531	41107	40697	410	1.0%	2194	1163	37341	3766	10.1%	1835
2006	36969	275	1518	2531	41293	41386	-93	-0.2%	2224	1158	38003	3290	8.7%	2410
10 Year Plan Winter Peak Demand														
Calendar Year	Installed Capacity (MW)	Capacity Changes Not Requiring FPSA (MW)	Contracted Firm Interchange (net import) (MW)	Projected Firm Net to Grid from NUG (MW)	Total Available Capacity (MW)	Total Peak Demand (MW)	Reserve Margin w/o Exercising Load Management and Int.		Load Management (MW)	Interruptible Load (MW)	Firm Peak Demand (MW)	Reserve Margin with Exercising Load Management & Int.		Additional Required for 15% Reserves (MW)
							(MW)	% of peak				(MW)	% of peak	
1997/98	36907	173	1723	2479	41282	38090	3192	8.4%	2281	1159	34650	6632	19.1%	-
1998/99	37080	18	1725	2554	41377	39091	2286	5.8%	2402	1210	35479	5898	16.6%	-
1999/00	37098	358	1728	2594	41778	40026	1752	4.4%	2533	1217	36276	5502	15.2%	-
2000/01	37456	236	1653	2594	41939	40962	977	2.4%	2658	1235	37068	4871	13.1%	689
2001/02	37692	80	1666	2594	42032	41737	295	0.7%	2773	1152	37812	4220	11.2%	1452
2002/03	37772	799	1655	2594	42820	42588	232	0.5%	2892	1147	38550	4270	11.1%	1513
2003/04	38571	256	1586	2594	43007	43467	-460	-1.1%	2996	1158	39313	3694	9.4%	2203
2004/05	38827	-13	1596	2594	43004	44374	-1370	-3.1%	3056	1145	40173	2831	7.0%	3195
2005/06	38814	156	1518	2594	43082	45304	-2222	-4.9%	3116	1140	41047	2035	5.0%	4122
2006/07	38970	275	1518	2594	43357	46188	-2831	-6.1%	3168	1137	41883	1474	3.5%	4808



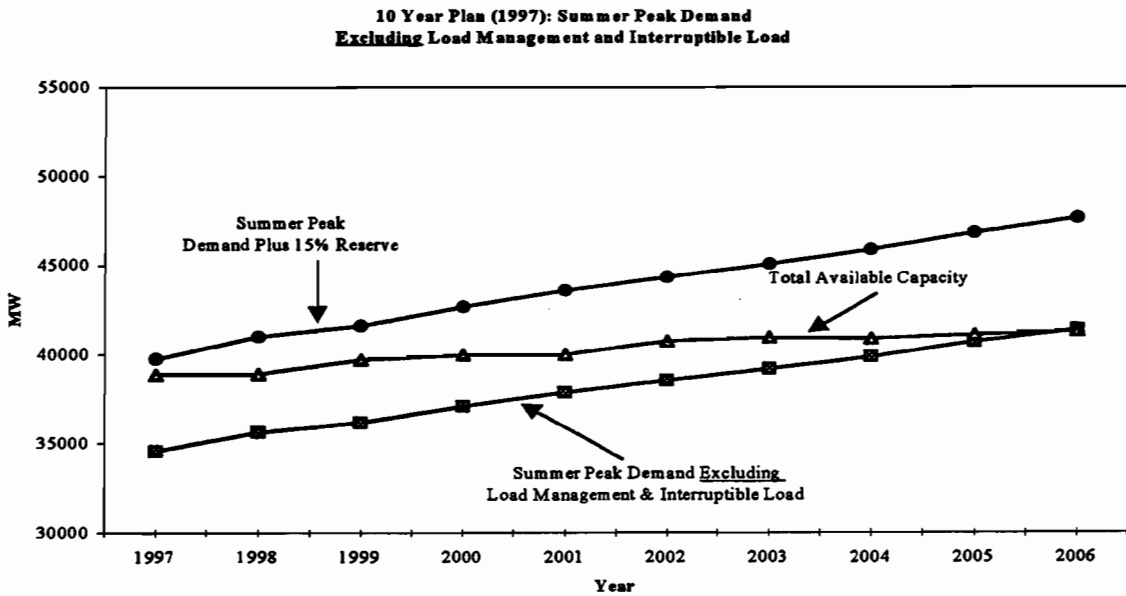
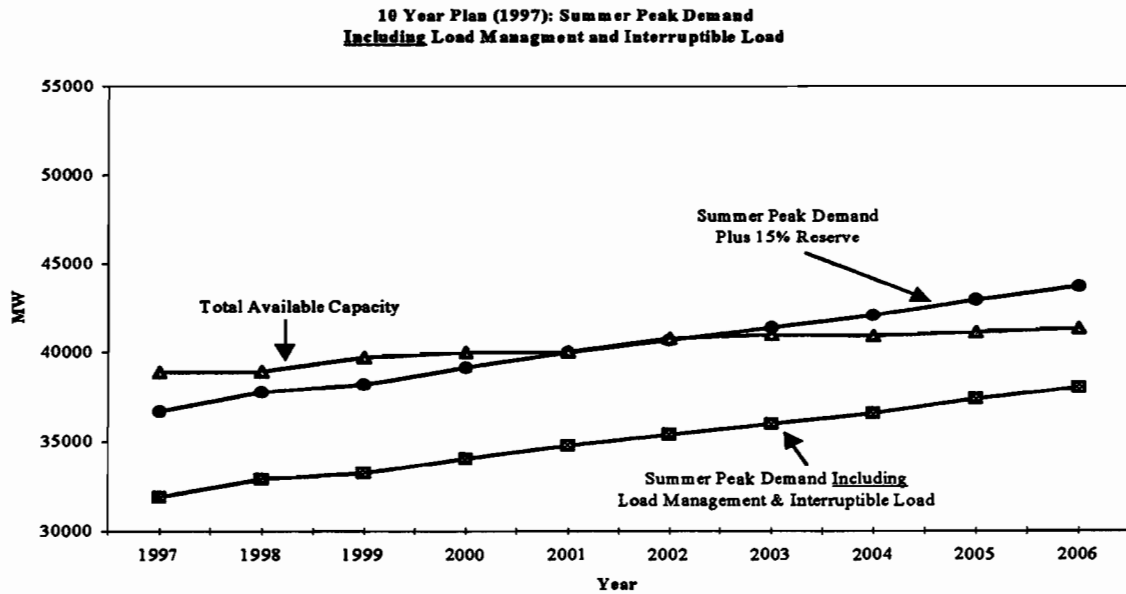
**10 Year Plan (1997): Winter Peak Demand
Including Load Management and Interruptible Load**



**10 Year Plan (1997): Winter Peak Demand
Excluding Load Management and Interruptible Load**



Peninsular Florida Capacity Reserves (Winter)
Figure 1A.4-1



Peninsular Florida Capacity Reserves (Summer)
Figure 1A.4-2



1A.5.0 Demand-Side Programs

Both KUA and FMPA consider conservation and demand-side management (DSM) an integral component in managing the efficiency of their electric systems and providing choice to their customers. Conservation and demand-side management programs for FMPA are generally administered by the individual All-Requirements Project member. Conservation programs were originally established under the Florida Energy Efficiency and Conservation Act (FEECA). Although neither KUA nor any of FMPA's All-Requirements Project members are currently classified as FEECA utilities, KUA and FMPA both are committed to conservation and load management programs.

Chapter 366.82, Fl. Stat. requires the Public Service Commission (PSC) to review and approve cost-effective utility conservation programs. In 1995, KUA performed a cost-effectiveness analysis for over 70 proposed DSM measures and submitted the results to the Public Service Commission (PSC). The results of the analysis indicated that DSM measures were not cost-effective. FMPA also regularly evaluates potential DSM programs to identify any which may call for implementation. In order to ensure their DSM program evaluations were current for this site certification, KUA and FMPA performed a new cost-effectiveness analysis using Cane Island 3 as the avoided unit of approximately 70 DSM programs using the Florida Integrated Resource Evaluator (FIRE). FIRE was originally developed by Florida Power Corporation. The results of the new analysis did not indicate any cost-effective DSM measures. More detailed discussion of the DSM penetration and existing conservation programs in place for KUA and FMPA are provided in Sections 1B.6.0 and 1C.6.0, respectively.

1A.5.1 Florida Integrated Resource Evaluator (FIRE) Results

The Florida Integrated Resource Evaluator uses avoided unit costs, DSM program costs, operations and maintenance costs, rebates/incentives and other input variables to calculate the incremental costs and incremental benefits of a DSM program. These incremental costs are used to perform three cost-effectiveness tests: the Rate Impact Test, the Total Resources Test, and the Participant Test. The DSM programs reviewed are listed in Table 1A.5-1, along with the results of the FIRE analysis.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Table 1A.5-1
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
New Construction				
RSC-1	High Efficiency Air Source Heat Pump	0.36	0.24	0.56
RSC-8A	Load Control for Residential Heat	0.00	0.01	8.61
RSC-8B	Load Control for Residential Heat	0.01	0.02	8.66
RSC-21A	High Efficiency Central AC	0.25	0.18	0.60
RSC-26A	DLC of Central AC	-0.30	-0.66	1.00
RSC-26B	DLC of Central AC	-0.30	-0.66	1.00
WH-10	DLC of Electric Water Heater	-0.22	-0.49	1.00
PP-3	DLC of Pool Pumps	-0.71	-0.72	1.00
SC-D-1	High Efficiency Chiller	0.62	9.99	28.50
SC-D-2	High Efficiency Chiller w/ASD	0.72	1.94	2.83
V-D-8	High Efficiency Motors - Chiller	0.40	1.47	8.92
V-D-9	High Efficiency Motors - DX AC	0.43	1.59	8.95
L-D-25	Compact Fluorescent Lamps (15/18/27W)	0.70	0.55	0.00
L-D-26	Two Lamp Compact Fluorescent (18W)	0.69	0.58	0.00
W-D-13	Heat Recovery Water Heater	0.57	1.44	3.28
C-D-19	Energy Efficient Electric Fryers	-0.07	-0.09	4.40
Existing Construction				
RSC-1	High Efficiency Air Source Heat Pump	0.35	0.25	0.60
RSC-5A	Reduced Duct Leakage	0.23	0.35	2.16
RSC-5B	Reduced Duct Leakage	0.23	0.35	2.16
RSC-8A	Load Control for Residential Heat	0.01	0.01	8.62
RSC-8B	Load Control for Residential Heat	0.01	0.01	8.62
RSC-10A	Ceiling Insulation (R0-R19)	0.42	0.51	1.37

Table 1A.5-1 (Continued)
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
RSC-10B	Ceiling Insulation (R0-R19)	0.40	0.46	1.27
RSC-11A	Ceiling Insulation (R11-R30)	0.32	0.26	0.65
RSC-11B	Ceiling Insulation (R11-R30)	0.25	0.18	0.49
RSC-17A	Low Emissivity	0.05	0.02	0.30
RSC-21A	High Efficiency Central AC	0.31	0.25	0.72
RSC-24A	High Efficiency Room AC	-0.05	-0.05	0.88
RSC-26A	DLC of Central AC	-0.49	-1.05	1.00
RSC-26B	DLC of Central AC	-0.29	-0.72	1.00
WH-7	DHW Pipe Insulation	0.05	0.05	1.00
WH-10	DLC of Electric Water Heater	-0.22	-0.49	1.00
PP-1	High Efficiency Pool Pumps	0.25	0.35	4.48
PP-3	DLC of Pool Pumps	-0.67	-0.69	1.00
SC-D-1	High Efficiency Chiller	0.65	10.03	27.29
SC-D-2	High Efficiency Chiller w/ASD	0.73	1.91	2.76
SC-D-4	High Efficiency Room AC Units	0.82	10.91	15.13
SC-D-8	2-Speed Motor for Cooling Tower	-0.22	-2.55	56.03
SC-D-9	Speed Control for Cooling Tower	0.72	2.31	5.03
SC-D-19	Roof Insulation - DX AC	0.17	0.56	4.75
SC-D-22	Window Film - Chiller	0.61	2.59	5.04
SC-D-23	Window Film - DX AC	0.47	1.48	3.70
V-D-1	Leak Free Ducts - DX AC	0.55	1.84	4.46
V-D-8	High Efficiency Motors - Chillers	0.58	1.56	6.01
V-D-9	High Efficiency Motors - DX AC	0.58	1.56	6.04
V-D-10	Separate Makeup Air/Exhaust Hoods - Chiller	0.53	0.03	0.05
V-D-11	Separate Makeup Air/Exhaust Hoods - DX AC	0.41	0.02	0.04

Table 1A.5-1 (Continued)
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
L-D-1	4' - 34W Flour. Lamps/Hybrid Ballasts (#1)	0.69	3.14	0.02
L-D-3	4' - 34W Flour. Lamps/Electronic Ballasts (#1)	0.68	2.56	0.02
L-D-5	8' - 60W Flour. Lamps/Electronic Ballasts (#1)	0.63	2.17	0.01
L-D-7	T8 Lamps/Electronic Ballasts (#1)	0.68	1.84	0.01
L-D-9	Refl/Delamp: Install 4' - 40W Flour. Lamps/EE Ball	0.63	4.15	0.06
L-D-10	Refl/Delamp: Install 4' - 34 and 40W Flour. Lamps/EE	0.63	3.88	0.05
L-D-11	Refl/Delamp: Install 8' - 75W Flour. Lamps/EE Ball	0.64	3.30	0.03
L-D-12	Refl/Delamp: Install 8' - 60W Flour. Lamps/EE Ball	0.63	3.16	0.03
L-D-21	High Pressure Sodium (70/100/150/250W)	0.63	0.87	0.00
L-D-23	High Pressure Sodium (35W)	0.69	0.35	0.00
L-D-25	Compact Fluorescent Lamps (15/18/27W)	0.69	0.50	0.00
L-D-26	Two Lamp Compact Fluorescent (18W)	0.63	0.23	0.00
R-D-4	Multiplex: Air-Cooled/Ambient and Mechanical Sub	0.80	1.41	0.00
R-D-5	Multiplex: Air-Cooled/External Liquid Suction HX	0.75	1.63	0.00
W-D-13	Heat Recovery Water Heater	0.57	1.43	3.29
W-D-14	DHW Heater Insulation	0.37	0.79	30.70
W-D-15	DHW Heat Trap	0.57	1.82	121.62
W-D-16	Low Flow Variable Flow Showerhead	0.52	2.44	255.52
C-D-19	Energy Efficient Electric Fryers	-0.07	-0.09	4.40



The DSM measures that correlate to the SRC codes listed in Table 1A.5-1 are based on the **Electricity Conservation and Energy Efficiency in Florida** study prepared by Synergic Resources Corporation for the Florida Energy Office.

1A.6.0 Supply-side Alternatives



1A.6.0 Supply-Side Alternatives

This Section presents a review of the conventional, advanced and renewable energy resources evaluated by KUA and FMFA as potential capacity addition alternatives. Although many technologies are not commercially viable at this time, cost and performance data were developed in as much detail as possible to provide the most accurate resource planning evaluation. In addition, due to the nature of some technologies dependence on site characteristics and resources, it is difficult to accurately estimate performance and costing information. For this reason, some of the options have been presented with a typical range for performance and cost. For most technologies, the performance and costs are based on a specified size. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy production accounts for capital, fuel, operations, and maintenance costs over the typical life expectancy of the unit, assuming municipal ownership and financing. Costs for advanced technologies and renewable energy sources are presented in 1998 dollars, and costs for conventional technologies are presented in 2001 dollars.

1A.6.1 Renewable Technologies

1A.6.1.1 Wind Energy Conversion

Wind power is growing significantly in the international market, but domestic growth in the United States has been slow. Worldwide installed wind power is over 5,000 MW, with around 1,700 MW in the U.S. Germany and India accounted for almost two-thirds of all new installations in 1996--nearly 900 MW. The U.S., on the other hand, lagged behind, adding only 41 MW of new wind capacity. In the last 10 years, the U.S. share of total world wind energy capacity has dropped from about 90 percent to 30 percent. Stagnation in the U.S. market can be attributed to the pending restructuring of the electric utility industry, which has made utility power planners hesitant to plan new capacity additions.

Utility scale wind energy systems consist of multiple wind turbines that range in size from 100 kW to 1,000 kW. Multiple turbines are used to supply the desired megawatt output. Reasonably sized installations may be 5 to 50 megawatts in size. Wind energy provides supplemental power when operating as a stand-alone resource with typical capacity factors of 15 to 40 percent, depending on wind regime in the area and energy capture characteristics



of the wind turbine. To provide a peaking resource, wind energy systems may be coupled with battery energy storage to provide power when required. Table 1A.6-1 provides wind energy characteristics for a 10 MW wind farm with average yearly wind speed of 20 miles per hour.

1A.6.1.2 Solar

Solar energy consists of capturing the sun's energy and converting it to either thermal energy (solar thermal) or electrical energy (photovoltaics). Numerous options and techniques are used for this purpose.

1A.6.1.2.1 Solar Thermal. Solar thermal systems convert solar insolation to high temperature thermal energy, usually steam, which is then used to drive heat engines, turbine/generators, or other devices for electricity generation. More than 350 MW are currently generated by commercial solar thermal plants in the U.S. Solar thermal technologies are appropriate for a wide range of intermediate and peak load applications including central power station power plants and modular power stations in both remote and grid-connected areas.

In order to achieve the high temperature needed for solar thermal systems, the sunlight is usually concentrated with mirrors or lenses. Three concentrating solar thermal collector technologies have been developed. Each is characterized by the shape of the mirrored surface on which the sunlight is concentrated. They are parabolic trough, parabolic dish, and central receiver.

A measure of solar thermal plant efficiency is the ratio of net electric output to annual solar energy received by the collector field. The amount of solar energy received is a product of annual direct normal solar radiation, in kWh/m², multiplied by the total collector area. An 80 MW parabolic trough solar thermal plant is represented in Table 1A.6-2.

1A.6.1.2.2 Photovoltaics. Photovoltaic cells convert sunlight directly into electricity by the interaction of photons and electrons within the semiconductor material. To create a photovoltaic cell, a material such as silicon is doped with atoms from an element with one more or less electrons than occurs in its matching substrate (e.g., silicon). A thin layer of each material is joined to form a junction. Photons, striking the cell, cause this mismatched electron to be dislodged, creating a current as it moves across the junction. Through a grid



Table 1A.6-1
Wind Energy Conversion
Performance and Costs

Commercial Status	Commercial
Average Wind Speed (mph)	20
Performance:	
Power Capacity (MW_{rated})	10
Power Capacity ($MW_{average}$)	3.5
Energy Production (MWh/yr)	29,127
Capacity Factor (percent)	35
Costs:	
Capital Cost ($\$/kW_{rated}$)	1,130
Capital Cost ($\$/kW_{average}$)	3,220
O&M Costs:	
Fixed O&M ($\$/kW\text{-}yr_{average}$)	31
Variable O&M ($\$/MWh_{average}$)	5.0
Levelized Cost (cents/kWh)	3.8 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-2
Solar Thermal - Parabolic Trough
Performance and Costs

Commercial Status	Commercial
Duty Cycle	Supplemental
Performance:	
Power Capacity (MW)	80
Energy Production (MWh/yr)	252,288
Capacity Factor (percent)	36
Costs:	
Capital Cost (\$/kW)	2,870 - 3,600
O&M Costs:	
Fixed O&M (\$/kW-yr)	47
Variable O&M (\$/MWh)	4.1
Levelized Cost (cents/kWh)	9.8 - 14.6 ¹

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.



of physical connections, the current is gathered. Various currents and voltages can be supplied through series and parallel arrays of cells.

The DC current produced depends on the material involved and the intensity of the solar radiation incident on the cell. Most widely used today is the single crystal silicon cell. The source silicon is highly purified and sliced into wafers from single-crystal ingots or is grown as thin crystalline sheets or ribbons. Polycrystalline cells are another alternative, which are inherently less efficient than single crystal solar cells, but also cheaper to produce. Gallium arsenide cells are among the most efficient solar cells today, with many other advantages, but are also expensive.

Another approach to producing solar cells that shows great promise is thin films. Commercial thin films today are principally made from amorphous silicon; however, copper indium diselenide and cadmium telluride also show promise as low-cost solar cells. Thin film solar cells require very little material and can be easily manufactured on a large scale. Manufacturing lends itself to automation and the fabricated cells can be flexibly sized and incorporated into building components.

Current utility grid connected photovoltaic systems are generally below 1 megawatt in size, however, several larger projects ranging from 1 megawatt to 50 megawatts have been proposed. Recently, Greece funded 5 megawatts of photovoltaic power of a 50 MW proposed plant on the island of Crete.

Numerous variations in photovoltaic cells are available such as single crystalline silicon, polycrystalline, thin film silicon, etc. and several structure concepts are available (fixed-tilt, one-axis tracking, two-axis tracking). For representative purposes a fixed-tilt, single crystalline photovoltaic system is characterized in Table 1A.6-3.

1A.6.1.3 Wood Chip

Direct wood chip combustion power plants in operation today essentially use the same steam-Rankine cycle introduced into commercial use 100 years ago. Pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to combustion in the boiler, the wood chip fuel may require some processing to improve the physical and chemical properties of the feedstock. Furnaces used in the combustion of wood chips include spreader stoker-fired, suspension-fired, fluidized bed, cyclone and pile burners.



Table 1A.6-3
Utility-Scale Photovoltaics
Performance and Costs

Commercial Status	Commercial
Module Type	Single Crystalline
Array Type	Fixed-tilt
Duty Cycle	Supplemental
Performance:	
Module Efficiency (%)	12.0
Power Capacity (MW)	10
Energy Production (MWh/yr)	17,520
Capacity Factor (percent)	20
Costs:	
Capital Cost (\$/kW _{rated})	2,000
Capital Cost (\$/kW _{average})	10,000
O&M Costs:	
Fixed O&M (\$/kW-yr _{average})	14
Variable O&M (\$/MWh _{average})	2.0
Levelized Cost (cents/kWh)	8.4 - 13.0 ¹

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.



The capacity of wood chip plants is usually less than 50 MW because of the large quantities and dispersed nature of the feedstock required. The stoker-fired grate is limited to the amount of fuel that can be handled. Wood chip plants will commonly have lower efficiencies as compared to modern coal plants. The low efficiency is due to the lower heating value and higher moisture content of the wood chip fuel compared to coal. Also, finding sufficient sources of fuel within a 100 mile radius may also limit the size of plant because of the transportation costs associated with low density wood chip fuel.

There are around 1,000 wood-fired plants in the country, with a typical size ranging from 10 to 25 MW. Only a third are operated to sell electricity, with the rest being owned and operated by the forest-products industry for self generation. Table 1A.6-4 provides typical characteristics of a 50 MW wood-fired combustion plant assuming spreader-stoker furnace technology using wet wood chips as fuel.

1A.6.1.4 Geothermal

The production of geothermal energy in the U.S. currently ranks third in renewable energy sources, following hydroelectric power and biomass energy. In the United States, the electrical-generation industry has an installed capacity of 2,900 megawatts of electricity (MWe) from geothermal energy, and direct applications have an installed capacity in excess of 2,100 thermal megawatts (MWt). Approximately 5,700 MWe are currently being generated in some 20 countries from geothermal energy, and there are 11,300 MWt of installed capacity worldwide for direct-heat applications at inlet temperatures above 95°F.

Geothermal power is limited to locations where geothermal pressure reserves are found. In the United States, most of these reserves can be found in the western portion of the country. Four types of geothermal power conversion systems are in common use. They are dry steam, single-flash, double-flash, and binary cycle power plants. No known geothermal sources are located in the state of Florida. For representative purposes a 25 MW binary-cycle power plant is characterized in Table 1A.6-5. Capital costs of geothermal facilities can vary widely as the drilling of wells can cost as much as four million dollars and the number of wells drilled depends on success of finding the resource. Variable O&M cost will also include the replacement of production wells.



Table 1A.6-4
Wood Chip Combustion
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	50
Net Plant HHV Heat Rate (Btu/kWh)	12,500 to 17,500
Energy Capacity (MWh)	260,000
Capacity Factor (percent)	60
Costs:	
Capital Cost (\$/kW)	1,450 - 1,850
O&M Costs:	
Fixed O&M (\$/kW-yr)	24 - 48
Variable O&M (\$/MWh)	4.0 - 5.0
Levelized Cost (cents/kWh)	5.8 - 11.1 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-5
Geothermal
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25
Energy Capacity (MWh)	175,200
Capacity Factor (percent)	80
Costs:	
Capital Cost (\$/kW)	2,000 - 4,000
O&M Costs:	
Fixed O&M (\$/kW-yr)	105
Variable O&M (\$/MWh)	7.2
Levelized Cost (cents/kWh)	3.4 - 12.1 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



1A.6.1.5 Hydroelectric

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable, however, construction techniques and cost have and are changing. Capital costs are highly dependent on site characteristics and may vary widely. To be able to predict performance and cost, site and river resource data would be required. Table 1A.6-6 has typical ranges for performance and cost estimates.

1A.6.2 Waste Technologies

1A.6.2.1 Refuse to Energy Conversion

There are a wide variety of refuse types that have the potential to produce energy. The use of municipal solids waste, used tires, and sewage sludge will be addressed in this section. Economic feasibility of refuse to energy facilities is difficult to assess in general. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location.

1A.6.2.1.1 MSW to Energy Conversion. Converting refuse or municipal solids waste (MSW) to energy can be accomplished by a variety of technologies. These technologies have been developed and implemented as a means of reducing the quantity of municipal and agricultural solid waste. The avoided cost of disposal is primarily what will determine if a waste to energy facility is economically feasible.

The degree of refuse processing determines the method used to convert municipal solids waste to energy. Unprocessed refuse is typically combusted in a water wall furnace (mass burning). After only limited processing to remove non-combustible and oversized items, the MSW is fed on to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. Other furnaces used in mass burning applications are refractory furnaces and rotary kiln furnaces, which use other means to transfer the heat to the steam cycle or add a mixing process to the combustion. For smaller modular units, controlled air furnaces which utilize two stage burning for more efficient combustion, can be used in mass burning applications. Table 1A.6-7 has typical ranges for performance and costs.



Table 1A.6-6
Hydroelectric
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	10 to 1,500+
Energy Capacity (MWh)	Resource dependent
Capacity Factor (percent)	Resource dependent
Costs:	
Capital Cost (\$/kW)	1,300 - 5,200
O&M Costs:	
Fixed O&M (\$/kW-yr)	10 - 30
Variable O&M (\$/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	3.3 - 6.3 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-7
Waste to Energy - Mass Burn Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	15,500
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost (\$/kW)	2,000 - 3,000
O&M Costs:	
Fixed O&M (\$/kW-yr)	100 - 150
Variable O&M (\$/MWh)	25 - 50
Levelized Cost (cents/kWh)	7.0 - 12.0 ^{1 2}
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	
(2) Excludes tipping fee credit.	



1A.6.2.1.2 RDF to Energy Conversion. Refuse Derived Fuel (RDF) is preferred in many refuse to energy applications because it can be combusted in coal fired technologies. Spreader stoker-fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been utilized to generate steam from RDF. Fluidized bed combustors are often preferred for RDF to energy applications due to their high combustion efficiency, capability to handle RDF with minimal processing, and inherent ability to effectively reduce nitrous oxides and sulfur dioxide emissions. In all boiler types the combustion temperature for MSW or RDF must be kept at a temperature less than 800°F in order to minimize boiler tube degradation due to chlorine compounds in the flue gas. Table 1A.6-8 has typical ranges for performance and costs.

1A.6.2.1.3 Landfill Gas Energy Conversion. Previously landfilled waste can be converted to energy by collecting the gases generated by the decomposition of waste in landfills. To reduce smog production and the risk of explosion, many landfills are currently required to collect the landfill gas and either flare the gas or generate energy with it. The major constituents released from landfill gas wells are carbon dioxide and methane. The methane concentration is typically around 50 percent. To convert this clean burning low Btu gas to electricity, the gas is piped from wells, filtered, compressed, and used in internal combustion engine generation sets. Depending on the scale of the gas collection facility, it may be feasible to blend this gas with natural gas and generate power via a combustion turbine generator.

In general, landfills that have over one million tons of waste in place, a waste depth greater than 40 feet, more than 30 acres available for gas recovery, and the equivalent of 25+ inches of annual precipitation are sites at which landfill gas recovery is economically feasible. In many cases the payback period of landfill gas energy facilities is between 2 and 5 years. The capital costs will be highly dependent on the conversion technology and landfill characteristics. Table 1A.6-9 has typical ranges for performance and costs.



Table 1A.6-8
Waste to Energy - RDF Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	17,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost (\$/kW)	2,500 - 3,500
O&M Costs:	
Fixed O&M (\$/kW-yr)	150 - 200
Variable O&M (\$/MWh)	25 - 50
Levelized Cost (cents/kWh)	8.0 - 13.0 ^{1 2}
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	
(2) Excludes tipping fee credit.	



Table 1A.6-9
Landfill Gas - IC Engine Unit
(Gas Collection/Processing Not Included)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500
Capacity Factor (percent)	60 - 75
Availability (percent)	93
Costs:	
Capital Cost (\$/kW)	825
O&M Costs:	
Fixed O&M (\$/kW-yr)	0.9 ¹
Variable O&M (\$/MWh)	6.7
Levelized Cost (cents/kWh)	2.0 - 4.0 ²

(1) Unstaffed site.

(2) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.



1A.6.2.2 Sewage Sludge to Energy Conversion

The disposal of sewage sludge is a significant environmental problem. The combustion of these materials in order to convert them into energy is one solution that has been proposed. Dewatered sewage sludge has a heating value of up to 7,000 Btu/lb. Typically the sludge has been co-fired with coal in a fluidized bed combustor. Some problems of fluidized bed agglomeration have been realized when utilizing large amounts of sludge. In addition to this performance problem, the low heating value of this waste has impeded the development of sludge combustion. Other waste to energy methods are currently being investigated that involve either digestion or fermentation of the sludge to produce a higher grade fuel or gas for energy conversion. There are also a number of sewage recycling methods that convert sludge to soil, fertilizer, or building materials. These applications compete with energy conversion methods.

1A.6.2.3 Used Tire to Energy Conversion

The conversion of used tires to energy via combustion is attractive due to the high heating value (15,000 - 17,000 Btu/lb) of tire derived fuel (TDF). The co-firing of TDF with coal can be done in either a cyclone or conventional stoker boiler without system modification. TDF at co-firing percentages of 2 to 10 percent has been utilized by eight utilities in the U.S. on a regular basis. In cyclone plants, the NO_x emissions and trace metal emissions have actually been reduced when burning TDF. Sulfur dioxide emissions did not change with the co-firing of TDF. On an energy basis, the cost of TDF (processed to 1 inch mesh) can be almost half that of coal. A new facility designed to co-fire TDF with coal would likely be a fluidized bed unit. Fluidized bed systems provide multi-fuel capability, in situ sulfur removal, high combustion efficiencies, and low NO_x emissions. The estimated cost and performance of a 100 MW multi-fuel (10 percent TDF co-fire) circulating fluidized bed system are shown in Table 1A.6-10. This plant has the flexibility to process MSW to RDF and co-fire up to 40 percent RDF with coal.



Table 1A.6-10
Multi-Fuel CFB
(~10 Percent TDF Co-Fire)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	11,000
TDF Tons per Day	100
Capacity Factor (percent)	60 - 75
Availability (percent)	85
Costs:	
Capital Cost (\$/kW)	1,650
O&M Costs:	
Fixed O&M (\$/kW-yr)	40
Variable O&M (\$/MWh)	3.0
Levelized Cost (cents/kWh)	4.0 - 8.0 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



1A.6.3 Advanced Technologies

1A.6.3.1 Brayton Cycles

The Brayton cycle is based on an all gas cycle that uses air and combustion gases as the working fluid, as opposed to the Rankine cycle that is a vapor cycle. Three of the Brayton cycles that are showing promise for advanced technologies and discussed below include: Humid Air cycle, Kalina cycle, and Cheng cycle.

1A.6.3.1.1 Humid Air. The humid air turbine (HAT) cycle is an intercooled, regenerative cycle burning natural gas with a saturator that adds considerable moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Table 1A.6-11 presents typical performance and cost characteristics.

1A.6.3.1.2 Kalina Cycle. The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages based on the non-isothermal boiling and condensing behavior of the working fluid's two-component mixture, coupled with the ability to alter the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters the heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger where it is heated with vapor turbine exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the high-pressure vapor turbine where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. Table 1A.6-12 presents typical performance and cost characteristics.



Table 1A.6-11
Humid Air Turbine Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost (\$/kW)	410
O&M Costs:	
Fixed O&M (\$/kW-yr)	7 - 9
Variable O&M (\$/MWh)	0.10 - 0.60
Levelized Cost (cents/kWh)	3.3 - 4.8 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-12
Kalina Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost (\$/kW)	1,025
O&M Costs:	
Fixed O&M (\$/kW-yr)	10 - 12
Variable O&M (\$/MWh)	0.1 - 0.5
Levelized Cost (cents/kWh)	4.2 - 6.3 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



1A.6.3.1.3 Cheng Cycle. The Cheng cycle, also known as the steam-injected gas turbine, increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a compressor, combustor, turbine, generator, and heat recovery steam generator (HRSG). The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

The typical application of the Cheng cycle is in a cogeneration plant where increased power can be produced during low cogeneration demand and/or peak demand periods. Several small cogeneration plants since 1984 have applied the Cheng cycle in California, Japan, Australia, and Europe. Table 1A.6-13 presents typical performance and cost characteristics.

1A.6.3.2 Advanced Coal Technologies

Coal continues to supply a large portion of the energy demand in the U.S. Current research is focused on making the conversion of energy from coal more clean and efficient. Supercritical pulverized coal boilers and pressurized fluidized bed systems are two systems that have been developed to improve coal conversion efficiency.

1A.6.3.2.1 Supercritical Pulverized Coal Boilers. New generation pulverized coal boilers can be designed at supercritical steam pressures of 3,000 to 4,500 psig, compared to the conventional 2,400 psig subcritical boilers. This increase in pressure can bring the overall efficiency of the unit from below 40 percent to nearly 45 percent. This efficiency increase coupled with the latest in emissions control technologies is expected to keep pulverized coal systems environmentally and economically competitive with other generation technologies. Table 1A.6-14 presents typical performance and cost characteristics.

1A.6.3.2.2 Pressurized Fluidized Bed Combustion. Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atm. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations PFBC exhaust is expanded to drive both the compressor and gas turbine generator. Heat recovery steam generators transfer heat from this exhaust to generate steam in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. These second generation PFBC systems are in the development stage. Table 1A.6-15 presents typical performance and cost characteristics.



Table 1A.6-13
Cheng Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost (\$/kW)	1,025
O&M Costs:	
Fixed O&M (\$/kW-yr)	12
Variable O&M (\$/MWh)	0.6
Levelized Cost (cents/kWh)	5.6 - 12.4 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-14
Supercritical Pulverized Coal Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	350 - 1,300
Net Plant Heat Rate (Btu/kWh)	9,300
Capacity Factor (percent)	60 - 75
Availability (percent)	78
Costs:	
Capital Cost (\$/kW)	1,230
O&M Costs:	
Fixed O&M (\$/kW-yr)	19 - 23
Variable O&M (\$/MWh)	3.3
Levelized Cost (cents/kWh)	3.7 - 4.7 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-15
PCFB Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	80 - 350
Net Plant Heat Rate (Btu/kWh)	8,600 (6,700 2nd generation)
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost (\$/kW)	1,330 - 2,050
O&M Costs:	
Fixed O&M (\$/kW-yr)	40 - 80
Variable O&M (\$/MWh)	3.5
Levelized Cost (cents/kWh)	3.5 - 5.8 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



1A.6.3.3 Magnetohydrodynamics

Magnetohydrodynamic (MHD) power generation converts the thermal energy of a high velocity ionized gas to electricity. Current prototypes and conceptual designs typically use the high temperature combustion of coal to produce a partially ionized flue gas which can be passed through a magnetic field. When this highly conductive plasma-like flue gas is accelerated in a nozzle and then passed through a channel perpendicular to a magnetic field an electric field is induced. To successfully ionize the flue gas the combustion temperatures must be around 5,000°F. A seed material such as potassium is added to the flue gas flow to increase gas conductivity.

An MHD system in simple cycle configuration only converts a portion of the flue gas energy to electricity. To optimize the performance of an MHD system, the energy in the hot flue gases exiting the MHD generator can be utilized to generate steam for additional power generation. This combined cycle configuration can result in an efficiency increase of 15 to 30 percent over conventional steam plant efficiencies. The overall thermal efficiency could potentially be as high as 60 percent.

Emission levels can be effectively controlled in MHD systems. NO_x levels are controlled by designing time-temperature profiles within the radiant boiler that promote the decomposition of NO_x formed in the combustion process. The potassium seed in the flue gas reacts with the sulfur compounds to produce a solid potassium sulfate. The spent seed is regenerated and converted to non-sulfur containing potassium species. Particulate emissions can be controlled by electrostatic precipitator.

Currently, MHD power generation technology is still in the development stage. Estimates on operation, performance, costs, and availability are based primarily on conceptual designs. Although variety of the individual subcomponents of this technology have been developed and tested, the operation of a fully integrated system has not been demonstrated. The driving force behind MHD combined cycle technology is improved performance; currently there is no commercial application of MHD technology that demonstrates that this improved performance is feasible. Table 1A.6-16 summarizes the characteristics of a conceptual 100 MW MHD plant. It is expected that MHD plant sizes will be 500 MW or greater for optimal economic feasibility.



Table 1A.6-16
Magnetohydrodynamic Combined Cycle Plant
Conceptual Performance and Costs

Commercial Status	Development/Conceptual
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	10,300
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost (\$/kW)	1,300 - 2,500
O&M Costs:	
Fixed O&M (\$/kW-yr)	20 - 35
Variable O&M (\$/MWh)	1.0 - 3.1
Levelized Cost (cents/kWh)	6.7 - 13.5



1A.6.3.4 Fuel Cells

Fuel cells are devices that can convert a hydrogen rich fuel directly to electricity through an electrochemical reaction. Fuel cell power systems have the capability of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Commercial stationary fuel cell plants are fueled by natural gas. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). Currently PAFC plants have efficiencies on the order of 40 percent. Fuel cells can sustain high efficiency operation even under part load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements. Current PAFC plants range from around 200 kW to 10 MW in size. PAFC cogeneration facilities can attain efficiencies approaching 85 percent when the thermal energy from the fuel cell is utilized. Also, the potential development of fuel cell/gas turbine combined cycles could reach efficiencies of 60 to 70 percent.

In addition to the potential for low heat rates and low O&M costs, the environmental benefits of fuel cell remain one of the primary reasons for commercialization. With natural gas as the fuel source, carbon dioxide and water are the only emissions. High capital costs are the primary disadvantage of fuel cell systems. These costs are expected to drop significantly in the future as development efforts continue. Fuel cell plants are typically less than 10 MW in size. The performance and costs of a 200 kW unit are shown in Table 1A.6-17.

1A.6.3.5 Fusion

Theoretically the potential for fusion power is great. Energy is released when two light nuclei such as deuterium and tritium undergo fusion to form a heavier nuclei such as helium. This new nuclei has less mass than the total of the two original nuclei, resulting in a release of energy. Large amounts of energy are released if this fusion reaction can be sustained, but fusion also has high initiation energy requirements. A temperature greater than 50 million K is required to sustain a deuterium-tritium reaction.



**Table 1A.6-17
Fuel Cell Power Plant
Performance and Costs**

Commercial Status	Commercially Available
Performance:	
Plant Capacity (MW)	0.2
Net Plant Heat Rate (Btu/kWh)	9,980
Capacity Factor (percent)	85
Costs:	
Capital Cost (\$/kW)	4,100
O&M Costs:	
Fixed O&M (\$/kW-yr)	330
Variable O&M (\$/MWh)	0.84
Levelized Cost (cents/kWh)	7.0 - 9.0 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



The concept of a fusion power plant is appealing not only because huge amounts of energy can be produced from relatively small amounts of readily available resources (water and lithium), but also because the fusion process has only a very limited impact on the environment. In contrast to fission, the fusion power plant is not likely to undergo a uncontrolled melt-down situation. The minimal amount radioactive fusion waste does not emit strong radiation during its moderate half life of approximately 12 years.

Despite the attractive possibilities of fusion, it has yet to yield a net energy output. At the current level of development, the energy required to sustain the fusion reaction is still over twice the amount produced. Recently, fusion research funding has been cut dramatically in the U.S. The Princeton Tokamak Fusion Test Reactor has been decommissioned in the spring of 1997 due to cuts in federal funding of the program. Alternative basic research on various aspects of fusion continue, and the international effort to develop a viable fusion power facility is still significant. Nonetheless, it is likely to be well into the next century before fusion develops to the point of commercial viability.

1A.6.3.6 Ocean Wave Energy

Wave energy systems convert the kinetic and potential energy contained in the natural oscillations of ocean waves into electricity. There are a variety of proposed mechanisms for the utilization of this energy source, most of which are still in the demonstration or prototype testing stage. The optimal regions for wave power applications typically occur between 40 and 60 degrees latitude, although seas that consistently experience trade winds can also produce sufficient wave energy for power applications. The potential for the utilization of wave energy is the greatest for offshore/deep wave plants, but the technical barriers and associated costs are also considerably higher. Surge devices and oscillating water column devices are the primary technologies for converting wave energy. Both types of systems convert the oscillatory flow of air or water (driven by the waves) to power via a turbine.

The technical problems of dealing with adverse sea conditions, complexity and difficulty of electricity interconnection and transmission, and low reliability have kept wave energy systems from being developed commercially. The high capital costs of such systems have deterred the implementation of wave energy systems. Table 1A.6-18 presents typical performance and cost characteristics.



Table 1A.6-18
Ocean Wave Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	0.1 - 1.0
Net Plant Heat Rate (Btu/kWh)	N/A
Capacity Factor (percent)	25
Costs:	
Capital Cost (\$/kW)	2,450
O&M Costs:	
Fixed O&M (\$/kW-yr)	50 - 103
Variable O&M (\$/MWh)	N/A
Levelized Cost (cents/kWh)	6.2 - 38.0 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



1A.6.3.7 Ocean Tidal Energy

The conversion of ocean tidal cycle energy to electricity can be done through the creation of a dam and tidal basin. By opening a sluice gate in the dam, the rising tidal waters are allowed to fill the tidal basin. At high tide these gates are closed and the tidal basin behind the dam is filled to capacity. After the ocean waters have receded, the tidal basin is released through a turbogenerator in the dam. The capacity factor of such a facility is around 24 percent. Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably from region to region. As a rule of thumb, a 16 foot tidal amplitude is considered the minimum amplitude for an energy conversion system to be considered economically feasible. In North America, the Northeast and Northwest coasts of Canada are generally considered the only regions where tidal energy plants would be economically feasible. Tidal amplitudes as high as 50 feet are experienced on the east coast of Canada in the Bay of Fundy.

Utilization of tidal energy for power generation has the environmental advantage of a zero emissions technology. At the same time, the environmental impact that the facility has on the coastline must be carefully evaluated. As with many developing technologies for energy utilization and conversion, high capital costs are the primary obstacle for widespread application. The economic viability of this option is highly dependent on the location chosen for application. Table 1A.6-19 presents typical performance and cost characteristics.

1A.6.3.8 Ocean Thermal Energy

The temperature of the ocean may differ up to 40 degrees from the surface to a depth of 3000 ft. The idea of utilizing this difference for energy production has existed for over a century. Ocean Thermal Energy Cycle (OTEC) concepts have been developed using two basic types of cycles. Closed cycle plants use a low boiling point working fluid such as ammonia. The working fluid is heated and vaporized by the warm surface water, expanded in a turbine generator, and condensed by the deep cold water. Open cycle plants use seawater as the working fluid. The warm surface water is flashed to low-pressure steam, expanded in the turbine generator, and condensed by the deep cold water.



Table 1A.6-19
Ocean Tidal Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	18 - 240
Annual Energy Capacity (GWh)	35 - 500
Capacity Factor (percent)	20 - 25
Costs:	
Capital Cost (\$/kW)	1,030 - 4,120
O&M Costs:	
Fixed O&M (\$/kW-yr)	10 - 52
Variable O&M (\$/MWh)	1.5 - 5.2
Levelized Cost (cents/kWh)	13.0 - 23.0



In OTEC systems, the relatively small temperature difference between the warm and cold thermal reservoirs and the large pumping power required combine for a very low overall system efficiency. The best potential for OTEC sites are in tropical and sub-tropical areas because of the higher temperature difference between the surface and the deep water. Although the potential of utilizing this zero emissions conversion technology is attractive, the high capital costs are expected to delay implementation. There are also some environmental questions yet to be answered regarding the effect of high pumping flow rates and local temperature changes on the surrounding aquatic environment.

OTEC systems are still in the development stage. A few 50-200 kW demonstration systems are being designed or tested in Hawaii. Due in part to the low cost of fossil fuels which makes OTEC implementation less competitive, funding for OTEC research has been limited. Currently, new heat exchanger configurations are being tested for closed cycle OTEC systems which could potentially improve performance and efficiency of OTEC systems.

1A.6.4 Energy Storage Systems

1A.6.4.1 Pumped Storage

A pumped storage hydroelectric facility requires a reservoir/dam system similar to conventional hydroelectric facility. Excess energy is used to pump water from a lower reservoir to an upper reservoir above a dam. When this energy is required, the potential energy of the water in the upper reservoir is converted to electricity as the water flows through a turbine to the lower reservoir. Capital cost is the primary consideration in implementing this storage technology. With careful planning and construction, the environmental impact of this technology will be negligible. For this study, estimates of the cost and performance of a 30 MW pumped storage system has been provided. Table 1A.6-20 presents typical performance and cost estimates.



Table 1A.6-20
Pumped Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Power Capacity (MW)	30 (5 hour duration)
Energy Capacity (MWh)	150
Capacity Factor (percent)	20
Costs:	
Capital Cost (\$/kW)	2,050
O&M Costs:	
Fixed O&M (\$/kW-yr)	28
Variable O&M (\$/MWh)	N/A
Levelized Cost (cents/kWh)	9.4 - 12.5 ¹

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.



1A.6.4.2 Battery Storage

A battery energy storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and a building to house these components. During the utility peak periods, the battery system can discharge ac power to the utility system for around 4 to 5 hours. The batteries are then recharged during nonpeak hours. In addition to the high initial cost, a battery system will require replacement every 8 to 10 years. Currently, the only commercially available battery systems are lead-acid based systems. Research to develop better performing batteries such as sodium-sulfur and zinc-bromine batteries is currently underway. Commercially available lead-acid systems have currently been installed with capacities of up to 21 MW, 140 MWh. The overall efficiency of battery systems is on average 72 percent from charge to discharge. The cost and performance of a 5 MW (15 MWh) system is provided in Table 1A.6-21.

1A.6.4.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) systems store energy in the form of compressed air in an underground cavern. Air is compressed during off-peak hours, stored in an underground cavern and then used when needed by expanding the compressed gas through a turbogeneration system. In combustion technology applications, over half the energy produced by the turbine generator is required to drive the compressors. The ability to compress the working fluid during the off-peak hours is the advantage of the CAES system. During peak hours the compressed air from the cavern is extracted and preheated in the recuperator. Once heated, the air is combusted with oil or gas and the hot exhaust is expanded through the combustion turbine. The location of a CAES plant must be suitable for cavern construction. To utilize this storage method, a new plant will typically be designed around the CAES system requirements.

The first commercial scale CAES plant in the world is a 290 MW plant in Huntorf, Germany. This plant has been operated since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility in McIntosh, Alabama, began operation. CAES units have a reputation for achieving good availability. Table 1A.6-22 shows the performance and cost characteristics of the compressed air energy storage.



Table 1A.6-21
Battery Energy Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Power Capacity (MW)	5 (3 hour duration)
Energy Capacity (MWh)	15
Capacity Factor (percent)	20
Costs:	
Capital Cost (\$/kW)	2,500
O&M Costs:	
Fixed O&M (\$/kW-yr)	13.5
Variable O&M (\$/MWh)	310 (includes replacement)
Levelized Cost (cents/kWh)	12.0 - 14.0 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



Table 1A.6-22
Compressed Air Energy Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25 - 300 MW
Availability (percent)	86
Costs:	
Capital Cost (\$/kW)	1,230
O&M Costs:	
Fixed O&M (\$/kW-yr)	8 - 20
Variable O&M (\$/MWh)	6.0 - 12.0
Levelized Cost (cents/kWh)	6.0 - 6.5 ¹
(1) California Energy Commission, <u>1996 Energy Technology Status Report</u> , adjusted to 1998 dollars.	



1A.6.4.4 Fly Wheel Energy Storage

The flywheel provides a means to store energy in the form of rotational inertia. Flywheels have a number of advantages as an energy storage device. First, compared to other storage technologies, such as lead-acid batteries or pumped storage hydro systems, they are very compact due to a high energy density (Wh/kg). They have a very long life cycle with low operating and maintenance costs. They also can transfer large amounts of energy quickly. These advantages make flywheel systems particularly advantageous to the transportation industry, where weight reduction and quick energy transfer (fast acceleration) are important parameters. Although high tech prototype flywheels can exceed 80 percent efficiency from storage to release, they are still in the research and development stage. In order for a flywheel to be economically viable for general purpose energy storage, the capital cost must be reduced, the performance must be enhanced with new materials and low friction bearings, and the motor/generator controls need to be enhanced to better utilize flywheel energy under the always changing flywheel speed. Current research is focusing on the development of magnetic bearings utilizing high temperature superconductor technology. At this point in flywheel development, the price per stored energy is significantly lower for conventional battery systems. Flywheels currently cannot compete against battery systems, particularly in the power industry.

1A.6.4.5 Super Conducting Magnetic Energy Storage

A superconducting magnetic energy storage (SMES) unit stores energy by allowing a current to pass through a "zero resistance" toroidal winding, storing the energy in a magnetic field. SMES systems for power industry storage applications are still in the research and development stage. The cost of these high tech systems must be reduced significantly before they will become commercially viable for large energy storage. Commercial SMES systems are available for eliminating power surges and dips in certain industries where elimination of these brief discontinuities is essential.

1A.6.5 Nuclear (Fission)

The environmental and safety issues (and associated costs) involved with producing power from nuclear reactors has kept new nuclear plants from being constructed in the U.S. Table 1A.6-23 provides a rough estimate of nuclear power plant costs.



Table 1A.6-23
Nuclear Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	>600 MW
Net Plant Heat Rate	10,500
Capacity Factor (percent)	65 - 80
Costs:	
Capital Cost (\$/kW)	3,300
O&M Costs:	
Fixed O&M (\$/kW-yr)	95
Variable O&M (\$/MWh)	13.0
Levelized Cost (cents/kWh)	5.8 - 15.0



1A.6.6 Conventional Technologies

Several conventional capacity addition alternatives were selected for consideration. The size of the alternatives selected considered the need for capacity and the suitability of the Cane Island site for installation of the alternatives. The alternatives considered include specific alternatives that KUA and FMPA have studied in the past as well as generic alternatives. Conventional generating unit alternatives considered for capacity expansion included the following:

- Pulverized coal.
- Fluidized bed.
- Combined cycle.
- Simple cycle combustion turbine.

Combustion turbine based alternatives were based on the size and performance of specific machines, but were not intended to limit consideration to only those machines. There are a number of combustion turbines available from different manufacturers with similar sizes and performance characteristics. The pulverized coal and fluidized bed units are assumed to be the first units located at new undetermined sites. Combined cycle and simple cycle combustion turbines were assumed to be installed on the Cane Island site and to take advantage of existing infrastructure.

Performance and O&M cost estimates have been compiled for each capacity addition alternative. The estimates provide representative values for each generation alternative and show expected trends in performance and costs within a given technology as well as between technologies. Degradation is also included. Actual unit performance and availability will vary based on site conditions, regulatory requirements, and operation practices. Capital costs for conventional technology alternatives are in 2001 dollars.

1A.6.6.1 Performance Estimates

1A.6.6.1.1 Net Plant Output. Net plant output (NPO) which is equal to the net turbine output less auxiliary power, refers to the net generation of the plant, after all internal uses and losses, that is available for uses outside the plant.

1A.6.6.1.2 Equivalent Availability (EA). Equivalent availability is a measure of the capacity of a generating unit to produce power considering limitations such as equipment failures, repairs, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance



outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

1A.6.6.1.3 Equivalent Forced Outage Rate (EFOR). Equivalent forced outage rate is a reliability index which reflects the probability that a unit will be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours, plus equivalent forced outage hours, by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

1A.6.6.1.4 Planned Maintenance Outage. Estimates are provided for the time required each year to perform scheduled maintenance.

1A.6.6.1.5 Startup Fuel. Estimates for startup energy, where applicable, in millions of Btu, are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operation conditions.

1A.6.6.1.6 Net Plant Heat Rate. Estimates for net plant heat rates are based on the higher heating value of the fuel. Heat rate estimates are provided for summer 95° F ambient) and ISO (59° F) conditions for combustion turbines and combined cycle units. Allowance for heat rate degradation over time because of aging has been included. Heat rates may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, and local site conditions.

1A.6.6.1.7 Degradation. For steam plants, the performance degrades with time due to erosion, corrosion, and increased leakage. Similarly, the performance of simple cycle combustion turbines and combined cycle plants will degrade with time. Part of the degraded performance can be recovered by periodic maintenance and overhauls. However, some performance cannot be recovered. Approximations for performance degradation, which were applied to the new clean performance estimates of the combined cycle and simple cycle alternatives, included a 2 percent heat rate and 4 percent output degradation. A 2 percent heat rate degradation was assumed for the pulverized coal and fluidized bed alternatives. No capacity degradation was assumed.



1A.6.6.2 Cost Estimates

1A.6.6.2.1 Capital Costs. Capital costs were developed on the basis of the current competitive generation market. Indirect costs include the typical items of engineering, construction management, general indirect costs and contingency. In addition, other indirect costs including SCADA interface costs, spares, owner's engineer, permitting, training, and substation costs to integrate the unit into the Cane Island substation, in order to place the costs on a comparable basis with costs resulting from purchase power bids, were included. Indirect costs for the larger alternatives, the 501G simple cycle and combined cycle, the 1x1 501F, and the 2x1 7EA, include a transmission line interconnection to FPC's Intercession City Plant. Direct costs for the combined cycle alternatives include bypass stacks with dampers, along with continuous emissions monitoring equipment. Direct costs for all alternatives include a fuel oil storage tank. Costs for the coal units to be located at a new site include costs for a substation and land costs based on average typical site requirements, and a land cost of \$2,000 per acre. Total capital cost is the summation of direct and indirect cost and interest during construction for commercial operation in 2001. The construction period is the time from start of construction to commercial operation. The construction period was used to estimate costs for interest during construction (IDC).

Based on discussions by the Department of Environmental Protection (DEP) in the City of Lakeland Electric and Water Utilities Technical Evaluation and Preliminary Determination for the C.D. McIntosh, Jr. Power Plant Unit 5, 501G combustion turbine, an SCR will be required for the 501G-series combustion turbines prior to 2002. Based on the DEP's determination, capital and operating costs for an SCR have been included for the 501G combustion turbine based alternatives for 2001. Beginning in 2002 these costs are not included in the economic evaluations since, based on the above DEP evaluation, the 501G combustion turbines will be capable of achieving BACT without the use of SCRs.

1A.6.6.2.2 O&M Costs. O&M estimates are based on a unit life of 25 years for combustion turbines and combined cycles, variable and fixed contingency of 20 percent, and baseload capacity factor (except simple cycle units). The fixed O&M analysis assumes that the fixed cost will remain constant over the life of the plant in real dollars. Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Fuel costs typically are determined separately and are not included in either fixed or variable O&M costs. The O&M costs presented in this report are typically referred to as nonfuel O&M costs. Variable O&M



costs include disposal of combustion wastes, consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation.

1A.6.6.2.3 Coal-Fueled O&M. O&M and performance estimates for the coal-fueled alternatives were based on the following assumptions.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Variable operations costs include an assumed lime cost of \$95/ton for flue gas desulfurization (FGD) and limestone cost of \$22/ton for the CFB, waste disposal which includes trucking to an onsite landfill, dozing and flattening (mobile reclaim equipment), and startup fuel oil. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs. Staffing estimates provided are based on recent utility experience with modern facilities.

An additional variable O&M cost of 0.73 \$/MWh is included for the SCR, which includes NH_3 costs and catalyst replacement costs. For the SNCR, the additional variable O&M cost is approximately 0.52 \$/MWh for NH_3 costs. The pulverized coal unit is assumed to require SCR, while the fluidized bed unit is assumed to require SNCR.

1A.6.6.2.4 Combined and Simple Cycle O&M. O&M and performance estimates for the combined cycle and simple cycle units were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors.
- Capacity and heat rate degradation of 4 and 2 percent, respectively, has been included in the performance estimates.
- Combustion turbine generator (CTG) maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at \$38/man-hour for Westinghouse and \$35/man-hour for General Electric (provided by manufacturers).
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost. These costs are included in the capital cost.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.



- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- Two additional staff are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle LM6000 and 7EA are based on a 5 percent capacity factor.
- O&M costs for the simple cycle 501G and 7FA are based on a 10 percent capacity factor.
- O&M costs for all the simple cycle combustion turbines are based on 200 starts per year.

1A.6.6.3 Pulverized Coal

A 250 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be the first unit at a undetermined new site in Central Florida. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 1A.6-24 presents the estimated cost and performance of the 250 MW pulverized coal unit.

1A.6.6.4 Fluidized Bed

A 250 MW atmospheric circulating fluidized bed unit (CFB) with selective noncatalytic reduction (SNCR) was selected as another solid fuel alternative. The CFB is capable of burning a wide range of fuels. For expansion planning purposes, the CFB is assumed to burn coal. Like the pulverized coal unit, the CFB is assumed to be the first unit at a undetermined new site in Central Florida. Coal is assumed to be delivered by rail and cooling is achieved



with mechanical draft cooling towers. Table 1A.6-25 presents the estimated cost and performance of the 250 MW CFB unit.

1A.6.6.5 Combined Cycle

Four combined cycle units were selected as generating unit alternatives:

- 1 x 1 General Electric 7EA (Table 1A.6-26)
- 2 x 1 General Electric 7EA (Table 1A.6-27)
- 1 x 1 Westinghouse 501FC (Table 1A.6-28)
- 1 x 1 Westinghouse 501G (Table 1A.6-29)

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. Specifications for performance and operating costs are based on natural gas fuel and baseload operation. The combined cycles assume that emission requirements will be met with dry low NO_x combustors. SCRs are only included for the 501G. The units would be located at the Cane Island site and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

1A.6.6.6 Simple Cycle Combustion Turbine

Four simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric LM6000 (Table 1A.6-30)
- General Electric 7EA (Table 1A.6-31)
- Westinghouse 501G (Table 1A.6-32)
- General Electric 7FA (Table 1A.6-33)

The 7EA, 501G, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The LM6000 is an aeroderivative combustion turbine. The combustion turbines are dual fueled with specifications for performance and operating costs based on natural gas operation.



Table 1A.6-24
Estimated Cost and Performance of 250 MW Pulverized Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 \$1,000	194,115
Indirect Capital Cost, 2001 \$1,000	84,958
Total Capital Cost, 2001 \$1,000	279,073 ¹
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 \$/kW-y	30.96
Variable O&M Cost, 1998 \$/MWh	4.31
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,750
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	240,749/10,157
75 Percent of Full Load	180,562/10,275
50 Percent of Full Load	120,374/10,967
25 Percent of Full Load	60,187/13,302
(1) Includes interest during construction.	



Table 1A.6-25
Estimated Cost and Performance of 250 MW Fluidized Bed Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 \$1,000	180,415
Indirect Capital Cost, 2001 \$1,000	81,710
Total Capital Cost, 2001 \$1,000	262,125 ¹
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 \$/kW-y	26.26
Variable O&M Cost, 1998 \$/MWh	4.46
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	4,800
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	242,794/10,250
75 Percent of Full Load	182,095/10,353
50 Percent of Full Load	121,397/11,025
25 Percent of Full Load	60,698/13,295
(1) Includes interest during construction.	



Table 1A.6-26
Generating Unit Characteristics
7EA 1 x 1 Combined Cycle

Table 1A.6-26 Generating Unit Characteristics 7EA 1 x 1 Combined Cycle		
Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	—	
Direct Capital Cost, 2001 \$1,000	56,981	
Indirect Capital Cost, 2001 \$1,000	20,923	
Total Capital Cost, 2001 \$1,000	77,904 ¹	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	3.29	
Variable O&M Cost, 1998 \$/MWh	2.37	
Equivalent Availability, percent	92.1	
Equivalent Forced Outage Rate, percent	3.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	59	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	109,939/8,114	124,166/7,849
79 Percent of Full Load	86,852/8,454	98,091/8,100
59 Percent of Full Load	64,864/9,219	73,258/8,738
35 Percent of Full Load	38,479/11,288	43,458/10,478
(1) Includes interest during construction.		



Table 1A.6-27
Generating Unit Characteristics
7EA 2 x 1 Combined Cycle

Table 1A.6-27 Generating Unit Characteristics 7EA 2 x 1 Combined Cycle		
Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	95,069	
Indirect Capital Cost, 2001 \$1,000	39,114	
Total Capital Cost, 2001 \$1,000	134,184 ¹	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	2.24	
Variable O&M Cost, 1998 \$/MWh	2.16	
Equivalent Availability, percent	94.1	
Equivalent Forced Outage Rate, percent	1.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	119	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	222,096/7,938	250,416/7,791
75 Percent of Full Load	166,572/8,258	187,812/8,025
50 Percent of Full Load	111,048/8,178	125,208/7,869
25 Percent of Full Load	55,524/9,865	62,604/9,309
(1) Includes interest during construction.		



Table 1A.6-28
Generating Unit Characteristics
Westinghouse 1 x 1 501F Combined Cycle

Item		
Steam Pressure, psia	1,800	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 \$1,000	83,622	
Indirect Capital Cost, 2001 \$1,000	33,945	
Total Capital Cost, 2001 \$1,000	117,567 ¹	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	2.08	
Variable O&M Cost, 1998 \$/MWh	2.58	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	84	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	236,630/6,945	261,792/6,815
75 Percent of Full Load	175,106/7,483	196,344/7,141
52 Percent of Full Load	123,048/8,011	138,750/7,699
27 Percent of Full Load	63,890/10,474	73,302/9,894
(1) Includes interest during construction.		



Table 1A.6-29
Generating Unit Characteristics
Westinghouse 1 x 1 501G Combined Cycle

Table 1A.6-29 Generating Unit Characteristics Westinghouse 1 x 1 501G Combined Cycle		
Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 \$1,000	107,386	
Indirect Capital Cost, 2001 \$1,000	39,976	
Total Capital Cost, 2001 \$1,000	147,363 ^{1 2}	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	1.95	
Variable O&M Cost, 1998 \$/MWh	2.27 ³	
Equivalent Availability, percent	83.0	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	294,960/7,062	333,456/6,784
75 Percent of Full Load	221,220/7,437	250,092/7,083
50 Percent of Full Load	147,480/8,190	166,728/7,714
25 Percent of Full Load	73,740/10,788	83,364/9,967
(1) Includes interest during construction.		
(2) After 2001, SCR is not included and total capital cost is reduced to \$145,157 in 2001 dollars.		
(3) After 2001, SCR is not included and variable O&M is reduced to \$2.14/MWh in 1998 dollars.		



Table 1A.6-30
Generating Unit Characteristics
General Electric LM6000 Simple Cycle

Table 1A.6-30 Generating Unit Characteristics General Electric LM6000 Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	16,210	
Indirect Capital Cost, 2001 \$1,000	5,956	
Total Capital Cost, 2001 \$1,000	22,165 ¹	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	5.45	
Variable O&M Cost, 1998 \$/MWh	6.92	
Equivalent Availability, percent	95.8	
Equivalent Forced Outage Rate, percent	2.3	
Planned Maintenance Outage, weeks/y	1	
Startup Fuel (cold start), MBtu	6	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	33,360/9,893	41,664/9,417
75 Percent of Full Load	25,020/10,475	31,248/9,806
50 Percent of Full Load	16,680/11,639	20,832/10,650
25 Percent of Full Load	8,340/15,136	10,416/13,183
(1) Includes interest during construction.		



Table 1A.6-31
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	22,527	
Indirect Capital Cost, 2001 \$1,000	8,924	
Total Capital Cost, 2001 \$1,000	31,451 ¹	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	3.32	
Variable O&M Cost, 1998 \$/MWh	23.56	
Equivalent Availability, percent	95.6	
Equivalent Forced Outage Rate, percent	2.1	
Planned Maintenance Outage, weeks/y	1.25	
Startup Fuel (cold start), MBtu	12	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	72,432/12,335	81,552/11,959
75 Percent of Full Load	54,324/13,504	61,164/13,050
50 Percent of Full Load	36,216/15,844	40,776/15,300
25 Percent of Full Load	18,108/23,515	20,388/22,097

(1) Includes interest during construction.



Table 1A.6-32
Generating Unit Characteristics
Westinghouse 501G Simple Cycle

Table 1A.6-32 Generating Unit Characteristics Westinghouse 501G Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	51,871	
Indirect Capital Cost, 2001 \$1,000	22,823	
Total Capital Cost, 2001 \$1,000	74,694 ^{1,2}	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	2.13	
Variable O&M Cost, 1998 \$/MWh	11.61 ³	
Equivalent Availability, percent	84.2	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	18	
Construction Period, months	15	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	197,040/10,502	223,872/10,047
75 Percent of Full Load	147,780/11,377	167,904/10,854
50 Percent of Full Load	98,520/13,128	111,936/12,470
25 Percent of Full Load	49,260/18,757	55,968/17,322
(1) Includes interest during construction.		
(2) After 2001, SCR is not included and total capital cost is reduced to \$72,522 in 2001 dollars.		
(3) After 2001, SCR is not included and variable O&M is reduced to \$10.24/MWh in 1998 dollars.		



Table 1A.6-33
Generating Unit Characteristics
General Electric 7FA Simple Cycle

Table 1A.6-33 Generating Unit Characteristics General Electric 7FA Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	35,301	
Indirect Capital Cost, 2001 \$1,000	13,457	
Total Capital Cost, 2001 \$1,000	48,757 ¹	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 \$/kW-y	2.47	
Variable O&M Cost, 1998 \$/MWh	10.37	
Equivalent Availability, percent	94.5	
Equivalent Forced Outage Rate, percent	2.7	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	35	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	147,168/11,063	165,312/10,698
75 Percent of Full Load	110,376/12,030	123,984/11,546
50 Percent of Full Load	73,584/14,090	82,656/13,400
25 Percent of Full Load	36,792/20,339	41,328/19,122
(1) Includes interest during construction.		



1A.6.7 Request for Proposals to Purchase Power

KUA and FMFA conducted a two-phase evaluation of purchased power alternatives based on bids received from a request for proposals for purchased power issued May 28, 1997. The comparison of purchase power bids included applicable transmission rates, transmission upgrade costs, and loss percentages. Certain nonprice items were also included in the evaluation including pricing terms and flexibility, supply availability for economy transactions, dispatchability, fuel risks, transmission path, commercial viability of technology, and potential environmental effects. Details of the RFP process for KUA and FMFA are presented in Sections 1B.9.0 and 1C.9.0, respectively.

1A.6.8 Supply-Side Screening

KUA and FMFA conducted individual screening analyses to determine the least cost alternative for capacity addition to their systems. The screening analysis was conducted in two phases. The first phase of the screening process, further described in Subsection 1A.6.8.1, was performed based on a broad-based comparison of the cost, commercial feasibility, and applicability of each generating technology.

The second phase screening analysis of the remaining generating alternatives was performed based on a comparison of the total cumulative present worth cost of each capacity addition alternative. EGEAS, an optimal generation expansion model, was used to determine the least cost cumulative present worth expansion plans for both utilities. The economic analysis included all cost, performance, and economic parameters listed in Sections 1A.3.0, 1B.4.0, and 1C.4.0. The second phase screening analyses are presented in Sections 1B.9.0 and 1C.9.0.

1A.6.8.1 Phase One Screening

1A.6.8.1.1 Renewable Technologies. Renewable technologies evaluated as capacity addition alternatives included wind energy, solar thermal and photovoltaics, wood chip fired, geothermal, and hydroelectric. Wind energy, solar thermal, and photovoltaics were deleted from consideration based on high capital costs (two to three times that of Cane Island 3) and low capacity factor. Wood chip fired generating alternatives were deleted based on high capital cost, environmental emission concerns, and lack of raw materials for baseload operation. Geothermal and hydroelectric generating alternatives were deleted based on high



capital cost and lack of natural resources. Cost and performance data for these alternatives is presented in Tables 1A.6-1 through 1A.6-6.

1A.6.8.1.2 Waste Technologies. Waste energy technologies evaluated include mass burn units, Refuse Derived Fuel (RDF), landfill gas, sewage sludge and used tire fueled generating units. All waste technology alternatives were eliminated based on high capital costs and insufficient fuel supply availability. Cost and performance data for these alternatives is presented in Tables 1A.6-7 through 1A.6-10.

1A.6.8.1.3 Advanced Technologies. Advanced technologies evaluated include humid air turbine (HAT), Kalina and Cheng cycles, advanced coal technologies, magnetohydrodynamics, fuel cells, fusion, and ocean wave and tidal systems. Only fuel cell and supercritical coal technologies are considered commercially viable. However, prohibitive capital and operating costs eliminate them from further analysis. Cost and performance data for these alternatives is presented in Tables 1A.6-11 through 1A.6-19.

1A.6.8.1.4 Energy Storage Systems. Energy storage systems evaluated include pumped storage, battery storage, compressed air energy storage, flywheel storage, and superconducting magnetic energy storage. Energy storage systems were eliminated from further analysis based on low operating capacity factor and high capital and operating costs. In addition, a majority of these alternatives are considered experimental. Cost and performance data for these alternatives is presented in Tables 1A.6-20 through 1A.6-22.

1A.6.8.1.5 Nuclear. Nuclear power plants are capital intensive, which requires that large units be built to benefit from economies of scale. The high capital cost and licensing requirements of a nuclear facility eliminates it as an alternative. Cost and performance data for a typical nuclear power plant is presented in Tables 1A.6-23.

1A.6.8.1.6 Conventional Technologies. Conventional generating unit alternatives considered for capacity expansion include pulverized coal, fluidized bed, combined cycle and simple cycle combustion turbines. These alternatives were included in the second phase EGEAS screening analysis. Cost and performance data for these alternatives is presented in Tables 1A.6-24 through 1A.6-33.



1A.7.0 FMPP Need for Cane Island 3

KUA and the FMPP All Requirements Project are both members of the Florida Municipal Power Pool (FMPP) along with Orlando Utilities Commission (OUC) and the City of Lakeland Electric & Water (Lakeland). All of the generating units for each of the members are economically committed and dispatched by OUC to meet the combined loads of FMPP. Savings from the combined commitment and dispatch, over what each utility would have spent if they had met their loads individually with their own generation, are then shared among the Pool members by prescribed formulas. Thus, the addition of Cane Island 3 will not only reduce costs for KUA and FMPP, but will also reduce costs for OUC and Lakeland. To project the savings to FMPP from the addition of Cane Island 3, the PROSYM chronological production costing program was used to model FMPP with and without Cane Island 3. Load forecasts and generation expansion plans for the FMPP members were based on information contained in the 1997 Ten Year Site Plans.

FMPP is an energy pool only and requires the members to supply their own capacity. Thus, for the case without Cane Island 3, KUA and FMPP would still be required to install or obtain capacity in 2001, since without Cane Island 3, both KUA and FMPP could not maintain a 15 percent reserve margin. For evaluation purposes, it was assumed that KUA and FMPP would install a simple cycle General Electric 7FA and 7EA as described in Section 1A.6.0 for a total summer capacity of 220 MW, which nearly equals the summer capacity of Cane Island 3. Since these units are simple cycle combustion turbines, they would not require licensing under the Florida Electrical Power Plant Siting Act. Table 1A.7-1 presents the FMPP annual and cumulative present worth savings in total production costs. Annual costs listed include all system costs for 1997 through 2006. As shown in Table 1A.7-1, the projected cumulative present worth production cost savings to FMPP from the installation of Cane Island 3 is estimated to be \$26,633,000 from only the first 6 years of operation.



Table 1A.7-1
FMPP Savings With Cane Island 3

	Total Annual FMPP Production Cost		Total Annual FMPP Production Cost Savings	
	With Cane Island (\$1000)	Without Cane Island (\$1000)	Annual Savings (\$1000)	Cumulative Present Worth Savings (\$1000)
1997-2000	0	0	0	0
2001	260,970	267,314	6,344	5,403
2002	275,005	281,402	6,397	10,567
2003	287,186	293,575	6,389	15,455
2004	301,123	306,762	5,639	19,545
2005	309,142	312,936	3,794	23,131
2006	326,205	331,579	5,374	26,633
			Total CPW	26,633



1A.8.0 Analysis of 1990 Clean Air Act Amendments

While the Florida Electrical Power Plant Siting Act carefully bifurcates the need for the power plant from the environmental impacts of the facility, the necessity of meeting environmental requirements has cost and performance impacts on the facility. The Clean Air Act requirements have the greatest impact on the power plant's cost and performance.

1A.8.1 History of the Clean Air Act

The Clean Air Act of 1970 was designed to protect human health and the environment by regulating the amount of pollutants released to the atmosphere. The major regulated air pollutants include carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO₂), hydrocarbon compounds (or volatile organic compounds, VOC), ozone, lead, and suspended particulates (PM/PM₁₀). NO_x and SO₂ contribute to the formation of acid rain. The listed pollutants, commonly referred to as criteria pollutants, have been regulated primarily through National Ambient Air Quality Standards (NAAQS) and the respective state implemented programs that support the NAAQS.

In the late 1980s, as it came time for Congress to reauthorize the Clean Air Act, air quality had improved, but it was clear that continuing the improvement was becoming more costly per unit of pollution removed. Under the 1990 Clean Air Act amendments, Congress required the EPA to establish an emissions trading program that would cut the emissions of sulphur dioxide in half by the year 2000. Under the program established by the EPA, existing power plants were allocated sulfur dioxide allowances with a given number of additional allowances auctioned each year. An allowance holder can emit 1 ton of sulfur dioxide for each allowance. Firms holding the allowances can use the allowances to emit pollutants, bank the allowances for the next year, or sell the allowances to other firms. Total emissions will fall because the sulfur dioxide emissions associated with the number of allowances available is less than existing emissions.

General discussion of the Unit 3 construction, operating, and acid rain permitting requirements associated with the Clean Air Act, is given below. However, a more detailed discussion of the Unit 3 environmental impacts and permitting requirements is given in Volumes 2 through 5 of this Site Certification Application. Additionally, the compliance strategy for KVA and FMFA for sulfur dioxide emissions is detailed in Volumes 1B and 1C.



1A.8.2 Authority to Construct

The Cane Island Power Park is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. An authority to construct (ATC) permit must be obtained prior to the construction of Unit 3. One aspect of the ATC permit is the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are NO_x, VOC, CO, and PM/PM₁₀. Unit 3 will achieve BACT for NO_x through the use of dry low NO_x combustors which will limit the NO_x emissions to 12 to 15 ppm while firing natural gas. When firing No. 2 oil, water injection will be used to limit NO_x emissions to 42 ppm. Unit 3 will achieve BACT for CO, VOCs, and PM/PM₁₀ through the use of good combustion control practices. Limited operation while firing No. 2 oil (approximately 30 days per year) will keep Unit 3 below the threshold level for SO₂.

1A.8.3 Title V Operating Permit

Along with the ATC, the Cane Island Power Park will be required to obtain an operating permit under Title V of the Clean Air Act. All three units of the Cane Island Power Park will ultimately be included in a single Title V permit. Requirements under the Title V permit for Unit 3 will require similar emissions control and operations to those required under the ATC BACT determination.

1A.8.4 Title IV Acid Rain Permit

In addition to the construction and operating permit requirements of the Cane Island Power Park, the regulations implementing the Acid Rain provisions of the Clean Air Act amendments require that electric utility units obtain acid rain permits. Unit 3 will be a Phase II unit requiring SO₂ allowances for emissions. Volumes 1B and 1C present KUA's and FMPPA's plans for supplying the SO₂ allowances necessary for operation of Unit 3. The acid rain permit requires the installation of continuous emissions monitoring equipment (CEM) and fuel flowmeters, which are included in the design and cost of Unit 3.

Appendix 1A.9.1

Analysis of Utility Fuel Prices in the South Atlantic Region

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Analysis of Utility Fuel Prices in the South Atlantic Region

Prepared for:
Kissimmee Utility Authority

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Note: The short-term distillate and natural gas price forecasts were prepared at the end of September 1997. The long-term forecasts represent DRI's latest long-term fuel price analysis, which was prepared in April 1997. For the natural gas concepts that appear in both the short and long-term forecasts (Henry Hub and Gulf Coast), the long-term forecasts have been updated with the latest short-term analysis through 1999. The other forecasts are not directly comparable between the short and long term since they do not represent the same concept (e.g., distillate spot prices compared with delivered price to utilities) and they were not prepared contemporaneously. The long-term forecasts of prices to South Atlantic utilities are all directly comparable.

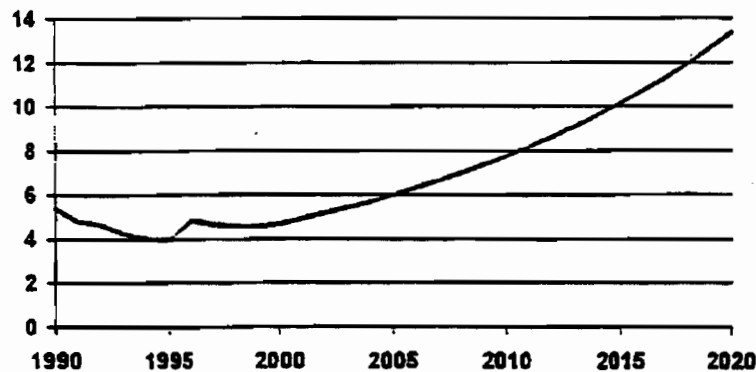
Forecast Highlights

Distillate

- Distillate fuel prices rose sharply at the end of 1996, but have since declined significantly in 1997. The key factors causing the 1996 price run-up, including uncertainty over Iraqi oil exports and very short inventories, are gone, and distillate prices have largely followed the downward trend in crude prices since the beginning of the year. The price of distillate (New York Harbor spot cargoes) has declined from a high of 72.0 cents per gallon in November 1996 to 52.3 cents in September, over a 27% drop.
- In the short term, prices will rise moderately, supported by both slightly firming crude prices and seasonal demand. Current distillate inventories are above historically average levels and about 20% above the low levels of last year at this time, so the acute stock shortages of last year and the resulting strong prices should not be repeated this heating season. The price of distillate (New York Harbor spot cargoes) will rise to 55.6 cents per gallon by this December, 8% above September's level but 19% below last December's level.
- In the long-term, distillate prices are determined primarily by the price of crude oil. DRI's forecast is that real crude prices will decline moderately through 2000. Strong non-OPEC production, weak OECD demand, and the eventual full reintroduction of Iraqi crude will allow average real crude prices to decline to about \$17.00 per barrel in 2000. Real distillate prices will also decline over the same period, with nominal prices remaining essentially flat. The price of distillate fuel oil to utilities in the South Atlantic region will fall slightly from \$4.84 per MMBtu (83.1 cents per gallon) in 1996 to \$4.69 per MMBtu (80.5 cents per gallon) in 2000.
- After 2000, world oil prices will increase moderately in real terms. As production from mature non-OPEC regions wanes, non-OPEC exploration and production costs will increase and OPEC's market share will gradually grow. Real crude prices will increase at about 1.0% per year through 2020, to just over \$25.00 per barrel. Distillate prices will also follow this trend, reaching \$13.37 per MMBtu (\$2.30 per gallon) in nominal terms for utilities in the South Atlantic region by 2020.
- In 1996, total distillate fuel demand was 3.4 million barrels per day (b/d). This represented 18.4% of total petroleum consumption, and distillate fuel is second only to gasoline in petroleum product demand. The transportation sector is the dominate consumer of distillate fuel, with diesel fuel and marine and rail distillate accounting for 63.3% of total distillate fuel demand. The balance is consumed by the industrial, residential, commercial, and electric utility sectors, with utilities consuming just 44,000 b/d (1.3% of the total).

- Over the forecast period, total distillate fuel demand will grow by 1.0% per year, reaching 4.3 million b/d by 2020. The transportation sector will remain the dominant consumer of distillate fuel and will realize the greatest volume increase in total distillate demand. For the stationary sectors, competition from natural gas will play a key role in shifting demand. Distillate demand in the residential and commercial sectors will decline, industrial consumption will increase slightly, and demand from electric power generators will increase strongly, although the total volume will remain small (340,000 b/d). The growth in demand for distillate fuel by electricity generators (including industrial cogenerators) is due in large part to its use as a back-up fuel for gas-fired units.

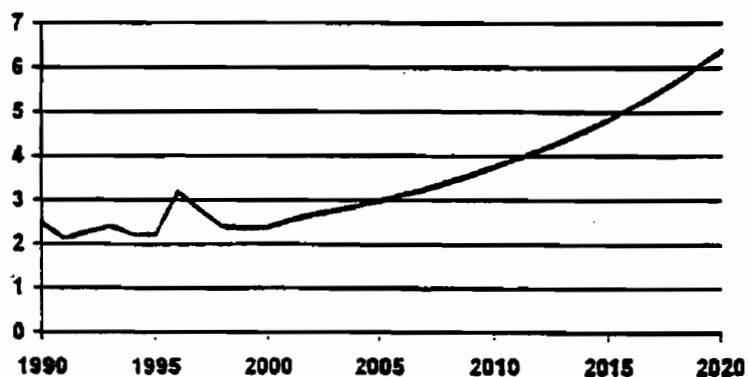
Distillate Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Natural Gas

- Natural gas prices in early 1997 exceeded \$4 per MMBtu compared to prices above \$3 in 1996. However, prices weakened significantly in March and April before rebounding in May and June. Gas markets will remain very volatile until the new pipeline projects are completed. Natural gas prices have again reached the \$3 level in late September 1997. This is evidence of the volatility that has prevailed in markets over the past two years. The current forecast is based upon normal weather, which in combination with adequate storage and a normal output from nuclear stations, presages moderate prices over this winter. Either abnormal weather or severe nuclear outages could trigger substantially higher prices this winter.
- Natural gas supply increases are expected to be at least adequate and possibly excessive by 2000. First, reserve additions have exceeded production in each of the past two years in the United States. Also, by 2000, pipeline capacity additions of 5 to 10 Bcf/day from Canada, the Rocky Mountains and the deep Gulf of Mexico have the potential to create a "gas bubble" even though gas demand is projected to grow by up to 7 Bcf/day. Thus natural gas prices are expected to weaken as new supply sources are added to the U.S. market.
- Swift demand growth will absorb the new supplies and gas markets will return to a better balance after 2000. For 1997, demand growth was absent in the first half but is expected to increase significantly for the second half to average 2% for the year. DRI expects demand growth for 1997 to 2000 to average about 1.9 Bcf/day per year.
- The price of natural gas to electric generators in the South Atlantic region was \$3.18 per MMBtu in 1996. This was the highest average price of all regions, and 16% above the national average. Over the forecast period, increased fuel competition and pipeline capacity expansions will allow the gap with other regions to narrow considerably, especially with other regions in the East. For much of the forecast period, the average price of natural gas to utilities in the South Atlantic region will be about 7% above the national average, and this will fall to just 4% by 2020.

Natural Gas Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Coal

- Expirations of many above market long-term coal contracts set in the late 1970s and 1980s have forced down the cost of delivered coal to utilities. As these contracts expire and are replaced by agreements that track the spot market price, the average delivered price will continue to decline.
- Deregulation and consolidation of the railroad industry have dramatically reduced transportation costs. Many onlookers in the nascent power-marketing industry are expecting the same type of improvements on the mining side of the coal supply business, as consolidation and realignment continues there as well. However, that amount of flexibility in the production process has yet to be seen.
- As utility fuel purchasers increase their spot purchases or supplies from fuel marketers, price volatility will increase, spurring more robust risk-mitigating strategies.
- Under the competing goals to lower costs and mitigate price risk in a volatile marketplace, utility fuel purchasers are increasingly relying upon a flexible purchasing approach. This includes using various types of coal (either low-sulfur or high-sulfur) with bundled emission allowances; increasing spot purchases in conjunction with shorter term contracts containing price adjustment clauses; and purchasing coal through multiple delivery routes as rail systems increasingly become integrated and reliable.
- As eastern utilities switching from high-sulfur Northern Appalachian and Ohio basin coal move to lower-sulfur coal, Central Appalachian low-sulfur coal will experience continued strong demand, suppressing movements towards dramatic price declines.
- Coastal power plants and those with easy rail access to port facilities are the plants best able to use the international coal market as an optional supply source for low-sulfur coal that meets emission limits. As rail transportation systems become more centralized and reliable, the import of coal farther inland will become feasible.

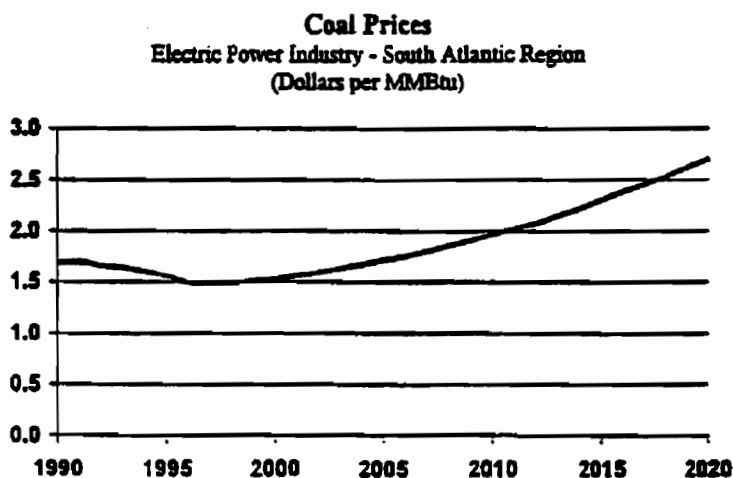


Table A-1

**Short-Term Forecast of
Distillate Fuel Prices
New York Harbor Spot Cargoes and
Tampa, Florida Posted Prices
(Cents per Gallon)**

<u>Month</u>	<u>New York</u>	<u>Tampa</u>
1996	55.0	55.3
Jan	60.2	58.7
Feb	62.2	61.5
Mar	63.2	64.1
Apr	55.2	61.8
May	51.2	59.1
Jun	55.3	56.8
Jul	60.0	61.7
Aug	67.3	68.9
Sep	72.0	74.0
Oct	69.7	71.5
Nov	72.0	71.7
Dec	69.8	70.5
1997		
Jan	69.8	70.5
Feb	60.8	64.7
Mar	54.6	57.6
Apr	58.6	57.3
May	55.5	58.5
Jun	51.9	54.6
Jul	52.7	54.9
Aug	53.6	58.8
Sep	52.3	54.9
Forecast		
Oct	53.9	55.8
Nov	55.8	57.1
Dec	58.6	56.3
1998		
Jan	55.6	58.6
Feb	54.4	54.5
Mar	54.2	55.1
Apr	52.8	53.9
May	52.0	55.4
Jun	50.7	54.4
Jul	51.5	52.9
Aug	53.2	54.8
Sep	53.8	55.6
Oct	55.4	57.4
Nov	56.7	58.0
Dec	58.0	57.7

Table A-2

**Long-Term Forecast of
Distillate Fuel Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)**

<u>Year</u>	<u>South Atlantic</u>
1993	4.22
1994	4.00
1995	3.96
1996	4.84

Forecast

1997	4.62
1998	4.58
1999	4.55
2000	4.69
2001	4.93
2002	5.18
2003	5.42
2004	5.68
2005	6.01
2006	6.32
2007	6.64
2008	7.00
2009	7.37
2010	7.75
2011	8.18
2012	8.63
2013	9.10
2014	9.61
2015	10.14
2016	10.71
2017	11.32
2018	11.96
2019	12.64
2020	13.37

Table B-1

**Short-Term Forecast of
Natural Gas Prices
Henry Hub and Gulf Coast Spot
(Dollars per MMBtu)**

<u>Month</u>	<u>Henry Hub</u>	<u>Gulf Coast</u>
1996		
Jan	3.42	3.25
Feb	2.40	2.33
Mar	2.94	2.81
Apr	2.70	2.58
May	2.21	2.15
Jun	2.38	2.28
Jul	2.66	2.57
Aug	2.30	2.22
Sep	1.83	1.72
Oct	1.85	1.75
Nov	2.76	2.63
Dec	3.90	3.73
1997		
Jan	4.09	3.84
Feb	2.96	2.79
Mar	1.78	1.66
Apr	1.85	1.77
May	2.15	2.04
Jun	2.31	2.24
Jul	2.16	2.07
Aug	2.18	2.11
Sep	2.55	2.46
Forecast		
Oct	3.20	3.13
Nov	2.80	2.71
Dec	3.14	3.02
1998		
Jan	3.21	3.08
Feb	2.41	2.30
Mar	2.11	2.01
Apr	2.13	2.04
May	2.07	2.00
Jun	2.19	2.11
Jul	2.14	2.07
Aug	2.03	1.96
Sep	2.05	1.98
Oct	2.21	2.13
Nov	2.24	2.15
Dec	2.62	2.50

Table B-2

**Long-Term Forecast of
Gulf Coast and Henry Hub
Spot Natural Gas Prices
Delivered To Pipeline
(Dollars per MMBtu)**

<u>Year</u>	<u>Henry Hub</u>	<u>Gulf Coast</u>
1993	2.11	2.06
1994	1.89	1.83
1995	1.64	1.57
1996	2.61	2.50

Forecast

1997	2.60	2.49
1998	2.28	2.19
1999	2.20	2.11
2000	2.12	2.03
2001	2.14	2.06
2002	2.28	2.19
2003	2.36	2.27
2004	2.42	2.34
2005	2.51	2.43
2006	2.61	2.53
2007	2.71	2.63
2008	2.85	2.77
2009	2.97	2.89
2010	3.15	3.07
2011	3.32	3.24
2012	3.48	3.41
2013	3.66	3.58
2014	3.88	3.80
2015	4.07	3.99
2016	4.30	4.22
2017	4.57	4.48
2018	4.79	4.70
2019	5.09	5.00
2020	5.40	5.31

Table B-3

Long-Term Forecast of
Natural Gas Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

<u>Year</u>	<u>South Atlantic</u>
1993	2.42
1994	2.20
1995	2.22
1996	3.18

Forecast

1997	2.78
1998	2.39
1999	2.36
2000	2.40
2001	2.54
2002	2.67
2003	2.77
2004	2.87
2005	2.98
2006	3.11
2007	3.25
2008	3.41
2009	3.58
2010	3.78
2011	3.95
2012	4.13
2013	4.35
2014	4.57
2015	4.83
2016	5.11
2017	5.40
2018	5.71
2019	6.04
2020	6.38

Table C-1

Long-Term Forecast of
Coal Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

<u>Year</u>	<u>South Atlantic</u>
1993	1.64
1994	1.60
1995	1.55
1996	1.49

Forecast

1997	1.50
1998	1.50
1999	1.51
2000	1.53
2001	1.56
2002	1.60
2003	1.64
2004	1.68
2005	1.72
2006	1.76
2007	1.81
2008	1.86
2009	1.91
2010	1.97
2011	2.03
2012	2.08
2013	2.15
2014	2.22
2015	2.30
2016	2.38
2017	2.46
2018	2.53
2019	2.62
2020	2.70

Appendix 1A.9.1

Analysis of Utility Fuel Prices in the South Atlantic Region

Analysis of Utility Fuel Prices in the South Atlantic Region

Prepared for:
Kissimmee Utility Authority

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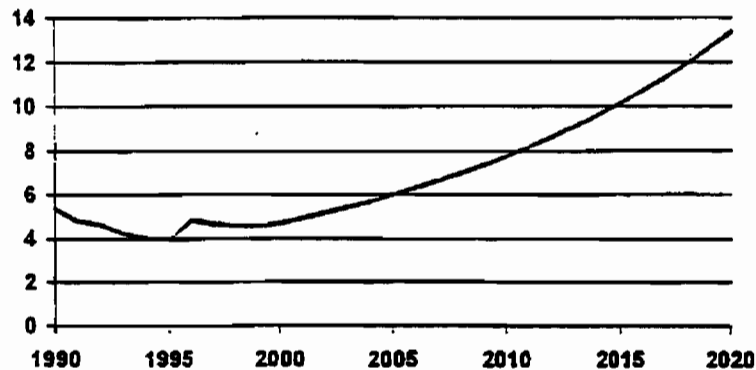
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- Distillate fuel prices rose sharply at the end of 1996, but have since declined significantly in 1997. The key factors causing the 1996 price run-up, including uncertainty over Iraqi oil exports and very short inventories, are gone, and distillate prices have largely followed the downward trend in crude prices since the beginning of the year. The price of distillate (New York Harbor spot cargoes) has declined from a high of 72.0 cents per gallon in November 1996 to 52.3 cents in September, over a 27% drop.
- In the short term, prices will rise moderately, supported by both slightly firming crude prices and seasonal demand. Current distillate inventories are above historically average levels and about 20% above the low levels of last year at this time, so the acute stock shortages of last year and the resulting strong prices should not be repeated this heating season. The price of distillate (New York Harbor spot cargoes) will rise to \$6.6 cents per gallon by this December, 3% above September's level but 19% below last December's level.
- In the long-term, distillate prices are determined primarily by the price of crude oil. DRI's forecast is that real crude prices will decline moderately through 2000. Strong non-OPEC production, weak OECD demand, and the eventual full reintroduction of Iraqi crude will allow average real crude prices to decline to about \$17.00 per barrel in 2000. Real distillate prices will also decline over the same period, with nominal prices remaining essentially flat. The price of distillate fuel oil to utilities in the South Atlantic region will fall slightly from \$4.84 per MMBtu (83.1 cents per gallon) in 1996 to \$4.69 per MMBtu (80.5 cents per gallon) in 2000.
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- In 1996, total distillate fuel demand was 3.4 million barrels per day (b/d). This represented 18.4% of total petroleum consumption, and distillate fuel is second only to gasoline in petroleum product demand. The transportation sector is the dominate consumer of distillate fuel, with diesel fuel and marine and rail distillate accounting for 63.3% of total distillate fuel demand. The balance is consumed by the industrial, residential, commercial, and electric utility sectors, with utilities consuming just 44,000 b/d (1.3% of the total).

- Over the forecast period, total distillate fuel demand will grow by 1.0% per year, reaching 4.3 million b/d by 2020. The transportation sector will remain the dominant consumer of distillate fuel and will realize the greatest volume increase in total distillate demand. For the stationary sectors, competition from natural gas will play a key role in shifting demand. Distillate demand in the residential and commercial sectors will decline, industrial consumption will increase slightly, and demand from electric power generators will increase strongly, although the total volume will remain small (340,000 b/d). The growth in demand for distillate fuel by electricity generators (including industrial cogenerators) is due in large part to its use as a back-up fuel for gas-fired units.

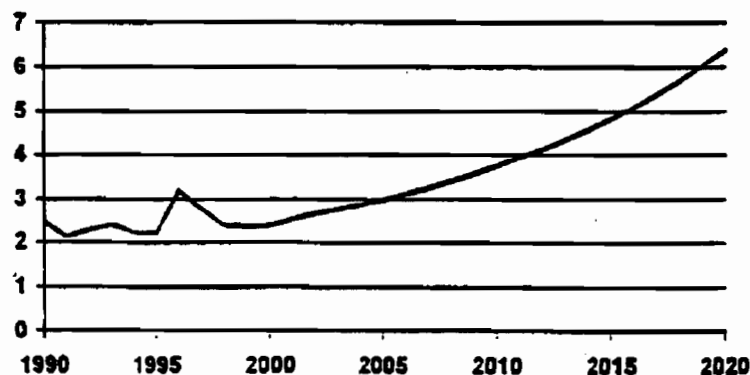
Distillate Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Natural Gas

- Natural gas prices in early 1997 exceeded \$4 per MMBtu compared to prices above \$3 in 1996. However, prices weakened significantly in March and April before rebounding in May and June. Gas markets will remain very volatile until the new pipeline projects are completed. Natural gas prices have again reached the \$3 level in late September 1997. This is evidence of the volatility that has prevailed in markets over the past two years. The current forecast is based upon normal weather, which in combination with adequate storage and a normal output from nuclear stations, presages moderate prices over this winter. Either abnormal weather or severe nuclear outages could trigger substantially higher prices this winter.
- Natural gas supply increases are expected to be at least adequate and possibly excessive by 2000. First, reserve additions have exceeded production in each of the past two years in the United States. Also, by 2000, pipeline capacity additions of 5 to 10 Bcf/day from Canada, the Rocky Mountains and the deep Gulf of Mexico have the potential to create a "gas bubble" even though gas demand is projected to grow by up to 7 Bcf/day. Thus natural gas prices are expected to weaken as new supply sources are added to the U.S. market.
- Swift demand growth will absorb the new supplies and gas markets will return to a better balance after 2000. For 1997, demand growth was absent in the first half but is expected to increase significantly for the second half to average 2% for the year. DRI expects demand growth for 1997 to 2000 to average about 1.9 Bcf/day per year.
- The price of natural gas to electric generators in the South Atlantic region was \$3.18 per MMBtu in 1996. This was the highest average price of all regions, and 16% above the national average. Over the forecast period, increased fuel competition and pipeline capacity expansions will allow the gap with other regions to narrow considerably, especially with other regions in the East. For much of the forecast period, the average price of natural gas to utilities in the South Atlantic region will be about 7% above the national average, and this will fall to just 4% by 2020.

Natural Gas Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Coal

- Expirations of many above market long-term coal contracts set in the late 1970s and 1980s have forced down the cost of delivered coal to utilities. As these contracts expire and are replaced by agreements that track the spot market price, the average delivered price will continue to decline.
- Deregulation and consolidation of the railroad industry have dramatically reduced transportation costs. Many onlookers in the nascent power-marketing industry are expecting the same type of improvements on the mining side of the coal supply business, as consolidation and realignment continues there as well. However, that amount of flexibility in the production process has yet to be seen.
- As utility fuel purchasers increase their spot purchases or supplies from fuel marketers, price volatility will increase, spurring more robust risk-mitigating strategies.
- Under the competing goals to lower costs and mitigate price risk in a volatile marketplace, utility fuel purchasers are increasingly relying upon a flexible purchasing approach. This includes using various types of coal (either low-sulfur or high-sulfur) with bundled emission allowances; increasing spot purchases in conjunction with shorter term contracts containing price adjustment clauses; and purchasing coal through multiple delivery routes as rail systems increasingly become integrated and reliable.
- As eastern utilities switching from high-sulfur Northern Appalachian and Ohio basin coal move to lower-sulfur coal, Central Appalachian low-sulfur coal will experience continued strong demand, suppressing movements towards dramatic price declines.
- Coastal power plants and those with easy rail access to port facilities are the plants best able to use the international coal market as an optional supply source for low-sulfur coal that meets emission limits. As rail transportation systems become more centralized and reliable, the import of coal farther inland will become feasible.

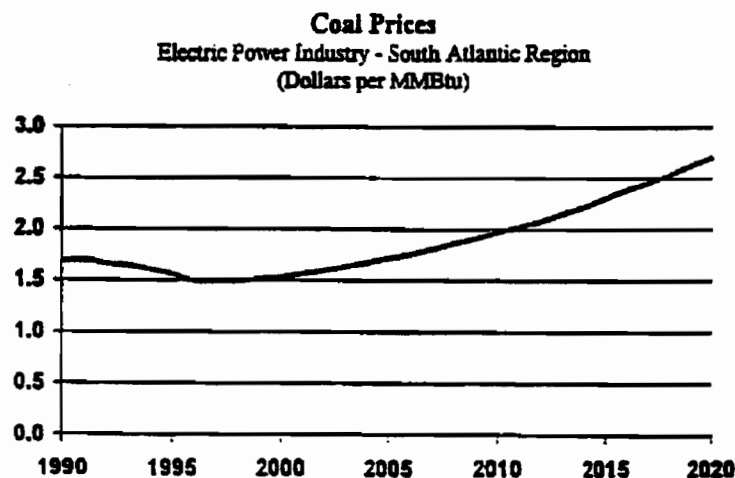


Table A-1

**Short-Term Forecast of
Distillate Fuel Prices
New York Harbor Spot Cargoes and
Tampa, Florida Posted Prices
(Cents per Gallon)**

<u>Month</u>	<u>New York</u>	<u>Tampa</u>
1996	55.0	55.3
Jan	60.2	58.7
Feb	62.2	61.5
Mar	63.2	64.1
Apr	55.2	61.8
May	51.2	59.1
Jun	55.3	56.8
Jul	60.0	61.7
Aug	67.3	68.9
Sep	72.0	74.0
Oct	69.7	71.5
Nov	72.0	71.7
Dec	69.8	70.5
1997		
Jan	69.8	70.5
Feb	60.8	64.7
Mar	54.6	57.6
Apr	56.6	57.3
May	55.5	58.5
Jun	51.9	54.6
Jul	52.7	54.9
Aug	53.6	56.8
Sep	52.3	54.9
Forecast		
Oct	53.9	55.8
Nov	55.8	57.1
Dec	56.6	56.3
1998		
Jan	55.6	56.6
Feb	54.4	54.5
Mar	54.2	55.1
Apr	52.8	53.9
May	52.0	55.4
Jun	50.7	54.4
Jul	51.5	52.9
Aug	53.2	54.8
Sep	53.8	55.6
Oct	55.4	57.4
Nov	56.7	58.0
Dec	58.0	57.7

Table A-2

**Long-Term Forecast of
Distillate Fuel Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)**

<u>Year</u>	<u>South Atlantic</u>
1993	4.22
1994	4.00
1995	3.96
1996	4.84

Forecast

1997	4.62
1998	4.58
1999	4.55
2000	4.69
2001	4.93
2002	5.18
2003	5.42
2004	5.68
2005	6.01
2006	6.32
2007	6.84
2008	7.00
2009	7.37
2010	7.75
2011	8.18
2012	8.63
2013	9.10
2014	9.61
2015	10.14
2016	10.71
2017	11.32
2018	11.96
2019	12.64
2020	13.37

Table B-1

**Short-Term Forecast of
Natural Gas Prices
Henry Hub and Gulf Coast Spot
(Dollars per MMBtu)**

<u>Month</u>	<u>Henry Hub</u>	<u>Gulf Coast</u>
1996		
Jan	3.42	3.25
Feb	2.40	2.33
Mar	2.94	2.81
Apr	2.70	2.58
May	2.21	2.15
Jun	2.38	2.28
Jul	2.66	2.57
Aug	2.30	2.22
Sep	1.83	1.72
Oct	1.85	1.75
Nov	2.76	2.63
Dec	3.90	3.73
1997		
Jan	4.09	3.84
Feb	2.96	2.79
Mar	1.78	1.66
Apr	1.85	1.77
May	2.15	2.04
Jun	2.31	2.24
Jul	2.18	2.07
Aug	2.18	2.11
Sep	2.55	2.46
Forecast		
Oct	3.20	3.13
Nov	2.80	2.71
Dec	3.14	3.02
1998		
Jan	3.21	3.08
Feb	2.41	2.30
Mar	2.11	2.01
Apr	2.13	2.04
May	2.07	2.00
Jun	2.19	2.11
Jul	2.14	2.07
Aug	2.03	1.96
Sep	2.05	1.98
Oct	2.21	2.13
Nov	2.24	2.15
Dec	2.62	2.50

Table B-2

Long-Term Forecast of
Gulf Coast and Henry Hub
Spot Natural Gas Prices
Delivered To Pipeline
(Dollars per MMBtu)

<u>Year</u>	<u>Henry Hub</u>	<u>Gulf Coast</u>
1993	2.11	2.06
1994	1.89	1.83
1995	1.64	1.57
1996	2.61	2.50

Forecast

1997	2.60	2.49
1998	2.28	2.19
1999	2.20	2.11
2000	2.12	2.03
2001	2.14	2.06
2002	2.28	2.19
2003	2.36	2.27
2004	2.42	2.34
2005	2.51	2.43
2006	2.61	2.53
2007	2.71	2.63
2008	2.85	2.77
2009	2.97	2.89
2010	3.15	3.07
2011	3.32	3.24
2012	3.48	3.41
2013	3.66	3.58
2014	3.88	3.80
2015	4.07	3.99
2016	4.30	4.22
2017	4.57	4.48
2018	4.79	4.70
2019	5.09	5.00
2020	5.40	5.31

Table B-3

Long-Term Forecast of
Natural Gas Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

<u>Year</u>	<u>South Atlantic</u>
1993	2.42
1994	2.20
1995	2.22
1996	3.18

Forecast

1997	2.78
1998	2.39
1999	2.36
2000	2.40
2001	2.54
2002	2.67
2003	2.77
2004	2.87
2005	2.98
2006	3.11
2007	3.25
2008	3.41
2009	3.58
2010	3.76
2011	3.95
2012	4.13
2013	4.35
2014	4.57
2015	4.83
2016	5.11
2017	5.40
2018	5.71
2019	6.04
2020	6.38

Table C-1

Long-Term Forecast of
Coal Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

<u>Year</u>	<u>South Atlantic</u>
1993	1.64
1994	1.60
1995	1.55
1996	1.49

Forecast

1997	1.50
1998	1.50
1999	1.51
2000	1.53
2001	1.56
2002	1.60
2003	1.64
2004	1.68
2005	1.72
2006	1.76
2007	1.81
2008	1.86
2009	1.91
2010	1.97
2011	2.03
2012	2.08
2013	2.15
2014	2.22
2015	2.30
2016	2.38
2017	2.46
2018	2.53
2019	2.62
2020	2.70

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Volume 1B

Kissimmee Utility Authority

Florida Municipal Power Agency

Cane Island - Unit 3



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Volume 1B

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Florida Municipal Power Agency



Cane Island Power Park Unit 3



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1B.1.0 Overview and Summary

1B.1.1 Overview

Cane Island Unit 3 is planned as a new combined cycle addition to the existing Cane Island site, located in Osceola County. Cane Island Units 1 and 2, a combustion turbine and combined cycle burning natural gas, are currently operating. The Cane Island Site was licensed for an ultimate capacity of approximately 1,000 MW. Cane Island Unit 3 will provide very economical power for the Kissimmee Utility Authority (KUA) with a minimal environmental impact. Cane Island Unit 3 will be a 1x1 "F" class combined cycle unit. The actual output of the unit will depend upon the combustion turbine vendor selected and the design and size of the steam turbine. Output will also vary with degradation and ambient conditions. KUA will be a 50 percent joint owner in Cane Island Unit 3. KUA's portion of the nominal 250 MW of generation from Cane Island Unit 3 will be approximately 125 MW. Details specific to the project are presented in Volume 1A. This volume, Volume 1B, contains information specific to KUA's need for the project.

KUA strives to meet its responsibility to supply its customer's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. KUA's rates are among the lowest in the state due to strategic planning and ability to provide economies of scale to its customers.

KUA is committed to meet its customer's needs and identify projects that will provide economical power through the combination of demand-side and supply-side resources. KUA has been a strong supporter of conservation and demand-side programs where cost effective. With KUA's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

A diversified mix of fuels for generation provides methods to reduce risk associated with fuel price volatility and supply risk. Cane Island Unit 3 provides the best alternative for fuel diversification for KUA with the price of natural gas projected to remain low and the availability of natural gas to remain high throughout the planning horizon.

KUA achieves savings through economy interchange and central dispatch which are obtained through participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, Kissimmee, and the FMPP All-Requirements Project.



KUA's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with the Cane Island Unit 3 project. Cane Island Unit 3 will burn natural gas as the primary fuel with dry low NO_x burners providing a very clean burning high efficiency unit.

As discussed in the remainder of this Volume, KUA has evaluated appropriate alternatives to Cane Island Unit 3 to determine if they are lower in cumulative present worth revenue requirements. As part of the evaluation process, KUA together with FMPA, issued a joint request for proposals (RFP) for power supply as an alternative to Cane Island Unit 3 in May 1997. Numerous bids were received and evaluated. All bids received that were feasible under current regulations in Florida resulted in higher costs than Cane Island Unit 3. As a result, KUA rejected all long-term bids and is pursuing the construction of Cane Island Unit 3.

KUA believes that Cane Island Unit 3 represents the minimal cost and performance risk to its customers due to the proven performance of the F class combined cycle technology. As demonstrated in this application, Cane Island Unit 3 represents KUA's least cost alternative that has been demonstrated through exhaustive evaluations as well as a thorough test of the marketplace.

1B.1.2 Summary

KUA historically has been one of the fastest growing utilities in the United States with a 6.7 percent annual growth rate in peak demand over the last ten years. Rapid growth is projected to continue with a 4.2 percent annual growth rate in peak demand projected through the end of the 20 year planning period. The development of the proposed World Exposition Center (Expo Center) on KUA's service territory is projected to contribute significantly to KUA's load growth. The Expo Center is projected to begin operation in 2000. KUA has incorporated estimates of the direct loads from the Expo Center into KUA's forecast. Indirect loads from the Expo Center are likely to be significant and currently are only considered in sensitivity projections.

KUA is currently using a 15 percent reserve margin for planning purposes. In 2000, KUA's reserve margin dips to 11.9 percent including projected loads from the Expo Center requiring an additional 8 MW to maintain a 15 percent reserve margin. Without the Expo Center, KUA's reserve margin is projected to be 18.2 percent in 2000. KUA has a



supplemental resale contract with Florida Power Corporation which allows KUA to purchase the capacity necessary to maintain a 15 percent reserve margin with the Expo Center's loads. While this purchase has not been explicitly included in KUA's expansion plans, KUA can implement it as the Expo Center loads develop. In 2001, KUA's reserve margin is projected to be negative with and without the Expo Center requiring the addition of capacity.

KUA has evaluated numerous demand and supply-side alternatives to meet capacity requirements. The low cost of Cane Island Unit 3 precludes demand-side alternatives from being cost effective. KUA issued a request for proposals (RFP) for purchase power on May 28, 1997. KUA received 22 proposals from 13 different bidders. After an extensive evaluation, the lowest cost purchase power proposal was almost 30 percent more costly than Cane Island 3. KUA evaluated 10 different generating unit alternatives using the EGEAS optional generation expansion model. Cane Island 3 was found to be the least cost alternative under both base and sensitivity conditions.



1B.2.0 Description of Existing Facilities

1B.2.1 KUA Structure

KUA has been a municipal utility, owned by the City of Kissimmee, since 1901. In 1985, voters approved the Charter for Kissimmee Utility Authority. KUA now operates as an independent utility authority owned by the City of Kissimmee and operated by a 5-member Board of Directors plus the mayor of the City of Kissimmee as a not voting member. Since becoming an independent utility authority, KUA has enjoyed stable management and has been operated by the Board of Directors in a very business like environment.

1B.2.2 Generation System

KUA owns and operates or has ownership interest in generating units comprised of several technologies, including nuclear, coal fired, diesel, simple cycle, combustion turbine, and combined cycle. Table 1B.2-1 provides a summary of KUA's existing generating resources. The following paragraphs describe KUA's generating assets and ownership interests in detail.

KUA owns and operates eight diesel generating units ranging in age from 15 to 39 years. All of these diesel units are located at the Roy B. Hansel Generating Station in Kissimmee. Six of these diesel units are fueled by natural gas with No. 2 oil as pilot oil while the remaining two burn No. 2 oil only. The total nameplate capacity of the eight diesels is 18.35 MW. In addition, KUA owns and operates a natural gas fired (with No. 2 oil as backup) combined cycle plant, which is also located at the Hansel site. This plant consists of a 35 MW (nameplate) combustion turbine which provides waste heat for two 10 MW (nameplate) steam turbine generators. The total nameplate generating capability at the Hansel site is approximately 73.35 MW.

KUA and FMPA are both 50 percent joint owners of Cane Island Units 1 and 2. Unit 1 is a simple cycle General Electric LM6000 aeroderivative combustion turbine with a nameplate rating of 42 MW. Unit 2 is a 1 x 1 General Electric Frame 7EA combined cycle with a nameplate rating of 120 MW. KUA's 50 percent ownership share of the Cane Island Units is 81 MW (nameplate).

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Table 1B.2-1
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Fuel Transportation		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability	
				Primary	Alternate	Primary	Alternate				Summer (MW)	Winter (MW)
Hansel	8	Osceola County 27,T255/R29E	IC	NG	FO2	PL	TK	02/59	-/98	3.00	3	3
	14		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	15		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	16		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	17		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	18		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	19		IC	FO2	---	TK	---	02/83	01/13	2.50	3	3
	20		IC	FO2	---	TK	---	02/83	01/13	2.50	3	3
	21		CT	NG	FO2	PL	TK	02/83	01/13	35.00	28	32
	22		ST	WH	---	---	---	02/83	01/13	10.00	10	10
	23		ST	WH	---	---	---	02/83	01/13	10.00	10	10
	Plant Total										73.35	67
Crystal River	3	Citrus County 33,T17S/R16E	N	UR	---	TK	---	03/77	Unknown	890.46	6 ^(a)	6 ^(a)
Plant Total										890.46	6	6
Stanton Energy Center	1	Orange County 13,14,23,24 /R31E/T23S and 18,19 /T23S/R32E	ST	BIT	---	RR	---	07/87	Unknown	464.58	21 ^(a)	21 ^(a)
Plant Total										464.58	21	21
Indian River	A	Brevard County 12/T23S/R35E	CT	NG	FO2	PL	TK	07/89	Unknown	41.40	4.5 ^(b)	5.5 ^(b)
	B		CT	NG	FO2	PL	TK	07/89	Unknown	41.40	4.5 ^(b)	5.5 ^(b)
Plant Total										82.80	9	11



Table 1B.2-1 (Continued)
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Fuel Transportation		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability	
				Primary	Alternate	Primary	Alternate				Summer (MW)	Winter (MW)
Cane Island	1	Osceola County 29,32/R28E /T25S	CT	NG	FO2	PL	TK	01/95	Unknown	42.00	15 ⁽⁴⁾	20 ⁽⁴⁾
	2		CT	NG	FO2	PL	TK	06/95	Unknown	80.00	34 ⁽⁴⁾	40 ⁽⁴⁾
	2		ST	WH	—	—	—	06/95	Unknown	40.00	20 ⁽⁴⁾	20 ⁽⁴⁾
Plant Total										162	69	80
System Total as of January 1, 1998											172	189

Notes:

(1)KUA's 0.6754 percent portion of joint ownership.

(2)KUA's 4.8193 percent ownership portion.

(3)KUA's 12.2 percent portion of joint ownership.

(4)KUA's 50 percent ownership portion.



KUA owns a 0.6754 percent interest, or 6 MW (nameplate), in Florida Power Corporation's (FPC) Crystal River Nuclear Unit 3, located in Citrus County, Florida. KUA also has a 4.8193 percent ownership interest, or 22.3 MW (nameplate), in Orlando Utilities Commission's (OUC) Stanton Energy Center Unit 1 and a 12.2 percent, or 10 MW (nameplate), of OUC's Indian River Combustion Turbine Project Units A and B.

1B.2.3 Purchase Power Resources and Entitlement

KUA is a member of the Florida Municipal Power Agency (FMPA), a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 14 other members of FMPA. KUA's entitlement share of this unit, based on a power purchase contract, is 0.8282 percent (6.9 MW). FMPA has also entered into a Reliability Exchange Agreement with FPL under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit No. 1 and half from Unit No.2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has one contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases up to an additional 50 MW if the capacity is available from OUC. KUA has a second contract with OUC for Stanton 2 unit power purchases. KUA is purchasing 30 MW of this capacity for 1998 and 1999, and 40 MW in 2000. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton II Project. The Stanton 2 percentage includes recently acquired Homestead and Lake Worth shares which total 3.8314 percent. Table 1B.2-2 presents KUA's purchase power resources.

1B.2.4 Transmission System

KUA is a member of the Florida Reliability Coordinating Council (FRCC). The FRCC has established an energy broker system which provides economic interchange of electric energy between member utilities, including KUA. KUA has purchased and sold energy through this broker system, and intends to continue such transactions whenever conditions



Table 1B.2-2
KUA's Purchase Power

Year	Utility/Unit (MW)				Annual Total
	St. Lucie 1 & 2	Stanton 1 ⁽¹⁾	Stanton 2 ⁽²⁾	OUC ⁽³⁾	
1998	6.9	7.86	33.3	50	98.1
1999	6.9	7.86	33.3	50	98.1
2000	6.9	7.86	33.3	60	108.1
2001	6.9	7.86	33.3	20	68.1
2002	6.9	7.86	33.3	20	68.1
2003	6.9	7.86	33.3	20	68.1
2004	6.9	7.86	33.3	0	48.1
2005	6.9	7.86	33.3	0	48.1
2006	6.9	7.86	33.3	0	48.1
2007	6.9	7.86	33.3	0	48.1
2008	6.9	7.86	33.3	0	48.1
2009	6.9	7.86	33.3	0	48.1
2010	6.9	7.86	33.3	0	48.1
2011	6.9	7.86	33.3	0	48.1
2012	6.9	7.86	33.3	0	48.1
2013	6.9	7.86	33.3	0	48.1
2014	6.9	7.86	33.3	0	48.1
2015	6.9	7.86	33.3	0	48.1
2016	6.9	7.86	33.3	0	48.1
2017	6.9	7.86	33.3	0	48.1

Notes:

No reserves are supplied by the selling utility. KUA provides for 15 percent reserves.

(1)KUA share of Stanton 1 through FMPA Stanton 1 Project is 1.80725 percent.

(2)KUA share of Stanton 2 through FMPA Stanton 2 Project is 7.6628 percent. Total percentage represents KUA's original purchase percentage plus sum of recently acquired Homestead and Lake Worth purchase percentages equal to 3.8314 percent.

(3)20 MW firm purchase plus 30 MW Stanton 2 unit purchase in 1998, 1999, and 40 MW in 2000.



are favorable. Currently, these economy transactions are conducted through the Florida Municipal Power Pool (FMPP).

KUA has direct transmission interconnections with: (i) FPC, delivered at 69 kV from the FPC Lake Bryan substation and at 230 kV at OUC's Taft substation; (ii) OUC delivered from two 230 kV lines from Cane Island, one 230 kV line from the Taft substation, and a 230/69 kV autotransformer at Taft substation serving KUA's 69 kV line; (iii) the City of St. Cloud, Florida now being operated by OUC, at KUA's 69 kV interconnection with St. Cloud's transmission facilities; and (iv) TECO, one 230 kV circuit through the interconnection with the Osceola and Lake Jewell circuits.

Electric power and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to eight distribution substations. KUA provides electric service to retail customers primarily by 13.2 kV feeder circuits from the distribution substations.

1B.2.5 Service Area

KUA serves a total area of approximately 85 square miles, which includes the City of Kissimmee and surrounding areas of Osceola County. As of January 1, 1998, KUA served approximately 42,743 electric customers. Of these, 34,662 were residential, 7,403 were general service non-demand, and the remaining 678 were general service demand customers. KUA's electric service area, shown on Figure 1B.2-1, is entirely located in Osceola county.

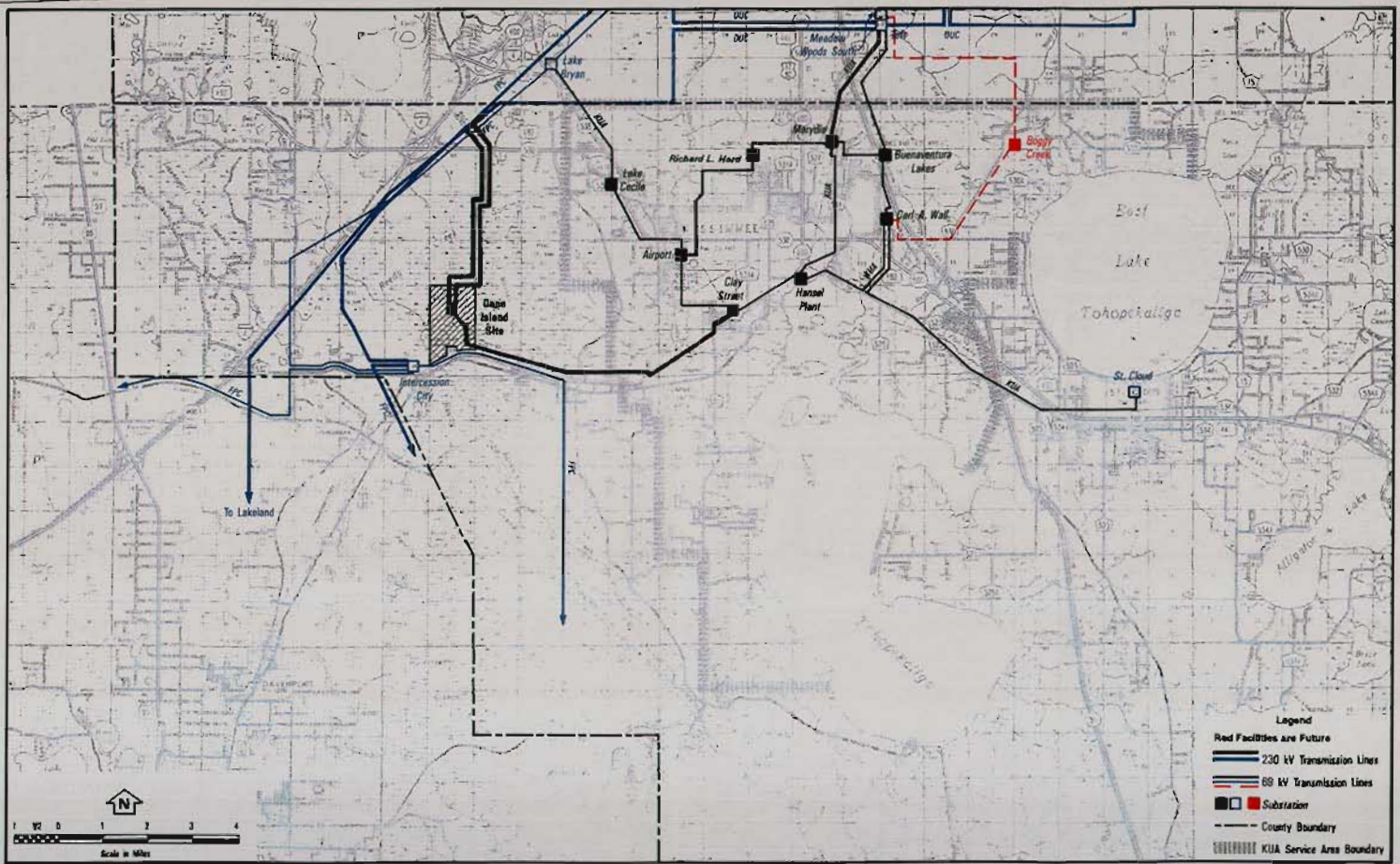


Figure 1B.2-1



1B.3.0 Methodology

This section provides a general description of the methodology used to analyze the Cane Island Unit 3 expansion for KUA and is arranged according to the sequence of the remaining sections of this volume. The purpose of the power supply planning study and determination of need is to develop evaluation criteria, a range of load and fuel forecasts, and potential capacity additions that will meet the least-cost power generation needs of its consumers while providing consideration for reliability, fuel diversity, environmental impacts, strategic goals, and regulatory requirements. To this end, KUA has provided in-depth analysis and evaluation of supply-side and demand-side resources to determine the least-cost plan which is in the collective best interest of all parties involved.

1B.3.1 Evaluation Criteria

The first step in the power supply planning process is to establish evaluation criteria, that is, to identify the assumptions about important parameters used in the analysis. Evaluation criteria presented in Section 1B.4.0 include the following:

- Economic forecast assumptions.
- Financial assumptions.
- Natural gas availability assumptions.
- Fuel price projections.

1B.3.2 Forecast of Electrical Power Demand and Energy Consumption

The load forecast for the KUA electric system is summarized in Section 1B.5.0 and shown in detail in Appendix 1B.16.1. The Appendix describes the development of the econometric models which forecast system peak demands and energy requirements. The load forecast takes into account KUA's existing conservation plans. Demand-side program reductions are forecast separately.



1B.3.3 Conservation and Demand-Side Management

KUA's conservation and demand-side management programs are discussed in Section 1B.6.0. Estimates of capacity avoided by the demand-side management program is provided.

1B.3.4 Reliability Criteria

Section 1B.7.0 presents the reliability criteria used to identify timing of capacity additions. KUA uses a 15 percent minimum reserve margin as the reliability criteria.

1B.3.5 Supply-Side Alternatives

Supply-side alternatives that are candidates for meeting the KUA capacity expansion requirements are outlined in Section 1A.5.0. A variety of plant sizes, capital costs, and operating parameters of conventional alternatives as well as advanced and renewable technologies are considered.

1B.3.6 Supply-Side Screening

The economics of the supply-side alternatives were evaluated on a screening level before modeling in detail in production cost programs. The screening analysis provides a method to eliminate alternatives that possess no potential of being economically viable under any operating parameters for KUA. The details of the screening analysis are provided in Section 1A.6.0.

1B.3.7 Economic Analyses

In Section 1B.10.0, the economics of the expansion alternatives are evaluated from the characteristics in Section 1A.5.0. The plans are evaluated on a comparative basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components:

- Fuel costs.
- Purchased power costs.
- Operation and maintenance (O&M) costs.



- Capital costs for new generation.
- Transmission Costs for new units.

An optimization program, EGEAS, is used to model the KUA system for the expansion alternatives developed in Section 1B.10.0. Annual system fuel and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions.

The objective of the economic analysis is to determine the total present worth of the annual comparative revenue requirements. This refers to the sum of the annual comparative revenue requirements discounted to 1998 using KUA's present worth discount rate.

1B.3.8 Sensitivity Analyses

Several sensitivity analyses were conducted to verify the robustness of the least-cost plan to altered conditions. The sensitivity analyses include a high load and energy forecast, low load and energy forecast, high fuel price forecast, low fuel price forecast, and a case where the differential fuel prices of coal versus natural gas/oil are held constant over the planning horizon. The results of the analyses are included in Section 1B.11.0.

1B.3.9 Strategic Considerations

Section 1B.12.0 outlines the strategic considerations involved in the alternative power supply plans. Such considerations include fuel mix, fuel supply, and availability of sites. The strategic considerations factor into the analysis of the least-cost plan. While the least-cost plan might provide the least-cost under the applied assumptions, the "best" plan may be different depending on strategic considerations.

1B.3.10 Consequences of Delay

Section 1B.13.0 addresses the adverse consequences of not building or delaying Cane Island Unit 3.

1B.3.11 Financial Analysis

Section 1B.14.0 addresses the financial feasibility of constructing Cane Island 3 with KUA's current financial position. This section highlights KUA's strong standing among Florida Utilities and high outlook for future growth.



1B.3.12 Analysis of 1990 Clean Air Act Amendments

Section 1B.15.0 addresses the impact of the 1990 Clean Air Act Amendments on the Cane Island 3 project.





1B.4.0 Evaluation Criteria

This section presents the assumptions applied for economic parameters and projections of prices used in evaluating the need for Cane Island Unit 3. The assumptions stated in this section are applied consistently throughout. Economic evaluation is conducted over a 20 year period from 1998 through 2017. The economic evaluation is based on the cumulative present worth of annual costs for capital costs, nonfuel O&M costs, fuel costs, and purchase power demand, energy, and transmission costs. Costs that are common to all expansion alternatives, such as demand charges for existing firm purchases, conservation and demand side management, existing transmission and distribution system costs, and administrative and general costs are not included.

1B.4.1 Economic Parameters

1B.4.1.1 Escalation Rates

A 2.5 percent general inflation rate is assumed. A 3.0 percent annual escalation rate is used for operation and maintenance (O&M) costs. A 2.5 percent annual escalation rate is used for capital costs.

1B.4.1.2 Bond Interest Rate

The bond interest rate is assumed to be 5.5 percent.

1B.4.1.3 Bond Issuance Fee

A bond issuance fee of 2.9 percent is assumed to apply to KUA bond issues.

1B.4.1.4 Present Worth Discount Rate

The base case present worth discount rate is equal to the bond interest rate of 5.5 percent.

1B.4.1.5 Interest During Construction

Interest during construction is assumed equal to bond interest rate of 5.5 percent.

1B.4.1.6 Fixed Charge Rate

The fixed charge rate is 8.2 percent. The fixed charge rate was developed based on a 30 year bond term including principal and interest, a 1 year debt service reserve fund, interest earnings credit based on the bond interest rate, a 2.9 percent bond issuance fee, and 1.0 percent for property insurance.



1B.4.2 Fuel Price Projections

A detailed discussion of the fuel price projections is in Section 1A.3.2.

1B.4.3 Fuel Availability

Natural gas is currently delivered to KUA's Hansel Plant and Cane Island Power Park under two firm transportation service agreements with Florida Gas Transmission Company (FGT). These two firm transportation services are commonly referred to as FTS-1 and FTS-2. KUA has contracted with FGT for FTS-1 and FTS-2 and has firm rights to deliver the following Maximum Daily Transportation Quantities (MDTQ) (Mbtu/day):

	<u>October</u>	<u>November-March</u>	<u>April</u>	<u>May-September</u>
FTS-1	2,310	3,340	4,360	6,441
		<u>November-April</u>		<u>May-October</u>
FTS-2		10,984		8,781

The FTS-1 agreement terminates August 1, 2005 and KUA has the right of first refusal to extend the agreement. The FTS-2 agreement was effective March 1, 1995 and has a term of 21 years.

KUA is a member of Florida Gas Utility (FGU) which is an organization of municipal utilities which manages and schedules member's transportation entitlements and purchases gas for members.

KUA can deliver additional volumes of natural gas to Hansel and Cane Island by utilizing the firm transportation rights of other member cities of FGU when available. KUA can release its unused firm transportation rights to other member cities of FGU as needed. When available, interruptible transportation can be utilized under KUA's interruptible contract through FGU.

KUA has also contracted with FGU which acts as agent to KUA and other member cities to make bulk purchases of natural gas which consist of a combination of spot market purchases and firm supplies. FGU contracts for approximately one third of its supply requirements on a firm basis.



1B.5.0 Forecast of Electrical Power Demand and Energy Consumption

1B.5.1 Introduction

KUA's detailed, long-term electric load and energy forecast is presented in the following Subsections. KUA's system wide forecast was developed in two components, which were summed to develop the total system load forecast.

The first component is the bulk system forecast, which KUA developed for planning purposes using econometric techniques to forecast customer class energy sales. The detailed econometric energy sales forecast is developed on a monthly basis. The model is reviewed annually and revised, if necessary.

The second forecast component is the proposed World Exposition Center (Expo Center) forecast. The Expo Center forecast, further described in Section 1B.5.4, presents KUA's detailed analysis of a significant, planned load addition to the system, which is the result of a major commercial development on an 800-acre site in the northwest corner of KUA's service territory.

1B.5.2 Econometric Energy Sales Forecast

Econometric forecast models were used to project monthly energy sales for each customer class. The econometric models and associated statistical relationships were developed for forecasting monthly changes in customer class electricity usage as a function of demographic influencing factors such as temperature, population and income. The models used were developed based on identifiable, statistical relationships between historical, economic, weather and electric system data.

1B.5.2.1 Forecast Methodology

The statistical estimating technique used in the development of the models was multiple least squares linear regression. This method was used to determine the linear relationship between the dependent variable, energy usage, and multiple independent econometric variables based on changes in the values of the variables through time. Implicit in the model development is the assumption that customer class energy usage will be affected by the same



key factors in the future as in the past. The following equation represents this linear relationship:

$$Y = a + \sum_{i=1}^n [b_i * X_i] + e$$

where: Y = dependent variable (predicted)

a = constant term

b_i = coefficient terms

X_i = independent variables

e = error term

The calculated equation minimizes the sum of the squared errors between the actual and predicted values of the dependent variable.

An important consideration in regression analysis is the selection of variables. Independent variables explain changes in the dependent variable. Therefore, sufficient historical data for both dependent and independent variables must be available to produce a reliable regression equation. Also, to forecast values of the dependent variable, the independent variables must have the potential to be projected into the future.

All regression equations were tested using five primary statistical measures. The first measure is the adjusted R^2 , the coefficient of determination corrected for reduced degrees of freedom due to inclusion of additional independent variables in the regression equation. The coefficient of determination (perfect = 1.0) is the proportion of variability in the dependent variable that is explained by the independent variables. The second measure is the F statistic, which is a test of whether there is a significant linear relationship between the dependent variable and the entire set of independent variables. The F-test is performed by determining the calculated F statistic (F_{CALC}) and comparing this value with the corresponding value of the F distribution (F_{DIST}). The third measure is the T statistic, which is a test for multicollinearity of the independent variables. This test is performed by determining the calculated T statistic (T_{CALC}) and comparing this value with the corresponding value of the T distribution (T_{DIST}). The fourth measure is the Durbin-Watson (DW) statistic, which is a test for serial correlation of adjacent error terms. The fifth, and final, measure is the Akaike Information Criterion (AIC). The AIC serves as a guide to the selection of the number of terms in an equation by placing a penalty on additional coefficients.



1B.5.2.2 Econometric Data and Projections

This subsection describes the data sources used in the development of the econometric variable projections for the forecast period. As in previous forecasts, economic and population forecasts from the Bureau of Economic and Business Research (BEBR) were included in the analysis as econometric variables.

1B.5.2.2.1 Historical Data. A careful compilation of historical data was developed to formulate a reliable econometric model for forecasting electricity sales. Monthly historical sales data were compiled for each major customer classification for the period of January 1985 through September 1997. Additional data including temperature, population, employment, households, real personal income and total housing starts was also compiled. The econometric data were obtained from BEBR data applicable to the MSA in which Kissimmee is located. MSAs are Metropolitan Statistical Areas defined by the census bureau for various regions within each state. Kissimmee is located within the Orlando MSA. The Orlando MSA includes Orange, Lake, Seminole and Osceola Counties. Although some variance in general MSA versus Kissimmee data can be expected, the homogeneous nature of the surrounding region provided well aligned trend relationships between historical electricity use and the econometric variables selected for the forecast. A complete listing of all historical data evaluated in the development of the load forecast, including projections of selected variables, is contained in Appendix 1B.16.2.

1B.5.2.2.2 Econometric Projections. The BEBR has estimated that, during the next fifteen years, employment will grow at an average annual rate of 2.2 percent, down from 3.5 percent from 1980 through 1995. Real personal income is estimated to grow at an average annual rate of 2.9 percent, down from 4.1 percent from 1980 through 1995. In general, the slower percentage growth rates of employment and income for Florida are related to a slowing annual population growth rate. Florida's average annual population growth rate is forecast to be 1.5 percent from 1995 through 2010, down from 2.5 percent from 1980 through 1995. Although Osceola County economic and population forecasts show slower growth, Osceola County's annual growth rate continues to exceed the surrounding counties. Osceola County is currently the third fastest growing county in Florida, and all but nine counties in Florida are growing faster than the national average.



1B.5.2.3 Forecasting Assumptions

The first key assumption included in the load forecast analysis is related to regional weather patterns. Because predicting future weather patterns is not possible, normal weather conditions were assumed for the load forecast model. Monthly average temperatures for the last 10 years were used as a representation of normal weather. For weather projections, the weather for every month of the forecast period was set equal to that month's 10-year average of daily temperatures for the historical period. The same methodology was applied uniformly to all other weather-related variables used in the analysis.

The second key assumption of significance to the 1998 sales forecast is the inclusion of an estimated annual rate decrease of 2.5 percent for all rate classes to be implemented during a 6-year period beginning October 1997. This assumption is based on KUA's goal of reducing rates by nearly 15 percent during the next six years to increase competitiveness in the changing utility regulatory environment. In general, the rate decrease will act to offset economic slowdown by increasing energy use per customer in both the Residential and General Service Non-Demand customer classes. The variables PRICERES and PRICEGSN were introduced correspondingly into the models to estimate the impacts of this rate reduction.

1B.5.3 Energy Sales Forecast

1B.5.3.1 Residential Sales

To forecast residential electricity sales, annual forecasts of residential electricity use per customer and number of customers were developed using multiple least-squares regression models. The product of residential service customers and electricity use per customer forecasts yielded total annual residential electricity sales.

1B.5.3.1.1 Residential Customers. In the development of the econometric model for residential customers, a important economic data series is included to the forecast as a potential explanatory variable. The new data series, total housing starts (TS), represents the number of houses for which construction begins during the year. Based on KUA's statistical evaluation, TS more accurately represents fluctuations in historical sales data compared to Osceola County population estimates. For this reason, TS is used for the projection of annual number of residential customers. Autoregressive correction (AR) factors are included to minimize the effects of serial correlation. In effect, the AR variable incorporates the residual from previous observations into the regression model for the current observation. The



resulting equation is shown in Table 1B.5-1. Results of statistical tests for the equation are listed in Appendix 1B.16.1.

1B.5.3.1.2 Residential Energy Use Per Customer. Residential electricity use per customer was based on the relationship between historical income per household and the previous year's real price of electricity. In addition, a strong relationship between the HEAT2 variable, which represents the combined effect of heating degree days and the saturation of large electric appliances, and residential electricity use per customer was discovered. The significance of the HEAT2 term in the model of residential use per customer was also very high.

1B.5.3.1.3 Weather Impacts. Temperature and billing data were adjusted to compensate for different reporting periods. The degree days were shifted from calendar month to billing month to more accurately reflect the relationship between temperature and energy consumption. An example of this shifting is described as follows:

A customer has his electric meter read on billing cycle 2. In February, billing cycle 2 corresponds with a meter reading date of February 2nd. Sales to this customer are billed in February, but primarily occur in January. If the remainder of February is bitterly cold, the corresponding degree days are not reflected in the customer's February bill. As a result, error is introduced.

By aligning the sales and degree days, the model became more responsive to changes in temperature. The resulting equation, showing the results of multiple regression on the independent variables, is listed in Table 1B.5-1. Results of statistical tests for the equation are listed in Appendix 1B.16.1.



Table 1B.5-1
Sales Forecast Equations

$$\text{RSCUSTT} = 7674.448 + 537.403 \cdot \text{TS} + 0.431 \cdot \text{AR}(1) + 0.414 \cdot \text{AR}(2)$$

RSCUSTT : Total Residential Customers
TS : Total Number of Housing Starts in Osceola County
AR(1) : First Order Auto-Regressive Term
AR(2) : Second Order Auto-Regressive Term

$$\text{RSUPC} = 413.260 + 1.040 \cdot \text{HEAT2} + 2.488 \cdot \text{MINTEMP} + 17.380 \cdot \text{INCPERHH} - 4.973 \cdot \text{PRICERES} - 84.227 \cdot \text{MAR} - 65.276 \cdot \text{APR} + 191.163 \cdot \text{JUN} + 362.351 \cdot \text{JUL} + 408.281 \cdot \text{AUG} + 437.390 \cdot \text{SEP} + 283.073 \cdot \text{OCT} - 83.888 \cdot \text{DEC} + 0.206 \cdot \text{AR}(1)$$

RSUPC : Residential Use Per Customer
HEAT2 : Billing Month Heating Degree Days * Appliance Saturation
MINTEMP : Minimum Temperature of the Month
INCPERHH : Real Personal Income Per Household
PRICERES : Residential Real Price of Electricity
MAR-DEC : Variables for the Months of March through December
AR(1) : First Order Auto-Regressive Term

$$\text{GSNCUSTT} = -2993.870 + 73.652 \cdot \text{POPA} + 0.764 \cdot \text{AR}(1) + 0.746 \cdot \text{MA}(2)$$

GSNCUSTT : Total General Service Non-Demand Customers
POPA : Population in Osceola County
AR(1) : First Order Auto-Regressive Term
MA(2) : Second Order Moving Average Term

Table 1B.5-1 (Continued)
Sales Forecast Equations

$$\text{GSNKWHT} = -41914.30 \cdot \text{PRICEGSN}(-1) + 262002.6 \cdot \text{GOODSERV} + 46.329 \cdot \text{BMC_TIME} + 0.785 \cdot \text{AR}(1) + 0.364 \cdot \text{MA}(11) + 0.515 \cdot \text{MA}(12)$$

GSNKWHT : Total General Service Non-Demand Energy Sales
PRICEGSN : Real Price of Electricity
GOODSERV : Goods-Producing and Service-Related Employment
BMC_TIME : Billing Month Cooling Degree Days*Time Trend Variable
AR(1) : First Order Auto-Regressive Term
MA(11) : Eleventh Order Moving Average Term
MA(12) : Twelfth Order Moving Average Term

$$\text{GSDKWHT} = 11631387 + 73.170 \cdot \text{BMC_TIME} + 231556.3 \cdot \text{GOODSERV} - 904931.3 \cdot \text{FEB} - 1376438 \cdot \text{MAR} + 981953.4 \cdot \text{JUN} + 1989366 \cdot \text{JUL} + 1888365 \cdot \text{AUG} + 3918532 \cdot \text{SEP} + 1359601 \cdot \text{OCT}$$

GSDKWHT : Total General Service Demand Energy Sales
BMC_TIME : Billing Month Cooling Degree Days*Time Trend Variable
GOODSERV : Goods-Producing and Service-Related Employment
FEB-OCT : Variables for the months.

$$\text{OLSKWHT} = -429999.1 + 6849.977 \cdot \text{POPA} + 0.568 \cdot \text{AR}(1) + 0.315 \cdot \text{AR}(2)$$

OLSKWHT : Outdoor Lighting Service Energy Sales
POPA : Osceola County Population
AR(1) : First-Order Auto-Regressive Term
AR(2) : Second-Order Auto-Regressive Term



1B.5.3.2 General Service Non-Demand Forecast

The model for the general service non-demand rate classification comprises forecasts for a number of customers and energy sales and includes temporary service and KUA rate classifications.

1B.5.3.2.1 General Service Non-Demand Customers. Osceola County population was used as the basis for forecasting the number of general service non-demand customers. The resulting equation, developed to forecast the number of general service non-demand customers, is shown in Table 1B.5-1. Results of statistical tests for the equation are listed in Appendix 1B.16.1.

1B.5.3.2.2 General Service Non-Demand Electricity Sales. The general service non-demand model for annual electricity sales is primarily driven by goods-producing and service-related employment and the real price of electricity. In addition, a BMC_TIME term was added as a proxy for the saturation of cooling-related equipment in the commercial sector. The resulting equation, used to forecast the energy sales in kilowatt-hours for the general service non-demand customer class, is shown in Table 1B.5-1. Results of statistical tests for the equation are listed in Appendix 1B.16.1.

1B.5.3.3 General Service Demand Forecast

The general service demand model currently in use is progressively being improved. For the purpose of this forecast, general service demand comprises: GSD, GSDT, GSLD, and interruptible rate classifications. The general service demand customer forecast was derived by assuming that the use per customer would be constant through the study period, and was divided into the energy sales forecast to estimate the number of customers.

The equation resulting from the model for general service energy sales is shown in Table 1B.5-1. Results of statistical tests for the equation are listed in Appendix 1B.16.1.

1B.5.3.4 Outdoor Lighting Forecast

Street lighting, vapor lighting, and outdoor lighting were combined into one class for forecasting purposes. A multiple regression model was developed for outdoor lighting energy sales using Osceola County population as the explanatory variable. The multiple regression generated the equation shown in Table 1B.5-1. Results of statistical tests for the equation are listed in Appendix 1B.16.1.



1B.5.4 World Exposition Center Load Forecast

1B.5.4.1 Project Description

The developers of the World Exposition Center (Expo Center) are planning a major commercial development on an 800-acre site in the northwest corner of KUA's service territory in Osceola County. The construction of this world-class, mixed-use facility is already in the planning stages and is expected to be operational in 2000.

Phase I of the current plan, to be completed by the first part of 2000, includes a 2.4 million sq ft exposition hall, 1.3 million sq ft outside parking area, and a 0.6 million sq ft parking garage. Phase IA, to be completed by the first part of 2001, includes a 1.0 million sq ft hotel, 1.3 million sq ft County convention center, and 79,000 sq ft of commercial office space.

Phase II of construction will be completed during 2002-2004 in stages after Phase I and IA are operational. Phase II facilities include three resort hotels totaling 1.6 million sq ft, two office buildings totaling 0.5 million sq ft, a 1.0 million sq ft retail and entertainment complex, a public safety facility, and 2.0 million sq ft of additional parking.

Complete build-out of this facility will require an estimated \$1.1 billion. Total employment projections for the project and supporting industries is nearly 30,000 jobs with an estimated annual payroll of \$700 million.

Once completed, the peak demand and energy requirements of the Expo Center will significantly impact KUA's current system demand and least-cost planning methodology. Accordingly, KUA has conducted a detailed consumption analysis to determine the potential peak demand and energy use of the facility.

1B.5.4.2 Peak Demand and Energy Consumption Estimate

Electric demand of the Expo Center was estimated using data compiled by the Energy Information Administration (EIA) contained in the most recent Commercial Buildings Energy Consumption (CBEC) survey. The survey is conducted every three years by the EIA for the purpose of developing estimates of annual peak demand and energy usage, per sq. ft., for various building activities. The last survey conducted was compiled during 1996. The target population for the CBEC survey consists of all commercial buildings in the United States with more than 1,000 sq. ft. of floorspace. A commercial building is defined as any enclosed structure with more than 50 percent of its floorspace devoted to activities other than residential, industrial or agricultural uses. Major categories of commercial buildings tabulated



in the report include education, food sales, food service, health care, lodging, mercantile and service, office, public assembly, public order and safety, religious worship, warehouse and storage, other and vacant.

Table 1B.5-2 presents the per sq. ft. peak demand and energy consumption estimates derived from the survey. Survey data was statistically analyzed and divide into 25th percentile, median, and 75th percentile categories. For forecasting purposes, the 25th percentile data was used for the low demand forecast, the median was used for the base demand forecast, and the 75th percentile data was used for the high demand forecast.

To develop the load forecast scenarios, the consumption estimates listed in Table 1B.5-2 were multiplied by the estimated square footage of each Expo Center building and summed to develop the total annual peak demand and energy requirements for the entire Expo Center. It is assumed that the Expo Center's peak demand is coincident with KUA's system peak demand. Peak demands associated with the parking areas are excluded from the estimate of total peak demand total based on the assumption that these demands will occur after KUA's coincident system peak demand.

Table 1B.5-3 presents the resulting high, low and base forecasts of peak demand and energy consumption for Phase I, Phase IA and Phase 2 of the Expo Center. Total annual estimates are based on the following building expansion plan supplied by the developer.

- 2000 - Exposition Hall, Parking Area, Parking Garage.
- 2001 - Hotel Rooms, Convention Center, Offices.
- 2002 - Hotel Rooms, Offices, Retail Stores, Public Safety Building.
- 2003 - Hotel Rooms, Offices, Parking Area.
- 2004 - Hotel Rooms.

The proposed facility layout is presented on Figure 1B.5-1.

The Expo Center forecast only includes the projected direct loads of the Expo Center. Additional loads will occur from the related jobs and development. These additional loads may be accounted for, to some extent, in the high band forecast.

IMAGE QUALITY

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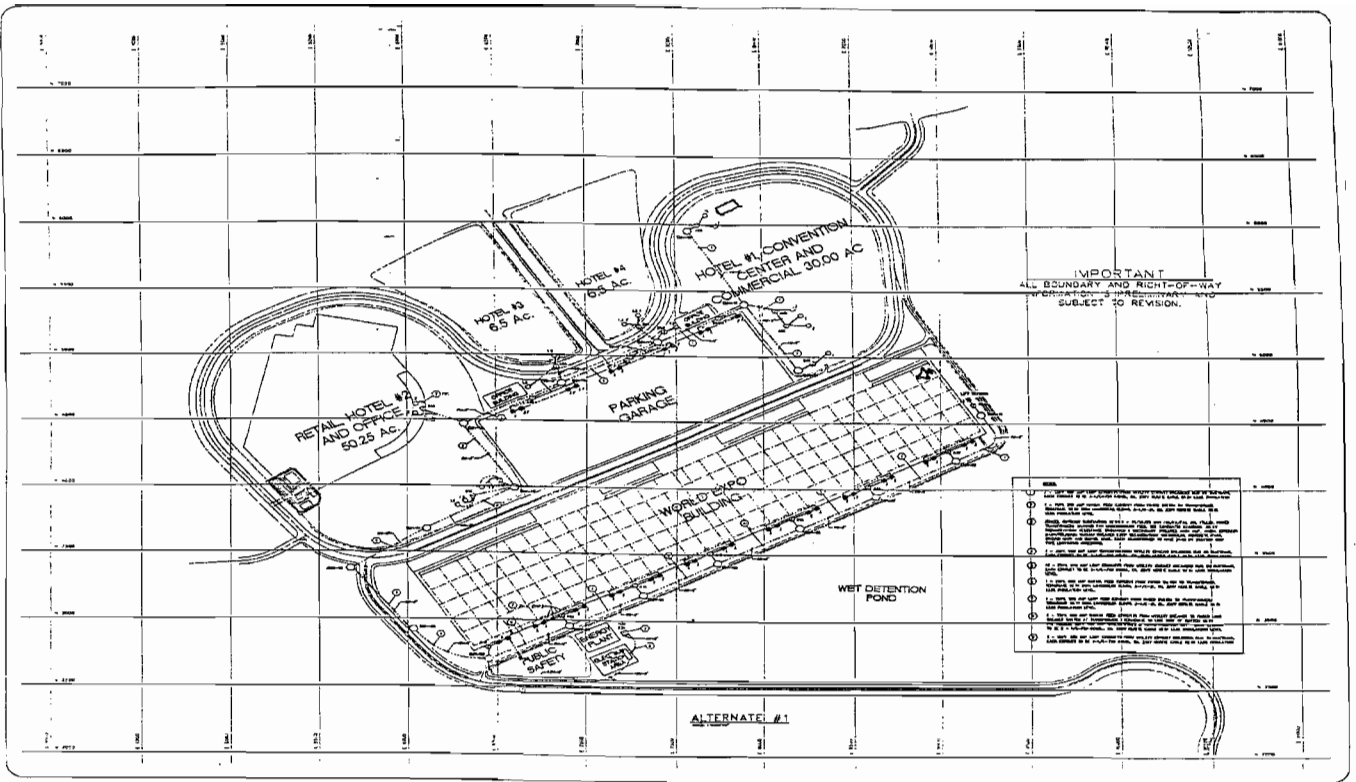
Table 1B.5-2
CBEC Commercial Buildings Survey
Annual Peak Demand and Energy Estimates (sq. Ft.)

Principal Building Activity	Peak Demand (W/sq. Ft.)			Energy (kWh/sq. Ft.)		
	25 th Percentile	Median	75 th Percentile	25 th Percentile	Median	75 th Percentile
Hotel	2.55	4.89	8.33	6.5	11.7	20.1
Mercantile and Service ¹	2.36	4.91	8.80	3.0	6.9	12.8
Office	3.40	6.00	7.99	6.1	12.2	20.2
Public Assembly ²	3.33	5.52	8.29	2.7	5.8	10.0
Public Order and Safety	2.24	5.00	5.14	3.3	3.9	9.8
Parking Garage	1.77	5.50	8.89	2.6	6.2	10.9
Notes						
¹ Mercantile and service estimates applied to retail and entertainment buildings.						
² Public assembly estimates applied to convention center buildings.						



Table 1B.5-3
World Exposition Center Load Forecast
Annual Peak Demand and Energy

Year	Low Forecast		Base Forecast		High Forecast	
	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)
2000	8.0	11,420	13.2	25,700	19.9	44,710
2001	15.1	21,912	25.8	45,904	39.6	79,406
2002	19.8	30,038	34.9	62,320	55.1	108,389
2003	22.0	40,458	39.1	94,490	61.6	146,796
2004	24.8	47,608	44.5	97,360	70.8	168,906
2005-2017	24.8	47,608	44.5	97,360	70.8	168,906



Poor Original



1B.5.5 System Net Energy for Load and Peak Demand Forecast

1B.5.5.1 Net Energy For Load

During the past several years, system net energy for load (NEL) was projected by applying an efficiency factor of 95 percent to the projection of total sales. During fiscal year 1997-98, an attempt was made to develop an econometric model for NEL using the relationship of NEL to total sales and certain monthly variables. After further review, it was decided that the econometric model did not provide significant accuracy to the projection of NEL and KUA returned to the 95 percent efficiency factor methodology.

Tables 1B.5-4 through 1B.5-6 present KUA's base-, high-, and low-case NEL forecasts. The total NEL forecast includes energy associated with the Expo Center load listed in Table 1B.5-3. Based on the current forecast, NEL is projected to grow at an average annual rate of 3.9 percent from 1998 through 2017 compared to 6.5 percent from 1988 through 1997.

1B.5.5.2 System Peak Demand Forecast

The forecast of system peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. Previous attempts to model peak load have been unsuccessful due to a lack of data. The estimate of peak load conditions is very dependent on weather and customer equipment. Although relatively reliable temperature data is available, peak load is extremely sensitive to other variables such as cloud cover, humidity and barometric pressure. KUA is continually investigating new methods of forecasting peak load to improve accuracy.

Tables 1B.5-7 through 1B.5-9 present KUA's summer low-, base- and high case peak demand forecasts. The total peak demand forecast equals the sum of the Expo Center and system-wide peak demand estimates. Based on the current forecast, a 4.2 percent average annual summer peak demand growth rate is projected for 1998 through 2017. This growth rate is significantly lower than KUA's historical average annual growth rate of 6.7 percent during the last 10 years.

1B.5.6 High and Low Sensitivities

In addition to the base-case load forecast, projections were developed for high- and low-system peak demand and customer class sales and resulting NEL load growth scenarios. The sensitivity analyses exclude the effects of 'spin-off' loads resulting from the construction of the Expo Center. Spin-off loads are difficult to estimate; however, the addition of several



thousand jobs and new commercial business establishments will result in additional system load growth within KUA's service territory.

1B.5.6.1 System NEL Sensitivities

The high and low bulk system sales and resulting NEL forecast sensitivities were developed based on changes in the independent economic variables, specifically, the BEBR's high and low population forecast. The economic forecast provided by BEBR is projected to 2010, and BEBR's long-term population forecast is projected to 2020. The BEBR economic forecast was used through 2010. To develop economic data beyond 2010, the economic data were adjusted by using their rate of change with respect to population in the base case, and maintaining that ratio in the high and low cases.

The high and low Expo Center NEL estimates were based on the 75th and 25th percentile data listed in Table 1B.5-2 as described in Section 1B.5.4.2.

1B.5.6.2 System Peak Demand Sensitivities

The high and low system peak demand forecast sensitivities were developed based on applying the system load factor listed in Section 1B.5.5.2 to the forecast of system NEL.

The high and low Expo Center peak demand estimates were based on the 75th and 25th percentile data listed in Table 1B.5-2 as described in Section 1B.5.4.2.

Figure 1B.5-2 presents a graphical representation of KUA's peak demand and energy forecasts. The base, high, and low peak demand forecasts are presented in Tables 1B.5-7 through 1B.5-9.



Table 1B.5-4
1998 Base-Case Net Energy for Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential		General Service Non-Demand		General Service Demand		Street and Outdoor Light MWh	Total Customer Accounts	Total KUA Sales MWh	Net Energy for Load Mwh (1)
	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh				
1988	22,588	251,281	2,963	39,023	769	235,618	2,508	26,320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	1,696	32,956	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	5,546	40,418	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,399	133,209	741	304,918	6,725	43,155	892,014	943,404
1997	35,613	447,647	7,619	142,325	730	322,243	7,173	43,962	919,388	981,406
1998	36,893	463,915	8,128	146,659	788	324,767	7,439	45,809	942,779	992,399
1999	38,228	491,509	8,567	159,480	811	334,039	7,779	47,606	992,808	1,045,061
2000	39,522	515,682	8,941	169,498	833	343,456	8,171	49,297	1,036,807	1,117,076
2001	40,816	540,467	9,301	179,779	855	352,299	8,565	50,971	1,081,110	1,183,915
2002	42,124	565,727	9,668	190,172	877	361,268	8,972	52,669	1,126,140	1,247,730
2003	43,453	591,481	10,046	200,661	899	370,486	9,394	54,398	1,172,023	1,328,198
2004	44,803	617,188	10,436	210,854	922	379,964	9,828	56,161	1,217,834	1,379,291
2005	46,174	642,085	10,829	221,148	945	389,551	10,267	57,948	1,263,051	1,426,887
2006	47,546	669,328	11,193	230,797	967	398,587	10,673	59,707	1,309,385	1,475,661



Table 1B.5-4 (Continued)
1998 Base-Case Net Energy for Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential		General Service Non-Demand		General Service Demand		Street and Outdoor Light MWh	Total Customer Accounts	Total KUA Sales MWh	Net Energy for Load MWh (1)
	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh				
2007	48,920	697,321	11,561	240,542	989	407,729	11,084	61,470	1,356,676	1,525,440
2008	50,293	725,810	11,939	250,513	1,012	417,088	11,505	63,244	1,404,917	1,622,800
2009	51,667	754,800	12,326	260,718	1,035	426,673	11,938	65,028	1,454,129	1,628,022
2010	53,042	784,221	12,718	271,059	1,059	436,394	12,375	66,819	1,504,049	1,680,569
2011	54,427	813,861	13,093	281,089	1,082	445,859	12,794	68,603	1,553,602	1,732,731
2012	55,851	844,499	13,474	291,262	1,105	455,466	13,219	70,430	1,604,445	1,786,250
2013	57,319	876,285	13,863	301,658	1,129	465,286	13,653	72,311	1,656,882	1,841,446
2014	58,831	909,267	14,262	312,284	1,154	475,325	14,098	74,246	1,710,974	1,898,385
2015	60,367	943,032	14,664	323,025	1,178	485,480	14,547	76,208	1,766,084	1,956,396
2016	61,833	975,680	15,045	333,365	1,202	495,297	14,972	78,080	1,819,314	2,012,428
2017	63,334	1,009,458	15,436	344,037	1,226	505,312	15,410	79,997	1,874,149	2,070,149

(1) Includes Expo Center 2000-2017 annual energy estimate listed in Table 1B.5-3.



Table 1B.5-5
1998 High-Case Net Energy for Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential		General Service Non-Demand		General Service Demand		Street and Outdoor Light MWh	Total Customer Accounts	Total KUA Sales MWh	Net Energy for Load Mwh (1)
	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh				
1988	22,588	251,281	2,963	39,023	769	235,618	2,508	26,123	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	1,925	29,485	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	1,696	32,748	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	4,686	34,949	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	4,962	36,695	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	5,046	38,512	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	5,546	40,416	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	6,237	42,059	857,503	915,228
1996	35,015	447,161	7,399	133,209	741	304,918	6,725	43,154	892,014	943,404
1997	35,754	449,897	7,617	143,631	740	326,183	7,200	44,162	926,910	989,324
1998	38,858	492,970	8,272	162,340	836	344,512	7,825	47,967	1,007,647	1,060,681
1999	41,954	545,460	8,995	192,981	875	360,703	8,527	51,824	1,107,672	1,165,970
2000	44,717	591,520	9,585	214,021	916	377,510	9,233	55,218	1,192,284	1,299,745
2001	47,167	634,737	10,089	232,403	952	392,407	9,855	58,208	1,269,401	1,415,618
2002	49,677	679,730	10,601	251,201	989	407,714	10,490	61,267	1,349,135	1,528,531
2003	52,332	727,581	11,138	270,856	1,029	423,859	11,157	64,498	1,433,453	1,655,694
2004	55,152	777,952	11,701	291,043	1,070	440,898	11,857	67,923	1,521,750	1,770,748
2005	58,098	829,833	12,282	311,577	1,112	458,235	12,579	71,492	1,612,225	1,865,985
2006	60,960	886,119	12,841	329,065	1,148	473,139	13,273	74,949	1,701,596	1,960,060
2007	63,949	946,622	13,417	346,718	1,185	488,192	13,990	78,551	1,795,523	2,058,930



Table 1B.5-5 (Continued)
1998 High-Case Net Energy for Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential		General Service Non-Demand		General Service Demand		Street and Outdoor Light MWh	Total Customer Accounts	Total KUA Sales MWh	Net Energy for Load Mwh (1)
	Average Accounts Billed	Sales Mwh	Average Accounts Billed	Sales Mwh	Average Accounts Billed	Sales Mwh				
2008	67,108	1,011,527	14,019	365,095	1,223	503,844	14,738	82,350	1,895,204	2,163,858
2009	70,447	1,081,170	14,648	384,231	1,262	520,124	15,519	86,357	2,001,044	2,275,268
2010	73,926	1,154,896	15,295	403,906	1,303	536,853	16,323	90,525	2,111,979	2,392,042
2011	77,347	1,228,718	15,924	423,065	1,342	553,182	17,105	94,613	2,222,068	2,507,925
2012	80,910	1,306,830	16,572	442,771	1,383	569,965	17,909	98,865	2,337,476	2,629,407
2013	84,658	1,390,168	17,245	463,226	1,425	587,367	18,747	103,329	2,459,507	2,757,861
2014	88,599	1,479,093	17,946	484,466	1,469	605,413	19,617	108,015	2,588,589	2,893,737
2015	92,691	1,572,789	18,666	506,205	1,514	623,874	20,511	112,870	2,723,380	3,035,621
2016	96,713	1,666,495	19,365	527,535	1,558	642,019	21,381	117,637	2,857,430	3,176,727
2017	100,911	1,765,784	20,091	549,764	1,603	660,692	22,287	122,604	2,998,078	3,324,778

(1) Includes Expo Center 2000-2017 annual energy estimate listed in Table 1B.5-3.



Table 1B.5-6
1998 Low-Case Net Energy for Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential		General Service Non-Demand		General Service Demand		Street and Outdoor Light MWh	Total Customer Accounts	Total KUA Sales MWh	Net Energy for Load Mwh (1)
	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh	Average Accounts Billed	Sales MWh				
1988	22,588	251,281	2,963	39,023	769	235,618	2,508	26,123	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	1,925	29,485	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	1,696	32,748	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	4,686	34,949	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	4,962	36,695	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	5,046	38,512	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	5,546	40,416	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	6,237	42,059	857,503	915,228
1996	35,015	447,161	7,399	133,209	741	304,918	6,725	43,154	892,014	943,404
1997	35,478	445,437	7,575	141,455	722	319,100	7,147	43,827	913,140	974,829
1998	35,018	436,186	7,442	135,169	748	308,365	7,006	43,208	886,726	933,396
1999	34,705	440,926	7,468	135,372	756	311,318	6,833	42,929	894,449	941,525
2000	34,647	445,473	7,504	137,061	763	314,397	6,761	42,915	903,693	962,675
2001	34,819	453,008	7,587	141,465	772	318,125	6,805	43,179	919,403	989,705
2002	35,050	461,122	7,678	146,043	781	321,954	6,888	43,509	936,008	1,015,309
2003	35,298	469,292	7,769	150,458	791	325,795	6,990	43,858	952,535	1,043,126
2004	35,555	476,964	7,860	154,298	800	329,648	7,103	44,215	968,012	1,066,568
2005	35,775	482,606	7,938	157,911	809	333,306	7,202	44,523	981,026	1,080,267
2006	35,788	484,952	7,943	160,406	815	335,913	7,204	44,547	988,475	1,088,108
2007	35,773	486,821	7,938	162,726	821	338,374	7,194	44,532	995,115	1,095,097



Table 1B.5-6 (Continued)
1998 Low-Case Net Energy for Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential		General Service Non-Demand		General Service Demand		Street and Outdoor Light MWh	Total Customer Accounts	Total KUA Sales MWh	Net Energy for Load MWh
	Average Accounts Billed	Sales Mwh	Average Accounts Billed	Sales Mwh	Average Accounts Billed	Sales Mwh				
2008	35,757	488,629	7,932	165,025	827	340,835	7,185	44,517	1,001,673	1,102,001
2009	35,742	490,375	7,927	167,303	833	343,295	7,176	44,502	1,008,151	1,108,819
2010	35,687	491,349	7,908	169,358	839	345,560	7,149	44,434	1,013,416	1,114,362
2011	35,430	488,587	7,818	170,345	842	346,821	7,024	44,090	1,012,777	1,113,689
2012	35,148	485,325	7,718	171,181	844	347,954	6,887	43,710	1,011,346	1,112,183
2013	34,868	482,045	7,619	172,014	847	349,101	6,750	43,335	1,009,909	1,110,670
2014	34,591	478,748	7,521	172,843	850	350,262	6,615	42,963	1,008,468	1,109,153
2015	34,272	474,624	7,408	173,445	852	351,222	6,458	42,533	1,005,749	1,106,291
2016	33,726	466,309	7,214	172,836	852	351,036	6,190	41,792	996,370	1,096,419
2017	33,188	458,139	7,025	172,229	851	350,850	5,933	41,064	987,079	1,086,639

(1) Includes Expo Center 2000-2017 annual energy estimate listed in Table 1B.5-3.



Table 1B.5-7
System Peak Demand Forecast
Low Case
(Summer)
(MW)

Year	Peak Demand	Expo Center	Total Peak Demand
1998	213	0	213
1999	215	0	215
2000	216	8	224
2001	220	15.1	235
2002	224	19.8	244
2003	228	22.0	250
2004	232	24.8	257
2005	235	24.8	260
2006	237	24.8	262
2007	239	24.8	264
2008	240	24.8	265
2009	242	24.8	267
2010	243	24.8	268
2011	244	24.8	269
2012	243	24.8	268
2013	243	24.8	268
2014	242	24.8	267
2015	242	24.8	267
2016	240	24.8	265
2017	238	24.8	263



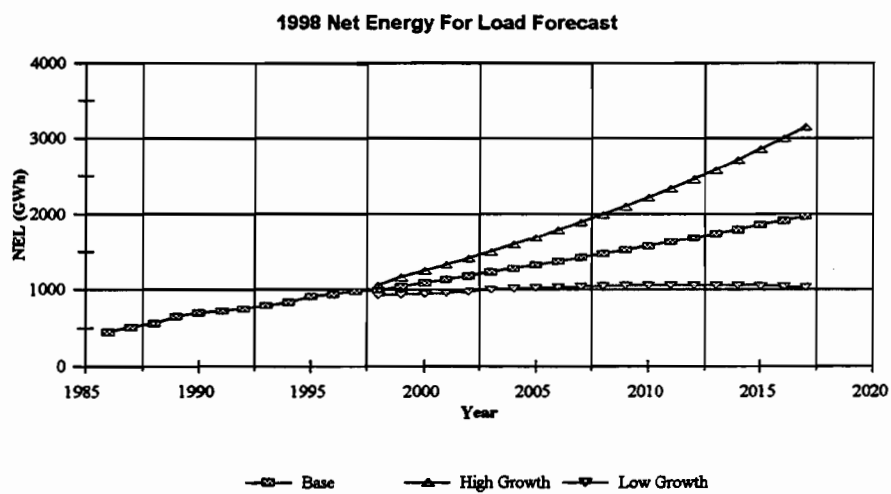
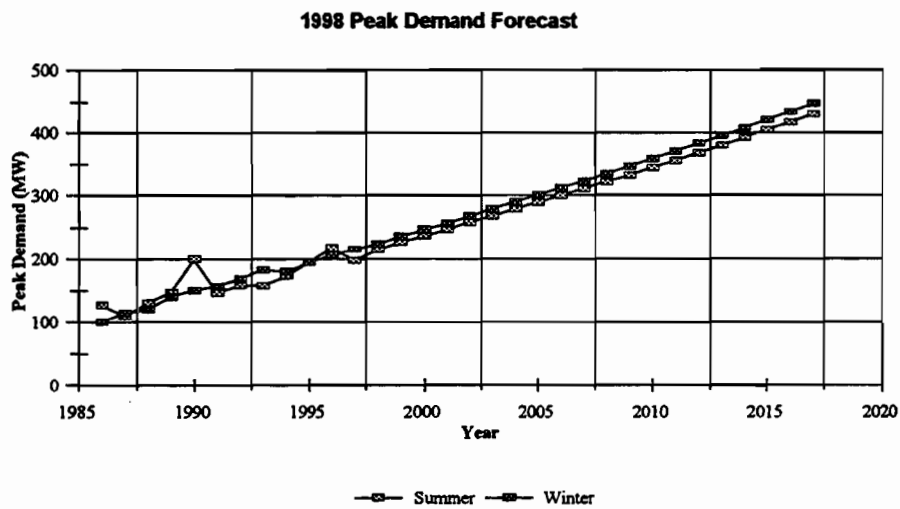
Table 1B.5-8
System Peak Demand Forecast
Base Case
(Summer)
(MW)

Year	Peak Demand	Expo Center	Total Peak Demand
1998	224	0	224
1999	236	0	236
2000	247	13.2	260
2001	257	25.8	283
2002	268	34.9	303
2003	279	39.1	318
2004	290	44.5	335
2005	301	44.5	346
2006	312	44.5	357
2007	323	44.5	368
2008	335	44.5	380
2009	347	44.5	392
2010	359	44.5	404
2011	371	44.5	416
2012	383	44.5	428
2013	395	44.5	440
2014	408	44.5	453
2015	421	44.5	466
2016	434	44.5	479
2017	447	44.5	492



Table 1B.5-9
System Peak Demand Forecast
High Case
(Summer)
(MW)

Year	Peak Demand	Expo Center	Total Peak Demand
1998	236	0	236
1999	261	0	261
2000	282	19.9	302
2001	301	39.6	341
2002	320	55.1	375
2003	340	61.6	402
2004	361	70.8	432
2005	382	70.8	453
2006	404	70.8	475
2007	426	70.8	497
2008	450	70.8	521
2009	475	70.8	546
2010	501	70.8	572
2011	528	70.8	599
2012	555	70.8	626
2013	584	70.8	655
2014	614	70.8	685
2015	647	70.8	718
2016	679	70.8	750
2017	713	70.8	784



KUA Historical and Projected
Peak Demand and Energy Forecast
Figure 1B.5-2



1B.6.0 Demand-side Programs

KUA considers conservation and demand-side management (DSM) an integral component in managing the efficiency of its electric system and providing choice to its customers. To support this Site Certification Application, KUA performed a cost-effectiveness analysis of nearly 70 proposed DSM measures. The results of the analysis indicated that none of the DSM measures were cost-effective. A more detailed discussion of the DSM programs evaluated and the method of evaluation is presented in Section 1A.5.0.

1B.6.1 Current Conservation and DSM Programs

Although the DSM analysis failed to identify any cost-effective measures, KUA is committed to conservation and load management programs. KUA has established several DSM programs and continues to evaluate both old and new DSM programs on a frequent and regular basis in an attempt to identify cost-effective programs for the electric system that add value for the customers. KUA's energy conservation specialist performs approximately 600 free audits annually, advising customers on the appropriate conservation programs to implement. Additionally, KUA continues to offer a residential load management program.

1B.6.1.1 Residential Load Management (SAVE)

KUA currently offers a residential direct load control program which has been in place since 1992. This program is called Shifting Adds Value to Energy (SAVE). SAVE is designed to cycle residential air conditioners, electric water heaters, and electric space heaters to reduce KUA's system peak demand. The SAVE program was administered to over 7,000 customers by the end of 1997. The program was originally mandatory for new customers, but is now voluntary for all residential customers. For participating in the program, customers receive a monthly credit on their bills. KUA installs load control receivers on eligible equipment, and transmits radio signals to cycle equipment for peak demand reduction. The SAVE program provides a utility controlled process that ensures direct capacity value to KUA while minimizing impacts to the customer's lifestyle. There are no significant reductions in energy consumption from this program. Table 1B.6-1 shows KUA's historical and forecasted estimate of peak demand reductions resulting from this load management program.



Table 1B.6-1
KUA Load Management Impact

Year	Average Active Customers	Estimated Participation Increase	Forecast of Customer Participation	Load Mgmt Impact (MW)
1993	1,914	-	-	3.16
1994	5,040	-	-	8.32
1995	7,213	-	-	11.90
1996	7,648	-	-	12.62
1997	7,261	-	-	11.98
1998	-	100	7,361	12.15
1999	-	100	7,461	12.31
2000	-	100	7,561	12.48
2001	-	100	7,661	12.64
2002	-	100	7,761	12.81
2003	-	100	7,861	12.97
2004	-	100	7,961	13.14
2005	-	100	8,061	13.30
2006	-	100	8,161	13.47
2007	-	100	8,261	13.63
2008	-	100	8,361	13.80
2009	-	100	8,461	13.96
2010	-	100	8,561	14.13
2011	-	100	8,661	14.29
2012	-	100	8,761	14.46
2013	-	100	8,861	14.62
2014	-	100	8,961	14.79
2015	-	100	9,061	14.95
2016	-	100	9,161	15.12
2017	-	100	9,261	15.28



1B.6.1.1.1 Delivery Strategy. The approach for delivering the program is based on two design components: (i) promoting the program to customers through bill inserts and general media and (ii) granting bill credits for participants based on the number and type of appliances being controlled. A schedule reflecting bill credits is presented in Table 1B.6-2.

Table 1B.6-2 Credits - SAVE Program			
Load Management Credit			
Appliance	Control Period	Monthly Credit ⁽¹⁾	With Water Heater Control ⁽¹⁾
Water Heater	Year Round	\$1.75	--
Central AC (15 minutes per 1/2 hour)	April-October	\$3.00	\$4.75
Central heating (15 minutes per 1/2 hour)	November-March	\$3.00	\$4.75
(1)Based on a minimum consumption at 500 kWh/month.			

1B.6.1.1.2 Implementation Activities. Because KUA has operated the program since 1992, current implementation activities focus on ongoing installation and maintenance of load switches, and updating and maintaining tracking systems to monitor participation.





1B.7.0 Reliability Criteria

1B.7.1 Development of Reliability Criteria

One of the most common criteria used in the utility industry to evaluate electric system reliability is reserve margin. Reserve margin is calculated as the system net capacity less system net peak demand, divided by the system peak demand.

KUA is a member of the Florida Reliability Coordinating Council (FRCC). FRCC has specific criteria for determining each utility's operating and spinning reserve requirements, but does not have specific planning reserve requirements. The selection of specific planning reserve requirements is up to the individual utility.

KUA has adopted a 15 percent reserve margin for capacity planning in accordance with Section 25-6.035, Fla. Admin. Code. A 15 percent reserve margin is typical for utilities in Florida and throughout the Southeast.

1B.7.2 Available Capacity

KUA's available generating and purchase power capacity are described in Section 1B.2.0. In addition, KUA has scheduled the following units for retirement.

<u>Unit</u>	<u>Type</u>	<u>Net Summer Capacity</u>	<u>Retirement Date</u>
Hansel 8	Diesel	3	01/03
Hansel 14-18	Diesel	10	01/03
Hansel 19-20	Diesel	6	01/13
Hansel 21-23	Combined Cycle	48	01/13

In 2002, Hansel Unit 8 will be 43 years old and will have exceeded its reliable economic life. KUA may continue to operate Hansel Unit 8 until it has a major failure or until maintenance costs become prohibitive, but for planning purposes, the unit is no longer considered as dependable capacity after the year 2002. Similarly, Hansel Units 14-18 will be 31 years old in 2003 and have been scheduled for retirement based on KUA's expectation of their reliable economic lifetime.

Tables 1B.7-1 and 1B.7-2 present the available capacity and purchase power for summer and winter, respectively.



1B.7.3 Reliability Need for Cane Island 3

Applying the base case forecast for electrical demand, KUA will need additional capacity by the year 2000 to maintain a 15 percent reserve margin. Table 1B.7-1 presents the projected reserve margins for KUA's system without resource additions for summer, while Table 1B.7-2 is for winter. Tables 1B.7-1 and 1B.7-2 clearly indicate that capacity is needed in 2001.



Table 1B.7-1
System Peak Demand Forecast and Capacity Balance
Base Case (Summer)

Year	Generation (MW)	Purchases (MW)	Total Resources (MW)	Peak Demand (MW)	Expo Center (MW)	DSM (MW)	Reserve Margin ¹ (percent)	
							Without Center	With Center
1998	172	98	270	224	0	12.2	27.5	27.5
1999	172	98	270	236	0	12.3	20.7	20.7
2000	172	108	280	247	13	12.5	19.4	13.1
2001	172	68	240	257	26	12.6	(1.8)	(11.1)
2002	172	68	240	268	35	12.8	(5.9)	(17.2)
2003	153	68	221	279	39	13.0	(16.9)	(27.5)
2004	153	48	201	290	45	13.1	(27.4)	(37.4)
2005	153	48	201	301	45	13.3	(30.1)	(39.5)
2006	153	48	201	312	45	13.5	(32.6)	(41.4)
2007	153	48	201	323	45	13.6	(35.0)	(43.2)
2008	153	48	201	335	45	13.8	(37.4)	(45.0)
2009	153	48	201	347	45	14.0	(39.6)	(46.7)
2010	153	48	201	359	45	14.1	(41.7)	(48.4)
2011	153	48	201	371	45	14.3	(43.6)	(49.9)
2012	153	48	201	383	45	14.5	(45.4)	(51.3)
2013	105	48	153	395	45	14.6	(59.8)	(64.0)
2014	105	48	153	408	45	14.8	(61.1)	(65.0)
2015	105	48	153	421	45	15.0	(62.3)	(66.0)
2016	105	48	153	434	45	15.1	(63.5)	(67.0)
2017	105	48	153	447	45	15.3	(64.5)	(67.9)

(1) DSM is subtracted from peak demand.



Table 1B.7-2
System Peak Demand Forecast and Capacity Balance
Base Case (Winter)

Year	Generation (MW)	Purchases (MW)	Total Resources (MW)	Peak Demand (MW)	Expo Center (MW)	DSM (MW)	Reserve Margin ¹ (percent)	
							Without Center	With Center
1998	189	98	287	215	0	12.2	41.6	41.6
1999	189	98	287	227	0	12.3	33.7	33.7
2000	189	108	297	237	13	12.5	32.3	25.0
2001	189	68	257	247	26	12.6	9.7	(1.2)
2002	189	68	257	258	35	12.8	4.9	(8.2)
2003	170	68	238	268	39	13.0	(6.6)	(19.0)
2004	170	48	218	279	45	13.1	(18.0)	(29.7)
2005	170	48	218	289	45	13.3	(20.9)	(31.9)
2006	170	48	218	300	45	13.5	(23.9)	(34.1)
2007	170	48	218	311	45	13.6	(26.7)	(36.2)
2008	170	48	218	322	45	13.8	(29.2)	(38.2)
2009	170	48	218	333	45	14.0	(31.6)	(40.0)
2010	170	48	218	345	45	14.1	(34.1)	(41.9)
2011	170	48	218	356	45	14.3	(36.2)	(43.5)
2012	170	48	218	368	45	14.5	(38.3)	(45.2)
2013	118	48	166	380	45	14.6	(54.5)	(59.5)
2014	118	48	166	392	45	14.8	(56.0)	(60.6)
2015	118	48	166	405	45	15.0	(57.4)	(61.8)
2016	118	48	166	417	45	15.1	(58.7)	(62.8)
2017	118	48	166	430	45	15.3	(59.9)	(63.8)

(1) DSM is subtracted from peak demand.





1B.8.0 Supply-side Alternatives

Several capacity addition alternatives were selected for consideration in the development of KUA's expansion plan. The size of the alternatives selected considered KUA's need for capacity and the size of KUA's system including the impact of the loss of a unit. The alternatives considered include specific alternatives that KUA has studied in the past as well as generic alternatives. Generating unit and purchase power alternatives being considered for capacity expansion include the following:

- Renewable technologies.
- Waste technologies.
- Advanced technologies.
- Energy storage systems.
- Nuclear (Fission).
- Coal fueled.
- Combined cycle.
- Simple cycle combustion turbine.
- Purchased power.

Unconventional technologies, including renewable technologies, waste technologies, advanced technologies, energy storage systems, and nuclear technology, were reviewed in Section 1A.6.0 on a summary level basis to identify any alternatives with reasonable economic and environmental characteristics. The coal fueled units and the unconventional technologies are assumed to be the first units located at new undetermined sites. Combined cycle and simple cycle combustion turbines were assumed to be installed on the Cane Island site to take advantage of existing infrastructure. Combustion turbine alternatives were based on the size and performance of specific machines, but were not intended to limit consideration to only those machines. There are a number of combustion turbines available from different manufacturers with similar sizes and performance characteristics. Purchased power was also investigated as an option to construction of additional generation at Cane Island.



1B.8.1 Unconventional Technologies

Unconventional generation methods utilizing renewable technologies, waste technologies, advanced technologies, energy storage systems, and nuclear fusion technology were evaluated as supply-side alternatives. Capital costs, technology specific siting, and relatively large footprints were included in the evaluation process. Performance and cost information for the unconventional technology alternatives evaluated are discussed in more detail in Section 1A.6.0. Section 1A.6.8 presents the discussion supporting the screening of these alternatives to eliminate them as possible expansion candidates to meet KUA's forecasted capacity needs.

1B.8.2 Coal Fueled Alternatives

1B.8.2.1 Pulverized Coal

A 250 MW pulverized coal unit with dry scrubber, electrostatic precipitator and selective catalytic reduction (SCR) was selected as a solid fuel alternative. The unit is assumed to be the first unit at an undetermined new site in Central Florida. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 1A.6-24 presents the estimated cost and performance of the 250 MW pulverized coal unit.

1B.8.2.2 Fluidized Bed

A 250 MW atmospheric circulating fluidized bed unit (CFB) with selective noncatalytic reduction (SNCR) was selected as another solid fuel alternative. The CFB is capable of burning a wide range of fuels. For expansion planning purposes, the CFB is assumed to burn coal. Like the pulverized coal unit, the CFB is assumed to be the first unit at a undetermined new site in Central Florida. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 1A.6-25 presents the estimated cost and performance of the 250 MW CFB unit.

1B.8.3 Combined Cycle Alternatives

Four combined cycle units were selected for further evaluation as generating unit alternatives:

- 1 x 1 General Electric 7EA (Table 1A.6-26)
- 2 x 1 General Electric 7EA (Table 1A.6-27)



- 1 x 1 Westinghouse 501FC (Table 1A.6-28)
- 1 x 1 Westinghouse 501G (Table 1A.6-29)

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. Specifications for performance and operating costs are based on natural gas fuel and baseload operation. The combined cycles assume that emission requirements will be met with dry low NO_x combustors. SCRs are not included except for the 501G combustion turbines prior to 2002. The units would be located at the Cane Island site and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

1B.8.4 Simple Cycle Alternatives

Four simple cycle combustion turbines were selected for further evaluation as generating unit alternatives:

- General Electric LM6000 (Table 1A.6-30)
- General Electric 7EA (Table 1A.6-31)
- Westinghouse 501G (Table 1A.6-32)
- General Electric 7FA (Table 1A.6-33)

The 7EA, 501G, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The LM6000 is an aeroderivative combustion turbine. The combustion turbines would be dual fueled with specifications for performance and operating costs based on natural gas operation.

1B.8.5 Purchased Power

KUA conducted a two-phase evaluation of purchased power alternatives from a request for proposals (RFP) for purchased power issued May 28, 1997. The comparison of purchase power bids included applicable transmission rates, transmission upgrade costs, and loss percentages. Certain non-price items were also included in the evaluation including pricing terms and flexibility, supply availability for economy transactions, dispatchability, fuel risks, transmission path, commercial viability of technology and potential environmental effects. A detailed discussion of the RFP evaluation is contained in Section 1B.9.0. The evaluation concluded that Cane Island 3 was KUA's least cost alternative.



In addition to 1997 RFP, KUA has a contract with Florida Power Corporation (FPC) for supplemental resale service. Under the contract, KUA can obtain base, intermediate, and peaking supplemental service. The contract term continues indefinitely; however, either party may terminate the contract by giving notice in any calendar year after the calendar year 1999 and the contract will terminate at the end of the fifth future calendar year. For example, the earliest that the contract could terminate is December 31, 2005 by either party giving notice in 2000.

The capacity is firm and includes reserves. Any curtailment of the capacity must be no more interruptive than FPC's service to their retail customers.

The capacity is stratified into base, intermediate, and peaking capacity. KUA must specify the future capacity levels as described below.

By May 31 of the current Year, Provide

Updated Contract Demand Values:

Range

Update of the First Future Year Base, Intermediate & Peaking Contract Demands

Previously-Specified Annual Contract Demands for that year with up to a cumulative increase no greater than 25 MW

Update of the Second Future Year Specify Base, Intermediate & Peaking Contract Demands

Sum of Base, Intermediate & Peaking +/- the greater of 20% or 30 MW of Total Demand For That Year

Update of the Third Future Year Total and Fourth Future Year Total Contract Demand

Previously-Specified Contract Demand For That Year + up to the greater of 20% or 55 MW Total Contract Demand or Previously-Specified Total Contract Demand For That Year less up to the greater of 20% or 30 MW of Previously-Specified Total Contract Demand

Initial Specification for Fifth Future Year Total Contract Demands

Previously-Specified Demand For Fourth Future Year +/- up to 55 MW



For example, on or before May 31, 1999, KUA shall provide an initial specification of KUA's Total Contract Demand for the calendar year 2004 and may adjust the previously-specified demand specifications in accordance with the above limitations.

In addition to the above limitations, in no event shall the total of updated Contract Demands (Base, Intermediate, Peaking) for any year be more than the greater of 20% or 55 MW above or the greater of 20% or 20 MW below the total initial specified Contract Demand for that year. In addition, the specification for the Second Future Year Base, Intermediate and Peaking Contract Demands shall not exceed the respective percent kW allocation of 40% for base, intermediate, and peaking times KUA's most recent historical system peak demand kW adjusted for the Average System Growth Rate (ASGR) of 10 percent (for example, second year peak demand equals the most recent historical system peak multiplied by $(1 + \text{ASGR})^2$).

In addition to the annual specification for the fifth future year provided for above, KUA, at its option, may make a further specification for Contract Demand for the seventh future calendar year. Such specification for the seventh future calendar year shall not be higher (unless FPC agrees in writing that it may be higher) than the specification for the fifth calendar year, but may, without limitation, be lower than the specification for the fifth future year. Such specification for the seventh year shall not be subject to change until the specification becomes the fourth future year specification as defined in the required rolling five-year specification or the specifications for any lesser future year; it may be updated but is subject to all limitations set out above.

KUA has currently specified 0 kW demand for base, intermediate, and peaking for all future years. Based on specifications made beginning no later than May 31, 1999, KUA can obtain up to the following capacity under the contract.

<u>Year</u>	<u>Base</u> MW	<u>Intermediate</u> MW	<u>Peaking</u> MW	<u>Total*</u> MW
2000	10	10	10	25
2001	22	22	22	55
2002	22	22	22	55
2003	22	22	22	55



<u>Year</u>	<u>Base</u> MW	<u>Intermediate</u> MW	<u>Peaking</u> MW	<u>Total*</u> MW
2004	44	44	44	110
2005	44	44	44	110

* Sum of base, intermediate, and peaking cannot exceed total.

The contract also contains limitations on how quickly KUA can reduce capacity once specified.

The price that KUA pays for the supplemental service is based on a FERC filed tariff and currently is as follows.

	<u>Base</u>	<u>Intermediate</u>	<u>Peaking</u>
Demand Charge (\$/kW/mo)	14.00	8.94	5.13
Non-Fuel Energy Charge (\$/MWh)	7.38	14.73	2.31
Transmission (\$/kW/mo)	1.15	1.15	1.15
Customer Charge (\$/month)	667.00	667.00	667.00

The fuel charge is based on the average fuel charge for the month for FPC units assigned to each category as follows.

Base

Crystal River Units #1-5
Cogeneration (Seminole Fertilizer)
Firm Southern Company Purchases (20.5%)

Intermediate

Firm Southern Company Purchases (79.5%)
Anclote Units #1-2
Bartow Units #1-3
Suwanne Units #1-3



Higgins Units #1-3

Turner Units #3-4

Cogeneration (Timber Energy, Dade County, Bay County)

Debary Peakers #7-10

Peaking

All Other Peaking Units

The fuel charge can vary considerably from month to month. The fuel charges for September 1996, the last month in which KUA was billed for energy under the supplemental service contract, are as follows.

	<u>\$/MWh</u>
Base	13.35
Intermediate	18.73
Peaking	59.76

As is shown, capacity and energy under the supplemental service contract is expensive, compared to current market prices. The supplemental service contract does, however, offer KUA low cost insurance against lack of capacity and protection by being able to purchase coal and nuclear energy if gas and oil prices increase. With no capacity specified, as is currently the case, the only cost for KUA of maintaining the contract is the \$667 per month service charge. The contract also contains provisions for KUA to obtain capacity above the specified demands, but at even higher rates.



1B.9.0 Supply-side Screening

1B.9.1 Generating Alternatives

The generating unit alternatives considered for evaluation include the coal, combined cycle and combustion turbine units identified in Section 1A.6.8.1.6.

1B.9.2 Purchased Power

1B.9.2.1 1997 RFP for Power Purchases

KUA conducted a two-phase evaluation of purchased power alternatives from a request for proposals (RFP #004-97) for purchased power issued May 28, 1997. The RFP is contained in Appendix 1B.16.3. The comparison of purchase power bids included applicable transmission rates and upgrade costs, and loss percentages. Certain nonprice items were also included in the evaluation such as: pricing terms and flexibility, supply availability for economy transactions, dispatch capability, fuel risks, transmission path, commercial viability of technology and potential environmental effects. The analysis results indicated that KUA's self-build option provided costs lower than all purchase bids.

KUA's RFP was developed by KUA and R. W. Beck and requested proposals for electric capacity and energy to satisfy up to 80 MW of KUA's projected requirements for the period from 2001 through 2030. The RFP requested proposals for base, intermediate or peaking capacity. The minimum capacity required for bidding was 10 MW with a minimum term of three years.

KUA received 22 proposals from 13 bidders. These proposals are summarized in Table 1B.9-1.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Table 1B.9-1
RFP Responses

No.	Bidder Name	Number Of Bids	No.	Bidder Name	Number Of Bids
1	Constellation Power, Inc.	1	8	Tarpon Power, Inc.	2
2	City of Lakeland Electric & Water	1	9	Tenaska Energy Partners, Inc.	1
3	LG&E Energy Marketing	2	10	Indeck Energy Services	2
4	NP Energy, Inc.	3	11	Progress Energy Corporation	1
5	Panda Energy International, Inc.	1	12	PECO Energy	1
6	Southern Wholesale Energy	5	13	Energy Pacific	1
7	Stewart & Stevenson International	1	Total Number of Proposals		22



The Stage I evaluation focused on the issue of completeness of the bid packages and satisfaction of minimum requirements, but did not address issues of price, operating characteristics or performance. The RFP contained a Minimum Requirements Form, which required the bidder to demonstrate the following:

1. Although capacity is required during all months, proposal must provide for capacity either one or both of the following peak load periods: (i) June through September; or (ii) December through March for a minimum of three calendar years.
2. The capacity and energy proposed are on a first call, nonrecallable basis, i.e., as long as the unit(s) from which the capacity is purchased is available, KUA has the right to the output of the unit(s) for the duration of the contract. KUA's rights must be equal to or superior to any other party's rights to such unit(s) output.
3. The proposal for capacity sales for terms of five years or less must remain in effect until December 31, 1997, or later if the purchase is to be finalized pending a transmission service request. All other proposals must remain effective until March 31, 1998, or later if the purchase is to be finalized pending a transmission service request.
4. The minimum capacity amount offered to KUA shall be 10 MW.
5. All generating units providing the proposed capacity must be in operation at least two months prior to the delivery commencement date of the term of the proposed power supply.
6. Proposals must identify and include the location of each capacity resource, name the originating control area, and identify the firm transmission contract path.
7. The bidder must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.



8. The bidder must declare ownership or contractual status of unit, plant, or system capacity as described in Section 15 of the RFP.
9. The bidder must complete the appropriate RFP Forms 1 through 5 and provide the information requested in Attachment B of the RFP. All forms requiring a signature must be signed by a duly authorized official.
10. Bidders offering power that impacts any transmission interface must provide a letter of intent from the owner(s) of the systems forming the interface stating that the required power transfer capability is available on a firm (nonrecallable) basis.
11. The bidder must be willing to provide adequate bid security prior to entering shortlist negotiations.
12. The bidder must not include any contractual limits on energy utilization (as opposed to price) by day, month or year.
13. The proposal must include scheduling provisions for the sale.
14. Each proposal must contain the appropriate proposal fee in accordance with Section 10 of the RFP.

During the Stage I evaluation, letters were sent and responses received from nine of the bidders requesting clarification on several minor issues. During the Stage I evaluation, proposals from PECO Energy and Energy Pacific were eliminated for failing to meet the minimum requirements of the RFP.

As a result of the Stage I evaluation, 11 bidders with 20 proposals totaling 1,600 MW were selected for the Stage II evaluation. The 20 proposals are summarized in Table 1B.9-2.

In the Stage II evaluation, the 11 bidders were sent clarifying questions to enable the bids to be compared on an equal basis. The following presents a brief summary of the proposals offered by each of the bidders.



Table 1B.9-2
Summary of Stage I Evaluation

Proposal	Bidder Name	Type of proposal (System or Unit Purchase)	Capacity (MW)
1	Constellation Power, Inc.	Unit Purchase	80.0
2	City of Lakeland Electric & Water	Unit Purchase	80.0
3	LG&E Energy Marketing (A) Alternative One (B) Alternative Two	Unit Purchase ¹ Unit Purchase ¹	80.0 80.0
4	NP Energy, Inc. (A) FSO Annual Option (B) FSO Season Option (C) AO Option	Unit Purchase Unit Purchase Unit Purchase	80.0 80.0 80.0
5	Panda Energy International, Inc.	Unit Purchase	80.0
6	Southern Wholesale Energy (A) 5x16 Strip (B) 7x16 Strip (C) 7x24 Strip (D) Intermediate Purchase (E) Peaking Purchase	System Purchase System Purchase System Purchase System Purchase System Purchase	80.0 80.0 80.0 80.0 80.0
7	Stewart & Stevenson International	Unit Purchase ²	120.0
8	Tarpon Power, Inc. (A) TP1 (B) TP2	Unit Purchase ¹ Unit Purchase ¹	80.0 80.0
9	Tenaska Energy Partners, Inc.	Unit Purchase ²	40.0
10	Indeck Energy Services (A) Option A (B) Option B	Unit Purchase ¹ Unit Purchase	80.0 80.0
11	Progress Energy Corporation	Unit Purchase	80.0
TOTAL			1,600.0
(1) Unit purchase offer included the option for KUA ownership. (2) Unit purchase only offered ownership options. Note: Of the 22 proposals received, 16 were long-term (more than 5 years) and 6 were short-term (5 years or less; 5 were system purchases and 17 were unit or plant purchases; of the 17 unit or plant purchases, all were new unit or plant constructions; proposal 9 is initially 40 MW and ramps to 80 MW by 2011.			



Constellation Power, Inc. Constellation offered an 80 MW, 20 year power purchase from a 700 MW 2x1 Westinghouse 501G combined cycle plant to be built in Hardee County, Florida.

City of Lakeland Electric & Water. The City of Lakeland Electric & Water (Lakeland) offered an 80 MW, 10 year unit power purchase from a coal-fired ABB presurized fluidized bed (PFB) repowering of McIntosh Units 1 and 2.

LG&E Energy Marketing. LG&E Energy Marketing proposed to sell KUA 80 MW of capacity and associated energy for a term of between 5 and 30 years. The capacity would be dispatchable between a minimum load of 48 MW and a maximum load of 80 MW. The power would come from a unit to be built on a confidential site in Central Florida. The power would be delivered from the FPC control area and would be supplemented by LG&E Energy Marketing's system power portfolio to make it 100 percent available. LG&E Energy Marketing's proposal makes two specific offers. The first is joint ownership in a 500 MW facility. The second calls for KUA to build, own, and operate a larger unit and sell LG&E Energy Marketing the excess capacity and energy.

NP Energy, Inc. NP Energy, Inc. made three proposals. The first proposal called for KUA and FMFA to construct a 240 MW unit at Cane Island. KUA would retain the 80 MW requested in the RFP and FMFA would retain the long-term 120 MW requested in FMFA's RFP. The remaining 40 MW would be sold to NP Energy, Inc. for a 10 year period. The second proposal was to sell KUA an 80 MW 5x16 strip on an annual basis for 10 years. The third proposal was to sell KUA an 80 MW 5x16 strip on a seasonal basis.

Panda Energy International, Inc. Panda Energy International, Inc. proposed to sell 80 MW of purchased capacity and energy for a term of 20 years. The power would be supplied from a 500 MW 2x1 Westinghouse 501F merchant plant to be built in Fellsmere, Florida and wheeled over Florida Power & Light's system.

Southern Wholesale Energy. Southern Wholesale Energy offered five 80 MW proposals. The first three were 5x16, 7x16 and 7x24 strips. The other two proposals were for peaking and intermediate capacity. Southern Wholesale Energy's proposals required transmission import capacity into the State.



Stewart & Stevenson International. Stewart & Stevenson International offered a proposal to provide a turnkey power generation project at Cane Island. In a phased approach, Stewart and Stevenson International proposed to install a LM6000PD combined cycle plant and to convert Cane Island Unit 1 into a LM6000PD.

Tarpon Power, Inc. Tarpon Power, Inc. offered two proposals for 80 MW for a term of 20 years. The power would come from either a 1,500 or 750 MW project that Tarpon Power, Inc. would develop in Hardee County, Florida. The projects would use the Westinghouse 501G combustion turbines. One proposal is for capacity from the 1,500 MW project and one from the 750 MW project.

Tenaska Energy Partners, Inc. Tenaska Energy Partners, Inc. proposed to provide KUA with an ownership share in the Tenaska-Lakeland Combined Cycle Project. The Project would be a 2x1 Westinghouse 501G combined cycle located at the McIntosh site. Tenaska Energy Partners, Inc. offered to initially buy back 40 MW of KUA's 80 MW ownership share with an annual reduction of the buy back capacity through the year 2007, when KUA would then receive their entire 80 MW ownership share.

Indeck Energy Services. Indeck Energy Services proposed to provide KUA with 80 MW of capacity and energy for a term of 20 years from a 500 MW combined cycle plant. Indeck Energy Services offered two options. One for municipal financing and one for private financing.

Progress Energy Corporation. Progress Energy Corporation proposed a sale of 80 MW of capacity and energy for a 7 year term. The capacity and energy would be from a 2x1 Westinghouse 501F combined cycle.

After receiving the responses from the clarifying questions, KUA selected 11 bids along with KUA's self-build combined cycle option for modeling with the Stage II Screening Model developed by R.W. Beck. The proposals evaluated are shown in Table 1B.9-3.

LG&E Energy Marketing's second offer, which called for KUA to build, own, and operate a larger unit and sell LG&E Energy Marketing the excess capacity and energy was judged to be no different than KUA's self build option and was not included in the Stage II Screening Model.

NP Energy, Inc.'s first proposal to KUA, which was for KUA and FMFA to construct a 240 MW combined cycle unit at Cane Island and sell 40 MW of capacity to NP Energy, Inc.



Table 1B.9-3
Proposals Evaluated at Stage II

Proposal Number	Bidder Name
1	Constellation Power, Inc.
2	City of Lakeland Electric & Water
3(A)	LG&E Energy Marketing
4(A)	NP Energy, Inc.
5(A)	Panda Energy International, Inc.
7	Stewart & Stevenson International
8(A)	Tarpon Power, Inc.
8(B)	Tarpon Power, Inc.
10(A)	Indeck Energy Services
10(B)	Indeck Energy Services
11	Progress Energy Corporation



was judged to be no different than KUA's self build option and was not included in the Stage II Screening Model. NP Energy, Inc.'s second proposal for a 5x16 strip of 80 MW for 10 years violated KUA's basic RFP requirement to identify the resource that will provide the capacity and energy, but was included in the Stage II Screening Model because KUA received very few short-term bids. NP Energy, Inc.'s third proposal of a 5x16 strip of 80 MW for 10 years on a seasonal basis also violated the requirement to identify the resource that was supplying the capacity and energy. Since KUA was seeking annual capacity and since NP Energy, Inc.'s second proposal was being evaluated in the Stage II Screening Model, NP Energy Inc.'s third proposal was not included in the Stage II Screening Model.

Southern Wholesale Energy's five proposals involved capacity and energy that originated from outside the State of Florida. Southern Wholesale Energy formally requested transmission from Florida Power & Light (FPL) and Florida Power Corporation (FPC). FPC responded and denied Southern Wholesale Energy's request on the grounds that no transmission import capacity exists at their Florida-Georgia interface. No communication was received indicating that any other entities were capable of providing the necessary transmission services. Therefore, the five Southern Wholesale Energy proposals were not included in the Stage II Screening Model.

Tenaska Energy Partners, Inc. proposal for KUA to participate in the Tenaska-Lakeland Combined Cycle Project was not included in the Stage II Screening Model because Lakeland withdrew from the Project and a replacement participant was not identified.

The Stage II Screening Model evaluated the cost of each bid on a cumulative present worth basis. The evaluations were conducted over 7, 15 and 20 year periods. To preserve the confidential nature of the pricing of the proposals, only the percentage differences between the self-build option and the proposals are presented. Tables 1B.9-4 through 1B.9-6 present the results of the Stage II Screening Model.

In addition to the Stage II Screening Model, KUA conducted a non-price evaluation of the proposals. A total of 40 scoring points were assigned to the attributes considered in the nonprice evaluation. Attributes evaluated included the following:

Power Cost (Maximum Score 4 points)

- Fixed Costs remain constant or escalate at a predetermined fixed index.
- No minimum payment provision.
- Pricing terms are market focused.



Flexibility (Maximum Score 4 points)

- KUA's sole option to increase or decrease contract purchases.
- KUA's sole option to increase or decrease contract term.

Dispatchability (Maximum Score 6 points)

- 100% dispatchable.
- Supply available for economy transactions.
- Scheduling provision to allow for change within one hour.

Fuel Risk (Maximum Score 8 points)

- Fuel prices are fixed and guaranteed.
- Fuel supply is fixed.
- Firmness of supply.
- Includes multiple suppliers.
- Improves diversity of fuel mix.
- Fuel incentives are provided.

Firm Supply (Maximum Score 4 points)

- Same priority as system's native load or assurance of guaranteed availability.
- Provides adequate corporate guarantee.
- Proposer provides adequate assurance that it is capable of mitigating risk.

Transmission (Maximum Score 5 points)

- Supply is connected to KUA's transmission system (directly, 1 away, 2 away ...).

Technology (Maximum Score 5 points)

- The proposed technology is commercially proven.

Environmental Effects (Maximum Score 4 points)

- Extraordinary measures taken to minimize adverse environmental impacts.
- Includes renewable resources.

The results of the non-price evaluation are presented in Table 1B.9-7. Based on the results of the Stage II Screening Model and the non-price evaluation, in which the installation of a self-build option of Cane Island 3, the 1x1 F-class combined cycle was clearly the least cost long-term alternative and preferred alternative in the nonprice evaluation, KUA decided to pursue the installation of Cane Island 3.



Table 1B.9-4
Performance of Stage II Bidders
7-Year Cumulative Present Worth

Rank	Bidder Name	Percent Cost Difference at Capacity Factor		
		50 Percent	75 Percent	100 Percent
1	KUA Self-Build Option	---	---	---
2	NP Energy, Inc.	-11.64	-6.77	-3.52
3	City of Lakeland Electric & Water	13.19	8.02	4.70
4	Progress Energy Corporation	21.72	15.95	12.17
5	Constellation Power, Inc.	38.79	29.12	22.83
6	Tarpon Power, Inc. (TP1)	44.80	35.12	28.85
7	Indeck Energy Services 10(A)	43.89	35.73	30.44
8	Tarpon Power, Inc. (TP2)	49.46	38.85	31.92
9	Indeck Energy Services 10(B)	51.75	41.95	35.58
10	LG&E Energy Marketing	56.80	43.97	35.61
11	Panda Energy International, Inc.	62.73	49.36	40.65
Note: Positive percentage difference for all table values represent the amount by which alternatives are more costly than the KUA Self-Build Option.				



Table 1B.9-5
Performance of Stage II Bidders
15-Year Cumulative Present Worth

Rank	Bidder Name	Percent Cost Difference at Capacity Factor		
		50 Percent	75 Percent	100 Percent
1	KUA Self-Build Option	---	---	---
2	Constellation Power, Inc.	39.51	29.37	22.83
3	Tarpon Power, Inc. (TP1)	41.97	32.98	23.76
4	Tarpon Power, Inc. (TP2)	46.97	32.98	29.78
5	Indeck Energy Services 10(A)	45.87	36.98	31.26
6	Indeck Energy Services 10(B)	53.94	43.31	36.45
7	LG&E Energy Marketing	59.66	45.85	36.92
8	Panda Energy International, Inc.	69.18	53.96	44.11
Note: Positive percentage difference for all table values represent the amount by which alternatives are more costly than the KUA Self-Build Option.				



Table 1B.9-6
Performance of Stage II Bidders
20-Year Cumulative Present Worth

Rank	Bidder Name	Percent Cost Difference at Capacity Factor		
		50 Percent	75 Percent	100 Percent
1	KUA Self-Build Option	---	---	---
2	Constellation Power, Inc.	39.34	29.07	22.50
3	Tarpon Power, Inc. (TP1)	41.08	31.76	25.76
4	Tarpon Power, Inc. (TP2)	45.51	35.22	28.61
5	Indeck Energy Services 10(A)	46.87	37.61	31.66
6	Indeck Energy Services 10(B)	55.01	43.95	36.86
7	LG&E Energy Marketing	61.05	46.75	37.53
8	Panda Energy International, Inc.	71.86	55.78	45.43
Note: Positive percentage difference for all table values represent the amount by which alternatives are more costly than the KUA Self-Build Option.				



Table 1B.9-7
Non-Price Evaluation Results

Rank	Bidder Name	Raw Score	Weighted Score	Percentage Score	Relative Score
1	KUA Self-Build Option	29.00	30.00	75.00	---
2	Progress Energy Corporation	20.00	21.00	52.50	30.00
3	Constellation Power, Inc.	17.50	18.34	45.84	38.88
4	Tarpon Power, Inc. (TP1)	13.00	14.00	35.00	53.33
5	Tarpon Power, Inc. (TP2)	13.00	14.00	35.00	53.33
6	City of Lakeland Electric & Water	13.00	13.00	32.50	56.67
7	Panda Energy International, Inc.	13.00	13.00	32.50	56.67
8	Indeck Energy Services 10(B)	12.00	12.00	30.00	60.00
9	Indeck Energy Services 10(A)	11.00	11.33	28.34	62.22
10	LG&E Energy Marketing	10.00	11.00	27.51	63.33
11	NP Energy, Inc.	7.00	7.67	19.17	74.44

Note: Percentage Score is calculated by dividing Weighted Score by the total possible points (40).
The positive percentages under Relative Score indicate the degree to which the KUA Self-Build option has outperformed other proposals in the non-price evaluation.



1B.9.2.2 Florida Power Corporation Power Purchase Agreement

In addition to the purchase power proposals KUA received from the RFP, KUA has a contract with Florida Power Corporation (FPC) for supplemental resale service in which KUA can increase or decrease capacity levels as described in detail in Section 1B.8.5. KUA can purchase peaking, intermediate or base capacity under the supplemental resale contract. Figure 1B.9-1 presents a comparison of the supplemental resale capacity costs and Cane Island 3 based on the supplemental resale prices contained in Section 1B.8.5. No escalation has been included to increase the supplemental resale prices to 2001 dollars. Even without escalation of the supplemental resale prices, Cane Island 3 is lower in cost than either the peaking, intermediate or base supplemental resale service. Therefore, the FPC supplemental resale service is not included in KUA's power supply plans - except in instances where it is not possible to obtain other capacity.

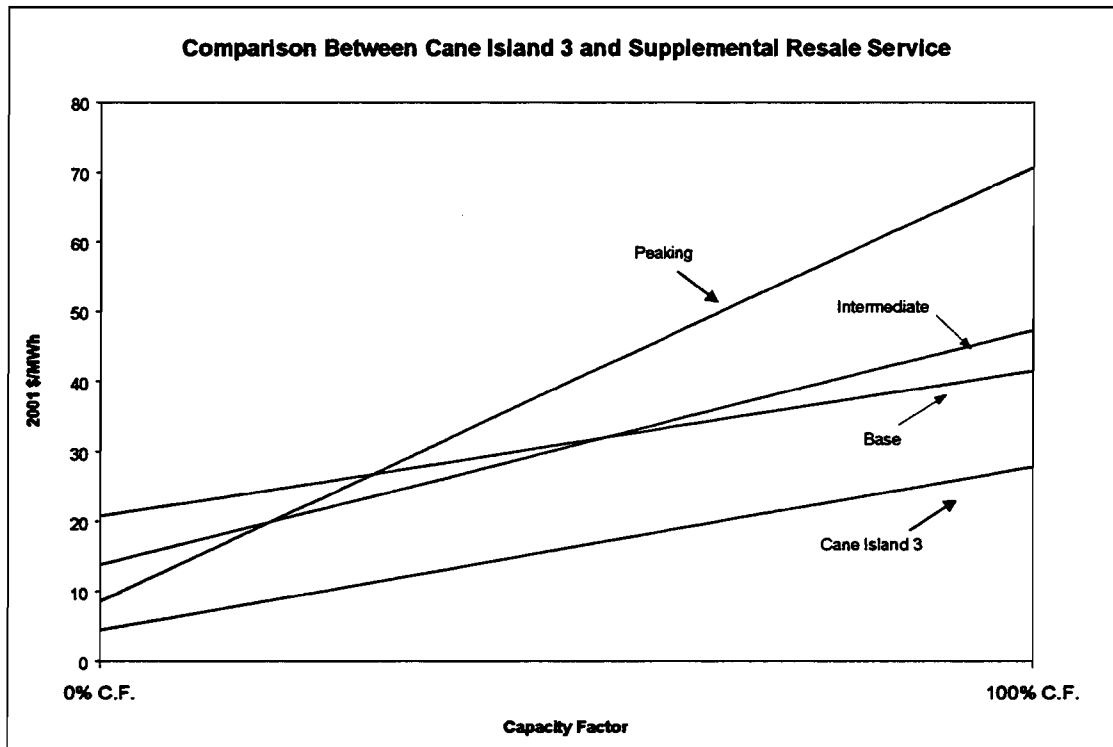


Figure 1B.9-1
Comparison Between Cane Island 3 and Supplemental Resale Service



1B.10.0 Economic Analysis

1B.10.1 Methodology

A three-phased economic analysis was conducted to determine KUA's optimum capacity expansion plan. The three phases included demand-side, supply-side and sensitivity analyses. Results of the supply- and demand-side analyses are presented in this section. Results of the sensitivity analyses are presented in Section 1B.11.0.

The demand-side analysis is presented in Section 1A.5.0. Over 60 demand-side alternatives were evaluated using the FIRE model. No demand-side alternatives were determined to be cost effective; therefore, no further analysis was included in the production cost modeling.

The supply-side evaluation of generating unit alternatives was performed using the EGEAS optimal generation expansion model. EGEAS is part of the "Resource Planning Workstation" suite of programs developed by the Electric Power Research Institute (EPRI). The EGEAS program is used to determine a set of optimal capacity expansion plans, simulate the operation of each of these plans, and select the most desirable plan based on the lowest system-wide cumulative present worth revenue requirement. EGEAS has the ability to incorporate any one of several optimization techniques including Dynamic Programming, Screening Audit Analysis or Generalized Benders Decomposition. EGEAS evaluates all combinations of generating unit alternatives and purchase power options while maintaining user-defined reliability criteria. The reserve criteria utilized included a minimum reserve margin of 15 percent and a maximum of 50 percent. All capacity expansion plans were analyzed over a twenty year period from 1998 to 2017.

Several sensitivities are addressed in Section 1B.11.0 to demonstrate the robustness of the expansion plan. Sensitivities addressed include: high load growth, low load growth, high fuel prices, low fuel prices and constant differential between natural gas/oil and coal.

1B.10.2 Expansion Candidates

The expansion candidates for the EGEAS evaluation were taken directly from the screening analysis in Section 1A.6.8. The expansion candidates were developed to be applied jointly by KUA and FMPA. Table 1B.10-1 provides a summary of the expansion alternatives considered.



1B.10.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case KUA load forecast, base case fuel price forecast and minimum reserve margin of 15 percent. Results of the base case scenario economic evaluation are summarized in this subsection.

Based upon the cost and performance characteristics described in detail in Section 1A.6.6 and summarized in Table 1B.10-1, the expansion plan outlined in Table 1B.10-2 represents the least-cost capacity addition plan for KUA under the base case scenario. The unit capacities shown on Table 1B.10-1 are based on the summer capacity and assume 50 percent KUA ownership share for all additions except the 501G combined cycle for which KUA's ownership share is assumed to be 37.5 percent.



Table 1B.10-1
Summary of Generation Alternatives (2001 \$)

Description	Capital Costs **	Capacity**		O&M Costs**		Fuel Type	Full Load Heat Rate*	Forced Outage Rate	Planned Maintenance	First Year Available
		Summer	Winter	Variable	Fixed					
	\$1,000	MW	MW	\$/MWh	\$k-W-Yr		Btu/kWh	percent	weeks	
Pulverized Coal	279,073	240.75	240.75	4.71	33.83	Coal	10,157	9.0	4.00	2002
Fluidized Bed	262,125	242.78	242.78	4.87	28.69	Coal	10,250	9.0	4.00	2002
7EA 1x1 CC	77,904	109.94	124.166	2.59	3.59	Nat. Gas	7,849	3.7	2.25	2001
7EA 2x1 CC	134,184	222.10	250.42	2.36	2.45	Nat. Gas	7,791	1.7	2.25	2001
501F 1x1 CC	117,566	236.63	261.79	2.82	2.27	Nat. Gas	6,815	4.1	2.25	2001
501G 1x1 CC ***	147,362/ 145,157	294.96	333.46	2.48/ 2.34	2.13	Nat. Gas	6,784	13.3	2.25	2001/ 2002
LM6000 SC	22,165	33.36	41.66	7.56	5.96	Nat. Gas	9,417	2.3	1.00	2000
7EA SC	31,451	72.43	81.55	25.74	3.63	Nat. Gas	11,959	2.1	1.25	2001
501G SC***	74,694 / 72,522	197.04	223.87	12.69/ 11.19	2.33	Nat. Gas	10,047	13.3	1.50	2001/ 2002
7FA SC	48,757	147.17	165.31	11.33	2.70	Nat. Gas	10,698	2.7	1.50	2001

*At ISO conditions including degradation.

** KUA would retain 50 percent ownership in the expansion alternative.

*** Capital and operating costs assume SCR through 2001; beyond 2001 SCR is not included in capital and operating costs.



Table 1B.10-2
Base Case Expansion Plan

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		37,749	37,749
1999		39,592	75,277
2000		41,565	112,621
2001	Build 501F 1x1 Combined Cycle (118 MW) *	44,876	150,838
2002		47,819	189,438
2003		50,480	228,062
2004	Build LM6000 Simple Cycle (17 MW)**	54,321	267,458
2005	Build 501G Combined Cycle (111)***	59,446	308,323
2006		62,019	348,735
2007		64,872	388,802
2008		68,078	428,657
2009		71,234	468,186
2010		75,102	507,688
2011		79,089	547,119
2012	Build 501G Combined Cycle (111 MW)***	84,538	587,069
2013		88,586	626,749
2014		93,198	666,319
2015		97,883	705,712
2016		102,851	744,946
2017		108,379	784,133

*Indicates KUA's share of 50 percent ownership with FMPPA.

** Assumes 50 percent KUA ownership share.

*** Assumes 37.5 percent KUA ownership share.



1B.11.0 Sensitivity Analyses

KUA performed several sensitivities to measure the impact of variations in key assumptions on the least-cost plan. The sensitivities, which are presented in Sections 1B.11.1 through 1B.11.6, include: low load and energy growth, high load and energy growth, low fuel price escalation, high fuel price escalation, and constant differential between oil/gas and coal prices over the planning horizon. For each sensitivity presented, the least-cost capacity expansion plan over the planning horizon is identified.

The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

The expansion plan tables indicate the resources necessary to maintain a system reserve margin above 15 percent in all years. All capacities listed in the expansion plan summary tables are the summer ratings of the units. It was assumed that KUA would have a 50 percent ownership share of all units except for the 501G combined cycle. A 37.5 percent ownership share was assumed for the 501G combined cycle. As demonstrated in the sensitivities and the base case expansion plans, the construction of Cane Island 3 is the best resource addition for KUA.

1B.11.1 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an economic environment where load and energy growth are less than the expected base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. Table 1B.11-1 indicates the need for power based upon the low load and energy forecast. Capacity is still required in 2001 for the low load and energy forecast. Table 1B.11-2 presents the results of the economic evaluation of the least-cost expansion plan for the low load and energy growth sensitivity. With the lower load and energy projections, EGEAS selects the 7EA simple cycle in 2001.



Table 1B.11-1
Projected Reliability Levels with
Demand-Side Management and Conservation
Before Expansion Plan - Low Growth

Year	Generation (MW)	Purchases (MW)	Total Resources (MW)	Peak Demand (MW)	Expo Center (MW)	DSM (MW)	Reserve Margin ¹ (percent)	
							Without Center	With Center
1998	172	98	270	213	12.1	12.2	34.5	26.9
1999	172	98	270	215	11.9	12.3	33.3	25.9
2000	172	108	280	224	11.9	12.5	32.4	25.4
2001	172	68	240	235	11.9	12.6	7.9	2.4
2002	172	68	240	244	12.0	12.8	3.9	(1.2)
2003	153	68	221	250	12.1	13.0	(6.7)	(11.2)
2004	153	48	201	257	12.2	13.1	(17.5)	(21.4)
2005	153	48	201	260	12.3	13.3	(18.4)	(22.3)
2006	153	48	201	262	12.3	13.5	(19.0)	(22.8)
2007	153	48	201	264	12.3	13.6	(19.6)	(23.4)
2008	153	48	201	265	12.3	13.8	(19.9)	(23.6)
2009	153	48	201	267	12.3	14.0	(20.5)	(24.1)
2010	153	48	201	268	12.3	14.1	(20.7)	(24.4)
2011	153	48	201	269	12.2	14.3	(21.0)	(24.6)
2012	153	48	201	268	12.1	14.5	(20.6)	(24.2)
2013	105	48	153	268	12.0	14.6	(39.5)	(42.3)
2014	105	48	153	267	11.9	14.8	(39.2)	(42.0)
2015	105	48	153	267	11.8	15.0	(39.2)	(41.9)
2016	105	48	153	265	11.6	15.1	(38.7)	(41.4)
2017	105	48	153	263	11.5	15.3	(38.1)	(40.9)

(1) DSM is subtracted from peak demand.



Table 1B.11-2
Low Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 7EA Simple Cycle (36MW) ¹	36,332	36,332
1999		37,069	71,469
2000		38,398	105,967
2001		40,216	140,216
2002		42,367	174,415
2003	Build 7EA 1x1 Combined Cycle (55MW) ¹	45,207	209,004
2004		46,928	243,039
2005		48,386	276,301
2006		49,900	308,816
2007		51,606	340,689
2008		53,344	371,918
2009		55,053	402,468
2010		57,019	432,459
2011		58,899	461,824
2012		60,817	490,564
2013		62,500	518,560
2014		64,258	545,843
2015		66,094	572,442
2016		67,636	598,243
2017		69,328	623,311

(1) Assumes 50 percent ownership share.



1B.11.2 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an economic environment where load and energy growth are greater than the expected forecast. The high load and energy growth scenario requires the addition of more generation resulting in an increase in cumulative present worth costs for the capacity expansion plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Subsection 1B.5.4.1. Table 1B.11-3 indicates the need for power based upon the high load and energy forecast.

As indicated in Table 1B.11-3, the need for power to maintain a 15 percent reserve margin occurs in 1999. Since the planning alternatives evaluated are not available until 2001, purchase power from an existing supplemental resale contract with Florida Power Corporation is assumed to be made to maintain system reserves. The least-cost plan selected for the high load sensitivity is the installation of a 501F 1x1 combined cycle and a 7FA simple cycle unit in 2001. Table 1B.11-4 presents the results of the economic evaluation for the least-cost capacity expansion plan for the high load and energy growth sensitivity.



Table 1B.11-3
Projected Reliability Levels with
Demand-Side Management and Conservation
Before Expansion Plan - High Load Growth

Year	Generation (MW)	Purchases (MW)	Total Resources (MW)	Peak Demand (MW)	Expo Center (MW)	DSM (MW)	Reserve Margin ¹ (percent)	
							Without Center	With Center
1998	172	98	270	236	0	13.0	21.1	21.1
1999	172	98	270	261	0	14.1	9.4	9.4
2000	172	138	310	282	20	15.1	16.1	8.1
2001	172	68	240	301	40	16.0	(15.8)	(26.0)
2002	153	68	221	320	55	16.8	(27.1)	(38.3)
2003	153	68	221	340	62	17.7	(31.4)	(42.4)
2004	153	48	201	361	71	18.7	(41.3)	(51.3)
2005	153	48	201	382	71	19.7	(44.5)	(53.6)
2006	153	48	201	404	71	20.7	(47.5)	(55.7)
2007	153	48	201	426	71	21.7	(50.3)	(57.7)
2008	153	48	201	450	71	22.7	(52.9)	(59.6)
2009	153	48	201	475	71	23.9	(55.4)	(61.5)
2010	153	48	201	501	71	25.1	(57.7)	(63.2)
2011	153	48	201	528	71	26.2	(59.9)	(64.9)
2012	153	48	201	555	71	27.4	(61.9)	(66.4)
2013	105	48	153	584	71	28.7	(72.4)	(75.5)
2014	105	48	153	614	71	30.1	(73.8)	(76.6)
2015	105	48	153	647	71	31.5	(75.1)	(77.7)
2016	105	48	153	679	71	32.8	(76.3)	(78.6)
2017	105	48	153	713	71	34.3	(77.4)	(79.6)

(1) DSM is subtracted from peak demand.



Table 1B.11-4
High Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118MW) ¹ Build 7FA Simple Cycle (74MW) ²	39,451	39,451
1999		42,792	80,012
2000		46,514	121,803
2001		52,214	166,268
2002		56,958	212,246
2003		61,599	259,377
2004	Build 501G 1x1 Combined Cycle (111MW) ³	67,524	308,349
2005		70,789	357,012
2006		75,095	405,944
2007	Build 501G 1x1 Combined Cycle (111MW) ³	82,936	457,168
2008		88,028	508,702
2009		93,239	560,442
2010		99,773	612,920
2011	Build 501G 1x1 Combined Cycle (111MW) ³	106,617	666,075
2012		114,254	720,068
2013		121,635	774,553
2014	Build 501G 1x1 Combined Cycle (111MW) ³	134,191	831,528
2015		142,647	888,935
2016		151,952	946,900
2017		162,578	1,005,685

(1) Assumes 50 percent ownership share with FMPPA.

(2) Assumes 50 percent ownership share.

(3) Assumes 37.5 percent KUA ownership share.



1B.11.3 Low Fuel Price Escalation

The low fuel price scenario applies the low fuel price forecast to the generation planning assumptions. The low fuel price forecast is provided in Section 1A.3.2. With the low fuel price forecast, the resource plan indicates increased amounts of energy from generation resources and decreased reliance on purchased power as low cost power sources. Table 1B.11-5 presents the results of the economic evaluation for the least-cost capacity expansion plan for the low fuel price escalation sensitivity.



Table 1B.11-5
Low Fuel Price Escalation Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118MW) ¹	37,372	37,372
1999		38,986	74,325
2000		41,159	111,304
2001		43,293	147,173
2002		45,783	185,129
2003	Build LM6000 Simple Cycle (17MW) ²	47,817	221,715
2004		51,073	258,756
2005		55,625	296,994
2006		57,582	334,515
2007		59,664	371,365
2008	Build 501G 1x1 Combined Cycle (111MW) ³	62,022	407,674
2009		64,257	443,331
2010		67,049	478,598
2011		70,002	513,498
2012		74,143	548,536
2013		76,824	582,948
2014		79,923	616,882
2015		82,993	650,282
2016		86,240	683,179
2017		89,970	715,711

(1) Assumes 50 percent ownership share with FMPA.

(2) Assumes 50 percent KUA ownership share.

(3) Assumes 37.5 percent KUA ownership share.



1B.11.4 High Fuel Price Escalation

The high fuel price scenario applies the high fuel price forecast to the generation planning assumptions. The high fuel price forecast is provided in Section 1A.3.2. Table 1B.11-6 presents the results of the economic evaluation for the least-cost capacity expansion plan for the high fuel price escalation sensitivity.



Table 1B.11-6
High Fuel Price Escalation Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118MW) ¹	38,148	38,148
1999		40,239	76,289
2000		42,191	114,195
2001		46,600	153,881
2002		50,006	194,247
2003	Build LM6000 Simple Cycle (17MW) ²	53,191	234,945
2004		57,756	276,832
2005		63,613	320,562
2006		66,975	364,203
2007		70,718	407,880
2008	Build 501G 1x1 Combined Cycle (111MW) ³	74,893	451,725
2009		79,229	495,690
2010		84,334	540,048
2011		89,916	584,876
2012		96,915	630,675
2013		102,824	676,733
2014		109,578	723,258
2015		116,685	770,218
2016		124,315	817,640
2017		133,129	865,776

(1) Assumes KUA share of 50 percent ownership with FMFA.

(2) Assumes 50 percent KUA ownership share.

(3) Assumes 37.5 percent KUA ownership share.



1B.11.5 Constant Differential of Oil/Gas Price Versus Coal Price

This scenario assumes the differential price between oil/gas and coal remains constant over the planning horizon based on current fuel prices. This fuel price sensitivity is outlined in Section 1A.3.2 with the fuel prices used shown in Table 1B.11-7. The evaluation results indicate the following plan in Table 1B.11-8.



Table 1B.11-7
Delivered Fuel Price Forecast—
Constant Differential Between Coal versus Natural Gas/Oil
(\$/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas ¹ <i>Existing Units</i>	Natural Gas ² <i>New Units</i>
1998	1.70	2.68	4.47	0.55	2.39	3.20
1999	1.71	2.69	4.48	0.56	2.40	3.21
2000	1.74	2.72	4.51	0.59	2.43	3.24
2001	1.77	2.75	4.54	0.62	2.46	3.27
2002	1.81	2.79	4.58	0.66	2.50	3.31
2003	1.86	2.84	4.63	0.71	2.55	3.36
2004	1.90	2.88	4.67	0.75	2.59	3.40
2005	1.93	2.91	4.70	0.78	2.62	3.43
2006	1.97	2.95	4.74	0.82	2.66	3.47
2007	2.02	3.00	4.79	0.87	2.71	3.52
2008	2.06	3.04	4.83	0.91	2.75	3.56
2009	2.10	3.08	4.87	0.95	2.79	3.60
2010	2.15	3.13	4.92	1.00	2.84	3.65
2011	2.20	3.18	4.97	1.05	2.89	3.70
2012	2.23	3.21	5.00	1.08	2.92	3.73
2013	2.29	3.27	5.06	1.14	2.98	3.79
2014	2.34	3.32	5.11	1.19	3.03	3.84
2015	2.40	3.38	5.17	1.25	3.09	3.90
2016	2.46	3.44	5.23	1.31	3.15	3.96
2017	2.51	3.49	5.28	1.36	3.20	4.01

(1) Delivered natural gas price less demand reservation.

(2) Includes demand reservation costs.



Table 1B.11-8
Constant Differential of Oil/Gas Versus Coal Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501G 1x1 Combined Cycle (111MW) ¹	37,749	37,749
1999		39,875	75,545
2000		41,948	113,233
2001		44,693	151,294
2002		47,272	189,453
2003	Build LM6000 Simple Cycle (17MW) ²	50,022	227,727
2004		53,678	266,657
2005		56,820	305,717
2006		59,048	344,192
2007		61,545	382,204
2008	Build 501G 1x1 Combined Cycle (111MW) ¹	64,095	419,727
2009		66,756	456,771
2010		69,620	493,390
2011		72,767	529,669
2012		75,210	565,211
2013		78,327	600,296
2014		81,437	634,873
2015		85,006	669,083
2016		88,499	702,842
2017		92,154	736,163

(1) Assumes 37.5 percent KUA ownership share.

(2) Assumes 50 percent KUA ownership share.



1B.12.0 Strategic Considerations

In selecting a power supply alternative, a utility must consider certain strategic factors that reflect the utility's long-term ability to provide economical and reliable electric capacity and energy to its consumers. There are a number of strategic considerations that favor the installation of Cane Island 3 over other alternatives. The strategic considerations include low installation cost on a \$/kW basis, low operating costs, domestically produced fuel, an existing site designed to accommodate the project capacity, electric industry deregulation, environmental benefits and efficiency.

Cane Island 3 is one of the lowest cost alternatives on a \$/kW basis in comparison to other resource additions. Cane Island 3 benefits from the lower cost of an existing site, economic conditions where capital costs for combined cycle F-class technology are at the lowest price in history and the availability of low cost funds for financing. These factors contribute to Cane Island 3 having a lower installed cost over other alternatives.

Cane Island 3's F-class technology has the lowest heat rate of any of the generating units commercially operated in the United States. The proposed G-class technology only has a marginally better heat rate than the F-class technology and is not yet in commercial operation in the United States. The efficiency of the F-class technology ensures that Cane Island 3 will produce competitively priced generation for many years. If deregulation in the retail market occurs in Florida, Cane Island 3's low heat rate would ensure that the unit will remain a competitive resource.

The ability to utilize the existing Cane Island site offers many strategic advantages. Only two additional personnel will be required for the operation and maintenance of Cane Island 3, which will result in significantly lower fixed O&M costs. Cane Island 3 will also have the advantage of a skilled and trained staff for operation and maintenance.

The use of the existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions with Cane Island Unit 3 provides assurance from risk from future environmental regulations while reducing emissions within the state.

Cane Island Unit 3 will utilize domestic natural gas, which minimizes risks from interruption of supply often associated with imported fuels.



1B.13.0 Consequences of Delay

The initial consequences of delaying the proposed generating plant is the risk of rising construction costs due to price escalation, the need to supply an alternative resource or purchase to maintain the same level of system reliability, which would have been provided by Cane Island 3, and the potential for capital costs to rise above the rate of inflation.

With the equipment costs for F-class combined cycles at their lowest point in history and industry experts indicating that capital costs for new generating facilities may begin to increase again, there could be significant impacts to KUA's system production costs and resulting revenue requirements without installation of Cane Island 3 in 2001.

Installation of Cane Island 3 will provide KUA consumers the lowest possible energy cost with the least possible environmental impacts. This is because Cane Island 3 will displace energy generated by higher cost, higher emission producing oil fired units with cleaner, more efficient natural gas-fired capacity. If Cane Island 3 is delayed, KUA will be required to obtain additional purchased power to meet system demand. This may result in adverse rate impacts to consumers due to increased annual system revenue requirements for capacity and energy purchases and/or increased operation of less efficient units.

Peninsular Florida's need for power is growing at one of the fastest rates in the nation, resulting in a steady decrease in available generating reserves. To maintain a reliable system, KUA and FMPP will require additional resources to meet demand. With a shortage of available purchase power on the market, KUA must build new capacity. The consequences of delaying the project could have potentially large impacts on system reliability.

1B.13.1 Economic Benefits

If the construction of Cane Island 3 is delayed or canceled, several consequences may occur including: risk of possible escalation of capital costs above inflation, the need to purchase power on the market or under emergency conditions, the higher fuel costs associated with running older units, and the environmental impacts of the emissions from the older units.

Ignoring the very realistic possibility of increasing costs for equipment and the effects of higher emissions on the environment, KUA has conducted an economic evaluation to



determine the impact on system cumulative present worth revenue requirements if the project is delayed by one year. KUA would, in lieu of building Cane Island 3 in 2001, purchase 125 MW of capacity and associated energy from an existing Unit Power Purchase Contract with OUC. The capacity and energy charges associated with the Unit Purchase contract are \$5.00/kW-mo and \$30.00/Mwh respectively. In addition to the capacity and energy charges, a transmission charge of \$1.50/kW-mo is assessed.

Table 1B.13-1 presents the results of the economic analysis. As indicated, KUA will experience an increase in total annual cumulative present worth system production costs of approximately \$6,806,000 if Cane Island 3 is not constructed. As in any industry, cost increases have detrimental effects on both rate structure and overall competitiveness. Based on KUA's analysis of service area load growth, regional capacity resources, and capacity addition alternatives, Cane Island 3 will provide the least-cost, most environmentally sound, and proven capacity addition alternative - in a dynamic industry where competition, deregulation, and the financial soundness of a utility are closely linked.



Table 1B.13-1
KUA Cumulative Present Worth (CPW) System Production Costs
With and Without Cane Island 3

Year	Annual Cost With Cane Island 3 (\$000)	Annual Cost Without Cane Island 3 (\$000)	Annual CPW Cost Difference (\$000)
1998	37,749	37,749	0
1999	39,592	39,592	0
2000	41,663	41,663	0
2001	44,876	56,057	9,522
2002	47,819	47,787	9,496
2003	52,124	50,455	8,219
2004	54,839	54,287	7,819
2005	57,374	59,498	9,279
2006	60,237	62,071	10,474
2007	63,501	64,924	11,353
2008	69,294	68,130	10,671
2009	72,634	71,287	9,924
2010	76,623	75,155	9,152
2011	80,855	79,141	8,297
2012	84,999	84,590	8,104
2013	89,097	88,638	7,898
2014	93,788	93,250	7,670
2015	98,575	97,935	7,412
2016	103,653	102,903	7,126
2017	109,317	108,431	<u>6,806</u>

18.14.0 Financial Analysis



1B.14.0 Financial Analysis

A portion of the funding for KUA's share of Cane Island Unit 3 is planned from approximately \$17 million remaining proceeds from existing revenue bonds for Cane Island Units 1 and 2. The remainder of funding for Unit 3 is planned from a new bond issue in the year 2000.

KUA is in a strong position to finance its ownership share of Cane Island Unit 3. KUA's outstanding revenue bonds are fully insured and thus carry a AAA risk rating.

KUA's debt service coverage ratio for the fiscal year ended September 30, 1997 was 2.83, and has averaged 2.97 over the past three fiscal years. While interest coverage ratios will be somewhat lower in upcoming years due to higher interest expenses, the coverage ratios are projected to significantly exceed KUA's minimum target of 1.50. KUA's self-imposed minimum target coverage is in turn higher than that defined in the current revenue bond resolutions, which prescribe that annual net revenues not be less than 1.25 times the bond service requirement.

As of September 30, 1997, KUA's reinvested earnings totaled \$129.2 million. The reinvested earnings are equal to about 35 percent of overall long-term capitalization and liabilities. This is a financially strong representation of reinvested earnings in relation to outstanding debt.

18.15.0 Analysis of 1990 Clean
Air Act Amendments



1B.15.0 Analysis of 1990 Clean Air Act Amendments

1B.15.1 Compliance Strategy

Cane Island Unit 3 will emit small amounts of sulfur dioxide while running on either natural gas or fuel oil. As an affected unit, Unit 3 must have allowances available for emissions of sulfur dioxide to comply with its Title IV Acid Rain permit. KUA is proposing to limit sulfur dioxide emissions to 40 tons per year for Unit 3. The 40 ton per year maximum emissions level minimizes permitting requirements for Unit 3. Forty tons per year of sulfur dioxide emissions for Unit 3 is equivalent to approximately 720 hours of full load operation on distillate oil (0.05 percent sulfur) and 8040 hours of full load operation on fuel gas. The current operating plan for the Cane Island Power Park, including Unit 3, includes operation on fuel oil only during emergency situations. To date Cane Island Units 1 and 2 have not had to operate on fuel oil.

KUA has identified two possible sulfur dioxide emissions compliance strategies. The first and preferred compliance strategy involves re-allocation of excess allowances currently maintained by the OUC Stanton Energy Center to cover the Cane Island Unit 3 sulfur dioxide emissions. KUA owns approximately 6.6 percent of Stanton Unit 1 and approximately 7.7 percent of Stanton Unit 2. Therefore, KUA has entitlements to a proportionate amount of the excess allowances of the Stanton Energy Center. Stanton Unit 1 currently receives 11,199 allowances per year while Stanton Unit 2 receives 0 allowances per year. Current operation of Stanton Unit 1 and Unit 2 results in a combined sulfur dioxide emissions rate of approximately 10,200 tons per year, leaving approximately 1000 excess allowances. Therefore, in accordance with the KUA ownership entitlements, over 60 allowances per year are currently available for reallocation from Stanton to Cane Island by KUA. The second possible compliance strategy involves purchasing allowances. Purchasing allowances will be the compliance strategy utilized if, for any reason, re-allocation proves to supply insufficient quantities of allowances.



Appendix 1B.16.1

Results of Statistical Tests



Appendix 1B.16.1

LS // Dependent Variable is GSNKWHT Sample (adjusted): 1985:03 1996:09 Included observations: 139 after adjusting endpoints Convergence achieved after 11 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
PRICESGN(-1)	-41914.30	9437.271	-4.441358	0.0000
GOODSERV	262002.6	25331.59	10.34292	0.0000
BMC_TIME	46.32923	7.723628	5.998376	0.0000
AR(1)	0.784862	0.053777	14.59470	0.0000
MA(11)	0.364201	0.070633	5.156272	0.0000
MA(12)	0.515291	0.067686	7.612998	0.0000
R-squared	0.977187	Mean dependent var		6092871.
Adjusted R-squared	0.976330	S.D. dependent var		3403380.
S.E. of regression	523614.9	Akaike info criterion		26.37923
Sum squared resid	3.65E+13	Schwarz criterion		26.50590
Log likelihood	-2024.589	F-statistic		1139.420
Durbin-Watson stat	2.028290	Prob (F-statistic)		0.000000
Inverted AR Roots	.78			
Inverted MA Roots	.95-.26i	.95+.26i	.68+.71i	.68-.71i
	.21+.95i	.21-.95i	-.30+.90i	-.30-.90i
	-.68-.61i	-.68+.61i	-.86-.20i	-.86+.20i



LS // Dependent Variable is GSNCUSTT				
Sample: 1991:01 1996:09				
Included observations: 69				
Convergence achieved after 12 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-2993.870	1024.119	-2.923363	0.0048
POPA	73.65239	7.783706	9.462381	0.0000
AR(1)	0.763806	0.065460	11.66824	0.0000
MA(2)	0.746148	0.076843	9.710012	0.0000
R-squared	0.991991	Mean dependent var		6478.203
Adjusted R-squared	0.991622	S.D. dependent var		791.6428
S.E. of regression	72.46208	Akaike info criterion		8.622350
Sum squared resid	341298.9	Schwarz criterion		8.751863
Log likelihood	-391.3778	F-statistic		2683.690
Durbin-Watson stat	2.005084	Prob (F-statistic)		0.000000
Inverted AR Roots	.76			



LS // Dependent Variable is RSUPC Sample (adjusted): 1986:02 1996:09 Included observations: 128 after adjusting endpoints Convergence achieved after 5 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	413.2600	252.7277	1.635199	0.1048
HEAT2	1.039933	0.139833	7.436980	0.0000
MINTEMP	2.487544	1.143512	2.175355	0.0317
INCPERHH	17.38039	7.772856	2.236036	0.0273
PRICERES(-12)	-4.972532	0.797516	-6.235022	0.0000
MAR	-84.22658	20.33522	-4.141906	0.0001
APR	-65.27621	20.45847	-3.190670	0.0018
JUN	191.1631	25.67054	7.446790	0.0000
JUL	362.3508	29.90318	12.11747	0.0000
AUG	408.2809	30.23031	13.50568	0.0000
SEP	437.3900	28.41160	15.39477	0.0000
OCT	283.0730	22.37330	12.65227	0.0000
DEC	-83.88816	20.94499	-4.005166	0.0001
AR(1)	0.205994	0.091024	2.263076	0.0255
R-squared	0.917427	Mean dependent var		964.3945
Adjusted R-squared	0.908011	S.D. dependent var		202.2864
S.E. of regression	61.35286	Akaike info criterion		8.336202
Sum squared resid	429115.7	Schwarz criterion		8.648142
Log likelihood	-701.1410	F-statistic		97.43068
Durbin-Watson stat	1.967069	Prob (F-statistic)		0.000000
Inverted AR Roots	.21			



LS // Dependent Variable is RSCUSTT				
Sample (adjusted): 1985:03 1996:09				
Included observations: 139 after adjusting endpoints				
Convergence achieved after 4 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7674.448	624.9708	12.27969	0.0000
TS	537.4033	15.77505	34.06666	0.0000
AR(1)	0.431372	0.078309	5.508612	0.0000
AR(2)	0.413804	0.078312	5.284067	0.0000
R-squared	0.997394	Mean dependent var		27282.23
Adjusted R-squared	0.997336	S.D. dependent var		5384.780
S.E. of regression	277.9465	Akaike info criterion		11.28321
Sum squared resid	10429325	Schwarz criterion		11.36766
Log likelihood	-977.4157	F-statistic		17220.19
Durbin-Watson stat	2.078771	Prob (F-statistic)		0.000000
Inverted AR Roots	.89	-.46		



LS // Dependent Variable is OLSKWH				
Sample: 1991:01 1996:09				
Included observations: 69				
Convergence achieved after 5 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-429999.1	173212.2	-2.482500	0.0156
POPA	6849.977	1287.725	5.319443	0.0000
AR(1)	0.568124	0.116598	4.872509	0.0000
AR(2)	0.315443	0.117173	2.692111	0.0090
R-squared	0.970393	Mean dependent var		456412.2
Adjusted R-squared	0.969026	S.D. dependent var		59816.40
S.E. of regression	10527.33	Akaike info criterion		18.57968
Sum squared resid	7.20E+09	Schwarz criterion		18.70920
Log likelihood	-734.9058	F-statistic		710.1322
Durbin-Watson stat	2.082227	Prob (F-statistic)		0.000000
Inverted AR Roots	.91	-.35		



LS // Dependent Variable is GSDKWHT				
Sample: 1991:01 1996:09				
Included observations: 69				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11631387	1160050.	10.02662	0.0000
BMC_TIME	73.17016	12.78002	5.725356	0.0000
GOODSERV	231556.3	28289.66	8.185192	0.0000
FEB	-904931.3	412473.9	-2.193912	0.0322
MAR	-1376438.	400371.5	-3.437902	0.0011
JUN	981953.4	513600.6	1.911901	0.0607
JUL	1989366.	574625.3	3.462023	0.0010
AUG	1888365.	608309.7	3.104282	0.0029
SEP	3918532.	559712.3	7.000975	0.0000
OCT	1359601.	497343.6	2.733725	0.0083
R-squared	0.933308	Mean dependent var		23939290
Adjusted R-squared	0.923135	S.D. dependent var		3076540.
S.E. of regression	852959.3	Akaike info criterion		27.44622
Sum squared resid	4.29E+13	Schwarz criterion		27.77000
Log likelihood	-1034.801	F-statistic		91.74024
Durbin-Watson stat	1.836650	Prob (F-statistic)		0.000000

Appendix 1B.16.2

Energy and Demand Forecast Variables



Appendix 1B.16.2

Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
1985:01	0.00	0.00	80.89	80.89	130.08	41.00	105.50
1985:02	0.00	0.00	129.22	64.61	196.25	102.50	106.00
1985:03	0.00	0.00	422.66	140.89	58.73	166.00	106.40
1985:04	1.00	0.00	666.83	166.71	17.06	227.00	106.90
1985:05	0.00	0.00	1,590.74	318.15	1.25	385.00	107.30
1985:06	0.00	0.00	2,807.31	467.89	0.00	501.00	107.60
1985:07	0.00	0.00	3,339.12	477.02	0.00	473.00	107.80
1985:08	0.00	1.00	3,955.23	494.40	0.00	508.00	108.00
1985:09	0.00	0.00	4,111.46	456.83	0.00	396.50	108.30
1985:10	0.00	0.00	3,901.87	390.19	0.00	395.00	108.70
1985:11	0.00	0.00	3,159.53	287.23	18.68	220.00	109.00
1985:12	0.00	0.00	1,973.37	164.45	75.33	52.00	109.30
1986:01	0.00	0.00	210.73	16.21	228.68	11.50	109.60
1986:02	0.00	0.00	454.66	32.48	164.06	55.00	109.30
1986:03	0.00	0.00	998.83	66.59	154.91	79.00	108.80
1986:04	1.00	0.00	1,519.91	94.99	52.32	115.00	108.60
1986:05	0.00	0.00	3,429.98	201.76	9.02	294.50	108.90
1986:06	0.00	0.00	6,964.56	386.92	0.00	452.50	109.50
1986:07	0.00	0.00	9,057.17	476.69	0.00	501.00	109.50
1986:08	0.00	1.00	10,019.03	500.95	0.00	505.00	109.70
1986:09	0.00	0.00	10,072.41	479.64	0.00	448.50	110.20
1986:10	0.00	0.00	9,062.01	411.91	0.00	321.50	110.30
1986:11	0.00	0.00	6,211.31	270.06	0.15	275.00	110.40
1986:12	0.00	0.00	4,392.95	183.04	28.56	80.00	110.50
1987:01	0.00	0.00	924.60	36.98	176.32	23.00	111.20
1987:02	0.00	0.00	464.63	17.87	199.95	25.00	111.60
1987:03	0.00	0.00	965.48	35.76	92.52	58.50	112.10
1987:04	1.00	0.00	2,126.99	75.96	93.73	108.00	112.70
1987:05	0.00	0.00	6,618.19	228.21	7.27	317.50	113.10
1987:06	0.00	0.00	12,122.60	404.09	0.00	485.50	113.50
1987:07	0.00	0.00	16,260.32	524.53	0.00	536.50	113.80
1987:08	0.00	1.00	17,377.55	543.05	0.00	545.00	114.40
1987:09	0.00	0.00	16,775.28	508.34	0.00	463.50	115.00
1987:10	0.00	0.00	10,284.34	302.48	1.81	154.00	115.30
1987:11	0.00	0.00	4,866.84	139.05	26.19	125.00	115.40
1987:12	0.00	0.00	2,634.81	73.19	108.79	60.00	115.40
1988:01	0.00	0.00	1,597.56	43.18	178.27	11.50	115.70



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
1988:02	0.00	0.00	1,034.82	27.23	263.08	30.50	116.00
1988:03	0.00	0.00	1,094.90	28.07	169.02	66.00	116.50
1988:04	1.00	0.00	5,205.08	130.13	54.79	186.00	117.10
1988:05	0.00	0.00	9,420.17	229.76	8.05	284.50	117.50
1988:06	0.00	0.00	14,990.07	356.91	0.00	416.50	118.00
1988:07	0.00	0.00	19,359.57	450.22	0.00	471.00	118.50
1988:08	0.00	1.00	22,611.74	513.90	0.00	525.50	119.00
1988:09	0.00	0.00	22,172.59	492.72	0.00	465.00	119.80
1988:10	0.00	0.00	16,689.91	362.82	0.00	254.00	120.20
1988:11	0.00	0.00	9,314.26	198.18	2.42	177.00	120.30
1988:12	0.00	0.00	5,306.40	110.55	92.58	57.50	120.50
1989:01	0.00	0.00	3,651.29	74.52	79.95	65.00	121.10
1989:02	0.00	0.00	4,255.44	85.11	75.57	83.00	121.60
1989:03	0.00	0.00	4,934.04	96.75	163.34	151.00	122.30
1989:04	1.00	0.00	7,431.44	142.91	43.36	161.50	123.10
1989:05	0.00	0.00	14,489.89	273.39	8.28	377.00	123.80
1989:06	0.00	0.00	24,276.92	449.57	0.00	466.50	124.10
1989:07	0.00	0.00	27,009.88	491.09	0.00	527.50	124.40
1989:08	0.00	1.00	30,751.23	549.13	0.00	568.50	124.60
1989:09	0.00	0.00	30,001.89	526.35	0.00	467.50	125.00
1989:10	0.00	0.00	22,268.60	383.94	10.13	265.50	125.60
1989:11	0.00	0.00	9,760.09	165.43	34.25	106.00	125.90
1989:12	0.00	0.00	2,672.55	44.54	203.18	7.50	126.10
1990:01	0.00	0.00	1,810.32	29.68	255.94	61.50	127.60
1990:02	0.00	0.00	6,488.32	104.65	68.43	117.50	128.20
1990:03	0.00	0.00	5,778.40	91.72	43.73	108.00	128.80
1990:04	1.00	0.00	8,145.65	127.28	13.14	153.00	129.10
1990:05	0.00	0.00	19,492.56	299.89	1.20	418.50	129.30
1990:06	0.00	0.00	29,205.96	442.51	0.00	450.00	129.90
1990:07	0.00	0.00	30,063.66	448.71	0.00	457.50	130.60
1990:08	0.00	1.00	32,360.32	475.89	0.00	487.50	131.60
1990:09	0.00	0.00	33,083.31	479.47	0.00	447.00	132.50
1990:10	0.00	0.00	28,023.67	400.34	1.55	311.00	133.40
1990:11	0.00	0.00	12,511.04	176.21	19.70	111.00	133.80
1990:12	0.00	0.00	5,690.17	79.03	77.54	101.00	134.10
1991:01	0.00	0.00	9,802.02	134.27	62.13	98.00	134.90
1991:02	0.00	0.00	4,228.87	57.15	116.51	44.00	135.10
1991:03	0.00	0.00	4,954.71	66.06	116.60	107.00	135.00
1991:04	1.00	0.00	13,936.07	183.37	37.67	274.50	135.40



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
1991:05	0.00	0.00	27,665.48	359.29	1.30	409.50	135.80
1991:06	0.00	0.00	32,863.33	421.32	0.00	461.50	136.00
1991:07	0.00	0.00	39,889.73	504.93	0.00	506.50	136.30
1991:08	0.00	1.00	42,272.26	528.40	0.00	525.00	136.60
1991:09	0.00	0.00	39,222.64	484.23	0.00	443.00	137.00
1991:10	0.00	0.00	28,662.62	349.54	0.00	263.00	137.30
1991:11	0.00	0.00	11,635.71	140.19	60.67	68.50	137.80
1991:12	0.00	0.00	7,591.52	90.38	104.69	65.50	138.10
1992:01	0.00	0.00	1,672.58	19.68	191.63	8.00	138.50
1992:02	0.00	0.00	2,193.79	25.51	205.57	63.50	138.80
1992:03	0.00	0.00	7,418.05	85.26	76.74	67.50	139.30
1992:04	1.00	0.00	7,370.57	83.76	69.13	133.00	139.70
1992:05	0.00	0.00	16,782.39	188.57	20.57	257.00	139.90
1992:06	0.00	0.00	33,121.55	368.02	1.02	429.50	140.20
1992:07	0.00	0.00	45,645.21	501.60	0.00	567.00	140.60
1992:08	0.00	1.00	48,344.52	525.48	0.00	477.00	140.90
1992:09	0.00	0.00	42,767.95	459.87	0.00	440.00	141.10
1992:10	0.00	0.00	29,035.44	308.89	0.42	200.00	141.70
1992:11	0.00	0.00	17,405.17	183.21	28.58	156.00	142.00
1992:12	0.00	0.00	7,215.23	75.16	149.65	24.00	142.20
1993:01	0.00	0.00	6,821.29	70.32	81.68	76.00	142.90
1993:02	0.00	0.00	2,172.43	22.17	167.09	2.50	143.40
1993:03	0.00	0.00	1,380.58	13.95	186.86	51.00	143.60
1993:04	1.00	0.00	7,897.26	78.97	52.08	76.50	144.20
1993:05	0.00	0.00	41,373.67	409.64	11.65	677.50	144.40
1993:06	0.00	0.00	54,695.09	536.23	0.00	434.00	144.40
1993:07	0.00	0.00	48,461.44	470.50	0.00	541.00	144.50
1993:08	0.00	1.00	56,316.00	541.50	0.00	504.00	144.90
1993:09	0.00	0.00	49,549.56	471.90	0.00	439.00	144.90
1993:10	0.00	0.00	36,283.06	342.29	0.45	257.00	145.50
1993:11	0.00	0.00	18,008.85	168.31	62.30	95.50	145.80
1993:12	0.00	0.00	5,340.72	49.45	162.56	6.50	146.10
1994:01	0.00	0.00	441.27	4.05	317.21	13.50	146.30
1994:02	0.00	0.00	4,378.58	39.81	174.41	62.00	146.70
1994:03	0.00	0.00	8,244.56	74.28	74.26	121.50	147.20
1994:04	1.00	0.00	19,212.09	171.54	36.14	209.50	147.40
1994:05	0.00	0.00	33,454.80	296.06	0.67	333.00	147.70
1994:06	0.00	0.00	42,072.44	369.06	0.00	436.00	148.10
1994:07	0.00	0.00	53,156.90	462.23	0.00	471.00	148.60



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
1994:08	0.00	1.00	54,353.48	468.56	0.00	457.00	149.10
1994:09	0.00	0.00	50,199.04	429.05	0.00	376.00	149.40
1994:10	0.00	0.00	38,140.26	323.22	0.00	283.50	149.50
1994:11	0.00	0.00	24,955.58	209.71	5.13	151.00	149.90
1994:12	0.00	0.00	13,176.65	109.81	60.66	56.00	150.10
1995:01	0.00	0.00	2,207.27	18.24	204.94	6.50	150.60
1995:02	0.00	0.00	1,863.73	15.28	283.22	35.50	150.90
1995:03	0.00	0.00	6,473.09	52.63	91.62	85.50	151.30
1995:04	1.00	0.00	16,122.00	130.02	22.14	184.50	151.80
1995:05	0.00	0.00	39,725.81	317.81	1.30	417.50	152.20
1995:06	0.00	0.00	52,381.59	415.73	0.00	392.50	152.60
1995:07	0.00	0.00	57,375.19	451.77	0.00	507.00	152.70
1995:08	0.00	1.00	60,707.10	474.27	0.00	455.00	153.00
1995:09	0.00	0.00	55,797.15	432.54	0.00	420.00	153.20
1995:10	0.00	0.00	49,433.06	380.25	0.00	283.00	153.70
1995:11	0.00	0.00	21,642.82	165.21	46.35	69.50	153.80
1995:12	0.00	0.00	4,643.06	35.17	134.17	30.00	154.10
1996:01	0.00	0.00	2,481.95	18.66	312.23	15.50	154.70
1996:02	0.00	0.00	2,123.70	15.85	260.06	40.00	155.00
1996:03	0.00	0.00	6,371.98	47.20	221.95	44.00	155.60
1996:04	1.00	0.00	8,375.19	61.58	108.06	109.50	156.20
1996:05	0.00	0.00	28,343.31	206.89	10.18	260.50	156.70
1996:06	0.00	0.00	35,235.70	255.33	0.00	276.50	156.80
1996:07	0.00	0.00	47,030.13	338.35	0.00	371.50	157.10
1996:08	0.00	1.00	50,987.10	364.19	0.00	336.50	157.20
1996:09	0.00	0.00	45,690.14	324.04	0.00	296.50	157.60
1996:10	0.00	0.00	29,129.01	205.13	5.63	186.00	158.30
1996:11	0.00	0.00	20,477.52	143.20	57.47	89.00	158.80
1996:12	0.00	0.00	12,829.08	89.09	67.01	86.00	159.20
1997:01	0.00	0.00	15,992.10	110.29	109.29	87.50	159.40
1997:02	0.00	0.00	14,285.54	97.85	94.56	173.00	159.80
1997:03	0.00	0.00	40,644.40	276.49	9.04	325.50	159.90
1997:04	1.00	0.00	38,960.52	263.25	0.00	225.00	160.00
1997:05	0.00	0.00	44,485.39	298.56	0.00	380.50	160.10
1997:06	0.00	0.00	64,258.55	428.39	0.00	469.50	160.30
1997:07	0.00	0.00	77,382.14	512.46	0.00	538.00	160.60
1997:08	0.00	1.00	83,771.61	551.13	0.00	552.00	160.90
1997:09	0.00	0.00	79,772.64	521.39	0.00	496.50	161.30
1997:10	0.00	0.00	51,727.37	335.89	2.00	245.70	161.70



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
1997:11	0.00	0.00	26,174.80	168.87	34.31	114.85	162.10
1997:12	0.00	0.00	11,799.34	75.64	116.08	49.40	162.50
1998:01	0.00	0.00	8,209.33	52.29	179.33	44.30	162.90
1998:02	0.00	0.00	7,751.35	49.06	170.85	65.15	163.30
1998:03	0.00	0.00	13,235.29	83.24	115.32	112.70	163.70
1998:04	1.00	0.00	21,964.72	137.28	43.65	171.30	164.11
1998:05	0.00	0.00	46,365.59	287.99	6.32	381.55	164.51
1998:06	0.00	0.00	65,497.68	404.31	0.10	423.25	164.92
1998:07	0.00	0.00	75,499.46	463.19	0.00	495.80	165.32
1998:08	0.00	1.00	81,876.47	499.25	0.00	488.80	165.73
1998:09	0.00	0.00	76,255.80	462.16	0.00	429.05	166.14
1998:10	0.00	0.00	55,758.07	335.89	2.00	245.70	166.55
1998:11	0.00	0.00	28,201.24	168.87	34.31	114.85	166.96
1998:12	0.00	0.00	12,706.98	75.64	116.08	49.40	167.37
1999:01	0.00	0.00	8,836.79	52.29	179.33	44.30	167.78
1999:02	0.00	0.00	8,340.06	49.06	170.85	65.15	168.20
1999:03	0.00	0.00	14,234.18	83.24	115.32	112.70	168.61
1999:04	1.00	0.00	23,612.08	137.28	43.65	171.30	169.03
1999:05	0.00	0.00	49,821.41	287.99	6.32	381.55	169.45
1999:06	0.00	0.00	70,349.36	404.31	0.10	423.25	169.86
1999:07	0.00	0.00	81,057.70	463.19	0.00	495.80	170.28
1999:08	0.00	1.00	87,867.43	499.25	0.00	488.80	170.70
1999:09	0.00	0.00	81,801.67	462.16	0.00	429.05	171.12
1999:10	0.00	0.00	59,788.77	335.89	2.00	245.70	171.55
1999:11	0.00	0.00	30,227.67	168.87	34.31	114.85	171.97
1999:12	0.00	0.00	13,614.62	75.64	116.08	49.40	172.39
2000:01	0.00	0.00	9,464.26	52.29	179.33	44.30	172.82
2000:02	0.00	0.00	8,928.77	49.06	170.85	65.15	173.24
2000:03	0.00	0.00	15,233.07	83.24	115.32	112.70	173.67
2000:04	1.00	0.00	25,259.43	137.28	43.65	171.30	174.10
2000:05	0.00	0.00	53,277.23	287.99	6.32	381.55	174.53
2000:06	0.00	0.00	75,201.04	404.31	0.10	423.25	174.96
2000:07	0.00	0.00	86,615.95	463.19	0.00	495.80	175.39
2000:08	0.00	1.00	93,858.39	499.25	0.00	488.80	175.82
2000:09	0.00	0.00	87,347.55	462.16	0.00	429.05	176.26
2000:10	0.00	0.00	63,819.48	335.89	2.00	245.70	176.69
2000:11	0.00	0.00	32,254.11	168.87	34.31	114.85	177.13
2000:12	0.00	0.00	14,522.26	75.64	116.08	49.40	177.56
2001:01	0.00	0.00	10,091.72	52.29	179.33	44.30	178.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
2001:02	0.00	0.00	9,517.48	49.06	170.85	65.15	178.44
2001:03	0.00	0.00	16,231.96	83.24	115.32	112.70	178.88
2001:04	1.00	0.00	26,906.79	137.28	43.65	171.30	179.32
2001:05	0.00	0.00	56,733.05	287.99	6.32	381.55	179.76
2001:06	0.00	0.00	80,052.72	404.31	0.10	423.25	180.21
2001:07	0.00	0.00	92,174.19	463.19	0.00	495.80	180.65
2001:08	0.00	1.00	99,849.35	499.25	0.00	488.80	181.10
2001:09	0.00	0.00	92,893.43	462.16	0.00	429.05	181.54
2001:10	0.00	0.00	67,850.18	335.89	2.00	245.70	181.99
2001:11	0.00	0.00	34,280.54	168.87	34.31	114.85	182.44
2001:12	0.00	0.00	15,429.90	75.64	116.08	49.40	182.89
2002:01	0.00	0.00	10,719.19	52.29	179.33	44.30	183.34
2002:02	0.00	0.00	10,106.19	49.06	170.85	65.15	183.79
2002:03	0.00	0.00	17,230.85	83.24	115.32	112.70	184.25
2002:04	1.00	0.00	28,554.14	137.28	43.65	171.30	184.70
2002:05	0.00	0.00	60,188.87	287.99	6.32	381.55	185.16
2002:06	0.00	0.00	84,904.40	404.31	0.10	423.25	185.61
2002:07	0.00	0.00	97,732.43	463.19	0.00	495.80	186.07
2002:08	0.00	1.00	105,840.32	499.25	0.00	488.80	186.53
2002:09	0.00	0.00	98,439.30	462.16	0.00	429.05	186.99
2002:10	0.00	0.00	71,880.89	335.89	2.00	245.70	187.45
2002:11	0.00	0.00	36,306.98	168.87	34.31	114.85	187.91
2002:12	0.00	0.00	16,337.54	75.64	116.08	49.40	188.38
2003:01	0.00	0.00	11,346.65	52.29	179.33	44.30	188.84
2003:02	0.00	0.00	10,694.90	49.06	170.85	65.15	189.31
2003:03	0.00	0.00	18,229.74	83.24	115.32	112.70	189.78
2003:04	1.00	0.00	30,201.49	137.28	43.65	171.30	190.24
2003:05	0.00	0.00	63,644.69	287.99	6.32	381.55	190.71
2003:06	0.00	0.00	89,756.08	404.31	0.10	423.25	191.18
2003:07	0.00	0.00	103,290.67	463.19	0.00	495.80	191.65
2003:08	0.00	1.00	111,831.28	499.25	0.00	488.80	192.13
2003:09	0.00	0.00	103,985.18	462.16	0.00	429.05	192.60
2003:10	0.00	0.00	75,911.59	335.89	2.00	245.70	193.08
2003:11	0.00	0.00	38,333.42	168.87	34.31	114.85	193.55
2003:12	0.00	0.00	17,245.18	75.64	116.08	49.40	194.03
2004:01	0.00	0.00	11,974.11	52.29	179.33	44.30	194.51
2004:02	0.00	0.00	11,283.61	49.06	170.85	65.15	194.99
2004:03	0.00	0.00	19,228.63	83.24	115.32	112.70	195.47
2004:04	1.00	0.00	31,848.85	137.28	43.65	171.30	195.95



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
2004:05	0.00	0.00	67,100.51	287.99	6.32	381.55	196.43
2004:06	0.00	0.00	94,607.76	404.31	0.10	423.25	196.92
2004:07	0.00	0.00	108,848.92	463.19	0.00	495.80	197.40
2004:08	0.00	1.00	117,822.24	499.25	0.00	488.80	197.89
2004:09	0.00	0.00	109,531.05	462.16	0.00	429.05	198.38
2004:10	0.00	0.00	79,942.29	335.89	2.00	245.70	198.87
2004:11	0.00	0.00	40,359.85	168.87	34.31	114.85	199.36
2004:12	0.00	0.00	18,152.83	75.64	116.08	49.40	199.85
2005:01	0.00	0.00	12,601.58	52.29	179.33	44.30	200.34
2005:02	0.00	0.00	11,872.32	49.06	170.85	65.15	200.84
2005:03	0.00	0.00	20,227.52	83.24	115.32	112.70	201.33
2005:04	1.00	0.00	33,496.20	137.28	43.65	171.30	201.83
2005:05	0.00	0.00	70,556.33	287.99	6.32	381.55	202.33
2005:06	0.00	0.00	99,459.44	404.31	0.10	423.25	202.83
2005:07	0.00	0.00	114,407.16	463.19	0.00	495.80	203.33
2005:08	0.00	1.00	123,813.20	499.25	0.00	488.80	203.83
2005:09	0.00	0.00	115,076.93	462.16	0.00	429.05	204.33
2005:10	0.00	0.00	83,973.00	335.89	2.00	245.70	204.83
2005:11	0.00	0.00	42,386.29	168.87	34.31	114.85	205.34
2005:12	0.00	0.00	19,060.47	75.64	116.08	49.40	205.85
2006:01	0.00	0.00	13,229.04	52.29	179.33	44.30	206.35
2006:02	0.00	0.00	12,461.03	49.06	170.85	65.15	206.86
2006:03	0.00	0.00	21,226.41	83.24	115.32	112.70	207.37
2006:04	1.00	0.00	35,143.56	137.28	43.65	171.30	207.88
2006:05	0.00	0.00	74,012.15	287.99	6.32	381.55	208.40
2006:06	0.00	0.00	104,311.12	404.31	0.10	423.25	208.91
2006:07	0.00	0.00	119,965.40	463.19	0.00	495.80	209.43
2006:08	0.00	1.00	129,804.16	499.25	0.00	488.80	209.94
2006:09	0.00	0.00	120,622.81	462.16	0.00	429.05	210.46
2006:10	0.00	0.00	88,003.70	335.89	2.00	245.70	210.98
2006:11	0.00	0.00	44,412.73	168.87	34.31	114.85	211.50
2006:12	0.00	0.00	19,968.11	75.64	116.08	49.40	212.02
2007:01	0.00	0.00	13,856.51	52.29	179.33	44.30	212.54
2007:02	0.00	0.00	13,049.74	49.06	170.85	65.15	213.07
2007:03	0.00	0.00	22,225.30	83.24	115.32	112.70	213.59
2007:04	1.00	0.00	36,790.91	137.28	43.65	171.30	214.12
2007:05	0.00	0.00	77,467.97	287.99	6.32	381.55	214.65
2007:06	0.00	0.00	109,162.80	404.31	0.10	423.25	215.18
2007:07	0.00	0.00	125,523.64	463.19	0.00	495.80	215.71



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
2007:08	0.00	1.00	135,795.12	499.25	0.00	488.80	216.24
2007:09	0.00	0.00	126,168.68	462.16	0.00	429.05	216.77
2007:10	0.00	0.00	92,034.41	335.89	2.00	245.70	217.31
2007:11	0.00	0.00	46,439.16	168.87	34.31	114.85	217.84
2007:12	0.00	0.00	20,875.75	75.64	116.08	49.40	218.38
2008:01	0.00	0.00	14,483.97	52.29	179.33	44.30	218.92
2008:02	0.00	0.00	13,638.45	49.06	170.85	65.15	219.46
2008:03	0.00	0.00	23,224.19	83.24	115.32	112.70	220.00
2008:04	1.00	0.00	38,438.26	137.28	43.65	171.30	220.54
2008:05	0.00	0.00	80,923.79	287.99	6.32	381.55	221.09
2008:06	0.00	0.00	114,014.48	404.31	0.10	423.25	221.63
2008:07	0.00	0.00	131,081.89	463.19	0.00	495.80	222.18
2008:08	0.00	1.00	141,786.08	499.25	0.00	488.80	222.73
2008:09	0.00	0.00	131,714.56	462.16	0.00	429.05	223.28
2008:10	0.00	0.00	96,065.11	335.89	2.00	245.70	223.83
2008:11	0.00	0.00	48,465.60	168.87	34.31	114.85	224.38
2008:12	0.00	0.00	21,783.39	75.64	116.08	49.40	224.93
2009:01	0.00	0.00	15,111.44	52.29	179.33	44.30	225.49
2009:02	0.00	0.00	14,227.16	49.06	170.85	65.15	226.04
2009:03	0.00	0.00	24,223.08	83.24	115.32	112.70	226.60
2009:04	1.00	0.00	40,085.62	137.28	43.65	171.30	227.16
2009:05	0.00	0.00	84,379.61	287.99	6.32	381.55	227.72
2009:06	0.00	0.00	118,866.16	404.31	0.10	423.25	228.28
2009:07	0.00	0.00	136,640.13	463.19	0.00	495.80	228.85
2009:08	0.00	1.00	147,777.05	499.25	0.00	488.80	229.41
2009:09	0.00	0.00	137,260.43	462.16	0.00	429.05	229.98
2009:10	0.00	0.00	100,095.81	335.89	2.00	245.70	230.54
2009:11	0.00	0.00	50,492.03	168.87	34.31	114.85	231.11
2009:12	0.00	0.00	22,691.03	75.64	116.08	49.40	231.68
2010:01	0.00	0.00	15,738.90	52.29	179.33	44.30	232.25
2010:02	0.00	0.00	14,815.87	49.06	170.85	65.15	232.83
2010:03	0.00	0.00	25,221.97	83.24	115.32	112.70	233.40
2010:04	1.00	0.00	41,732.97	137.28	43.65	171.30	233.97
2010:05	0.00	0.00	87,835.43	287.99	6.32	381.55	234.55
2010:06	0.00	0.00	123,717.84	404.31	0.10	423.25	235.13
2010:07	0.00	0.00	142,198.37	463.19	0.00	495.80	235.71
2010:08	0.00	1.00	153,768.01	499.25	0.00	488.80	236.29
2010:09	0.00	0.00	142,806.31	462.16	0.00	429.05	236.87
2010:10	0.00	0.00	104,126.52	335.89	2.00	245.70	237.46



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
2010:11	0.00	0.00	52,518.47	168.87	34.31	114.85	238.04
2010:12	0.00	0.00	23,598.67	75.64	116.08	49.40	238.63
2011:01	0.00	0.00	16,366.37	52.29	179.33	44.30	239.22
2011:02	0.00	0.00	15,404.58	49.06	170.85	65.15	239.81
2011:03	0.00	0.00	26,220.86	83.24	115.32	112.70	240.40
2011:04	1.00	0.00	43,380.33	137.28	43.65	171.30	240.99
2011:05	0.00	0.00	91,291.25	287.99	6.32	381.55	241.59
2011:06	0.00	0.00	128,569.52	404.31	0.10	423.25	242.18
2011:07	0.00	0.00	147,756.62	463.19	0.00	495.80	242.78
2011:08	0.00	1.00	159,758.97	499.25	0.00	488.80	243.38
2011:09	0.00	0.00	148,352.19	462.16	0.00	429.05	243.98
2011:10	0.00	0.00	108,157.22	335.89	2.00	245.70	244.58
2011:11	0.00	0.00	54,544.91	168.87	34.31	114.85	245.19
2011:12	0.00	0.00	24,506.31	75.64	116.08	49.40	245.79
2012:01	0.00	0.00	16,993.83	52.29	179.33	44.30	246.40
2012:02	0.00	0.00	15,993.29	49.06	170.85	65.15	247.00
2012:03	0.00	0.00	27,219.76	83.24	115.32	112.70	247.61
2012:04	1.00	0.00	45,027.68	137.28	43.65	171.30	248.22
2012:05	0.00	0.00	94,747.07	287.99	6.32	381.55	248.84
2012:06	0.00	0.00	133,421.20	404.31	0.10	423.25	249.45
2012:07	0.00	0.00	153,314.86	463.19	0.00	495.80	250.07
2012:08	0.00	1.00	165,749.93	499.25	0.00	488.80	250.68
2012:09	0.00	0.00	153,898.06	462.16	0.00	429.05	251.30
2012:10	0.00	0.00	112,187.92	335.89	2.00	245.70	251.92
2012:11	0.00	0.00	56,571.34	168.87	34.31	114.85	252.54
2012:12	0.00	0.00	25,413.96	75.64	116.08	49.40	253.16
2013:01	0.00	0.00	17,621.30	52.29	179.33	44.30	253.79
2013:02	0.00	0.00	16,582.00	49.06	170.85	65.15	254.41
2013:03	0.00	0.00	28,218.65	83.24	115.32	112.70	255.04
2013:04	1.00	0.00	46,675.04	137.28	43.65	171.30	255.67
2013:05	0.00	0.00	98,202.89	287.99	6.32	381.55	256.30
2013:06	0.00	0.00	138,272.88	404.31	0.10	423.25	256.93
2013:07	0.00	0.00	158,873.10	463.19	0.00	495.80	257.57
2013:08	0.00	1.00	171,740.89	499.25	0.00	488.80	258.20
2013:09	0.00	0.00	159,443.94	462.16	0.00	429.05	258.84
2013:10	0.00	0.00	116,218.63	335.89	2.00	245.70	259.48
2013:11	0.00	0.00	58,597.78	168.87	34.31	114.85	260.12
2013:12	0.00	0.00	26,321.60	75.64	116.08	49.40	260.76
2014:01	0.00	0.00	18,248.76	52.29	179.33	44.30	261.40



Historical and Projected Energy and Demand Forecast Variables

Year/Month	APR	AUG	BMC_TIME	BM_CDD	BM_HDD	CDD	CPI
2014:02	0.00	0.00	17,170.71	49.06	170.85	65.15	262.05
2014:03	0.00	0.00	29,217.54	83.24	115.32	112.70	262.69
2014:04	1.00	0.00	48,322.39	137.28	43.65	171.30	263.34
2014:05	0.00	0.00	101,658.71	287.99	6.32	381.55	263.99
2014:06	0.00	0.00	143,124.56	404.31	0.10	423.25	264.64
2014:07	0.00	0.00	164,431.34	463.19	0.00	495.80	265.29
2014:08	0.00	1.00	177,731.85	499.25	0.00	488.80	265.95
2014:09	0.00	0.00	164,989.81	462.16	0.00	429.05	266.60
2014:10	0.00	0.00	120,249.33	335.89	2.00	245.70	267.26
2014:11	0.00	0.00	60,624.21	168.87	34.31	114.85	267.92
2014:12	0.00	0.00	27,229.24	75.64	116.08	49.40	268.58
2015:01	0.00	0.00	18,876.22	52.29	179.33	44.30	269.24
2015:02	0.00	0.00	17,759.42	49.06	170.85	65.15	269.91
2015:03	0.00	0.00	30,216.43	83.24	115.32	112.70	270.57
2015:04	1.00	0.00	49,969.74	137.28	43.65	171.30	271.24
2015:05	0.00	0.00	105,114.53	287.99	6.32	381.55	271.91
2015:06	0.00	0.00	147,976.24	404.31	0.10	423.25	272.58
2015:07	0.00	0.00	169,989.59	463.19	0.00	495.80	273.25
2015:08	0.00	1.00	183,722.81	499.25	0.00	488.80	273.93
2015:09	0.00	0.00	170,535.69	462.16	0.00	429.05	274.60
2015:10	0.00	0.00	124,280.04	335.89	2.00	245.70	275.28
2015:11	0.00	0.00	62,650.65	168.87	34.31	114.85	275.96
2015:12	0.00	0.00	28,136.88	75.64	116.08	49.40	276.64
2016:01	0.00	0.00	19,503.69	52.29	179.33	44.30	277.32
2016:02	0.00	0.00	18,348.13	49.06	170.85	65.15	278.01
2016:03	0.00	0.00	31,215.32	83.24	115.32	112.70	278.69
2016:04	1.00	0.00	51,617.10	137.28	43.65	171.30	279.38
2016:05	0.00	0.00	108,570.35	287.99	6.32	381.55	280.07
2016:06	0.00	0.00	152,827.92	404.31	0.10	423.25	280.76
2016:07	0.00	0.00	175,547.83	463.19	0.00	495.80	281.45
2016:08	0.00	1.00	189,713.77	499.25	0.00	488.80	282.14
2016:09	0.00	0.00	176,081.57	462.16	0.00	429.05	282.84
2016:10	0.00	0.00	128,310.74	335.89	2.00	245.70	283.54
2016:11	0.00	0.00	64,677.09	168.87	34.31	114.85	284.24
2016:12	0.00	0.00	29,044.52	75.64	116.08	49.40	284.94



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
1985:01	0.00	0.00	3.52	23.45	240.50	110.96	28.52
1985:02	0.00	1.00	3.53	23.61	115.50	167.41	28.73
1985:03	0.00	0.00	3.54	23.77	20.50	50.10	28.94
1985:04	0.00	0.00	3.55	23.92	6.50	14.55	29.14
1985:05	0.00	0.00	3.56	24.08	0.00	1.07	29.35
1985:06	0.00	0.00	3.57	24.24	0.00	0.00	29.56
1985:07	0.00	0.00	3.59	24.45	0.00	0.00	29.71
1985:08	0.00	0.00	3.61	24.66	0.00	0.00	29.86
1985:09	0.00	0.00	3.63	24.87	0.00	0.00	30.01
1985:10	0.00	0.00	3.65	25.08	0.00	0.00	30.16
1985:11	0.00	0.00	3.67	25.29	22.00	15.94	30.31
1985:12	1.00	0.00	3.69	25.50	221.00	64.48	30.46
1986:01	0.00	0.00	3.71	25.71	201.00	195.86	30.61
1986:02	0.00	1.00	3.73	25.92	101.00	140.60	30.76
1986:03	0.00	0.00	3.75	26.13	141.50	132.84	30.91
1986:04	0.00	0.00	3.77	26.34	16.50	44.89	31.07
1986:05	0.00	0.00	3.78	26.55	0.00	7.74	31.22
1986:06	0.00	0.00	3.80	26.76	0.00	0.00	31.37
1986:07	0.00	0.00	3.83	27.00	0.00	0.00	31.54
1986:08	0.00	0.00	3.85	27.24	0.00	0.00	31.71
1986:09	0.00	0.00	3.88	27.48	0.00	0.00	31.88
1986:10	0.00	0.00	3.90	27.72	0.00	0.00	32.05
1986:11	0.00	0.00	3.92	27.96	0.50	0.13	32.22
1986:12	1.00	0.00	3.95	28.20	74.00	24.63	32.39
1987:01	0.00	0.00	3.97	28.43	258.00	152.19	32.56
1987:02	0.00	1.00	3.99	28.67	121.00	172.70	32.73
1987:03	0.00	0.00	4.02	28.91	72.00	79.96	32.90
1987:04	0.00	0.00	4.04	29.15	73.00	80.42	33.07
1987:05	0.00	0.00	4.07	29.39	0.00	6.29	33.24
1987:06	0.00	0.00	4.09	29.63	0.00	0.00	33.41
1987:07	0.00	0.00	4.14	29.88	0.00	0.00	33.57
1987:08	0.00	0.00	4.19	30.12	0.00	0.00	33.73
1987:09	0.00	0.00	4.25	30.36	0.00	0.00	33.90



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
1987:10	0.00	0.00	4.30	30.60	6.00	1.57	34.06
1987:11	0.00	0.00	4.35	30.85	53.00	22.78	34.23
1987:12	1.00	0.00	4.40	31.09	123.50	94.67	34.39
1988:01	0.00	0.00	4.45	31.33	286.50	155.27	34.55
1988:02	0.00	1.00	4.51	31.58	225.50	229.31	34.72
1988:03	0.00	0.00	4.56	31.82	99.50	147.44	34.88
1988:04	0.00	0.00	4.61	32.06	16.00	47.83	35.05
1988:05	0.00	0.00	4.66	32.31	0.00	7.03	35.21
1988:06	0.00	0.00	4.71	32.55	0.00	0.00	35.37
1988:07	0.00	0.00	4.73	32.79	0.00	0.00	35.50
1988:08	0.00	0.00	4.75	33.02	0.00	0.00	35.63
1988:09	0.00	0.00	4.77	33.26	0.00	0.00	35.75
1988:10	0.00	0.00	4.79	33.50	0.00	0.00	35.88
1988:11	0.00	0.00	4.80	33.74	9.50	2.12	36.01
1988:12	1.00	0.00	4.82	33.97	136.50	81.41	36.13
1989:01	0.00	0.00	4.84	34.21	57.50	70.37	36.26
1989:02	0.00	1.00	4.86	34.45	149.50	66.57	36.39
1989:03	0.00	0.00	4.88	34.69	82.00	144.02	36.52
1989:04	0.00	0.00	4.89	34.92	30.50	38.27	36.64
1989:05	0.00	0.00	4.91	35.16	0.00	7.32	36.77
1989:06	0.00	0.00	4.93	35.40	0.00	0.00	36.90
1989:07	0.00	0.00	4.90	35.53	0.00	0.00	37.14
1989:08	0.00	0.00	4.88	35.67	0.00	0.00	37.39
1989:09	0.00	0.00	4.85	35.81	0.00	0.00	37.64
1989:10	0.00	0.00	4.83	35.94	28.00	8.99	37.89
1989:11	0.00	0.00	4.80	36.08	53.00	30.45	38.14
1989:12	1.00	0.00	4.77	36.21	358.00	180.82	38.39
1990:01	0.00	0.00	4.75	36.35	111.00	228.01	38.64
1990:02	0.00	1.00	4.72	36.48	60.50	61.03	38.89
1990:03	0.00	0.00	4.70	36.62	13.00	39.04	39.14
1990:04	0.00	0.00	4.67	36.76	6.50	11.74	39.38
1990:05	0.00	0.00	4.64	36.89	0.00	1.07	39.63
1990:06	0.00	0.00	4.62	37.03	0.00	0.00	39.88
1990:07	0.00	0.00	4.58	36.99	0.00	0.00	40.08
1990:08	0.00	0.00	4.54	36.96	0.00	0.00	40.28
1990:09	0.00	0.00	4.50	36.92	0.00	0.00	40.48
1990:10	0.00	0.00	4.46	36.88	8.50	1.39	40.68
1990:11	0.00	0.00	4.43	36.85	31.00	17.76	40.88
1990:12	1.00	0.00	4.39	36.81	84.50	69.97	41.08



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
1991:01	0.00	0.00	4.35	36.78	90.50	56.13	41.28
1991:02	0.00	1.00	4.31	36.74	124.00	105.39	41.48
1991:03	0.00	0.00	4.27	36.70	87.00	105.60	41.68
1991:04	0.00	0.00	4.23	36.67	7.50	34.16	41.88
1991:05	0.00	0.00	4.20	36.63	0.00	1.18	42.08
1991:06	0.00	0.00	4.16	36.60	0.00	0.00	42.28
1991:07	0.00	0.00	4.15	36.74	0.00	0.00	42.43
1991:08	0.00	0.00	4.14	36.88	0.00	0.00	42.59
1991:09	0.00	0.00	4.13	37.02	0.00	0.00	42.75
1991:10	0.00	0.00	4.12	37.17	0.00	0.00	42.90
1991:11	0.00	0.00	4.11	37.31	112.50	55.54	43.06
1991:12	1.00	0.00	4.10	37.45	116.50	95.97	43.21
1992:01	0.00	0.00	4.09	37.60	252.00	175.92	43.37
1992:02	0.00	1.00	4.08	37.74	110.00	188.98	43.52
1992:03	0.00	0.00	4.07	37.88	100.50	70.64	43.68
1992:04	0.00	0.00	4.07	38.02	34.00	63.73	43.83
1992:05	0.00	0.00	4.06	38.17	4.50	18.99	43.99
1992:06	0.00	0.00	4.05	38.31	0.00	0.94	44.15
1992:07	0.00	0.00	4.06	38.55	0.00	0.00	44.33
1992:08	0.00	0.00	4.07	38.79	0.00	0.00	44.51
1992:09	0.00	0.00	4.08	39.03	0.00	0.00	44.69
1992:10	0.00	0.00	4.09	39.27	1.00	0.39	44.87
1992:11	0.00	0.00	4.10	39.51	84.50	26.63	45.06
1992:12	1.00	0.00	4.11	39.75	145.50	139.67	45.24
1993:01	0.00	0.00	4.11	40.00	99.00	76.35	45.42
1993:02	0.00	1.00	4.12	40.24	203.00	156.45	45.60
1993:03	0.00	0.00	4.13	40.48	124.00	175.24	45.78
1993:04	0.00	0.00	4.14	40.72	21.00	48.91	45.97
1993:05	0.00	0.00	4.15	40.96	0.00	10.96	46.15
1993:06	0.00	0.00	4.16	41.20	0.00	0.00	46.33
1993:07	0.00	0.00	4.16	41.31	0.00	0.00	46.50
1993:08	0.00	0.00	4.17	41.41	0.00	0.00	46.67
1993:09	0.00	0.00	4.17	41.52	0.00	0.00	46.83
1993:10	0.00	0.00	4.17	41.63	14.00	0.43	47.00
1993:11	0.00	0.00	4.17	41.73	93.00	59.23	47.17
1993:12	1.00	0.00	4.17	41.84	291.00	154.83	47.33
1994:01	0.00	0.00	4.17	41.95	247.50	302.67	47.50
1994:02	0.00	1.00	4.17	42.06	101.00	166.71	47.67
1994:03	0.00	0.00	4.18	42.16	68.50	71.11	47.83



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
1994:04	0.00	0.00	4.18	42.27	13.00	34.67	48.00
1994:05	0.00	0.00	4.18	42.38	0.00	0.64	48.17
1994:06	0.00	0.00	4.18	42.48	0.00	0.00	48.34
1994:07	0.00	0.00	4.17	42.63	0.00	0.00	48.49
1994:08	0.00	0.00	4.16	42.77	0.00	0.00	48.64
1994:09	0.00	0.00	4.16	42.92	0.00	0.00	48.80
1994:10	0.00	0.00	4.15	43.06	0.00	0.00	48.95
1994:11	0.00	0.00	4.14	43.21	15.00	4.98	49.10
1994:12	1.00	0.00	4.14	43.35	132.50	58.92	49.26
1995:01	0.00	0.00	4.13	43.50	266.50	199.36	49.41
1995:02	0.00	1.00	4.12	43.64	197.00	275.92	49.56
1995:03	0.00	0.00	4.11	43.79	45.00	89.39	49.71
1995:04	0.00	0.00	4.11	43.93	13.00	21.63	49.87
1995:05	0.00	0.00	4.10	44.07	0.00	1.27	50.02
1995:06	0.00	0.00	4.09	44.22	0.00	0.00	50.17
1995:07	0.00	0.00	4.10	44.39	0.00	0.00	50.33
1995:08	0.00	0.00	4.11	44.56	0.00	0.00	50.48
1995:09	0.00	0.00	4.12	44.74	0.00	0.00	50.63
1995:10	0.00	0.00	4.12	44.91	0.00	0.00	50.78
1995:11	0.00	0.00	4.13	45.08	101.50	45.42	50.93
1995:12	1.00	0.00	4.14	45.25	234.50	131.48	51.08
1996:01	0.00	0.00	4.15	45.42	251.50	305.98	51.23
1996:02	0.00	1.00	4.16	45.60	251.50	254.86	51.38
1996:03	0.00	0.00	4.16	45.77	214.00	217.52	51.53
1996:04	0.00	0.00	4.17	45.94	40.00	105.90	51.68
1996:05	0.00	0.00	4.18	46.11	0.00	9.98	51.84
1996:06	0.00	0.00	4.19	46.28	0.00	0.00	51.99
1996:07	0.00	0.00	4.20	46.47	0.00	0.00	52.14
1996:08	0.00	0.00	4.20	46.65	0.00	0.00	52.30
1996:09	0.00	0.00	4.21	46.83	0.00	0.00	52.46
1996:10	0.00	0.00	4.22	47.01	14.50	5.52	52.61
1996:11	0.00	0.00	4.23	47.19	63.50	56.32	52.77
1996:12	1.00	0.00	4.24	47.37	102.00	65.67	52.93
1997:01	0.00	0.00	4.24	47.55	132.50	107.10	53.08
1997:02	0.00	1.00	4.25	47.73	30.50	92.67	53.24
1997:03	0.00	0.00	4.26	47.91	0.00	8.86	53.39
1997:04	0.00	0.00	4.27	48.09	0.00	0.00	53.55
1997:05	0.00	0.00	4.28	48.27	0.00	0.00	53.71
1997:06	0.00	0.00	4.28	48.45	0.00	0.00	53.86



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
1997:07	0.00	0.00	4.29	48.64	0.00	0.00	54.03
1997:08	0.00	0.00	4.30	48.83	0.00	0.00	54.19
1997:09	0.00	0.00	4.31	49.02	0.00	0.00	54.35
1997:10	0.00	0.00	4.32	49.21	7.20	1.96	54.51
1997:11	0.00	0.00	4.33	49.40	61.65	33.62	54.67
1997:12	1.00	0.00	4.33	49.58	172.45	113.76	54.84
1998:01	0.00	0.00	4.34	49.77	179.45	175.74	55.00
1998:02	0.00	1.00	4.35	49.96	145.25	167.43	55.16
1998:03	0.00	0.00	4.36	50.15	83.35	113.01	55.32
1998:04	0.00	0.00	4.37	50.34	18.15	42.78	55.49
1998:05	0.00	0.00	4.38	50.53	0.45	6.19	55.65
1998:06	0.00	0.00	4.38	50.72	0.00	0.10	55.81
1998:07	0.00	0.00	4.39	50.92	0.00	0.00	55.98
1998:08	0.00	0.00	4.40	51.11	0.00	0.00	56.15
1998:09	0.00	0.00	4.41	51.31	0.00	0.00	56.31
1998:10	0.00	0.00	4.42	51.51	7.20	1.96	56.48
1998:11	0.00	0.00	4.43	51.71	61.65	33.62	56.65
1998:12	1.00	0.00	4.44	51.91	172.45	113.76	56.82
1999:01	0.00	0.00	4.44	52.11	179.45	175.74	56.99
1999:02	0.00	1.00	4.45	52.30	145.25	167.43	57.15
1999:03	0.00	0.00	4.46	52.50	83.35	113.01	57.32
1999:04	0.00	0.00	4.47	52.70	18.15	42.78	57.49
1999:05	0.00	0.00	4.48	52.90	0.45	6.19	57.66
1999:06	0.00	0.00	4.49	53.10	0.00	0.10	57.83
1999:07	0.00	0.00	4.50	53.30	0.00	0.00	58.00
1999:08	0.00	0.00	4.50	53.51	0.00	0.00	58.17
1999:09	0.00	0.00	4.51	53.72	0.00	0.00	58.35
1999:10	0.00	0.00	4.52	53.93	7.20	1.96	58.52
1999:11	0.00	0.00	4.53	54.13	61.65	33.62	58.70
1999:12	1.00	0.00	4.54	54.34	172.45	113.76	58.87
2000:01	0.00	0.00	4.55	54.55	179.45	175.74	59.04
2000:02	0.00	1.00	4.56	54.76	145.25	167.43	59.22
2000:03	0.00	0.00	4.56	54.97	83.35	113.01	59.39
2000:04	0.00	0.00	4.57	55.17	18.15	42.78	59.57
2000:05	0.00	0.00	4.58	55.38	0.45	6.19	59.74
2000:06	0.00	0.00	4.59	55.59	0.00	0.10	59.91
2000:07	0.00	0.00	4.60	55.77	0.00	0.00	60.08
2000:08	0.00	0.00	4.61	55.95	0.00	0.00	60.24
2000:09	0.00	0.00	4.63	56.13	0.00	0.00	60.40



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
2000:10	0.00	0.00	4.64	56.32	7.20	1.96	60.56
2000:11	0.00	0.00	4.65	56.50	61.65	33.62	60.72
2000:12	1.00	0.00	4.66	56.68	172.45	113.76	60.88
2001:01	0.00	0.00	4.67	56.86	179.45	175.74	61.05
2001:02	0.00	1.00	4.69	57.04	145.25	167.43	61.21
2001:03	0.00	0.00	4.70	57.23	83.35	113.01	61.37
2001:04	0.00	0.00	4.71	57.41	18.15	42.78	61.53
2001:05	0.00	0.00	4.72	57.59	0.45	6.19	61.69
2001:06	0.00	0.00	4.73	57.77	0.00	0.10	61.85
2001:07	0.00	0.00	4.75	57.96	0.00	0.00	62.02
2001:08	0.00	0.00	4.76	58.15	0.00	0.00	62.19
2001:09	0.00	0.00	4.77	58.34	0.00	0.00	62.36
2001:10	0.00	0.00	4.78	58.53	7.20	1.96	62.52
2001:11	0.00	0.00	4.80	58.72	61.65	33.62	62.69
2001:12	1.00	0.00	4.81	58.91	172.45	113.76	62.86
2002:01	0.00	0.00	4.82	59.10	179.45	175.74	63.02
2002:02	0.00	1.00	4.83	59.28	145.25	167.43	63.19
2002:03	0.00	0.00	4.85	59.47	83.35	113.01	63.36
2002:04	0.00	0.00	4.86	59.66	18.15	42.78	63.52
2002:05	0.00	0.00	4.87	59.85	0.45	6.19	63.69
2002:06	0.00	0.00	4.88	60.04	0.00	0.10	63.86
2002:07	0.00	0.00	4.90	60.24	0.00	0.00	64.03
2002:08	0.00	0.00	4.91	60.43	0.00	0.00	64.20
2002:09	0.00	0.00	4.92	60.63	0.00	0.00	64.38
2002:10	0.00	0.00	4.93	60.83	7.20	1.96	64.55
2002:11	0.00	0.00	4.95	61.02	61.65	33.62	64.72
2002:12	1.00	0.00	4.96	61.22	172.45	113.76	64.89
2003:01	0.00	0.00	4.97	61.42	179.45	175.74	65.06
2003:02	0.00	1.00	4.98	61.61	145.25	167.43	65.24
2003:03	0.00	0.00	5.00	61.81	83.35	113.01	65.41
2003:04	0.00	0.00	5.01	62.01	18.15	42.78	65.58
2003:05	0.00	0.00	5.02	62.20	0.45	6.19	65.75
2003:06	0.00	0.00	5.04	62.40	0.00	0.10	65.93
2003:07	0.00	0.00	5.05	62.61	0.00	0.00	66.10
2003:08	0.00	0.00	5.06	62.81	0.00	0.00	66.28
2003:09	0.00	0.00	5.08	63.01	0.00	0.00	66.46
2003:10	0.00	0.00	5.09	63.22	7.20	1.96	66.64
2003:11	0.00	0.00	5.10	63.42	61.65	33.62	66.82
2003:12	1.00	0.00	5.11	63.63	172.45	113.76	66.99



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
2004:01	0.00	0.00	5.13	63.83	179.45	175.74	67.17
2004:02	0.00	1.00	5.14	64.04	145.25	167.43	67.35
2004:03	0.00	0.00	5.15	64.24	83.35	113.01	67.53
2004:04	0.00	0.00	5.17	64.44	18.15	42.78	67.71
2004:05	0.00	0.00	5.18	64.65	0.45	6.19	67.88
2004:06	0.00	0.00	5.19	64.85	0.00	0.10	68.06
2004:07	0.00	0.00	5.21	65.07	0.00	0.00	68.25
2004:08	0.00	0.00	5.22	65.28	0.00	0.00	68.43
2004:09	0.00	0.00	5.23	65.49	0.00	0.00	68.61
2004:10	0.00	0.00	5.25	65.70	7.20	1.96	68.80
2004:11	0.00	0.00	5.26	65.92	61.65	33.62	68.98
2004:12	1.00	0.00	5.27	66.13	172.45	113.76	69.16
2005:01	0.00	0.00	5.29	66.34	179.45	175.74	69.35
2005:02	0.00	1.00	5.30	66.55	145.25	167.43	69.53
2005:03	0.00	0.00	5.32	66.76	83.35	113.01	69.72
2005:04	0.00	0.00	5.33	66.98	18.15	42.78	69.90
2005:05	0.00	0.00	5.34	67.19	0.45	6.19	70.08
2005:06	0.00	0.00	5.36	67.40	0.00	0.10	70.27
2005:07	0.00	0.00	5.37	67.59	0.00	0.00	70.43
2005:08	0.00	0.00	5.38	67.78	0.00	0.00	70.60
2005:09	0.00	0.00	5.39	67.97	0.00	0.00	70.77
2005:10	0.00	0.00	5.41	68.15	7.20	1.96	70.94
2005:11	0.00	0.00	5.42	68.34	61.65	33.62	71.11
2005:12	1.00	0.00	5.43	68.53	172.45	113.76	71.27
2006:01	0.00	0.00	5.44	68.72	179.45	175.74	71.44
2006:02	0.00	1.00	5.46	68.91	145.25	167.43	71.61
2006:03	0.00	0.00	5.47	69.09	83.35	113.01	71.78
2006:04	0.00	0.00	5.48	69.28	18.15	42.78	71.94
2006:05	0.00	0.00	5.49	69.47	0.45	6.19	72.11
2006:06	0.00	0.00	5.50	69.66	0.00	0.10	72.28
2006:07	0.00	0.00	5.52	69.85	0.00	0.00	72.45
2006:08	0.00	0.00	5.53	70.05	0.00	0.00	72.62
2006:09	0.00	0.00	5.54	70.24	0.00	0.00	72.80
2006:10	0.00	0.00	5.56	70.44	7.20	1.96	72.97
2006:11	0.00	0.00	5.57	70.63	61.65	33.62	73.14
2006:12	1.00	0.00	5.58	70.82	172.45	113.76	73.31
2007:01	0.00	0.00	5.59	71.02	179.45	175.74	73.49
2007:02	0.00	1.00	5.61	71.21	145.25	167.43	73.66
2007:03	0.00	0.00	5.62	71.41	83.35	113.01	73.83



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
2007:04	0.00	0.00	5.63	71.60	18.15	42.78	74.01
2007:05	0.00	0.00	5.64	71.80	0.45	6.19	74.18
2007:06	0.00	0.00	5.66	71.99	0.00	0.10	74.35
2007:07	0.00	0.00	5.67	72.19	0.00	0.00	74.53
2007:08	0.00	0.00	5.68	72.39	0.00	0.00	74.71
2007:09	0.00	0.00	5.70	72.59	0.00	0.00	74.88
2007:10	0.00	0.00	5.71	72.79	7.20	1.96	75.06
2007:11	0.00	0.00	5.72	73.00	61.65	33.62	75.24
2007:12	1.00	0.00	5.74	73.20	172.45	113.76	75.41
2008:01	0.00	0.00	5.75	73.40	179.45	175.74	75.59
2008:02	0.00	1.00	5.76	73.60	145.25	167.43	75.77
2008:03	0.00	0.00	5.77	73.80	83.35	113.01	75.95
2008:04	0.00	0.00	5.79	74.00	18.15	42.78	76.12
2008:05	0.00	0.00	5.80	74.20	0.45	6.19	76.30
2008:06	0.00	0.00	5.81	74.40	0.00	0.10	76.48
2008:07	0.00	0.00	5.83	74.61	0.00	0.00	76.66
2008:08	0.00	0.00	5.84	74.82	0.00	0.00	76.84
2008:09	0.00	0.00	5.85	75.02	0.00	0.00	77.03
2008:10	0.00	0.00	5.87	75.23	7.20	1.96	77.21
2008:11	0.00	0.00	5.88	75.44	61.65	33.62	77.39
2008:12	1.00	0.00	5.89	75.65	172.45	113.76	77.58
2009:01	0.00	0.00	5.91	75.85	179.45	175.74	77.76
2009:02	0.00	1.00	5.92	76.06	145.25	167.43	77.94
2009:03	0.00	0.00	5.93	76.27	83.35	113.01	78.12
2009:04	0.00	0.00	5.95	76.48	18.15	42.78	78.31
2009:05	0.00	0.00	5.96	76.69	0.45	6.19	78.49
2009:06	0.00	0.00	5.98	76.89	0.00	0.10	78.67
2009:07	0.00	0.00	5.99	77.11	0.00	0.00	78.86
2009:08	0.00	0.00	6.00	77.32	0.00	0.00	79.05
2009:09	0.00	0.00	6.02	77.54	0.00	0.00	79.23
2009:10	0.00	0.00	6.03	77.75	7.20	1.96	79.42
2009:11	0.00	0.00	6.04	77.97	61.65	33.62	79.61
2009:12	1.00	0.00	6.06	78.18	172.45	113.76	79.80
2010:01	0.00	0.00	6.07	78.40	179.45	175.74	79.99
2010:02	0.00	1.00	6.09	78.61	145.25	167.43	80.17
2010:03	0.00	0.00	6.10	78.82	83.35	113.01	80.36
2010:04	0.00	0.00	6.11	79.04	18.15	42.78	80.55
2010:05	0.00	0.00	6.13	79.25	0.45	6.19	80.74
2010:06	0.00	0.00	6.14	79.47	0.00	0.10	80.92



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
2010:07	0.00	0.00	6.15	79.67	0.00	0.00	81.10
2010:08	0.00	0.00	6.17	79.87	0.00	0.00	81.28
2010:09	0.00	0.00	6.18	80.07	0.00	0.00	81.45
2010:10	0.00	0.00	6.19	80.28	7.20	1.96	81.63
2010:11	0.00	0.00	6.21	80.48	61.65	33.62	81.80
2010:12	1.00	0.00	6.22	80.68	172.45	113.76	81.98
2011:01	0.00	0.00	6.23	80.88	179.45	175.74	82.16
2011:02	0.00	1.00	6.24	81.09	145.25	167.43	82.33
2011:03	0.00	0.00	6.26	81.29	83.35	113.01	82.51
2011:04	0.00	0.00	6.27	81.49	18.15	42.78	82.68
2011:05	0.00	0.00	6.28	81.69	0.45	6.19	82.86
2011:06	0.00	0.00	6.30	81.89	0.00	0.10	83.04
2011:07	0.00	0.00	6.31	82.10	0.00	0.00	83.22
2011:08	0.00	0.00	6.32	82.31	0.00	0.00	83.40
2011:09	0.00	0.00	6.34	82.52	0.00	0.00	83.58
2011:10	0.00	0.00	6.35	82.73	7.20	1.96	83.76
2011:11	0.00	0.00	6.36	82.94	61.65	33.62	83.94
2011:12	1.00	0.00	6.38	83.14	172.45	113.76	84.12
2012:01	0.00	0.00	6.39	83.35	179.45	175.74	84.30
2012:02	0.00	1.00	6.40	83.56	145.25	167.43	84.48
2012:03	0.00	0.00	6.42	83.77	83.35	113.01	84.66
2012:04	0.00	0.00	6.43	83.98	18.15	42.78	84.84
2012:05	0.00	0.00	6.44	84.19	0.45	6.19	85.02
2012:06	0.00	0.00	6.46	84.39	0.00	0.10	85.20
2012:07	0.00	0.00	6.47	84.61	0.00	0.00	85.39
2012:08	0.00	0.00	6.48	84.82	0.00	0.00	85.58
2012:09	0.00	0.00	6.50	85.04	0.00	0.00	85.76
2012:10	0.00	0.00	6.51	85.25	7.20	1.96	85.95
2012:11	0.00	0.00	6.52	85.47	61.65	33.62	86.13
2012:12	1.00	0.00	6.54	85.68	172.45	113.76	86.32
2013:01	0.00	0.00	6.55	85.90	179.45	175.74	86.50
2013:02	0.00	1.00	6.56	86.11	145.25	167.43	86.69
2013:03	0.00	0.00	6.58	86.33	83.35	113.01	86.87
2013:04	0.00	0.00	6.59	86.54	18.15	42.78	87.06
2013:05	0.00	0.00	6.60	86.76	0.45	6.19	87.24
2013:06	0.00	0.00	6.62	86.97	0.00	0.10	87.43
2013:07	0.00	0.00	6.63	87.19	0.00	0.00	87.62
2013:08	0.00	0.00	6.65	87.41	0.00	0.00	87.81
2013:09	0.00	0.00	6.66	87.63	0.00	0.00	88.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	DEC	FEB	GOODS	GOODSERV	HDD	HEAT2	HH
2013:10	0.00	0.00	6.67	87.86	7.20	1.96	88.19
2013:11	0.00	0.00	6.69	88.08	61.65	33.62	88.38
2013:12	1.00	0.00	6.70	88.30	172.45	113.76	88.57
2014:01	0.00	0.00	6.72	88.52	179.45	175.74	88.76
2014:02	0.00	1.00	6.73	88.74	145.25	167.43	88.95
2014:03	0.00	0.00	6.74	88.96	83.35	113.01	89.14
2014:04	0.00	0.00	6.76	89.18	18.15	42.78	89.33
2014:05	0.00	0.00	6.77	89.40	0.45	6.19	89.52
2014:06	0.00	0.00	6.79	89.63	0.00	0.10	89.71
2014:07	0.00	0.00	6.80	89.85	0.00	0.00	89.91
2014:08	0.00	0.00	6.81	90.08	0.00	0.00	90.10
2014:09	0.00	0.00	6.83	90.31	0.00	0.00	90.30
2014:10	0.00	0.00	6.84	90.54	7.20	1.96	90.49
2014:11	0.00	0.00	6.86	90.77	61.65	33.62	90.69
2014:12	1.00	0.00	6.87	90.99	172.45	113.76	90.88
2015:01	0.00	0.00	6.89	91.22	179.45	175.74	91.08
2015:02	0.00	1.00	6.90	91.45	145.25	167.43	91.27
2015:03	0.00	0.00	6.91	91.68	83.35	113.01	91.47
2015:04	0.00	0.00	6.93	91.91	18.15	42.78	91.66
2015:05	0.00	0.00	6.94	92.13	0.45	6.19	91.86
2015:06	0.00	0.00	6.96	92.36	0.00	0.10	92.05
2015:07	0.00	0.00	6.97	92.57	0.00	0.00	92.23
2015:08	0.00	0.00	6.98	92.79	0.00	0.00	92.42
2015:09	0.00	0.00	7.00	93.00	0.00	0.00	92.60
2015:10	0.00	0.00	7.01	93.21	7.20	1.96	92.78
2015:11	0.00	0.00	7.02	93.42	61.65	33.62	92.96
2015:12	1.00	0.00	7.04	93.64	172.45	113.76	93.14
2016:01	0.00	0.00	7.05	93.85	179.45	175.74	93.32
2016:02	0.00	1.00	7.06	94.06	145.25	167.43	93.50
2016:03	0.00	0.00	7.08	94.27	83.35	113.01	93.68
2016:04	0.00	0.00	7.09	94.49	18.15	42.78	93.86
2016:05	0.00	0.00	7.10	94.70	0.45	6.19	94.04
2016:06	0.00	0.00	7.12	94.91	0.00	0.10	94.23
2016:07	0.00	0.00	7.13	95.13	0.00	0.00	94.41
2016:08	0.00	0.00	7.14	95.35	0.00	0.00	94.60
2016:09	0.00	0.00	7.16	95.57	0.00	0.00	94.78
2016:10	0.00	0.00	7.17	95.78	7.20	1.96	94.97
2016:11	0.00	0.00	7.18	96.00	61.65	33.62	95.15
2016:12	1.00	0.00	7.20	96.22	172.45	113.76	95.34



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
1985:01	32.79	1.00	0.00	0.00	0.00	88.00	0.00
1985:02	32.83	0.00	0.00	0.00	0.00	89.00	0.00
1985:03	32.88	0.00	0.00	0.00	1.00	88.00	0.00
1985:04	32.92	0.00	0.00	0.00	0.00	92.00	0.00
1985:05	32.97	0.00	0.00	0.00	0.00	96.00	1.00
1985:06	33.01	0.00	0.00	1.00	0.00	100.00	0.00
1985:07	33.11	0.00	1.00	0.00	0.00	97.00	0.00
1985:08	33.22	0.00	0.00	0.00	0.00	96.00	0.00
1985:09	33.32	0.00	0.00	0.00	0.00	95.00	0.00
1985:10	33.42	0.00	0.00	0.00	0.00	94.00	0.00
1985:11	33.52	0.00	0.00	0.00	0.00	90.00	0.00
1985:12	33.62	0.00	0.00	0.00	0.00	84.00	0.00
1986:01	33.71	1.00	0.00	0.00	0.00	80.00	0.00
1986:02	33.81	0.00	0.00	0.00	0.00	83.00	0.00
1986:03	33.91	0.00	0.00	0.00	1.00	88.00	0.00
1986:04	34.00	0.00	0.00	0.00	0.00	95.00	0.00
1986:05	34.09	0.00	0.00	0.00	0.00	93.00	1.00
1986:06	34.19	0.00	0.00	1.00	0.00	95.00	0.00
1986:07	34.23	0.00	1.00	0.00	0.00	97.00	0.00
1986:08	34.27	0.00	0.00	0.00	0.00	97.00	0.00
1986:09	34.31	0.00	0.00	0.00	0.00	95.00	0.00
1986:10	34.34	0.00	0.00	0.00	0.00	95.00	0.00
1986:11	34.38	0.00	0.00	0.00	0.00	88.00	0.00
1986:12	34.42	0.00	0.00	0.00	0.00	85.00	0.00
1987:01	34.46	1.00	0.00	0.00	0.00	83.00	0.00
1987:02	34.49	0.00	0.00	0.00	0.00	82.00	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
1987:03	34.53	0.00	0.00	0.00	1.00	86.00	0.00
1987:04	34.57	0.00	0.00	0.00	0.00	91.00	0.00
1987:05	34.60	0.00	0.00	0.00	0.00	92.00	1.00
1987:06	34.64	0.00	0.00	1.00	0.00	99.00	0.00
1987:07	34.68	0.00	1.00	0.00	0.00	99.00	0.00
1987:08	34.73	0.00	0.00	0.00	0.00	101.00	0.00
1987:09	34.77	0.00	0.00	0.00	0.00	98.00	0.00
1987:10	34.82	0.00	0.00	0.00	0.00	88.00	0.00
1987:11	34.86	0.00	0.00	0.00	0.00	86.00	0.00
1987:12	34.90	0.00	0.00	0.00	0.00	82.00	0.00
1988:01	34.95	1.00	0.00	0.00	0.00	79.00	0.00
1988:02	34.99	0.00	0.00	0.00	0.00	87.00	0.00
1988:03	35.03	0.00	0.00	0.00	1.00	86.00	0.00
1988:04	35.07	0.00	0.00	0.00	0.00	92.00	0.00
1988:05	35.11	0.00	0.00	0.00	0.00	96.00	1.00
1988:06	35.15	0.00	0.00	1.00	0.00	97.00	0.00
1988:07	35.21	0.00	1.00	0.00	0.00	96.00	0.00
1988:08	35.26	0.00	0.00	0.00	0.00	100.00	0.00
1988:09	35.31	0.00	0.00	0.00	0.00	98.00	0.00
1988:10	35.37	0.00	0.00	0.00	0.00	91.00	0.00
1988:11	35.42	0.00	0.00	0.00	0.00	91.00	0.00
1988:12	35.47	0.00	0.00	0.00	0.00	87.00	0.00
1989:01	35.52	1.00	0.00	0.00	0.00	84.00	0.00
1989:02	35.57	0.00	0.00	0.00	0.00	89.00	0.00
1989:03	35.63	0.00	0.00	0.00	1.00	90.00	0.00
1989:04	35.68	0.00	0.00	0.00	0.00	98.00	0.00
1989:05	35.73	0.00	0.00	0.00	0.00	99.00	1.00
1989:06	35.78	0.00	0.00	1.00	0.00	102.00	0.00
1989:07	35.67	0.00	1.00	0.00	0.00	102.00	0.00
1989:08	35.56	0.00	0.00	0.00	0.00	103.00	0.00
1989:09	35.46	0.00	0.00	0.00	0.00	99.00	0.00
1989:10	35.36	0.00	0.00	0.00	0.00	96.00	0.00
1989:11	35.25	0.00	0.00	0.00	0.00	90.00	0.00
1989:12	35.15	0.00	0.00	0.00	0.00	79.00	0.00
1990:01	35.06	1.00	0.00	0.00	0.00	85.00	0.00
1990:02	34.96	0.00	0.00	0.00	0.00	89.00	0.00
1990:03	34.86	0.00	0.00	0.00	1.00	89.00	0.00
1990:04	34.77	0.00	0.00	0.00	0.00	95.00	0.00
1990:05	34.67	0.00	0.00	0.00	0.00	97.00	1.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
1990:06	34.58	0.00	0.00	1.00	0.00	100.00	0.00
1990:07	34.45	0.00	1.00	0.00	0.00	102.00	0.00
1990:08	34.32	0.00	0.00	0.00	0.00	97.00	0.00
1990:09	34.20	0.00	0.00	0.00	0.00	102.00	0.00
1990:10	34.07	0.00	0.00	0.00	0.00	95.00	0.00
1990:11	33.95	0.00	0.00	0.00	0.00	91.00	0.00
1990:12	33.83	0.00	0.00	0.00	0.00	90.00	0.00
1991:01	33.71	1.00	0.00	0.00	0.00	88.00	0.00
1991:02	33.59	0.00	0.00	0.00	0.00	92.00	0.00
1991:03	33.47	0.00	0.00	0.00	1.00	90.00	0.00
1991:04	33.35	0.00	0.00	0.00	0.00	95.00	0.00
1991:05	33.23	0.00	0.00	0.00	0.00	99.00	1.00
1991:06	33.12	0.00	0.00	1.00	0.00	100.00	0.00
1991:07	33.14	0.00	1.00	0.00	0.00	101.00	0.00
1991:08	33.16	0.00	0.00	0.00	0.00	102.00	0.00
1991:09	33.18	0.00	0.00	0.00	0.00	98.00	0.00
1991:10	33.20	0.00	0.00	0.00	0.00	94.00	0.00
1991:11	33.22	0.00	0.00	0.00	0.00	84.00	0.00
1991:12	33.24	0.00	0.00	0.00	0.00	86.00	0.00
1992:01	33.26	1.00	0.00	0.00	0.00	80.00	0.00
1992:02	33.28	0.00	0.00	0.00	0.00	87.00	0.00
1992:03	33.30	0.00	0.00	0.00	1.00	88.00	0.00
1992:04	33.32	0.00	0.00	0.00	0.00	94.00	0.00
1992:05	33.34	0.00	0.00	0.00	0.00	96.00	1.00
1992:06	33.36	0.00	0.00	1.00	0.00	101.00	0.00
1992:07	33.33	0.00	1.00	0.00	0.00	101.00	0.00
1992:08	33.30	0.00	0.00	0.00	0.00	102.00	0.00
1992:09	33.28	0.00	0.00	0.00	0.00	100.00	0.00
1992:10	33.25	0.00	0.00	0.00	0.00	94.00	0.00
1992:11	33.23	0.00	0.00	0.00	0.00	89.00	0.00
1992:12	33.20	0.00	0.00	0.00	0.00	81.00	0.00
1993:01	33.18	1.00	0.00	0.00	0.00	84.00	0.00
1993:02	33.15	0.00	0.00	0.00	0.00	81.00	0.00
1993:03	33.13	0.00	0.00	0.00	1.00	88.00	0.00
1993:04	33.11	0.00	0.00	0.00	0.00	92.00	0.00
1993:05	33.08	0.00	0.00	0.00	0.00	899.00	1.00
1993:06	33.06	0.00	0.00	1.00	0.00	99.00	0.00
1993:07	33.04	0.00	1.00	0.00	0.00	101.00	0.00
1993:08	33.01	0.00	0.00	0.00	0.00	100.00	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
1993:09	32.99	0.00	0.00	0.00	0.00	98.00	0.00
1993:10	32.97	0.00	0.00	0.00	0.00	91.00	0.00
1993:11	32.95	0.00	0.00	0.00	0.00	90.00	0.00
1993:12	32.93	0.00	0.00	0.00	0.00	79.00	0.00
1994:01	32.90	1.00	0.00	0.00	0.00	79.00	0.00
1994:02	32.88	0.00	0.00	0.00	0.00	84.00	0.00
1994:03	32.86	0.00	0.00	0.00	1.00	94.00	0.00
1994:04	32.84	0.00	0.00	0.00	0.00	90.00	0.00
1994:05	32.82	0.00	0.00	0.00	0.00	97.00	1.00
1994:06	32.80	0.00	0.00	1.00	0.00	98.00	0.00
1994:07	32.85	0.00	1.00	0.00	0.00	100.00	0.00
1994:08	32.90	0.00	0.00	0.00	0.00	96.00	0.00
1994:09	32.94	0.00	0.00	0.00	0.00	98.00	0.00
1994:10	32.99	0.00	0.00	0.00	0.00	93.00	0.00
1994:11	33.04	0.00	0.00	0.00	0.00	87.00	0.00
1994:12	33.09	0.00	0.00	0.00	0.00	85.00	0.00
1995:01	33.13	1.00	0.00	0.00	0.00	81.00	0.00
1995:02	33.18	0.00	0.00	0.00	0.00	84.00	0.00
1995:03	33.23	0.00	0.00	0.00	1.00	87.00	0.00
1995:04	33.27	0.00	0.00	0.00	0.00	95.00	0.00
1995:05	33.32	0.00	0.00	0.00	0.00	98.00	1.00
1995:06	33.36	0.00	0.00	1.00	0.00	100.00	0.00
1995:07	33.38	0.00	1.00	0.00	0.00	102.00	0.00
1995:08	33.40	0.00	0.00	0.00	0.00	96.00	0.00
1995:09	33.42	0.00	0.00	0.00	0.00	94.00	0.00
1995:10	33.43	0.00	0.00	0.00	0.00	90.00	0.00
1995:11	33.45	0.00	0.00	0.00	0.00	87.00	0.00
1995:12	33.47	0.00	0.00	0.00	0.00	84.00	0.00
1996:01	33.48	1.00	0.00	0.00	0.00	83.00	0.00
1996:02	33.50	0.00	0.00	0.00	0.00	86.00	0.00
1996:03	33.52	0.00	0.00	0.00	1.00	86.00	0.00
1996:04	33.53	0.00	0.00	0.00	0.00	92.00	0.00
1996:05	33.55	0.00	0.00	0.00	0.00	92.00	1.00
1996:06	33.56	0.00	0.00	1.00	0.00	97.00	0.00
1996:07	33.58	0.00	1.00	0.00	0.00	95.00	0.00
1996:08	33.60	0.00	0.00	0.00	0.00	93.00	0.00
1996:09	33.62	0.00	0.00	0.00	0.00	94.00	0.00
1996:10	33.63	0.00	0.00	0.00	0.00	92.00	0.00
1996:11	33.65	0.00	0.00	0.00	0.00	87.00	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
1996:12	33.67	0.00	0.00	0.00	0.00	86.00	0.00
1997:01	33.68	1.00	0.00	0.00	0.00	87.00	0.00
1997:02	33.70	0.00	0.00	0.00	0.00	93.00	0.00
1997:03	33.72	0.00	0.00	0.00	1.00	93.00	0.00
1997:04	33.73	0.00	0.00	0.00	0.00	87.00	0.00
1997:05	33.75	0.00	0.00	0.00	0.00	86.00	1.00
1997:06	33.77	0.00	0.00	1.00	0.00	90.00	0.00
1997:07	33.78	0.00	1.00	0.00	0.00	92.00	0.00
1997:08	33.80	0.00	0.00	0.00	0.00	90.00	0.00
1997:09	33.82	0.00	0.00	0.00	0.00	89.00	0.00
1997:10	33.84	0.00	0.00	0.00	0.00	92.40	0.00
1997:11	33.85	0.00	0.00	0.00	0.00	88.20	0.00
1997:12	33.87	0.00	0.00	0.00	0.00	83.90	0.00
1998:01	33.89	1.00	0.00	0.00	0.00	83.00	0.00
1998:02	33.90	0.00	0.00	0.00	0.00	87.20	0.00
1998:03	33.92	0.00	0.00	0.00	1.00	89.10	0.00
1998:04	33.94	0.00	0.00	0.00	0.00	93.00	0.00
1998:05	33.95	0.00	0.00	0.00	0.00	175.90	1.00
1998:06	33.97	0.00	0.00	1.00	0.00	98.40	0.00
1998:07	33.99	0.00	1.00	0.00	0.00	99.20	0.00
1998:08	34.00	0.00	0.00	0.00	0.00	97.90	0.00
1998:09	34.02	0.00	0.00	0.00	0.00	97.00	0.00
1998:10	34.04	0.00	0.00	0.00	0.00	92.40	0.00
1998:11	34.06	0.00	0.00	0.00	0.00	88.20	0.00
1998:12	34.07	0.00	0.00	0.00	0.00	83.90	0.00
1999:01	34.09	1.00	0.00	0.00	0.00	83.00	0.00
1999:02	34.11	0.00	0.00	0.00	0.00	87.20	0.00
1999:03	34.12	0.00	0.00	0.00	1.00	89.10	0.00
1999:04	34.14	0.00	0.00	0.00	0.00	93.00	0.00
1999:05	34.16	0.00	0.00	0.00	0.00	175.90	1.00
1999:06	34.17	0.00	0.00	1.00	0.00	98.40	0.00
1999:07	34.19	0.00	1.00	0.00	0.00	99.20	0.00
1999:08	34.21	0.00	0.00	0.00	0.00	97.90	0.00
1999:09	34.23	0.00	0.00	0.00	0.00	97.00	0.00
1999:10	34.24	0.00	0.00	0.00	0.00	92.40	0.00
1999:11	34.26	0.00	0.00	0.00	0.00	88.20	0.00
1999:12	34.28	0.00	0.00	0.00	0.00	83.90	0.00
2000:01	34.30	1.00	0.00	0.00	0.00	83.00	0.00
2000:02	34.31	0.00	0.00	0.00	0.00	87.20	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
2000:03	34.33	0.00	0.00	0.00	1.00	89.10	0.00
2000:04	34.35	0.00	0.00	0.00	0.00	93.00	0.00
2000:05	34.36	0.00	0.00	0.00	0.00	175.90	1.00
2000:06	34.38	0.00	0.00	1.00	0.00	98.40	0.00
2000:07	34.40	0.00	1.00	0.00	0.00	99.20	0.00
2000:08	34.43	0.00	0.00	0.00	0.00	97.90	0.00
2000:09	34.45	0.00	0.00	0.00	0.00	97.00	0.00
2000:10	34.47	0.00	0.00	0.00	0.00	92.40	0.00
2000:11	34.50	0.00	0.00	0.00	0.00	88.20	0.00
2000:12	34.52	0.00	0.00	0.00	0.00	83.90	0.00
2001:01	34.54	1.00	0.00	0.00	0.00	83.00	0.00
2001:02	34.56	0.00	0.00	0.00	0.00	87.20	0.00
2001:03	34.59	0.00	0.00	0.00	1.00	89.10	0.00
2001:04	34.61	0.00	0.00	0.00	0.00	93.00	0.00
2001:05	34.63	0.00	0.00	0.00	0.00	175.90	1.00
2001:06	34.65	0.00	0.00	1.00	0.00	98.40	0.00
2001:07	34.68	0.00	1.00	0.00	0.00	99.20	0.00
2001:08	34.70	0.00	0.00	0.00	0.00	97.90	0.00
2001:09	34.72	0.00	0.00	0.00	0.00	97.00	0.00
2001:10	34.75	0.00	0.00	0.00	0.00	92.40	0.00
2001:11	34.77	0.00	0.00	0.00	0.00	88.20	0.00
2001:12	34.79	0.00	0.00	0.00	0.00	83.90	0.00
2002:01	34.82	1.00	0.00	0.00	0.00	83.00	0.00
2002:02	34.84	0.00	0.00	0.00	0.00	87.20	0.00
2002:03	34.86	0.00	0.00	0.00	1.00	89.10	0.00
2002:04	34.88	0.00	0.00	0.00	0.00	93.00	0.00
2002:05	34.91	0.00	0.00	0.00	0.00	175.90	1.00
2002:06	34.93	0.00	0.00	1.00	0.00	98.40	0.00
2002:07	34.95	0.00	1.00	0.00	0.00	99.20	0.00
2002:08	34.98	0.00	0.00	0.00	0.00	97.90	0.00
2002:09	35.00	0.00	0.00	0.00	0.00	97.00	0.00
2002:10	35.02	0.00	0.00	0.00	0.00	92.40	0.00
2002:11	35.05	0.00	0.00	0.00	0.00	88.20	0.00
2002:12	35.07	0.00	0.00	0.00	0.00	83.90	0.00
2003:01	35.09	1.00	0.00	0.00	0.00	83.00	0.00
2003:02	35.12	0.00	0.00	0.00	0.00	87.20	0.00
2003:03	35.14	0.00	0.00	0.00	1.00	89.10	0.00
2003:04	35.16	0.00	0.00	0.00	0.00	93.00	0.00
2003:05	35.18	0.00	0.00	0.00	0.00	175.90	1.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
2003:06	35.21	0.00	0.00	1.00	0.00	98.40	0.00
2003:07	35.23	0.00	1.00	0.00	0.00	99.20	0.00
2003:08	35.26	0.00	0.00	0.00	0.00	97.90	0.00
2003:09	35.28	0.00	0.00	0.00	0.00	97.00	0.00
2003:10	35.30	0.00	0.00	0.00	0.00	92.40	0.00
2003:11	35.33	0.00	0.00	0.00	0.00	88.20	0.00
2003:12	35.35	0.00	0.00	0.00	0.00	83.90	0.00
2004:01	35.37	1.00	0.00	0.00	0.00	83.00	0.00
2004:02	35.40	0.00	0.00	0.00	0.00	87.20	0.00
2004:03	35.42	0.00	0.00	0.00	1.00	89.10	0.00
2004:04	35.44	0.00	0.00	0.00	0.00	93.00	0.00
2004:05	35.46	0.00	0.00	0.00	0.00	175.90	1.00
2004:06	35.49	0.00	0.00	1.00	0.00	98.40	0.00
2004:07	35.51	0.00	1.00	0.00	0.00	99.20	0.00
2004:08	35.54	0.00	0.00	0.00	0.00	97.90	0.00
2004:09	35.56	0.00	0.00	0.00	0.00	97.00	0.00
2004:10	35.58	0.00	0.00	0.00	0.00	92.40	0.00
2004:11	35.61	0.00	0.00	0.00	0.00	88.20	0.00
2004:12	35.63	0.00	0.00	0.00	0.00	83.90	0.00
2005:01	35.65	1.00	0.00	0.00	0.00	83.00	0.00
2005:02	35.68	0.00	0.00	0.00	0.00	87.20	0.00
2005:03	35.70	0.00	0.00	0.00	1.00	89.10	0.00
2005:04	35.72	0.00	0.00	0.00	0.00	93.00	0.00
2005:05	35.75	0.00	0.00	0.00	0.00	175.90	1.00
2005:06	35.77	0.00	0.00	1.00	0.00	98.40	0.00
2005:07	35.82	0.00	1.00	0.00	0.00	99.20	0.00
2005:08	35.86	0.00	0.00	0.00	0.00	97.90	0.00
2005:09	35.91	0.00	0.00	0.00	0.00	97.00	0.00
2005:10	35.96	0.00	0.00	0.00	0.00	92.40	0.00
2005:11	36.01	0.00	0.00	0.00	0.00	88.20	0.00
2005:12	36.05	0.00	0.00	0.00	0.00	83.90	0.00
2006:01	36.10	1.00	0.00	0.00	0.00	83.00	0.00
2006:02	36.14	0.00	0.00	0.00	0.00	87.20	0.00
2006:03	36.19	0.00	0.00	0.00	1.00	89.10	0.00
2006:04	36.23	0.00	0.00	0.00	0.00	93.00	0.00
2006:05	36.28	0.00	0.00	0.00	0.00	175.90	1.00
2006:06	36.33	0.00	0.00	1.00	0.00	98.40	0.00
2006:07	36.37	0.00	1.00	0.00	0.00	99.20	0.00
2006:08	36.42	0.00	0.00	0.00	0.00	97.90	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
2006:09	36.47	0.00	0.00	0.00	0.00	97.00	0.00
2006:10	36.52	0.00	0.00	0.00	0.00	92.40	0.00
2006:11	36.56	0.00	0.00	0.00	0.00	88.20	0.00
2006:12	36.61	0.00	0.00	0.00	0.00	83.90	0.00
2007:01	36.66	1.00	0.00	0.00	0.00	83.00	0.00
2007:02	36.70	0.00	0.00	0.00	0.00	87.20	0.00
2007:03	36.75	0.00	0.00	0.00	1.00	89.10	0.00
2007:04	36.80	0.00	0.00	0.00	0.00	93.00	0.00
2007:05	36.84	0.00	0.00	0.00	0.00	175.90	1.00
2007:06	36.89	0.00	0.00	1.00	0.00	98.40	0.00
2007:07	36.94	0.00	1.00	0.00	0.00	99.20	0.00
2007:08	36.99	0.00	0.00	0.00	0.00	97.90	0.00
2007:09	37.04	0.00	0.00	0.00	0.00	97.00	0.00
2007:10	37.08	0.00	0.00	0.00	0.00	92.40	0.00
2007:11	37.13	0.00	0.00	0.00	0.00	88.20	0.00
2007:12	37.18	0.00	0.00	0.00	0.00	83.90	0.00
2008:01	37.23	1.00	0.00	0.00	0.00	83.00	0.00
2008:02	37.27	0.00	0.00	0.00	0.00	87.20	0.00
2008:03	37.32	0.00	0.00	0.00	1.00	89.10	0.00
2008:04	37.37	0.00	0.00	0.00	0.00	93.00	0.00
2008:05	37.42	0.00	0.00	0.00	0.00	175.90	1.00
2008:06	37.46	0.00	0.00	1.00	0.00	98.40	0.00
2008:07	37.51	0.00	1.00	0.00	0.00	99.20	0.00
2008:08	37.56	0.00	0.00	0.00	0.00	97.90	0.00
2008:09	37.61	0.00	0.00	0.00	0.00	97.00	0.00
2008:10	37.66	0.00	0.00	0.00	0.00	92.40	0.00
2008:11	37.71	0.00	0.00	0.00	0.00	88.20	0.00
2008:12	37.76	0.00	0.00	0.00	0.00	83.90	0.00
2009:01	37.81	1.00	0.00	0.00	0.00	83.00	0.00
2009:02	37.85	0.00	0.00	0.00	0.00	87.20	0.00
2009:03	37.90	0.00	0.00	0.00	1.00	89.10	0.00
2009:04	37.95	0.00	0.00	0.00	0.00	93.00	0.00
2009:05	38.00	0.00	0.00	0.00	0.00	175.90	1.00
2009:06	38.04	0.00	0.00	1.00	0.00	98.40	0.00
2009:07	38.09	0.00	1.00	0.00	0.00	99.20	0.00
2009:08	38.14	0.00	0.00	0.00	0.00	97.90	0.00
2009:09	38.19	0.00	0.00	0.00	0.00	97.00	0.00
2009:10	38.24	0.00	0.00	0.00	0.00	92.40	0.00
2009:11	38.29	0.00	0.00	0.00	0.00	88.20	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
2009:12	38.34	0.00	0.00	0.00	0.00	83.90	0.00
2010:01	38.39	1.00	0.00	0.00	0.00	83.00	0.00
2010:02	38.44	0.00	0.00	0.00	0.00	87.20	0.00
2010:03	38.49	0.00	0.00	0.00	1.00	89.10	0.00
2010:04	38.54	0.00	0.00	0.00	0.00	93.00	0.00
2010:05	38.59	0.00	0.00	0.00	0.00	175.90	1.00
2010:06	38.63	0.00	0.00	1.00	0.00	98.40	0.00
2010:07	38.68	0.00	1.00	0.00	0.00	99.20	0.00
2010:08	38.73	0.00	0.00	0.00	0.00	97.90	0.00
2010:09	38.77	0.00	0.00	0.00	0.00	97.00	0.00
2010:10	38.82	0.00	0.00	0.00	0.00	92.40	0.00
2010:11	38.87	0.00	0.00	0.00	0.00	88.20	0.00
2010:12	38.91	0.00	0.00	0.00	0.00	83.90	0.00
2011:01	38.96	1.00	0.00	0.00	0.00	83.00	0.00
2011:02	39.00	0.00	0.00	0.00	0.00	87.20	0.00
2011:03	39.05	0.00	0.00	0.00	1.00	89.10	0.00
2011:04	39.09	0.00	0.00	0.00	0.00	93.00	0.00
2011:05	39.14	0.00	0.00	0.00	0.00	175.90	1.00
2011:06	39.18	0.00	0.00	1.00	0.00	98.40	0.00
2011:07	39.23	0.00	1.00	0.00	0.00	99.20	0.00
2011:08	39.28	0.00	0.00	0.00	0.00	97.90	0.00
2011:09	39.32	0.00	0.00	0.00	0.00	97.00	0.00
2011:10	39.37	0.00	0.00	0.00	0.00	92.40	0.00
2011:11	39.42	0.00	0.00	0.00	0.00	88.20	0.00
2011:12	39.46	0.00	0.00	0.00	0.00	83.90	0.00
2012:01	39.51	1.00	0.00	0.00	0.00	83.00	0.00
2012:02	39.56	0.00	0.00	0.00	0.00	87.20	0.00
2012:03	39.60	0.00	0.00	0.00	1.00	89.10	0.00
2012:04	39.65	0.00	0.00	0.00	0.00	93.00	0.00
2012:05	39.69	0.00	0.00	0.00	0.00	175.90	1.00
2012:06	39.74	0.00	0.00	1.00	0.00	98.40	0.00
2012:07	39.79	0.00	1.00	0.00	0.00	99.20	0.00
2012:08	39.83	0.00	0.00	0.00	0.00	97.90	0.00
2012:09	39.88	0.00	0.00	0.00	0.00	97.00	0.00
2012:10	39.93	0.00	0.00	0.00	0.00	92.40	0.00
2012:11	39.98	0.00	0.00	0.00	0.00	88.20	0.00
2012:12	40.02	0.00	0.00	0.00	0.00	83.90	0.00
2013:01	40.07	1.00	0.00	0.00	0.00	83.00	0.00
2013:02	40.12	0.00	0.00	0.00	0.00	87.20	0.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
2013:03	40.16	0.00	0.00	0.00	1.00	89.10	0.00
2013:04	40.21	0.00	0.00	0.00	0.00	93.00	0.00
2013:05	40.26	0.00	0.00	0.00	0.00	175.90	1.00
2013:06	40.30	0.00	0.00	1.00	0.00	98.40	0.00
2013:07	40.35	0.00	1.00	0.00	0.00	99.20	0.00
2013:08	40.40	0.00	0.00	0.00	0.00	97.90	0.00
2013:09	40.45	0.00	0.00	0.00	0.00	97.00	0.00
2013:10	40.50	0.00	0.00	0.00	0.00	92.40	0.00
2013:11	40.54	0.00	0.00	0.00	0.00	88.20	0.00
2013:12	40.59	0.00	0.00	0.00	0.00	83.90	0.00
2014:01	40.64	1.00	0.00	0.00	0.00	83.00	0.00
2014:02	40.69	0.00	0.00	0.00	0.00	87.20	0.00
2014:03	40.73	0.00	0.00	0.00	1.00	89.10	0.00
2014:04	40.78	0.00	0.00	0.00	0.00	93.00	0.00
2014:05	40.83	0.00	0.00	0.00	0.00	175.90	1.00
2014:06	40.87	0.00	0.00	1.00	0.00	98.40	0.00
2014:07	40.92	0.00	1.00	0.00	0.00	99.20	0.00
2014:08	40.97	0.00	0.00	0.00	0.00	97.90	0.00
2014:09	41.02	0.00	0.00	0.00	0.00	97.00	0.00
2014:10	41.07	0.00	0.00	0.00	0.00	92.40	0.00
2014:11	41.12	0.00	0.00	0.00	0.00	88.20	0.00
2014:12	41.17	0.00	0.00	0.00	0.00	83.90	0.00
2015:01	41.22	1.00	0.00	0.00	0.00	83.00	0.00
2015:02	41.26	0.00	0.00	0.00	0.00	87.20	0.00
2015:03	41.31	0.00	0.00	0.00	1.00	89.10	0.00
2015:04	41.36	0.00	0.00	0.00	0.00	93.00	0.00
2015:05	41.41	0.00	0.00	0.00	0.00	175.90	1.00
2015:06	41.45	0.00	0.00	1.00	0.00	98.40	0.00
2015:07	41.50	0.00	1.00	0.00	0.00	99.20	0.00
2015:08	41.54	0.00	0.00	0.00	0.00	97.90	0.00
2015:09	41.59	0.00	0.00	0.00	0.00	97.00	0.00
2015:10	41.63	0.00	0.00	0.00	0.00	92.40	0.00
2015:11	41.68	0.00	0.00	0.00	0.00	88.20	0.00
2015:12	41.72	0.00	0.00	0.00	0.00	83.90	0.00
2016:01	41.77	1.00	0.00	0.00	0.00	83.00	0.00
2016:02	41.81	0.00	0.00	0.00	0.00	87.20	0.00
2016:03	41.86	0.00	0.00	0.00	1.00	89.10	0.00
2016:04	41.90	0.00	0.00	0.00	0.00	93.00	0.00
2016:05	41.94	0.00	0.00	0.00	0.00	175.90	1.00



Historical and Projected Energy and Demand Forecast Variables

Year/Month	INCPERHH	JAN	JUL	JUN	MAR	MAXTEMP	MAY
2016:06	41.99	0.00	0.00	1.00	0.00	98.40	0.00
2016:07	42.03	0.00	1.00	0.00	0.00	99.20	0.00
2016:08	42.08	0.00	0.00	0.00	0.00	97.90	0.00
2016:09	42.12	0.00	0.00	0.00	0.00	97.00	0.00
2016:10	42.17	0.00	0.00	0.00	0.00	92.40	0.00
2016:11	42.21	0.00	0.00	0.00	0.00	88.20	0.00
2016:12	42.26	0.00	0.00	0.00	0.00	83.90	0.00

Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
1985:01	19.00	0.00	0.00	76.76	1,703.95	139.18	82.65
1985:02	32.00	0.00	0.00	77.35	1,695.91	138.53	82.26
1985:03	37.00	0.00	0.00	77.93	1,689.53	138.01	81.95
1985:04	45.00	0.00	0.00	78.52	1,714.00	139.99	83.13
1985:05	59.00	0.00	0.00	79.11	1,707.61	139.46	82.82
1985:06	67.00	0.00	0.00	79.70	1,702.84	139.08	82.59
1985:07	66.00	0.00	0.00	80.13	1,699.69	138.82	82.44
1985:08	68.00	0.00	0.00	80.56	1,696.54	138.56	82.29
1985:09	68.00	0.00	0.00	80.99	1,691.84	138.18	82.06
1985:10	58.00	0.00	1.00	81.43	1,719.31	140.42	83.39
1985:11	44.00	1.00	0.00	81.86	1,714.57	140.03	83.17
1985:12	26.00	0.00	0.00	82.29	1,709.87	139.65	82.94
1986:01	24.00	0.00	0.00	82.73	1,705.19	139.27	82.71
1986:02	36.00	0.00	0.00	83.16	1,709.87	139.65	82.94
1986:03	31.00	0.00	0.00	83.59	1,717.73	140.29	83.32
1986:04	44.00	0.00	0.00	84.03	1,716.06	135.71	78.64
1986:05	52.00	0.00	0.00	84.46	1,711.33	135.34	78.42
1986:06	67.00	0.00	0.00	84.89	1,701.95	134.60	77.99



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
1986:07	66.00	0.00	0.00	85.38	1,701.95	134.60	77.99
1986:08	68.00	0.00	0.00	85.87	1,698.85	134.35	77.85
1986:09	66.00	0.00	0.00	86.36	1,691.14	133.74	77.50
1986:10	56.00	0.00	1.00	86.85	1,513.86	120.72	77.43
1986:11	51.00	1.00	0.00	87.33	1,512.49	120.61	77.36
1986:12	47.00	0.00	0.00	87.82	1,505.47	114.84	71.63
1987:01	29.00	0.00	0.00	88.31	1,495.99	114.12	71.18
1987:02	34.00	0.00	0.00	88.80	1,490.63	113.71	70.92
1987:03	40.00	0.00	0.00	89.29	1,483.98	113.20	70.61
1987:04	35.00	0.00	0.00	89.77	1,476.08	112.60	70.23
1987:05	53.00	0.00	0.00	90.26	1,477.52	118.86	76.64
1987:06	65.00	0.00	0.00	90.75	1,472.31	118.44	76.37
1987:07	67.00	0.00	0.00	91.23	1,468.43	118.13	76.17
1987:08	67.00	0.00	0.00	91.71	1,464.49	121.27	79.53
1987:09	66.00	0.00	0.00	92.18	1,456.85	120.63	79.11
1987:10	50.00	0.00	1.00	92.66	1,453.05	120.32	78.91
1987:11	41.00	1.00	0.00	93.14	1,451.80	120.22	78.84
1987:12	36.00	0.00	0.00	93.62	1,451.80	120.22	78.84
1988:01	33.00	0.00	0.00	94.10	1,448.03	119.90	78.63
1988:02	35.00	0.00	0.00	94.58	1,444.29	119.59	78.43
1988:03	36.00	0.00	0.00	95.05	1,438.09	119.08	78.09
1988:04	43.00	0.00	0.00	95.53	1,430.72	118.47	77.69
1988:05	54.00	0.00	0.00	96.01	1,419.47	111.69	71.06
1988:06	61.00	0.00	0.00	96.49	1,413.46	111.22	70.75
1988:07	66.00	0.00	0.00	96.87	1,407.50	110.75	70.46
1988:08	67.00	0.00	0.00	97.25	1,401.58	110.29	70.16
1988:09	59.00	0.00	0.00	97.63	1,392.22	109.55	69.69
1988:10	51.00	0.00	1.00	98.00	1,387.59	109.18	69.46
1988:11	47.00	1.00	0.00	98.38	1,391.14	113.80	74.11
1988:12	29.00	0.00	0.00	98.76	1,388.83	113.61	73.98
1989:01	41.00	0.00	0.00	99.14	1,381.95	113.05	73.62
1989:02	25.00	0.00	0.00	99.52	1,376.27	112.58	73.31
1989:03	39.00	0.00	0.00	99.90	1,368.39	111.94	72.89
1989:04	45.00	0.00	0.00	100.28	1,359.50	111.21	72.42
1989:05	51.00	0.00	0.00	100.66	1,348.77	107.54	68.97
1989:06	62.00	0.00	0.00	101.04	1,345.51	107.28	68.81
1989:07	65.00	0.00	0.00	101.75	1,342.27	107.03	68.64
1989:08	66.00	0.00	0.00	102.46	1,344.34	111.08	72.75
1989:09	66.00	0.00	0.00	103.18	1,340.03	110.72	72.52



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
1989:10	39.00	0.00	1.00	103.89	1,333.63	110.19	72.17
1989:11	42.00	1.00	0.00	104.60	1,330.45	109.93	72.00
1989:12	18.00	0.00	0.00	105.31	1,328.34	109.75	71.89
1990:01	36.00	0.00	0.00	106.03	1,312.73	108.46	71.04
1990:02	42.00	0.00	0.00	106.74	1,306.59	107.96	70.71
1990:03	44.00	0.00	0.00	107.45	1,300.50	107.45	70.38
1990:04	42.00	0.00	0.00	108.16	1,297.48	107.20	70.22
1990:05	55.00	0.00	0.00	108.88	1,295.47	107.04	70.11
1990:06	60.00	0.00	0.00	109.59	1,289.49	106.54	69.78
1990:07	66.00	0.00	0.00	110.13	1,282.57	105.97	69.41
1990:08	65.00	0.00	0.00	110.67	1,275.11	107.45	71.16
1990:09	62.00	0.00	0.00	111.21	1,266.45	106.72	70.68
1990:10	46.00	0.00	1.00	111.74	1,238.92	104.45	69.19
1990:11	45.00	1.00	0.00	112.28	1,235.63	104.55	69.39
1990:12	38.00	0.00	0.00	112.82	1,235.20	106.65	71.57
1991:01	35.00	0.00	0.00	113.36	1,227.87	106.02	71.15
1991:02	29.00	0.00	0.00	113.90	1,226.05	105.86	71.04
1991:03	36.00	0.00	0.00	114.44	1,226.96	105.94	71.10
1991:04	49.00	0.00	0.00	114.98	1,220.56	102.85	68.11
1991:05	62.00	0.00	0.00	115.52	1,218.52	104.10	69.46
1991:06	63.00	0.00	0.00	116.06	1,219.29	106.51	71.93
1991:07	66.00	0.00	0.00	116.47	1,216.18	105.84	71.34
1991:08	68.00	0.00	0.00	116.89	1,209.33	101.43	67.00
1991:09	61.00	0.00	0.00	117.31	1,205.12	100.46	66.13
1991:10	48.00	0.00	1.00	117.73	1,202.22	99.97	65.72
1991:11	37.00	1.00	0.00	118.15	1,197.97	99.72	65.59
1991:12	38.00	0.00	0.00	118.57	1,194.52	98.66	64.61
1992:01	29.00	0.00	0.00	118.98	1,193.12	100.43	66.47
1992:02	35.00	0.00	0.00	119.40	1,188.66	98.32	64.44
1992:03	40.00	0.00	0.00	119.82	1,183.50	97.08	63.32
1992:04	44.00	0.00	0.00	120.24	961.53	83.74	55.93
1992:05	44.00	0.00	0.00	120.66	962.16	85.63	57.86
1992:06	65.00	0.00	0.00	121.08	961.18	86.52	58.81
1992:07	66.00	0.00	0.00	121.58	958.31	86.15	58.51
1992:08	60.00	0.00	0.00	122.08	955.92	85.61	58.03
1992:09	66.00	0.00	0.00	122.58	953.94	84.86	57.33
1992:10	53.00	0.00	1.00	123.08	949.50	84.10	56.68
1992:11	36.00	1.00	0.00	123.58	947.82	84.25	56.89
1992:12	36.00	0.00	0.00	124.08	946.97	84.62	57.30



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
1993:01	37.00	0.00	0.00	124.59	942.66	84.53	57.34
1993:02	32.00	0.00	0.00	125.09	939.24	84.10	57.01
1993:03	30.00	0.00	0.00	125.59	938.16	84.21	57.16
1993:04	42.00	0.00	0.00	126.09	934.47	84.08	57.14
1993:05	53.00	0.00	0.00	126.59	933.67	84.45	57.55
1993:06	62.00	0.00	0.00	127.09	933.09	83.87	56.97
1993:07	65.00	0.00	0.00	127.54	932.37	83.74	56.86
1993:08	64.00	0.00	0.00	127.98	930.75	84.47	57.65
1993:09	62.00	0.00	0.00	128.43	930.85	84.56	57.75
1993:10	40.00	0.00	1.00	128.87	926.91	84.11	57.41
1993:11	34.00	1.00	0.00	129.32	924.88	83.81	57.17
1993:12	26.00	0.00	0.00	129.76	922.72	83.38	56.79
1994:01	33.00	0.00	0.00	130.20	921.35	83.16	56.60
1994:02	33.00	0.00	0.00	130.65	918.72	82.82	56.34
1994:03	37.00	0.00	0.00	131.09	915.83	82.77	56.38
1994:04	42.00	0.00	0.00	131.54	914.55	82.62	56.26
1994:05	50.00	0.00	0.00	131.98	912.96	82.71	56.41
1994:06	61.00	0.00	0.00	132.43	914.77	86.77	60.54
1994:07	66.00	0.00	0.00	132.89	910.80	85.59	59.44
1994:08	66.00	0.00	0.00	133.36	907.15	84.71	58.65
1994:09	62.00	0.00	0.00	133.82	903.60	82.80	56.80
1994:10	59.00	0.00	1.00	134.28	901.44	81.20	55.21
1994:11	48.00	1.00	0.00	134.75	897.12	79.06	53.14
1994:12	39.00	0.00	0.00	135.21	895.98	79.01	53.13
1995:01	34.00	0.00	0.00	135.68	892.55	78.29	52.50
1995:02	25.00	0.00	0.00	136.14	889.33	76.69	50.95
1995:03	42.00	0.00	0.00	136.61	887.68	77.11	51.43
1995:04	44.00	0.00	0.00	137.07	884.43	76.61	51.01
1995:05	61.00	0.00	0.00	137.53	882.53	76.83	51.31
1995:06	59.00	0.00	0.00	138.00	881.51	77.92	52.46
1995:07	65.00	0.00	0.00	138.37	881.14	78.08	52.64
1995:08	68.00	0.00	0.00	138.74	878.22	76.74	51.35
1995:09	65.00	0.00	0.00	139.12	876.57	76.14	50.78
1995:10	53.00	0.00	1.00	139.49	872.91	75.07	49.80
1995:11	37.00	1.00	0.00	139.86	871.70	74.39	49.13
1995:12	25.00	0.00	0.00	140.24	870.10	74.34	49.13
1996:01	25.00	0.00	0.00	140.61	866.36	73.68	48.57
1996:02	23.00	0.00	0.00	140.98	866.17	75.03	49.97
1996:03	29.00	0.00	0.00	141.35	862.67	74.58	49.61



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
1996:04	41.00	0.00	0.00	141.73	859.74	74.67	49.80
1996:05	55.00	0.00	0.00	142.10	857.39	74.83	50.04
1996:06	56.00	0.00	0.00	142.47	859.78	77.72	52.94
1996:07	61.00	0.00	0.00	142.86	857.97	77.41	52.68
1996:08	60.00	0.00	0.00	143.24	855.74	75.67	50.95
1996:09	55.00	0.00	0.00	143.63	858.24	80.15	55.50
1996:10	43.00	0.00	1.00	144.01	851.52	76.87	52.33
1996:11	40.00	1.00	0.00	144.40	845.55	73.34	48.88
1996:12	35.00	0.00	0.00	144.78	844.12	73.85	49.45
1997:01	30.00	0.00	0.00	145.17	846.72	77.42	53.05
1997:02	43.00	0.00	0.00	145.55	846.11	78.74	54.42
1997:03	51.00	0.00	0.00	145.94	845.56	78.67	54.37
1997:04	52.00	0.00	0.00	146.32	843.91	77.49	53.21
1997:05	63.00	0.00	0.00	146.71	842.97	77.03	52.76
1997:06	71.00	0.00	0.00	147.09	840.18	75.20	50.96
1997:07	74.00	0.00	0.00	147.49	837.69	74.13	49.94
1997:08	72.00	0.00	0.00	147.89	837.34	75.21	51.06
1997:09	72.00	0.00	0.00	148.28	833.62	73.38	49.29
1997:10	48.20	0.00	1.00	148.68	811.69	71.81	48.37
1997:11	40.70	1.00	0.00	149.08	809.69	71.64	48.25
1997:12	32.00	0.00	0.00	149.48	807.70	71.46	48.14
1998:01	33.30	0.00	0.00	149.87	805.71	71.29	48.02
1998:02	32.20	0.00	0.00	150.27	803.73	71.11	47.90
1998:03	38.40	0.00	0.00	150.67	801.75	70.94	47.78
1998:04	44.40	0.00	0.00	151.07	799.78	70.76	47.66
1998:05	54.80	0.00	0.00	151.46	797.81	70.59	47.55
1998:06	62.00	0.00	0.00	151.86	795.85	70.41	47.43
1998:07	66.00	0.00	0.00	152.27	793.89	70.24	47.31
1998:08	65.60	0.00	0.00	152.68	791.94	70.07	47.20
1998:09	63.00	0.00	0.00	153.09	789.99	69.89	47.08
1998:10	48.20	0.00	1.00	153.50	768.87	68.07	45.86
1998:11	40.70	1.00	0.00	153.91	766.98	67.90	45.75
1998:12	32.00	0.00	0.00	154.32	765.09	67.73	45.64
1999:01	33.30	0.00	0.00	154.73	763.21	67.56	45.53
1999:02	32.20	0.00	0.00	155.14	761.33	67.40	45.41
1999:03	38.40	0.00	0.00	155.55	759.46	67.23	45.30
1999:04	44.40	0.00	0.00	155.96	757.59	67.07	45.19
1999:05	54.80	0.00	0.00	156.37	755.73	66.90	45.08
1999:06	62.00	0.00	0.00	156.78	753.87	66.74	44.97



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
1999:07	66.00	0.00	0.00	157.21	752.01	66.57	44.86
1999:08	65.60	0.00	0.00	157.63	750.16	66.41	44.75
1999:09	63.00	0.00	0.00	158.05	748.32	66.25	44.64
1999:10	48.20	0.00	1.00	158.48	728.31	64.51	43.48
1999:11	40.70	1.00	0.00	158.90	726.52	64.36	43.38
1999:12	32.00	0.00	0.00	159.33	724.73	64.20	43.27
2000:01	33.30	0.00	0.00	159.75	722.95	64.04	43.16
2000:02	32.20	0.00	0.00	160.17	721.17	63.88	43.06
2000:03	38.40	0.00	0.00	160.60	719.40	63.72	42.95
2000:04	44.40	0.00	0.00	161.02	717.63	63.57	42.85
2000:05	54.80	0.00	0.00	161.44	715.86	63.41	42.74
2000:06	62.00	0.00	0.00	161.87	714.10	63.26	42.64
2000:07	66.00	0.00	0.00	162.27	712.34	63.10	42.53
2000:08	65.60	0.00	0.00	162.67	710.59	62.94	42.43
2000:09	63.00	0.00	0.00	163.08	708.84	62.79	42.32
2000:10	48.20	0.00	1.00	163.48	689.89	61.15	41.23
2000:11	40.70	1.00	0.00	163.88	688.20	61.00	41.13
2000:12	32.00	0.00	0.00	164.28	686.50	60.85	41.03
2001:01	33.30	0.00	0.00	164.69	684.81	60.70	40.93
2001:02	32.20	0.00	0.00	165.09	683.13	60.55	40.83
2001:03	38.40	0.00	0.00	165.49	681.45	60.40	40.72
2001:04	44.40	0.00	0.00	165.90	679.77	60.25	40.62
2001:05	54.80	0.00	0.00	166.30	678.10	60.10	40.52
2001:06	62.00	0.00	0.00	166.70	676.43	59.96	40.42
2001:07	66.00	0.00	0.00	167.12	674.77	59.81	40.33
2001:08	65.60	0.00	0.00	167.53	673.11	59.66	40.23
2001:09	63.00	0.00	0.00	167.95	671.45	59.51	40.13
2001:10	48.20	0.00	1.00	168.36	653.50	57.96	39.09
2001:11	40.70	1.00	0.00	168.78	651.90	57.82	39.00
2001:12	32.00	0.00	0.00	169.19	650.29	57.68	38.90
2002:01	33.30	0.00	0.00	169.61	648.69	57.53	38.80
2002:02	32.20	0.00	0.00	170.02	647.10	57.39	38.71
2002:03	38.40	0.00	0.00	170.44	645.50	57.25	38.61
2002:04	44.40	0.00	0.00	170.85	643.92	57.11	38.52
2002:05	54.80	0.00	0.00	171.27	642.33	56.97	38.42
2002:06	62.00	0.00	0.00	171.68	640.75	56.83	38.33
2002:07	66.00	0.00	0.00	172.11	639.17	56.69	38.24
2002:08	65.60	0.00	0.00	172.54	637.60	56.55	38.14
2002:09	63.00	0.00	0.00	172.96	636.03	56.41	38.05



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
2002:10	48.20	0.00	1.00	173.39	619.03	54.94	37.07
2002:11	40.70	1.00	0.00	173.82	617.51	54.80	36.98
2002:12	32.00	0.00	0.00	174.25	615.99	54.67	36.88
2003:01	33.30	0.00	0.00	174.67	614.48	54.53	36.79
2003:02	32.20	0.00	0.00	175.10	612.96	54.40	36.70
2003:03	38.40	0.00	0.00	175.53	611.46	54.27	36.61
2003:04	44.40	0.00	0.00	175.96	609.95	54.13	36.52
2003:05	54.80	0.00	0.00	176.38	608.45	54.00	36.43
2003:06	62.00	0.00	0.00	176.81	606.95	53.87	36.34
2003:07	66.00	0.00	0.00	177.25	605.46	53.73	36.25
2003:08	65.60	0.00	0.00	177.69	603.97	53.60	36.17
2003:09	63.00	0.00	0.00	178.13	602.49	53.47	36.08
2003:10	48.20	0.00	1.00	178.57	601.00	53.34	35.99
2003:11	40.70	1.00	0.00	179.01	599.52	53.21	35.90
2003:12	32.00	0.00	0.00	179.45	598.05	53.08	35.81
2004:01	33.30	0.00	0.00	179.89	596.58	52.95	35.72
2004:02	32.20	0.00	0.00	180.33	595.11	52.82	35.63
2004:03	38.40	0.00	0.00	180.77	593.65	52.69	35.55
2004:04	44.40	0.00	0.00	181.21	592.19	52.56	35.46
2004:05	54.80	0.00	0.00	181.65	590.73	52.43	35.37
2004:06	62.00	0.00	0.00	182.09	589.28	52.30	35.29
2004:07	66.00	0.00	0.00	182.55	587.83	52.17	35.20
2004:08	65.60	0.00	0.00	183.00	586.38	52.04	35.11
2004:09	63.00	0.00	0.00	183.45	584.94	51.91	35.03
2004:10	48.20	0.00	1.00	183.91	583.50	51.78	34.94
2004:11	40.70	1.00	0.00	184.36	582.06	51.66	34.85
2004:12	32.00	0.00	0.00	184.81	580.63	51.53	34.77
2005:01	33.30	0.00	0.00	185.27	579.20	51.40	34.68
2005:02	32.20	0.00	0.00	185.72	577.78	51.28	34.60
2005:03	38.40	0.00	0.00	186.17	576.36	51.15	34.51
2005:04	44.40	0.00	0.00	186.63	574.94	51.03	34.43
2005:05	54.80	0.00	0.00	187.08	573.52	50.90	34.34
2005:06	62.00	0.00	0.00	187.53	572.11	50.77	34.26
2005:07	66.00	0.00	0.00	187.94	570.70	50.65	34.17
2005:08	65.60	0.00	0.00	188.34	569.30	50.52	34.09
2005:09	63.00	0.00	0.00	188.75	567.90	50.40	34.01
2005:10	48.20	0.00	1.00	189.15	566.50	50.28	33.92
2005:11	40.70	1.00	0.00	189.56	565.11	50.15	33.84
2005:12	32.00	0.00	0.00	189.97	563.72	50.03	33.75



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
2006:01	33.30	0.00	0.00	190.37	562.33	49.91	33.67
2006:02	32.20	0.00	0.00	190.78	560.95	49.78	33.59
2006:03	38.40	0.00	0.00	191.18	559.57	49.66	33.51
2006:04	44.40	0.00	0.00	191.59	558.19	49.54	33.42
2006:05	54.80	0.00	0.00	191.99	556.82	49.42	33.34
2006:06	62.00	0.00	0.00	192.40	555.45	49.30	33.26
2006:07	66.00	0.00	0.00	192.81	554.08	49.17	33.18
2006:08	65.60	0.00	0.00	193.23	552.72	49.05	33.10
2006:09	63.00	0.00	0.00	193.65	551.36	48.93	33.01
2006:10	48.20	0.00	1.00	194.06	550.00	48.81	32.93
2006:11	40.70	1.00	0.00	194.48	548.65	48.69	32.85
2006:12	32.00	0.00	0.00	194.89	547.30	48.57	32.77
2007:01	33.30	0.00	0.00	195.31	545.95	48.45	32.69
2007:02	32.20	0.00	0.00	195.73	544.61	48.33	32.61
2007:03	38.40	0.00	0.00	196.14	543.27	48.21	32.53
2007:04	44.40	0.00	0.00	196.56	541.93	48.10	32.45
2007:05	54.80	0.00	0.00	196.97	540.60	47.98	32.37
2007:06	62.00	0.00	0.00	197.39	539.27	47.86	32.29
2007:07	66.00	0.00	0.00	197.82	537.94	47.74	32.21
2007:08	65.60	0.00	0.00	198.24	536.62	47.62	32.13
2007:09	63.00	0.00	0.00	198.67	535.30	47.51	32.05
2007:10	48.20	0.00	1.00	199.10	533.98	47.39	31.97
2007:11	40.70	1.00	0.00	199.52	532.67	47.27	31.90
2007:12	32.00	0.00	0.00	199.95	531.36	47.16	31.82
2008:01	33.30	0.00	0.00	200.38	530.05	47.04	31.74
2008:02	32.20	0.00	0.00	200.80	528.75	46.93	31.66
2008:03	38.40	0.00	0.00	201.23	527.45	46.81	31.58
2008:04	44.40	0.00	0.00	201.66	526.15	46.70	31.51
2008:05	54.80	0.00	0.00	202.08	524.86	46.58	31.43
2008:06	62.00	0.00	0.00	202.51	523.56	46.47	31.35
2008:07	66.00	0.00	0.00	202.95	522.28	46.35	31.27
2008:08	65.60	0.00	0.00	203.39	520.99	46.24	31.20
2008:09	63.00	0.00	0.00	203.82	519.71	46.12	31.12
2008:10	48.20	0.00	1.00	204.26	518.43	46.01	31.04
2008:11	40.70	1.00	0.00	204.70	517.16	45.90	30.97
2008:12	32.00	0.00	0.00	205.14	515.88	45.78	30.89
2009:01	33.30	0.00	0.00	205.57	514.61	45.67	30.81
2009:02	32.20	0.00	0.00	206.01	513.35	45.56	30.74
2009:03	38.40	0.00	0.00	206.45	512.08	45.45	30.66



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
2009:04	44.40	0.00	0.00	206.89	510.82	45.34	30.59
2009:05	54.80	0.00	0.00	207.33	509.57	45.22	30.51
2009:06	62.00	0.00	0.00	207.76	508.31	45.11	30.44
2009:07	66.00	0.00	0.00	208.21	507.06	45.00	30.36
2009:08	65.60	0.00	0.00	208.66	505.82	44.89	30.29
2009:09	63.00	0.00	0.00	209.11	504.57	44.78	30.21
2009:10	48.20	0.00	1.00	209.56	503.33	44.67	30.14
2009:11	40.70	1.00	0.00	210.01	502.09	44.56	30.06
2009:12	32.00	0.00	0.00	210.46	500.86	44.45	29.99
2010:01	33.30	0.00	0.00	210.91	499.62	44.34	29.92
2010:02	32.20	0.00	0.00	211.36	498.40	44.23	29.84
2010:03	38.40	0.00	0.00	211.81	497.17	44.12	29.77
2010:04	44.40	0.00	0.00	212.25	495.95	44.01	29.70
2010:05	54.80	0.00	0.00	212.70	494.73	43.91	29.62
2010:06	62.00	0.00	0.00	213.15	493.51	43.80	29.55
2010:07	66.00	0.00	0.00	213.57	492.29	43.69	29.48
2010:08	65.60	0.00	0.00	213.99	491.08	43.58	29.41
2010:09	63.00	0.00	0.00	214.41	489.88	43.48	29.33
2010:10	48.20	0.00	1.00	214.83	488.67	43.37	29.26
2010:11	40.70	1.00	0.00	215.25	487.47	43.26	29.19
2010:12	32.00	0.00	0.00	215.67	486.27	43.16	29.12
2011:01	33.30	0.00	0.00	216.09	485.07	43.05	29.05
2011:02	32.20	0.00	0.00	216.51	483.88	42.94	28.97
2011:03	38.40	0.00	0.00	216.93	482.69	42.84	28.90
2011:04	44.40	0.00	0.00	217.35	481.50	42.73	28.83
2011:05	54.80	0.00	0.00	217.77	480.32	42.63	28.76
2011:06	62.00	0.00	0.00	218.19	479.14	42.52	28.69
2011:07	66.00	0.00	0.00	218.62	477.96	42.42	28.62
2011:08	65.60	0.00	0.00	219.05	476.78	42.31	28.55
2011:09	63.00	0.00	0.00	219.48	475.61	42.21	28.48
2011:10	48.20	0.00	1.00	219.91	474.44	42.11	28.41
2011:11	40.70	1.00	0.00	220.34	473.27	42.00	28.34
2011:12	32.00	0.00	0.00	220.77	472.11	41.90	28.27
2012:01	33.30	0.00	0.00	221.20	470.94	41.80	28.20
2012:02	32.20	0.00	0.00	221.63	469.79	41.69	28.13
2012:03	38.40	0.00	0.00	222.06	468.63	41.59	28.06
2012:04	44.40	0.00	0.00	222.49	467.48	41.49	27.99
2012:05	54.80	0.00	0.00	222.92	466.33	41.39	27.92
2012:06	62.00	0.00	0.00	223.35	465.18	41.28	27.85



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
2012:07	66.00	0.00	0.00	223.79	464.04	41.18	27.79
2012:08	65.60	0.00	0.00	224.23	462.89	41.08	27.72
2012:09	63.00	0.00	0.00	224.67	461.75	40.98	27.65
2012:10	48.20	0.00	1.00	225.11	460.62	40.88	27.58
2012:11	40.70	1.00	0.00	225.55	459.49	40.78	27.51
2012:12	32.00	0.00	0.00	225.99	458.36	40.68	27.45
2013:01	33.30	0.00	0.00	226.43	457.23	40.58	27.38
2013:02	32.20	0.00	0.00	226.87	456.10	40.48	27.31
2013:03	38.40	0.00	0.00	227.31	454.98	40.38	27.24
2013:04	44.40	0.00	0.00	227.75	453.86	40.28	27.18
2013:05	54.80	0.00	0.00	228.19	452.74	40.18	27.11
2013:06	62.00	0.00	0.00	228.63	451.63	40.08	27.04
2013:07	66.00	0.00	0.00	229.08	450.52	39.98	26.98
2013:08	65.60	0.00	0.00	229.53	449.41	39.88	26.91
2013:09	63.00	0.00	0.00	229.98	448.31	39.79	26.84
2013:10	48.20	0.00	1.00	230.43	447.20	39.69	26.78
2013:11	40.70	1.00	0.00	230.88	446.10	39.59	26.71
2013:12	32.00	0.00	0.00	231.33	445.00	39.49	26.65
2014:01	33.30	0.00	0.00	231.79	443.91	39.40	26.58
2014:02	32.20	0.00	0.00	232.24	442.82	39.30	26.52
2014:03	38.40	0.00	0.00	232.69	441.73	39.20	26.45
2014:04	44.40	0.00	0.00	233.14	440.64	39.11	26.39
2014:05	54.80	0.00	0.00	233.59	439.56	39.01	26.32
2014:06	62.00	0.00	0.00	234.04	438.48	38.91	26.26
2014:07	66.00	0.00	0.00	234.50	437.40	38.82	26.19
2014:08	65.60	0.00	0.00	234.96	436.32	38.72	26.13
2014:09	63.00	0.00	0.00	235.42	435.25	38.63	26.06
2014:10	48.20	0.00	1.00	235.88	434.18	38.53	26.00
2014:11	40.70	1.00	0.00	236.34	433.11	38.44	25.93
2014:12	32.00	0.00	0.00	236.80	432.04	38.34	25.87
2015:01	33.30	0.00	0.00	237.27	430.98	38.25	25.81
2015:02	32.20	0.00	0.00	237.73	429.92	38.15	25.74
2015:03	38.40	0.00	0.00	238.19	428.86	38.06	25.68
2015:04	44.40	0.00	0.00	238.65	427.81	37.97	25.62
2015:05	54.80	0.00	0.00	239.11	426.76	37.87	25.55
2015:06	62.00	0.00	0.00	239.57	425.71	37.78	25.49
2015:07	66.00	0.00	0.00	240.00	424.66	37.69	25.43
2015:08	65.60	0.00	0.00	240.42	423.61	37.60	25.37
2015:09	63.00	0.00	0.00	240.85	422.57	37.50	25.30



Historical and Projected Energy and Demand Forecast Variables

Year/Month	MINTEMP	NOV	OCT	POPA	PRICEGSD	PRICEGSN	PRICERES
2015:10	48.20	0.00	1.00	241.28	421.53	37.41	25.24
2015:11	40.70	1.00	0.00	241.70	420.49	37.32	25.18
2015:12	32.00	0.00	0.00	242.13	419.46	37.23	25.12
2016:01	33.30	0.00	0.00	242.56	418.43	37.13	25.06
2016:02	32.20	0.00	0.00	242.98	417.40	37.04	24.99
2016:03	38.40	0.00	0.00	243.41	416.37	36.95	24.93
2016:04	44.40	0.00	0.00	243.84	415.35	36.86	24.87
2016:05	54.80	0.00	0.00	244.26	414.33	36.77	24.81
2016:06	62.00	0.00	0.00	244.69	413.31	36.68	24.75
2016:07	66.00	0.00	0.00	245.13	412.29	36.59	24.69
2016:08	65.60	0.00	0.00	245.56	411.27	36.50	24.63
2016:09	63.00	0.00	0.00	246.00	410.26	36.41	24.57
2016:10	48.20	0.00	1.00	246.43	409.25	36.32	24.51
2016:11	40.70	1.00	0.00	246.87	408.25	36.23	24.45
2016:12	32.00	0.00	0.00	247.30	407.24	36.14	24.39

Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
1985:01	935.05	680.00	0.61	0.71	0.85	0.00	19.93
1985:02	943.20	681.00	0.61	0.71	0.85	0.00	20.08
1985:03	951.35	682.00	0.61	0.71	0.85	0.00	20.23
1985:04	959.51	683.00	0.61	0.71	0.85	0.00	20.37
1985:05	967.66	684.00	0.61	0.71	0.85	0.00	20.52
1985:06	975.81	685.00	0.61	0.71	0.85	0.00	20.67
1985:07	983.86	686.00	0.61	0.71	0.85	0.00	20.86
1985:08	991.90	687.00	0.61	0.71	0.85	0.00	21.05
1985:09	999.94	688.00	0.61	0.71	0.85	1.00	21.24
1985:10	1,007.98	689.00	0.61	0.71	0.85	0.00	21.43



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
1985:11	1,016.02	690.00	0.61	0.71	0.85	0.00	21.62
1985:12	1,024.07	691.00	0.61	0.71	0.86	0.00	21.81
1986:01	1,032.11	692.00	0.61	0.71	0.86	0.00	22.00
1986:02	1,040.15	693.00	0.61	0.71	0.86	0.00	22.19
1986:03	1,048.19	694.00	0.61	0.71	0.86	0.00	22.38
1986:04	1,056.24	695.00	0.61	0.72	0.86	0.00	22.57
1986:05	1,064.28	696.00	0.61	0.72	0.86	0.00	22.76
1986:06	1,072.32	697.00	0.62	0.72	0.86	0.00	22.96
1986:07	1,079.39	698.00	0.62	0.72	0.86	0.00	23.17
1986:08	1,086.45	699.00	0.62	0.72	0.86	0.00	23.39
1986:09	1,093.52	700.00	0.62	0.72	0.86	1.00	23.60
1986:10	1,100.59	701.00	0.62	0.72	0.86	0.00	23.82
1986:11	1,107.65	702.00	0.62	0.72	0.86	0.00	24.03
1986:12	1,114.72	703.00	0.62	0.72	0.86	0.00	24.25
1987:01	1,121.79	704.00	0.62	0.72	0.86	0.00	24.46
1987:02	1,128.85	705.00	0.62	0.72	0.86	0.00	24.68
1987:03	1,135.92	706.00	0.62	0.72	0.86	0.00	24.90
1987:04	1,142.99	707.00	0.61	0.72	0.86	0.00	25.11
1987:05	1,150.05	708.00	0.63	0.72	0.87	0.00	25.33
1987:06	1,157.12	709.00	0.63	0.72	0.87	0.00	25.54
1987:07	1,164.32	710.00	0.63	0.73	0.87	0.00	25.73
1987:08	1,171.51	711.00	0.63	0.73	0.87	0.00	25.92
1987:09	1,178.71	712.00	0.63	0.73	0.87	1.00	26.12
1987:10	1,185.91	713.00	0.63	0.73	0.87	0.00	26.31
1987:11	1,193.10	714.00	0.63	0.73	0.87	0.00	26.50
1987:12	1,200.30	715.00	0.63	0.73	0.87	0.00	26.69
1988:01	1,207.50	716.00	0.64	0.73	0.87	0.00	26.88
1988:02	1,214.69	717.00	0.64	0.73	0.87	0.00	27.07
1988:03	1,221.89	718.00	0.64	0.73	0.87	0.00	27.26
1988:04	1,229.09	719.00	0.64	0.73	0.87	0.00	27.45
1988:05	1,236.28	720.00	0.64	0.73	0.87	0.00	27.64
1988:06	1,243.48	721.00	0.64	0.73	0.87	0.00	27.84
1988:07	1,249.86	722.00	0.64	0.73	0.88	0.00	28.05
1988:08	1,256.24	723.00	0.64	0.74	0.88	0.00	28.27
1988:09	1,262.61	724.00	0.65	0.74	0.88	1.00	28.49
1988:10	1,268.99	725.00	0.65	0.74	0.88	0.00	28.71
1988:11	1,275.37	726.00	0.65	0.74	0.88	0.00	28.93
1988:12	1,281.75	727.00	0.65	0.74	0.88	0.00	29.15
1989:01	1,288.12	728.00	0.65	0.74	0.88	0.00	29.37



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
1989:02	1,294.50	729.00	0.65	0.74	0.88	0.00	29.59
1989:03	1,300.88	730.00	0.65	0.74	0.88	0.00	29.81
1989:04	1,307.26	731.00	0.66	0.74	0.88	0.00	30.03
1989:05	1,313.63	732.00	0.66	0.74	0.88	0.00	30.25
1989:06	1,320.01	733.00	0.66	0.75	0.88	0.00	30.47
1989:07	1,324.93	734.00	0.66	0.75	0.89	0.00	30.63
1989:08	1,329.85	735.00	0.66	0.75	0.89	0.00	30.79
1989:09	1,334.78	736.00	0.66	0.75	0.89	1.00	30.95
1989:10	1,339.70	737.00	0.67	0.75	0.89	0.00	31.11
1989:11	1,344.62	738.00	0.67	0.75	0.89	0.00	31.28
1989:12	1,349.54	739.00	0.67	0.75	0.89	0.00	31.44
1990:01	1,354.46	740.00	0.67	0.75	0.89	0.00	31.60
1990:02	1,359.38	741.00	0.67	0.75	0.89	0.00	31.76
1990:03	1,364.31	742.00	0.67	0.76	0.89	0.00	31.92
1990:04	1,369.23	743.00	0.68	0.76	0.89	0.00	32.09
1990:05	1,374.15	744.00	0.68	0.76	0.89	0.00	32.25
1990:06	1,379.07	745.00	0.68	0.76	0.90	0.00	32.41
1990:07	1,380.83	746.00	0.68	0.76	0.90	0.00	32.41
1990:08	1,382.59	747.00	0.68	0.76	0.90	0.00	32.41
1990:09	1,384.35	748.00	0.69	0.76	0.90	1.00	32.42
1990:10	1,386.10	749.00	0.69	0.76	0.90	0.00	32.42
1990:11	1,387.86	750.00	0.69	0.77	0.90	0.00	32.42
1990:12	1,389.62	751.00	0.69	0.77	0.90	0.00	32.42
1991:01	1,391.38	752.00	0.69	0.77	0.90	0.00	32.43
1991:02	1,393.14	753.00	0.70	0.77	0.90	0.00	32.43
1991:03	1,394.90	754.00	0.70	0.77	0.91	0.00	32.43
1991:04	1,396.65	755.00	0.70	0.77	0.91	0.00	32.43
1991:05	1,398.41	756.00	0.70	0.77	0.91	0.00	32.44
1991:06	1,400.17	757.00	0.71	0.78	0.91	0.00	32.44
1991:07	1,406.20	758.00	0.71	0.78	0.91	0.00	32.59
1991:08	1,412.23	759.00	0.71	0.78	0.91	0.00	32.74
1991:09	1,418.26	760.00	0.71	0.78	0.91	1.00	32.90
1991:10	1,424.29	761.00	0.71	0.78	0.91	0.00	33.05
1991:11	1,430.32	762.00	0.72	0.78	0.92	0.00	33.20
1991:12	1,436.35	763.00	0.72	0.79	0.92	0.00	33.35
1992:01	1,442.37	764.00	0.72	0.79	0.92	0.00	33.50
1992:02	1,448.40	765.00	0.72	0.79	0.92	0.00	33.66
1992:03	1,454.43	766.00	0.73	0.79	0.92	0.00	33.81
1992:04	1,460.46	767.00	0.73	0.79	0.92	0.00	33.96



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
1992:05	1,466.49	768.00	0.73	0.79	0.92	0.00	34.11
1992:06	1,472.52	769.00	0.73	0.79	0.92	0.00	34.26
1992:07	1,477.44	770.00	0.74	0.80	0.93	0.00	34.49
1992:08	1,482.37	771.00	0.74	0.80	0.93	0.00	34.73
1992:09	1,487.29	772.00	0.74	0.80	0.93	1.00	34.96
1992:10	1,492.21	773.00	0.75	0.80	0.93	0.00	35.19
1992:11	1,497.14	774.00	0.75	0.80	0.93	0.00	35.42
1992:12	1,502.06	775.00	0.75	0.81	0.93	0.00	35.65
1993:01	1,506.98	776.00	0.76	0.81	0.93	0.00	35.88
1993:02	1,511.91	777.00	0.76	0.81	0.94	0.00	36.11
1993:03	1,516.83	778.00	0.76	0.81	0.94	0.00	36.34
1993:04	1,521.75	779.00	0.76	0.81	0.94	0.00	36.57
1993:05	1,526.68	780.00	0.77	0.82	0.94	0.00	36.80
1993:06	1,531.60	781.00	0.77	0.82	0.94	0.00	37.04
1993:07	1,536.08	782.00	0.77	0.82	0.94	0.00	37.14
1993:08	1,540.56	783.00	0.78	0.82	0.95	0.00	37.25
1993:09	1,545.04	784.00	0.78	0.82	0.95	1.00	37.35
1993:10	1,549.51	785.00	0.78	0.83	0.95	0.00	37.46
1993:11	1,553.99	786.00	0.79	0.83	0.95	0.00	37.56
1993:12	1,558.47	787.00	0.79	0.83	0.95	0.00	37.67
1994:01	1,562.95	788.00	0.79	0.83	0.95	0.00	37.78
1994:02	1,567.43	789.00	0.80	0.83	0.96	0.00	37.88
1994:03	1,571.91	790.00	0.80	0.84	0.96	0.00	37.99
1994:04	1,576.38	791.00	0.81	0.84	0.96	0.00	38.09
1994:05	1,580.86	792.00	0.81	0.84	0.96	0.00	38.20
1994:06	1,585.34	793.00	0.81	0.84	0.96	0.00	38.30
1994:07	1,592.73	794.00	0.82	0.85	0.96	0.00	38.46
1994:08	1,600.12	795.00	0.82	0.85	0.97	0.00	38.61
1994:09	1,607.50	796.00	0.82	0.85	0.97	1.00	38.76
1994:10	1,614.89	797.00	0.83	0.85	0.97	0.00	38.91
1994:11	1,622.28	798.00	0.83	0.86	0.97	0.00	39.06
1994:12	1,629.67	799.00	0.83	0.86	0.97	0.00	39.22
1995:01	1,637.05	800.00	0.84	0.86	0.97	0.00	39.37
1995:02	1,644.44	801.00	0.84	0.86	0.97	0.00	39.52
1995:03	1,651.83	802.00	0.84	0.87	0.98	0.00	39.67
1995:04	1,659.22	803.00	0.85	0.87	0.98	0.00	39.82
1995:05	1,666.60	804.00	0.85	0.87	0.98	0.00	39.98
1995:06	1,673.99	805.00	0.86	0.87	0.98	0.00	40.13
1995:07	1,679.90	806.00	0.86	0.88	0.98	0.00	40.29



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
1995:08	1,685.81	807.00	0.86	0.88	0.98	0.00	40.46
1995:09	1,691.72	807.00	0.86	0.88	0.98	1.00	40.62
1995:10	1,697.62	807.00	0.86	0.88	0.98	0.00	40.78
1995:11	1,703.53	807.00	0.87	0.88	0.98	0.00	40.95
1995:12	1,709.44	807.00	0.87	0.89	0.98	0.00	41.11
1996:01	1,715.35	807.00	0.87	0.89	0.98	0.00	41.28
1996:02	1,721.26	807.00	0.87	0.89	0.98	0.00	41.44
1996:03	1,727.17	807.00	0.88	0.89	0.98	0.00	41.61
1996:04	1,733.07	807.00	0.88	0.90	0.98	0.00	41.77
1996:05	1,738.98	807.00	0.88	0.90	0.98	0.00	41.93
1996:06	1,744.89	807.00	0.88	0.90	0.98	0.00	42.10
1996:07	1,751.05	807.00	0.88	0.90	0.98	0.00	42.27
1996:08	1,757.21	807.00	0.88	0.90	0.98	0.00	42.44
1996:09	1,763.37	807.00	0.88	0.90	0.98	1.00	42.61
1996:10	1,769.52	807.00	0.88	0.90	0.98	0.00	42.79
1996:11	1,775.68	807.00	0.88	0.90	0.98	0.00	42.96
1996:12	1,781.84	807.00	0.88	0.90	0.98	0.00	43.13
1997:01	1,788.00	807.00	0.88	0.90	0.98	0.00	43.30
1997:02	1,794.16	807.00	0.88	0.90	0.98	0.00	43.48
1997:03	1,800.32	807.00	0.88	0.90	0.98	0.00	43.65
1997:04	1,806.48	807.00	0.88	0.90	0.98	0.00	43.82
1997:05	1,812.64	807.00	0.88	0.90	0.98	0.00	43.99
1997:06	1,818.79	807.00	0.88	0.90	0.98	0.00	44.17
1997:07	1,825.21	807.00	0.88	0.90	0.98	0.00	44.35
1997:08	1,831.63	807.00	0.88	0.90	0.98	0.00	44.53
1997:09	1,838.05	807.00	0.88	0.90	0.98	1.00	44.71
1997:10	1,844.47	807.00	0.88	0.90	0.98	0.00	44.89
1997:11	1,850.89	807.00	0.88	0.90	0.98	0.00	45.07
1997:12	1,857.31	807.00	0.88	0.90	0.98	0.00	45.25
1998:01	1,863.73	807.00	0.88	0.90	0.98	0.00	45.43
1998:02	1,870.15	807.00	0.88	0.90	0.98	0.00	45.61
1998:03	1,876.57	807.00	0.88	0.90	0.98	0.00	45.79
1998:04	1,882.99	807.00	0.88	0.90	0.98	0.00	45.97
1998:05	1,889.41	807.00	0.88	0.90	0.98	0.00	46.15
1998:06	1,895.83	807.00	0.88	0.90	0.98	0.00	46.33
1998:07	1,902.52	807.00	0.88	0.90	0.98	0.00	46.52
1998:08	1,909.21	807.00	0.88	0.90	0.98	0.00	46.71
1998:09	1,915.90	807.00	0.88	0.90	0.98	1.00	46.90
1998:10	1,922.59	807.00	0.88	0.90	0.98	0.00	47.09



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
1998:11	1,929.28	807.00	0.88	0.90	0.98	0.00	47.28
1998:12	1,935.98	807.00	0.88	0.90	0.98	0.00	47.47
1999:01	1,942.67	807.00	0.88	0.90	0.98	0.00	47.66
1999:02	1,949.36	807.00	0.88	0.90	0.98	0.00	47.85
1999:03	1,956.05	807.00	0.88	0.90	0.98	0.00	48.04
1999:04	1,962.74	807.00	0.88	0.90	0.98	0.00	48.23
1999:05	1,969.43	807.00	0.88	0.90	0.98	0.00	48.42
1999:06	1,976.12	807.00	0.88	0.90	0.98	0.00	48.61
1999:07	1,983.10	807.00	0.88	0.90	0.98	0.00	48.81
1999:08	1,990.07	807.00	0.88	0.90	0.98	0.00	49.01
1999:09	1,997.05	807.00	0.88	0.90	0.98	1.00	49.21
1999:10	2,004.02	807.00	0.88	0.90	0.98	0.00	49.41
1999:11	2,011.00	807.00	0.88	0.90	0.98	0.00	49.60
1999:12	2,017.97	807.00	0.88	0.90	0.98	0.00	49.80
2000:01	2,024.95	807.00	0.88	0.90	0.98	0.00	50.00
2000:02	2,031.92	807.00	0.88	0.90	0.98	0.00	50.20
2000:03	2,038.90	807.00	0.88	0.90	0.98	0.00	50.40
2000:04	2,045.87	807.00	0.88	0.90	0.98	0.00	50.60
2000:05	2,052.85	807.00	0.88	0.90	0.98	0.00	50.80
2000:06	2,059.82	807.00	0.88	0.90	0.98	0.00	51.00
2000:07	2,066.79	807.00	0.88	0.90	0.98	0.00	51.17
2000:08	2,073.76	807.00	0.88	0.90	0.98	0.00	51.34
2000:09	2,080.73	807.00	0.88	0.90	0.98	1.00	51.51
2000:10	2,087.70	807.00	0.88	0.90	0.98	0.00	51.68
2000:11	2,094.67	807.00	0.88	0.90	0.98	0.00	51.85
2000:12	2,101.65	807.00	0.88	0.90	0.98	0.00	52.02
2001:01	2,108.62	807.00	0.88	0.90	0.98	0.00	52.19
2001:02	2,115.59	807.00	0.88	0.90	0.98	0.00	52.36
2001:03	2,122.56	807.00	0.88	0.90	0.98	0.00	52.53
2001:04	2,129.53	807.00	0.88	0.90	0.98	0.00	52.70
2001:05	2,136.50	807.00	0.88	0.90	0.98	0.00	52.87
2001:06	2,143.47	807.00	0.88	0.90	0.98	0.00	53.04
2001:07	2,150.72	807.00	0.88	0.90	0.98	0.00	53.21
2001:08	2,157.98	807.00	0.88	0.90	0.98	0.00	53.39
2001:09	2,165.23	807.00	0.88	0.90	0.98	1.00	53.57
2001:10	2,172.49	807.00	0.88	0.90	0.98	0.00	53.74
2001:11	2,179.74	807.00	0.88	0.90	0.98	0.00	53.92
2001:12	2,186.99	807.00	0.88	0.90	0.98	0.00	54.10
2002:01	2,194.25	807.00	0.88	0.90	0.98	0.00	54.27



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
2002:02	2,201.50	807.00	0.88	0.90	0.98	0.00	54.45
2002:03	2,208.76	807.00	0.88	0.90	0.98	0.00	54.63
2002:04	2,216.01	807.00	0.88	0.90	0.98	0.00	54.80
2002:05	2,223.26	807.00	0.88	0.90	0.98	0.00	54.98
2002:06	2,230.52	807.00	0.88	0.90	0.98	0.00	55.16
2002:07	2,238.07	807.00	0.88	0.90	0.98	0.00	55.34
2002:08	2,245.61	807.00	0.88	0.90	0.98	0.00	55.53
2002:09	2,253.16	807.00	0.88	0.90	0.98	1.00	55.71
2002:10	2,260.71	807.00	0.88	0.90	0.98	0.00	55.89
2002:11	2,268.26	807.00	0.88	0.90	0.98	0.00	56.08
2002:12	2,275.81	807.00	0.88	0.90	0.98	0.00	56.26
2003:01	2,283.36	807.00	0.88	0.90	0.98	0.00	56.45
2003:02	2,290.91	807.00	0.88	0.90	0.98	0.00	56.63
2003:03	2,298.45	807.00	0.88	0.90	0.98	0.00	56.81
2003:04	2,306.00	807.00	0.88	0.90	0.98	0.00	57.00
2003:05	2,313.55	807.00	0.88	0.90	0.98	0.00	57.18
2003:06	2,321.10	807.00	0.88	0.90	0.98	0.00	57.36
2003:07	2,328.96	807.00	0.88	0.90	0.98	0.00	57.56
2003:08	2,336.81	807.00	0.88	0.90	0.98	0.00	57.75
2003:09	2,344.67	807.00	0.88	0.90	0.98	1.00	57.94
2003:10	2,352.52	807.00	0.88	0.90	0.98	0.00	58.13
2003:11	2,360.38	807.00	0.88	0.90	0.98	0.00	58.32
2003:12	2,368.23	807.00	0.88	0.90	0.98	0.00	58.51
2004:01	2,376.09	807.00	0.88	0.90	0.98	0.00	58.70
2004:02	2,383.94	807.00	0.88	0.90	0.98	0.00	58.89
2004:03	2,391.80	807.00	0.88	0.90	0.98	0.00	59.09
2004:04	2,399.65	807.00	0.88	0.90	0.98	0.00	59.28
2004:05	2,407.51	807.00	0.88	0.90	0.98	0.00	59.47
2004:06	2,415.36	807.00	0.88	0.90	0.98	0.00	59.66
2004:07	2,423.54	807.00	0.88	0.90	0.98	0.00	59.86
2004:08	2,431.71	807.00	0.88	0.90	0.98	0.00	60.06
2004:09	2,439.88	807.00	0.88	0.90	0.98	1.00	60.26
2004:10	2,448.06	807.00	0.88	0.90	0.98	0.00	60.46
2004:11	2,456.23	807.00	0.88	0.90	0.98	0.00	60.65
2004:12	2,464.41	807.00	0.88	0.90	0.98	0.00	60.85
2005:01	2,472.58	807.00	0.88	0.90	0.98	0.00	61.05
2005:02	2,480.75	807.00	0.88	0.90	0.98	0.00	61.25
2005:03	2,488.93	807.00	0.88	0.90	0.98	0.00	61.45
2005:04	2,497.10	807.00	0.88	0.90	0.98	0.00	61.65



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
2005:05	2,505.28	807.00	0.88	0.90	0.98	0.00	61.85
2005:06	2,513.45	807.00	0.88	0.90	0.98	0.00	62.05
2005:07	2,522.79	807.00	0.88	0.90	0.98	0.00	62.22
2005:08	2,532.14	807.00	0.88	0.90	0.98	0.00	62.40
2005:09	2,541.48	807.00	0.88	0.90	0.98	1.00	62.57
2005:10	2,550.83	807.00	0.88	0.90	0.98	0.00	62.75
2005:11	2,560.17	807.00	0.88	0.90	0.98	0.00	62.92
2005:12	2,569.52	807.00	0.88	0.90	0.98	0.00	63.10
2006:01	2,578.86	807.00	0.88	0.90	0.98	0.00	63.28
2006:02	2,588.21	807.00	0.88	0.90	0.98	0.00	63.45
2006:03	2,597.55	807.00	0.88	0.90	0.98	0.00	63.63
2006:04	2,606.90	807.00	0.88	0.90	0.98	0.00	63.80
2006:05	2,616.24	807.00	0.88	0.90	0.98	0.00	63.98
2006:06	2,625.59	807.00	0.88	0.90	0.98	0.00	64.15
2006:07	2,635.35	807.00	0.88	0.90	0.98	0.00	64.34
2006:08	2,645.11	807.00	0.88	0.90	0.98	0.00	64.52
2006:09	2,654.87	807.00	0.88	0.90	0.98	1.00	64.70
2006:10	2,664.64	807.00	0.88	0.90	0.98	0.00	64.88
2006:11	2,674.40	807.00	0.88	0.90	0.98	0.00	65.06
2006:12	2,684.16	807.00	0.88	0.90	0.98	0.00	65.24
2007:01	2,693.92	807.00	0.88	0.90	0.98	0.00	65.43
2007:02	2,703.68	807.00	0.88	0.90	0.98	0.00	65.61
2007:03	2,713.45	807.00	0.88	0.90	0.98	0.00	65.79
2007:04	2,723.21	807.00	0.88	0.90	0.98	0.00	65.97
2007:05	2,732.97	807.00	0.88	0.90	0.98	0.00	66.15
2007:06	2,742.73	807.00	0.88	0.90	0.98	0.00	66.33
2007:07	2,752.93	807.00	0.88	0.90	0.98	0.00	66.52
2007:08	2,763.13	807.00	0.88	0.90	0.98	0.00	66.71
2007:09	2,773.32	807.00	0.88	0.90	0.98	1.00	66.90
2007:10	2,783.52	807.00	0.88	0.90	0.98	0.00	67.08
2007:11	2,793.72	807.00	0.88	0.90	0.98	0.00	67.27
2007:12	2,803.92	807.00	0.88	0.90	0.98	0.00	67.46
2008:01	2,814.11	807.00	0.88	0.90	0.98	0.00	67.65
2008:02	2,824.31	807.00	0.88	0.90	0.98	0.00	67.84
2008:03	2,834.51	807.00	0.88	0.90	0.98	0.00	68.02
2008:04	2,844.71	807.00	0.88	0.90	0.98	0.00	68.21
2008:05	2,854.90	807.00	0.88	0.90	0.98	0.00	68.40
2008:06	2,865.10	807.00	0.88	0.90	0.98	0.00	68.59
2008:07	2,875.75	807.00	0.88	0.90	0.98	0.00	68.78



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
2008:08	2,886.40	807.00	0.88	0.90	0.98	0.00	68.98
2008:09	2,897.06	807.00	0.88	0.90	0.98	1.00	69.17
2008:10	2,907.71	807.00	0.88	0.90	0.98	0.00	69.36
2008:11	2,918.36	807.00	0.88	0.90	0.98	0.00	69.56
2008:12	2,929.01	807.00	0.88	0.90	0.98	0.00	69.75
2009:01	2,939.67	807.00	0.88	0.90	0.98	0.00	69.95
2009:02	2,950.32	807.00	0.88	0.90	0.98	0.00	70.14
2009:03	2,960.97	807.00	0.88	0.90	0.98	0.00	70.34
2009:04	2,971.62	807.00	0.88	0.90	0.98	0.00	70.53
2009:05	2,982.28	807.00	0.88	0.90	0.98	0.00	70.72
2009:06	2,992.93	807.00	0.88	0.90	0.98	0.00	70.92
2009:07	3,004.06	807.00	0.88	0.90	0.98	0.00	71.12
2009:08	3,015.18	807.00	0.88	0.90	0.98	0.00	71.32
2009:09	3,026.31	807.00	0.88	0.90	0.98	1.00	71.52
2009:10	3,037.44	807.00	0.88	0.90	0.98	0.00	71.72
2009:11	3,048.57	807.00	0.88	0.90	0.98	0.00	71.92
2009:12	3,059.69	807.00	0.88	0.90	0.98	0.00	72.12
2010:01	3,070.82	807.00	0.88	0.90	0.98	0.00	72.32
2010:02	3,081.95	807.00	0.88	0.90	0.98	0.00	72.52
2010:03	3,093.08	807.00	0.88	0.90	0.98	0.00	72.72
2010:04	3,104.20	807.00	0.88	0.90	0.98	0.00	72.93
2010:05	3,115.33	807.00	0.88	0.90	0.98	0.00	73.13
2010:06	3,126.46	807.00	0.88	0.90	0.98	0.00	73.33
2010:07	3,137.05	807.00	0.88	0.90	0.98	0.00	73.52
2010:08	3,147.65	807.00	0.88	0.90	0.98	0.00	73.71
2010:09	3,158.24	807.00	0.88	0.90	0.98	1.00	73.89
2010:10	3,168.84	807.00	0.88	0.90	0.98	0.00	74.08
2010:11	3,179.43	807.00	0.88	0.90	0.98	0.00	74.27
2010:12	3,190.02	807.00	0.88	0.90	0.98	0.00	74.46
2011:01	3,200.62	807.00	0.88	0.90	0.98	0.00	74.65
2011:02	3,211.21	807.00	0.88	0.90	0.98	0.00	74.84
2011:03	3,221.81	807.00	0.88	0.90	0.98	0.00	75.03
2011:04	3,232.40	807.00	0.88	0.90	0.98	0.00	75.22
2011:05	3,242.99	807.00	0.88	0.90	0.98	0.00	75.41
2011:06	3,253.59	807.00	0.88	0.90	0.98	0.00	75.60
2011:07	3,264.61	807.00	0.88	0.90	0.98	0.00	75.79
2011:08	3,275.64	807.00	0.88	0.90	0.98	0.00	75.99
2011:09	3,286.66	807.00	0.88	0.90	0.98	1.00	76.18
2011:10	3,297.69	807.00	0.88	0.90	0.98	0.00	76.38



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
2011:11	3,308.71	807.00	0.88	0.90	0.98	0.00	76.57
2011:12	3,319.74	807.00	0.88	0.90	0.98	0.00	76.77
2012:01	3,330.76	807.00	0.88	0.90	0.98	0.00	76.96
2012:02	3,341.79	807.00	0.88	0.90	0.98	0.00	77.16
2012:03	3,352.81	807.00	0.88	0.90	0.98	0.00	77.35
2012:04	3,363.84	807.00	0.88	0.90	0.98	0.00	77.55
2012:05	3,374.86	807.00	0.88	0.90	0.98	0.00	77.74
2012:06	3,385.89	807.00	0.88	0.90	0.98	0.00	77.94
2012:07	3,397.36	807.00	0.88	0.90	0.98	0.00	78.14
2012:08	3,408.83	807.00	0.88	0.90	0.98	0.00	78.34
2012:09	3,420.31	807.00	0.88	0.90	0.98	1.00	78.54
2012:10	3,431.78	807.00	0.88	0.90	0.98	0.00	78.74
2012:11	3,443.25	807.00	0.88	0.90	0.98	0.00	78.94
2012:12	3,454.72	807.00	0.88	0.90	0.98	0.00	79.14
2013:01	3,466.20	807.00	0.88	0.90	0.98	0.00	79.35
2013:02	3,477.67	807.00	0.88	0.90	0.98	0.00	79.55
2013:03	3,489.14	807.00	0.88	0.90	0.98	0.00	79.75
2013:04	3,500.62	807.00	0.88	0.90	0.98	0.00	79.95
2013:05	3,512.09	807.00	0.88	0.90	0.98	0.00	80.15
2013:06	3,523.56	807.00	0.88	0.90	0.98	0.00	80.35
2013:07	3,535.50	807.00	0.88	0.90	0.98	0.00	80.56
2013:08	3,547.44	807.00	0.88	0.90	0.98	0.00	80.77
2013:09	3,559.38	807.00	0.88	0.90	0.98	1.00	80.97
2013:10	3,571.32	807.00	0.88	0.90	0.98	0.00	81.18
2013:11	3,583.26	807.00	0.88	0.90	0.98	0.00	81.39
2013:12	3,595.20	807.00	0.88	0.90	0.98	0.00	81.60
2014:01	3,607.14	807.00	0.88	0.90	0.98	0.00	81.80
2014:02	3,619.08	807.00	0.88	0.90	0.98	0.00	82.01
2014:03	3,631.02	807.00	0.88	0.90	0.98	0.00	82.22
2014:04	3,642.96	807.00	0.88	0.90	0.98	0.00	82.43
2014:05	3,654.90	807.00	0.88	0.90	0.98	0.00	82.63
2014:06	3,666.84	807.00	0.88	0.90	0.98	0.00	82.84
2014:07	3,679.26	807.00	0.88	0.90	0.98	0.00	83.05
2014:08	3,691.69	807.00	0.88	0.90	0.98	0.00	83.27
2014:09	3,704.11	807.00	0.88	0.90	0.98	1.00	83.48
2014:10	3,716.54	807.00	0.88	0.90	0.98	0.00	83.69
2014:11	3,728.96	807.00	0.88	0.90	0.98	0.00	83.91
2014:12	3,741.39	807.00	0.88	0.90	0.98	0.00	84.12
2015:01	3,753.81	807.00	0.88	0.90	0.98	0.00	84.34



Historical and Projected Energy and Demand Forecast Variables

Year/Month	RYTOT	SATURATE	SAT_APPL	SAT_HEAT	SAT_RFRG	SEP	SERVICES
2015:02	3,766.24	807.00	0.88	0.90	0.98	0.00	84.55
2015:03	3,778.66	807.00	0.88	0.90	0.98	0.00	84.76
2015:04	3,791.09	807.00	0.88	0.90	0.98	0.00	84.98
2015:05	3,803.51	807.00	0.88	0.90	0.98	0.00	85.19
2015:06	3,815.94	807.00	0.88	0.90	0.98	0.00	85.40
2015:07	3,827.63	807.00	0.88	0.90	0.98	0.00	85.60
2015:08	3,839.31	807.00	0.88	0.90	0.98	0.00	85.80
2015:09	3,851.00	807.00	0.88	0.90	0.98	1.00	86.00
2015:10	3,862.69	807.00	0.88	0.90	0.98	0.00	86.20
2015:11	3,874.37	807.00	0.88	0.90	0.98	0.00	86.40
2015:12	3,886.06	807.00	0.88	0.90	0.98	0.00	86.60
2016:01	3,897.74	807.00	0.88	0.90	0.98	0.00	86.80
2016:02	3,909.43	807.00	0.88	0.90	0.98	0.00	87.00
2016:03	3,921.12	807.00	0.88	0.90	0.98	0.00	87.20
2016:04	3,932.80	807.00	0.88	0.90	0.98	0.00	87.40
2016:05	3,944.49	807.00	0.88	0.90	0.98	0.00	87.60
2016:06	3,956.18	807.00	0.88	0.90	0.98	0.00	87.79
2016:07	3,968.29	807.00	0.88	0.90	0.98	0.00	88.00
2016:08	3,980.41	807.00	0.88	0.90	0.98	0.00	88.20
2016:09	3,992.52	807.00	0.88	0.90	0.98	1.00	88.41
2016:10	4,004.64	807.00	0.88	0.90	0.98	0.00	88.61
2016:11	4,016.76	807.00	0.88	0.90	0.98	0.00	88.82
2016:12	4,028.87	807.00	0.88	0.90	0.98	0.00	89.02

Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
1985:01	0.00	1.00	18.72	857.58	3.52	23.54	28.52
1985:02	0.00	2.00	18.85	867.71	3.53	23.70	28.73



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
1985:03	0.00	3.00	18.98	877.85	3.54	23.86	28.94
1985:04	0.00	4.00	19.12	887.98	3.55	24.02	29.14
1985:05	0.00	5.00	19.25	898.11	3.56	24.18	29.35
1985:06	0.00	6.00	19.38	908.24	3.57	24.34	29.56
1985:07	0.00	7.00	19.58	918.34	3.59	24.55	29.71
1985:08	0.00	8.00	19.77	928.44	3.61	24.76	29.86
1985:09	0.00	9.00	19.96	938.54	3.63	24.98	30.01
1985:10	0.00	10.00	20.16	948.63	3.65	25.19	30.16
1985:11	0.00	11.00	20.35	958.73	3.67	25.40	30.31
1985:12	0.00	12.00	20.55	968.83	3.69	25.61	30.46
1986:01	0.00	13.00	20.74	978.93	3.71	25.82	30.61
1986:02	0.00	14.00	20.93	989.03	3.73	26.03	30.76
1986:03	0.00	15.00	21.13	999.13	3.75	26.25	30.91
1986:04	0.00	16.00	21.32	1,009.23	3.77	26.46	31.07
1986:05	0.00	17.00	21.52	1,019.33	3.78	26.67	31.22
1986:06	0.00	18.00	21.71	1,029.43	3.80	26.88	31.37
1986:07	0.00	19.00	21.95	1,040.07	3.83	27.12	31.54
1986:08	0.00	20.00	22.19	1,050.71	3.85	27.36	31.71
1986:09	0.00	21.00	22.43	1,061.35	3.88	27.60	31.88
1986:10	0.00	22.00	22.67	1,071.99	3.90	27.84	32.05
1986:11	0.00	23.00	22.90	1,082.63	3.92	28.08	32.22
1986:12	0.00	24.00	23.14	1,093.27	3.95	28.32	32.39
1987:01	0.00	25.00	23.38	1,103.91	3.97	28.56	32.56
1987:02	0.00	26.00	23.62	1,114.55	3.99	28.80	32.73
1987:03	0.00	27.00	23.86	1,125.20	4.02	29.04	32.90
1987:04	0.00	28.00	24.10	1,135.84	4.04	29.28	33.07
1987:05	0.00	29.00	24.34	1,146.48	4.07	29.52	33.24
1987:06	0.00	30.00	24.58	1,157.12	4.09	29.76	33.41
1987:07	0.00	31.00	24.95	1,168.69	4.14	30.00	33.57
1987:08	0.00	32.00	25.32	1,180.27	4.19	30.25	33.73
1987:09	0.00	33.00	25.70	1,191.84	4.25	30.50	33.90
1987:10	0.00	34.00	26.07	1,203.42	4.30	30.75	34.06
1987:11	0.00	35.00	26.45	1,214.99	4.35	30.99	34.23
1987:12	0.00	36.00	26.82	1,226.57	4.40	31.24	34.39
1988:01	0.00	37.00	27.19	1,238.14	4.45	31.49	34.55
1988:02	0.00	38.00	27.57	1,249.72	4.51	31.73	34.72
1988:03	0.00	39.00	27.94	1,261.29	4.56	31.98	34.88
1988:04	0.00	40.00	28.32	1,272.87	4.61	32.23	35.05
1988:05	0.00	41.00	28.69	1,284.44	4.66	32.48	35.21



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
1988:06	0.00	42.00	29.06	1,296.02	4.71	32.72	35.37
1988:07	0.00	43.00	29.39	1,308.85	4.73	32.96	35.50
1988:08	0.00	44.00	29.72	1,321.69	4.75	33.20	35.63
1988:09	0.00	45.00	30.05	1,334.52	4.77	33.44	35.75
1988:10	0.00	46.00	30.38	1,347.36	4.79	33.67	35.88
1988:11	0.00	47.00	30.71	1,360.19	4.80	33.91	36.01
1988:12	0.00	48.00	31.04	1,373.03	4.82	34.15	36.13
1989:01	0.00	49.00	31.37	1,385.86	4.84	34.39	36.26
1989:02	0.00	50.00	31.70	1,398.70	4.86	34.62	36.39
1989:03	0.00	51.00	32.03	1,411.53	4.88	34.86	36.52
1989:04	0.00	52.00	32.36	1,424.37	4.89	35.10	36.64
1989:05	0.00	53.00	32.69	1,437.21	4.91	35.34	36.77
1989:06	0.00	54.00	33.02	1,450.04	4.93	35.57	36.90
1989:07	0.00	55.00	33.35	1,461.28	4.90	35.71	37.14
1989:08	0.00	56.00	33.68	1,472.52	4.88	35.84	37.39
1989:09	0.00	57.00	34.01	1,483.76	4.85	35.98	37.64
1989:10	0.00	58.00	34.34	1,494.99	4.83	36.11	37.89
1989:11	0.00	59.00	34.67	1,506.23	4.80	36.25	38.14
1989:12	1.00	60.00	34.99	1,517.47	4.77	36.38	38.39
1990:01	0.00	61.00	35.32	1,528.71	4.75	36.52	38.64
1990:02	0.00	62.00	35.65	1,539.95	4.72	36.65	38.89
1990:03	0.00	63.00	35.98	1,551.18	4.70	36.79	39.14
1990:04	0.00	64.00	36.31	1,562.42	4.67	36.92	39.38
1990:05	0.00	65.00	36.64	1,573.66	4.64	37.06	39.63
1990:06	0.00	66.00	36.97	1,584.90	4.62	37.19	39.88
1990:07	0.00	67.00	37.15	1,592.52	4.58	37.15	40.08
1990:08	0.00	68.00	37.33	1,600.14	4.54	37.12	40.28
1990:09	0.00	69.00	37.51	1,607.76	4.50	37.08	40.48
1990:10	0.00	70.00	37.69	1,615.38	4.46	37.04	40.68
1990:11	0.00	71.00	37.87	1,623.00	4.43	37.00	40.88
1990:12	0.00	72.00	38.05	1,630.62	4.39	36.97	41.08
1991:01	0.00	73.00	38.23	1,638.25	4.35	36.93	41.28
1991:02	0.00	74.00	38.41	1,645.87	4.31	36.89	41.48
1991:03	0.00	75.00	38.60	1,653.49	4.27	36.86	41.68
1991:04	0.00	76.00	38.78	1,661.11	4.23	36.82	41.88
1991:05	0.00	77.00	38.96	1,668.73	4.20	36.78	42.08
1991:06	0.00	78.00	39.14	1,676.35	4.16	36.74	42.28
1991:07	0.00	79.00	39.37	1,688.17	4.15	36.89	42.43
1991:08	0.00	80.00	39.61	1,699.99	4.14	37.03	42.59



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
1991:09	0.00	81.00	39.84	1,711.81	4.13	37.17	42.75
1991:10	0.00	82.00	40.08	1,723.63	4.12	37.31	42.90
1991:11	0.00	83.00	40.31	1,735.45	4.11	37.45	43.06
1991:12	0.00	84.00	40.54	1,747.27	4.10	37.60	43.21
1992:01	0.00	85.00	40.78	1,759.09	4.09	37.74	43.37
1992:02	0.00	86.00	41.01	1,770.91	4.08	37.88	43.52
1992:03	0.00	87.00	41.25	1,782.73	4.07	38.02	43.68
1992:04	0.00	88.00	41.48	1,794.55	4.07	38.16	43.83
1992:05	0.00	89.00	41.72	1,806.36	4.06	38.31	43.99
1992:06	0.00	90.00	41.95	1,818.18	4.05	38.45	44.15
1992:07	0.00	91.00	42.19	1,828.25	4.06	38.69	44.33
1992:08	0.00	92.00	42.43	1,838.32	4.07	38.93	44.51
1992:09	0.00	93.00	42.67	1,848.39	4.08	39.18	44.69
1992:10	0.00	94.00	42.92	1,858.46	4.09	39.42	44.87
1992:11	0.00	95.00	43.16	1,868.53	4.10	39.66	45.06
1992:12	0.00	96.00	43.40	1,878.60	4.11	39.91	45.24
1993:01	0.00	97.00	43.64	1,888.67	4.11	40.15	45.42
1993:02	0.00	98.00	43.88	1,898.73	4.12	40.39	45.60
1993:03	0.00	99.00	44.12	1,908.80	4.13	40.64	45.78
1993:04	0.00	100.00	44.37	1,918.87	4.14	40.88	45.97
1993:05	0.00	101.00	44.61	1,928.94	4.15	41.12	46.15
1993:06	0.00	102.00	44.85	1,939.01	4.16	41.37	46.33
1993:07	0.00	103.00	45.03	1,948.24	4.16	41.48	46.50
1993:08	0.00	104.00	45.20	1,957.48	4.17	41.60	46.67
1993:09	0.00	105.00	45.38	1,966.72	4.17	41.72	46.83
1993:10	0.00	106.00	45.56	1,975.95	4.17	41.83	47.00
1993:11	0.00	107.00	45.73	1,985.19	4.17	41.95	47.17
1993:12	0.00	108.00	45.91	1,994.42	4.17	42.06	47.33
1994:01	0.00	109.00	46.09	2,003.66	4.17	42.18	47.50
1994:02	0.00	110.00	46.26	2,012.90	4.17	42.29	47.67
1994:03	0.00	111.00	46.44	2,022.13	4.18	42.41	47.83
1994:04	0.00	112.00	46.62	2,031.37	4.18	42.53	48.00
1994:05	0.00	113.00	46.79	2,040.60	4.18	42.64	48.17
1994:06	0.00	114.00	46.97	2,049.84	4.18	42.76	48.34
1994:07	0.00	115.00	47.11	2,063.61	4.17	43.03	48.49
1994:08	0.00	116.00	47.26	2,077.38	4.16	43.29	48.64
1994:09	0.00	117.00	47.41	2,091.16	4.16	43.56	48.80
1994:10	0.00	118.00	47.55	2,104.93	4.15	43.83	48.95
1994:11	0.00	119.00	47.70	2,118.70	4.14	44.10	49.10



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
1994:12	0.00	120.00	47.84	2,132.47	4.14	44.37	49.26
1995:01	0.00	121.00	47.99	2,146.24	4.13	44.64	49.41
1995:02	0.00	122.00	48.13	2,160.02	4.12	44.90	49.56
1995:03	0.00	123.00	48.28	2,173.79	4.11	45.17	49.71
1995:04	0.00	124.00	48.43	2,187.56	4.11	45.44	49.87
1995:05	0.00	125.00	48.57	2,201.33	4.10	45.71	50.02
1995:06	0.00	126.00	48.72	2,215.11	4.09	45.98	50.17
1995:07	0.00	127.00	48.87	2,228.35	4.11	46.32	50.47
1995:08	0.00	128.00	49.03	2,241.59	4.12	46.67	50.76
1995:09	0.00	129.00	49.18	2,254.83	4.14	47.01	51.06
1995:10	0.00	130.00	49.34	2,268.07	4.15	47.36	51.35
1995:11	0.00	131.00	49.49	2,281.31	4.17	47.70	51.65
1995:12	0.00	132.00	49.64	2,294.55	4.18	48.04	51.94
1996:01	0.00	133.00	49.80	2,307.79	4.20	48.39	52.23
1996:02	0.00	134.00	49.95	2,321.03	4.22	48.73	52.53
1996:03	0.00	135.00	50.11	2,334.27	4.23	49.08	52.82
1996:04	0.00	136.00	50.26	2,347.51	4.25	49.42	53.12
1996:05	0.00	137.00	50.42	2,360.75	4.26	49.77	53.41
1996:06	0.00	138.00	50.57	2,373.99	4.28	50.11	53.71
1996:07	0.00	139.00	50.74	2,388.18	4.29	50.49	54.02
1996:08	0.00	140.00	50.90	2,402.37	4.31	50.86	54.34
1996:09	0.00	141.00	51.06	2,416.56	4.33	51.24	54.65
1996:10	0.00	142.00	51.23	2,430.75	4.34	51.61	54.97
1996:11	0.00	143.00	51.39	2,444.94	4.36	51.99	55.28
1996:12	0.00	144.00	51.55	2,459.13	4.37	52.37	55.60
1997:01	0.00	145.00	51.72	2,473.32	4.39	52.74	55.91
1997:02	0.00	146.00	51.88	2,487.51	4.41	53.12	56.23
1997:03	0.00	147.00	52.05	2,501.70	4.42	53.49	56.54
1997:04	0.00	148.00	52.21	2,515.89	4.44	53.87	56.86
1997:05	0.00	149.00	52.37	2,530.08	4.46	54.25	57.17
1997:06	0.00	150.00	52.54	2,544.27	4.47	54.62	57.49
1997:07	0.00	151.00	52.71	2,559.48	4.49	55.03	57.82
1997:08	0.00	152.00	52.89	2,574.69	4.51	55.44	58.16
1997:09	0.00	153.00	53.06	2,589.90	4.52	55.85	58.50
1997:10	0.00	154.00	53.23	2,605.10	4.54	56.26	58.84
1997:11	0.00	155.00	53.41	2,620.31	4.56	56.67	59.17
1997:12	0.00	156.00	53.58	2,635.52	4.57	57.08	59.51
1998:01	0.00	157.00	53.75	2,650.73	4.59	57.49	59.85
1998:02	0.00	158.00	53.93	2,665.93	4.61	57.90	60.19



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
1998:03	0.00	159.00	54.10	2,681.14	4.62	58.31	60.52
1998:04	0.00	160.00	54.28	2,696.35	4.64	58.72	60.86
1998:05	0.00	161.00	54.45	2,711.56	4.66	59.13	61.20
1998:06	0.00	162.00	54.62	2,726.77	4.67	59.54	61.53
1998:07	0.00	163.00	54.81	2,743.06	4.69	59.99	61.90
1998:08	0.00	164.00	54.99	2,759.36	4.71	60.44	62.26
1998:09	0.00	165.00	55.18	2,775.66	4.73	60.89	62.62
1998:10	0.00	166.00	55.36	2,791.96	4.75	61.34	62.98
1998:11	0.00	167.00	55.55	2,808.26	4.76	61.78	63.34
1998:12	0.00	168.00	55.73	2,824.56	4.78	62.23	63.70
1999:01	0.00	169.00	55.91	2,840.86	4.80	62.68	64.06
1999:02	0.00	170.00	56.10	2,857.16	4.82	63.13	64.42
1999:03	0.00	171.00	56.28	2,873.45	4.83	63.57	64.78
1999:04	0.00	172.00	56.47	2,889.75	4.85	64.02	65.14
1999:05	0.00	173.00	56.65	2,906.05	4.87	64.47	65.51
1999:06	0.00	174.00	56.84	2,922.35	4.89	64.92	65.87
1999:07	0.00	175.00	57.03	2,939.82	4.91	65.41	66.25
1999:08	0.00	176.00	57.23	2,957.29	4.92	65.90	66.64
1999:09	0.00	177.00	57.42	2,974.75	4.94	66.38	67.03
1999:10	0.00	178.00	57.62	2,992.22	4.96	66.87	67.41
1999:11	0.00	179.00	57.81	3,009.69	4.98	67.36	67.80
1999:12	0.00	180.00	58.01	3,027.16	5.00	67.85	68.19
2000:01	0.00	181.00	58.21	3,044.62	5.02	68.34	68.57
2000:02	0.00	182.00	58.40	3,062.09	5.03	68.83	68.96
2000:03	0.00	183.00	58.60	3,079.56	5.05	69.32	69.34
2000:04	0.00	184.00	58.79	3,097.03	5.07	69.80	69.73
2000:05	0.00	185.00	58.99	3,114.50	5.09	70.29	70.12
2000:06	0.00	186.00	59.18	3,131.96	5.11	70.78	70.50
2000:07	0.00	187.00	59.38	3,151.49	5.13	71.17	70.82
2000:08	0.00	188.00	59.58	3,171.01	5.15	71.57	71.14
2000:09	0.00	189.00	59.78	3,190.54	5.17	71.96	71.45
2000:10	0.00	190.00	59.98	3,210.06	5.20	72.35	71.77
2000:11	0.00	191.00	60.18	3,229.59	5.22	72.75	72.08
2000:12	0.00	192.00	60.38	3,249.11	5.24	73.14	72.40
2001:01	0.00	193.00	60.58	3,268.63	5.26	73.53	72.72
2001:02	0.00	194.00	60.78	3,288.16	5.29	73.92	73.03
2001:03	0.00	195.00	60.97	3,307.68	5.31	74.32	73.35
2001:04	0.00	196.00	61.17	3,327.21	5.33	74.71	73.67
2001:05	0.00	197.00	61.37	3,346.73	5.35	75.10	73.98



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
2001:06	0.00	198.00	61.57	3,366.26	5.37	75.49	74.30
2001:07	0.00	199.00	61.77	3,387.24	5.40	75.91	74.63
2001:08	0.00	200.00	61.98	3,408.23	5.42	76.33	74.96
2001:09	0.00	201.00	62.18	3,429.21	5.44	76.75	75.30
2001:10	0.00	202.00	62.38	3,450.20	5.47	77.17	75.63
2001:11	0.00	203.00	62.58	3,471.18	5.49	77.59	75.96
2001:12	0.00	204.00	62.78	3,492.17	5.51	78.01	76.30
2002:01	0.00	205.00	62.99	3,513.15	5.54	78.42	76.63
2002:02	0.00	206.00	63.19	3,534.14	5.56	78.84	76.96
2002:03	0.00	207.00	63.39	3,555.12	5.58	79.26	77.30
2002:04	0.00	208.00	63.59	3,576.11	5.61	79.68	77.63
2002:05	0.00	209.00	63.80	3,597.09	5.63	80.10	77.96
2002:06	0.00	210.00	64.00	3,618.08	5.65	80.52	78.30
2002:07	0.00	211.00	64.20	3,640.63	5.68	80.97	78.65
2002:08	0.00	212.00	64.41	3,663.19	5.70	81.41	79.00
2002:09	0.00	213.00	64.62	3,685.74	5.73	81.86	79.35
2002:10	0.00	214.00	64.82	3,708.29	5.75	82.31	79.70
2002:11	0.00	215.00	65.03	3,730.85	5.78	82.75	80.05
2002:12	0.00	216.00	65.23	3,753.40	5.80	83.20	80.40
2003:01	0.00	217.00	65.44	3,775.96	5.83	83.65	80.75
2003:02	0.00	218.00	65.64	3,798.51	5.85	84.09	81.11
2003:03	0.00	219.00	65.85	3,821.07	5.87	84.54	81.46
2003:04	0.00	220.00	66.06	3,843.62	5.90	84.99	81.81
2003:05	0.00	221.00	66.26	3,866.18	5.92	85.43	82.16
2003:06	0.00	222.00	66.47	3,888.73	5.95	85.88	82.51
2003:07	0.00	223.00	66.68	3,912.98	5.97	86.36	82.88
2003:08	0.00	224.00	66.89	3,937.22	6.00	86.83	83.25
2003:09	0.00	225.00	67.10	3,961.46	6.03	87.31	83.62
2003:10	0.00	226.00	67.30	3,985.70	6.05	87.79	83.99
2003:11	0.00	227.00	67.51	4,009.94	6.08	88.26	84.36
2003:12	0.00	228.00	67.72	4,034.19	6.10	88.74	84.73
2004:01	0.00	229.00	67.93	4,058.43	6.13	89.22	85.10
2004:02	0.00	230.00	68.14	4,082.67	6.15	89.69	85.47
2004:03	0.00	231.00	68.35	4,106.91	6.18	90.17	85.84
2004:04	0.00	232.00	68.56	4,131.15	6.21	90.65	86.21
2004:05	0.00	233.00	68.77	4,155.40	6.23	91.12	86.58
2004:06	0.00	234.00	68.98	4,179.64	6.26	91.60	86.95
2004:07	0.00	235.00	69.19	4,205.69	6.28	92.11	87.34
2004:08	0.00	236.00	69.40	4,231.75	6.31	92.62	87.73



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
2004:09	0.00	237.00	69.62	4,257.80	6.34	93.13	88.12
2004:10	0.00	238.00	69.83	4,283.86	6.37	93.64	88.51
2004:11	0.00	239.00	70.04	4,309.92	6.39	94.14	88.90
2004:12	0.00	240.00	70.26	4,335.97	6.42	94.65	89.29
2005:01	0.00	241.00	70.47	4,362.03	6.45	95.16	89.68
2005:02	0.00	242.00	70.68	4,388.08	6.47	95.67	90.07
2005:03	0.00	243.00	70.89	4,414.14	6.50	96.18	90.46
2005:04	0.00	244.00	71.11	4,440.19	6.53	96.69	90.85
2005:05	0.00	245.00	71.32	4,466.25	6.56	97.20	91.24
2005:06	0.00	246.00	71.53	4,492.30	6.58	97.70	91.63
2005:07	0.00	247.00	71.75	4,522.32	6.61	98.10	92.00
2005:08	0.00	248.00	71.96	4,552.34	6.63	98.49	92.37
2005:09	0.00	249.00	72.17	4,582.35	6.66	98.88	92.75
2005:10	0.00	250.00	72.38	4,612.37	6.69	99.27	93.12
2005:11	0.00	251.00	72.60	4,642.39	6.71	99.66	93.49
2005:12	0.00	252.00	72.81	4,672.40	6.74	100.05	93.86
2006:01	0.00	253.00	73.02	4,702.42	6.76	100.45	94.24
2006:02	0.00	254.00	73.24	4,732.44	6.79	100.84	94.61
2006:03	0.00	255.00	73.45	4,762.45	6.82	101.23	94.98
2006:04	0.00	256.00	73.66	4,792.47	6.84	101.62	95.35
2006:05	0.00	257.00	73.87	4,822.48	6.87	102.01	95.73
2006:06	0.00	258.00	74.09	4,852.50	6.89	102.40	96.10
2006:07	0.00	259.00	74.30	4,884.92	6.92	102.81	96.49
2006:08	0.00	260.00	74.51	4,917.35	6.95	103.23	96.88
2006:09	0.00	261.00	74.73	4,949.77	6.97	103.64	97.27
2006:10	0.00	262.00	74.94	4,982.19	7.00	104.05	97.66
2006:11	0.00	263.00	75.15	5,014.62	7.03	104.46	98.05
2006:12	0.00	264.00	75.36	5,047.04	7.06	104.87	98.44
2007:01	0.00	265.00	75.58	5,079.46	7.08	105.28	98.83
2007:02	0.00	266.00	75.79	5,111.89	7.11	105.69	99.22
2007:03	0.00	267.00	76.00	5,144.31	7.14	106.10	99.61
2007:04	0.00	268.00	76.22	5,176.73	7.16	106.51	100.00
2007:05	0.00	269.00	76.43	5,209.16	7.19	106.92	100.39
2007:06	0.00	270.00	76.64	5,241.58	7.22	107.33	100.79
2007:07	0.00	271.00	76.86	5,276.60	7.25	107.76	101.20
2007:08	0.00	272.00	77.07	5,311.63	7.28	108.19	101.60
2007:09	0.00	273.00	77.28	5,346.65	7.30	108.62	102.01
2007:10	0.00	274.00	77.49	5,381.67	7.33	109.06	102.42
2007:11	0.00	275.00	77.71	5,416.69	7.36	109.49	102.83



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
2007:12	0.00	276.00	77.92	5,451.72	7.39	109.92	103.24
2008:01	0.00	277.00	78.13	5,486.74	7.42	110.35	103.65
2008:02	0.00	278.00	78.35	5,521.76	7.45	110.78	104.06
2008:03	0.00	279.00	78.56	5,556.79	7.47	111.21	104.47
2008:04	0.00	280.00	78.77	5,591.81	7.50	111.64	104.88
2008:05	0.00	281.00	78.99	5,626.83	7.53	112.07	105.29
2008:06	0.00	282.00	79.20	5,661.85	7.56	112.50	105.70
2008:07	0.00	283.00	79.41	5,699.69	7.59	112.95	106.13
2008:08	0.00	284.00	79.62	5,737.52	7.62	113.40	106.56
2008:09	0.00	285.00	79.84	5,775.35	7.65	113.86	106.99
2008:10	0.00	286.00	80.05	5,813.18	7.68	114.31	107.42
2008:11	0.00	287.00	80.26	5,851.01	7.71	114.76	107.85
2008:12	0.00	288.00	80.48	5,888.84	7.74	115.21	108.28
2009:01	0.00	289.00	80.69	5,926.67	7.77	115.66	108.71
2009:02	0.00	290.00	80.90	5,964.50	7.80	116.12	109.14
2009:03	0.00	291.00	81.12	6,002.33	7.83	116.57	109.57
2009:04	0.00	292.00	81.33	6,040.17	7.86	117.02	110.00
2009:05	0.00	293.00	81.54	6,078.00	7.89	117.47	110.43
2009:06	0.00	294.00	81.75	6,115.83	7.92	117.92	110.86
2009:07	0.00	295.00	81.97	6,156.69	7.95	118.40	111.31
2009:08	0.00	296.00	82.18	6,197.56	7.98	118.87	111.76
2009:09	0.00	297.00	82.39	6,238.42	8.01	119.34	112.21
2009:10	0.00	298.00	82.61	6,279.29	8.04	119.82	112.66
2009:11	0.00	299.00	82.82	6,320.15	8.07	120.29	113.11
2009:12	0.00	300.00	83.03	6,361.01	8.10	120.76	113.56
2010:01	0.00	301.00	83.25	6,401.88	8.13	121.24	114.01
2010:02	0.00	302.00	83.46	6,442.74	8.17	121.71	114.46
2010:03	0.00	303.00	83.67	6,483.61	8.20	122.19	114.91
2010:04	0.00	304.00	83.89	6,524.47	8.23	122.66	115.36
2010:05	0.00	305.00	84.10	6,565.34	8.26	123.13	115.81
2010:06	0.00	306.00	84.31	6,606.20	8.29	123.61	116.26
2010:07	0.00	307.00	84.53	6,646.43	8.32	124.06	116.69
2010:08	0.00	308.00	84.74	6,686.66	8.35	124.51	117.12
2010:09	0.00	309.00	84.95	6,726.89	8.38	124.95	117.55
2010:10	0.00	310.00	85.17	6,767.12	8.41	125.40	117.98
2010:11	0.00	311.00	85.38	6,807.35	8.44	125.85	118.41
2010:12	0.00	312.00	85.60	6,847.58	8.47	126.30	118.84
2011:01	0.00	313.00	85.81	6,887.81	8.50	126.75	119.27
2011:02	0.00	314.00	86.02	6,928.04	8.53	127.20	119.70



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
2011:03	0.00	315.00	86.24	6,968.27	8.56	127.65	120.13
2011:04	0.00	316.00	86.45	7,008.50	8.59	128.10	120.56
2011:05	0.00	317.00	86.67	7,048.73	8.62	128.55	120.99
2011:06	0.00	318.00	86.88	7,088.95	8.65	128.99	121.42
2011:07	0.00	319.00	87.10	7,132.12	8.68	129.46	121.86
2011:08	0.00	320.00	87.32	7,175.29	8.71	129.93	122.31
2011:09	0.00	321.00	87.54	7,218.46	8.74	130.40	122.76
2011:10	0.00	322.00	87.76	7,261.63	8.77	130.87	123.21
2011:11	0.00	323.00	87.98	7,304.80	8.80	131.34	123.66
2011:12	0.00	324.00	88.20	7,347.97	8.83	131.81	124.11
2012:01	0.00	325.00	88.42	7,391.14	8.86	132.28	124.56
2012:02	0.00	326.00	88.64	7,434.31	8.89	132.74	125.00
2012:03	0.00	327.00	88.86	7,477.48	8.92	133.21	125.45
2012:04	0.00	328.00	89.08	7,520.65	8.96	133.68	125.90
2012:05	0.00	329.00	89.31	7,563.82	8.99	134.15	126.35
2012:06	0.00	330.00	89.53	7,606.99	9.02	134.62	126.80
2012:07	0.00	331.00	89.75	7,653.31	9.05	135.11	127.27
2012:08	0.00	332.00	89.98	7,699.63	9.08	135.60	127.73
2012:09	0.00	333.00	90.21	7,745.96	9.11	136.09	128.20
2012:10	0.00	334.00	90.43	7,792.28	9.15	136.58	128.67
2012:11	0.00	335.00	90.66	7,838.60	9.18	137.07	129.14
2012:12	0.00	336.00	90.89	7,884.93	9.21	137.56	129.61
2013:01	0.00	337.00	91.12	7,931.25	9.24	138.04	130.08
2013:02	0.00	338.00	91.34	7,977.58	9.28	138.53	130.54
2013:03	0.00	339.00	91.57	8,023.90	9.31	139.02	131.01
2013:04	0.00	340.00	91.80	8,070.22	9.34	139.51	131.48
2013:05	0.00	341.00	92.03	8,116.55	9.37	140.00	131.95
2013:06	0.00	342.00	92.25	8,162.87	9.40	140.49	132.42
2013:07	0.00	343.00	92.49	8,212.58	9.44	141.00	132.91
2013:08	0.00	344.00	92.72	8,262.29	9.47	141.51	133.40
2013:09	0.00	345.00	92.96	8,312.00	9.51	142.02	133.88
2013:10	0.00	346.00	93.19	8,361.71	9.54	142.54	134.37
2013:11	0.00	347.00	93.42	8,411.42	9.57	143.05	134.86
2013:12	0.00	348.00	93.66	8,461.13	9.61	143.56	135.35
2014:01	0.00	349.00	93.89	8,510.84	9.64	144.07	135.84
2014:02	0.00	350.00	94.13	8,560.54	9.67	144.58	136.33
2014:03	0.00	351.00	94.36	8,610.25	9.71	145.09	136.82
2014:04	0.00	352.00	94.59	8,659.96	9.74	145.60	137.31
2014:05	0.00	353.00	94.83	8,709.67	9.77	146.11	137.80



Historical and Projected Energy and Demand Forecast Variables

Year/Month	SPIKE89	TIME	TS	YTOT	HGOODS	HGOODSERV	HHH
2014:06	0.00	354.00	95.06	8,759.38	9.81	146.62	138.29
2014:07	0.00	355.00	95.30	8,812.72	9.84	147.16	138.80
2014:08	0.00	356.00	95.55	8,866.06	9.88	147.69	139.31
2014:09	0.00	357.00	95.79	8,919.41	9.91	148.22	139.82
2014:10	0.00	358.00	96.03	8,972.75	9.95	148.76	140.33
2014:11	0.00	359.00	96.27	9,026.09	9.98	149.29	140.84
2014:12	0.00	360.00	96.51	9,079.43	10.02	149.82	141.35
2015:01	0.00	361.00	96.75	9,132.77	10.05	150.36	141.86
2015:02	0.00	362.00	96.99	9,186.11	10.09	150.89	142.37
2015:03	0.00	363.00	97.23	9,239.45	9.71	151.20	142.88
2015:04	0.00	364.00	97.48	9,292.80	10.16	151.96	143.39
2015:05	0.00	365.00	97.72	9,346.14	10.19	152.49	143.90
2015:06	0.00	366.00	97.96	9,399.48	10.23	153.03	144.42
2015:07	0.00	367.00	98.18	9,451.21	10.26	153.53	144.90
2015:08	0.00	368.00	98.41	9,502.95	10.30	154.04	145.39
2015:09	0.00	369.00	98.63	9,554.68	10.33	154.55	145.88
2015:10	0.00	370.00	98.86	9,606.41	10.36	155.06	146.37
2015:11	0.00	371.00	99.08	9,658.14	10.40	155.57	146.86
2015:12	0.00	372.00	99.31	9,709.88	10.43	156.07	147.34
2016:01	0.00	373.00	99.53	9,761.61	10.46	156.58	147.83
2016:02	0.00	374.00	99.76	9,813.34	10.50	157.09	148.32
2016:03	0.00	375.00	99.98	9,865.08	10.53	157.60	148.81
2016:04	0.00	376.00	100.20	9,916.81	10.56	158.11	149.30
2016:05	0.00	377.00	100.43	9,968.54	10.60	158.61	149.78
2016:06	0.00	378.00	100.65	10,020.27	10.63	159.12	150.27
2016:07	0.00	379.00	100.89	10,075.42	10.66	159.65	150.78
2016:08	0.00	380.00	101.12	10,130.57	10.70	160.18	151.29
2016:09	0.00	381.00	101.35	10,185.72	10.73	160.71	151.79
2016:10	0.00	382.00	101.58	10,240.87	10.77	161.24	152.30
2016:11	0.00	383.00	101.81	10,296.02	10.80	161.77	152.81
2016:12	0.00	384.00	102.04	10,351.17	10.84	162.29	153.32



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
1985:01	32.79	76.76	935.05	19.93	18.72	857.58	3.52
1985:02	32.83	77.35	943.20	20.08	18.85	867.71	3.53
1985:03	32.88	77.93	951.35	20.23	18.98	877.85	3.54
1985:04	32.92	78.52	959.51	20.37	19.12	887.98	3.55
1985:05	32.97	79.11	967.66	20.52	19.25	898.11	3.56
1985:06	33.01	79.70	975.81	20.67	19.38	908.24	3.57
1985:07	33.11	80.13	983.86	20.86	19.58	918.34	3.59
1985:08	33.22	80.56	991.90	21.05	19.77	928.44	3.61
1985:09	33.32	80.99	999.94	21.24	19.96	938.54	3.63
1985:10	33.42	81.43	1,007.98	21.43	20.16	948.63	3.65
1985:11	33.52	81.86	1,016.02	21.62	20.35	958.73	3.67
1985:12	33.62	82.29	1,024.07	21.81	20.55	968.83	3.69
1986:01	33.71	82.73	1,032.11	22.00	20.74	978.93	3.71
1986:02	33.81	83.16	1,040.15	22.19	20.93	989.03	3.73
1986:03	33.91	83.59	1,048.19	22.38	21.13	999.13	3.75
1986:04	34.00	84.03	1,056.24	22.57	21.32	1,009.23	3.77
1986:05	34.09	84.46	1,064.28	22.76	21.52	1,019.33	3.78
1986:06	34.19	84.89	1,072.32	22.96	21.71	1,029.43	3.80
1986:07	34.23	85.38	1,079.39	23.17	21.95	1,040.07	3.83
1986:08	34.27	85.87	1,086.45	23.39	22.19	1,050.71	3.85
1986:09	34.31	86.36	1,093.52	23.60	22.43	1,061.35	3.88
1986:10	34.34	86.85	1,100.59	23.82	22.67	1,071.99	3.90
1986:11	34.38	87.33	1,107.65	24.03	22.90	1,082.63	3.92
1986:12	34.42	87.82	1,114.72	24.25	23.14	1,093.27	3.95
1987:01	34.46	88.31	1,121.79	24.46	23.38	1,103.91	3.97
1987:02	34.49	88.80	1,128.85	24.68	23.62	1,114.55	3.99
1987:03	34.53	89.29	1,135.92	24.90	23.86	1,125.20	4.02
1987:04	34.57	89.77	1,142.99	25.11	24.10	1,135.84	4.04
1987:05	34.60	90.26	1,150.05	25.33	24.34	1,146.48	4.07
1987:06	34.64	90.75	1,157.12	25.54	24.58	1,157.12	4.09
1987:07	34.68	91.23	1,164.32	25.73	24.95	1,168.69	4.14
1987:08	34.73	91.71	1,171.51	25.92	25.32	1,180.27	4.19
1987:09	34.77	92.18	1,178.71	26.12	25.70	1,191.84	4.25
1987:10	34.82	92.66	1,185.91	26.31	26.07	1,203.42	4.30
1987:11	34.86	93.14	1,193.10	26.50	26.45	1,214.99	4.35
1987:12	34.90	93.62	1,200.30	26.69	26.82	1,226.57	4.40



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
1988:01	34.95	94.10	1,207.50	26.88	27.19	1,238.14	4.45
1988:02	34.99	94.58	1,214.69	27.07	27.57	1,249.72	4.51
1988:03	35.03	95.05	1,221.89	27.26	27.94	1,261.29	4.56
1988:04	35.07	95.53	1,229.09	27.45	28.32	1,272.87	4.61
1988:05	35.11	96.01	1,236.28	27.64	28.69	1,284.44	4.66
1988:06	35.15	96.49	1,243.48	27.84	29.06	1,296.02	4.71
1988:07	35.21	96.87	1,249.86	28.05	29.39	1,308.85	4.73
1988:08	35.26	97.25	1,256.24	28.27	29.72	1,321.69	4.75
1988:09	35.31	97.63	1,262.61	28.49	30.05	1,334.52	4.77
1988:10	35.37	98.00	1,268.99	28.71	30.38	1,347.36	4.79
1988:11	35.42	98.38	1,275.37	28.93	30.71	1,360.19	4.80
1988:12	35.47	98.76	1,281.75	29.15	31.04	1,373.03	4.82
1989:01	35.52	99.14	1,288.12	29.37	31.37	1,385.86	4.84
1989:02	35.57	99.52	1,294.50	29.59	31.70	1,398.70	4.86
1989:03	35.63	99.90	1,300.88	29.81	32.03	1,411.53	4.88
1989:04	35.68	100.28	1,307.26	30.03	32.36	1,424.37	4.89
1989:05	35.73	100.66	1,313.63	30.25	32.69	1,437.21	4.91
1989:06	35.78	101.04	1,320.01	30.47	33.02	1,450.04	4.93
1989:07	35.67	101.75	1,324.93	30.63	33.35	1,461.28	4.90
1989:08	35.56	102.46	1,329.85	30.79	33.68	1,472.52	4.88
1989:09	35.46	103.18	1,334.78	30.95	34.01	1,483.76	4.85
1989:10	35.36	103.89	1,339.70	31.11	34.34	1,494.99	4.83
1989:11	35.25	104.60	1,344.62	31.28	34.67	1,506.23	4.80
1989:12	35.15	105.31	1,349.54	31.44	34.99	1,517.47	4.77
1990:01	35.06	106.03	1,354.46	31.60	35.32	1,528.71	4.75
1990:02	34.96	106.74	1,359.38	31.76	35.65	1,539.95	4.72
1990:03	34.86	107.45	1,364.31	31.92	35.98	1,551.18	4.70
1990:04	34.77	108.16	1,369.23	32.09	36.31	1,562.42	4.67
1990:05	34.67	108.88	1,374.15	32.25	36.64	1,573.66	4.64
1990:06	34.58	109.59	1,379.07	32.41	36.97	1,584.90	4.62
1990:07	34.45	110.13	1,380.83	32.41	37.15	1,592.52	4.58
1990:08	34.32	110.67	1,382.59	32.41	37.33	1,600.14	4.54
1990:09	34.20	111.21	1,384.35	32.42	37.51	1,607.76	4.50
1990:10	34.07	111.74	1,386.10	32.42	37.69	1,615.38	4.46
1990:11	33.95	112.28	1,387.86	32.42	37.87	1,623.00	4.43
1990:12	33.83	112.82	1,389.62	32.42	38.05	1,630.62	4.39
1991:01	33.71	113.36	1,391.38	32.43	38.23	1,638.25	4.35
1991:02	33.59	113.90	1,393.14	32.43	38.41	1,645.87	4.31
1991:03	33.47	114.44	1,394.90	32.43	38.60	1,653.49	4.27



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
1991:04	33.35	114.98	1,396.65	32.43	38.78	1,661.11	4.23
1991:05	33.23	115.52	1,398.41	32.44	38.96	1,668.73	4.20
1991:06	33.12	116.06	1,400.17	32.44	39.14	1,676.35	4.16
1991:07	33.14	116.47	1,406.20	32.59	39.37	1,688.17	4.15
1991:08	33.16	116.89	1,412.23	32.74	39.61	1,699.99	4.14
1991:09	33.18	117.31	1,418.26	32.90	39.84	1,711.81	4.13
1991:10	33.20	117.73	1,424.29	33.05	40.08	1,723.63	4.12
1991:11	33.22	118.15	1,430.32	33.20	40.31	1,735.45	4.11
1991:12	33.24	118.57	1,436.35	33.35	40.54	1,747.27	4.10
1992:01	33.26	118.98	1,442.37	33.50	40.78	1,759.09	4.09
1992:02	33.28	119.40	1,448.40	33.66	41.01	1,770.91	4.08
1992:03	33.30	119.82	1,454.43	33.81	41.25	1,782.73	4.07
1992:04	33.32	120.24	1,460.46	33.96	41.48	1,794.55	4.07
1992:05	33.34	120.66	1,466.49	34.11	41.72	1,806.36	4.06
1992:06	33.36	121.08	1,472.52	34.26	41.95	1,818.18	4.05
1992:07	33.33	121.58	1,477.44	34.49	42.19	1,828.25	4.06
1992:08	33.30	122.08	1,482.37	34.73	42.43	1,838.32	4.07
1992:09	33.28	122.58	1,487.29	34.96	42.67	1,848.39	4.08
1992:10	33.25	123.08	1,492.21	35.19	42.92	1,858.46	4.09
1992:11	33.23	123.58	1,497.14	35.42	43.16	1,868.53	4.10
1992:12	33.20	124.08	1,502.06	35.65	43.40	1,878.60	4.11
1993:01	33.18	124.59	1,506.98	35.88	43.64	1,888.67	4.11
1993:02	33.15	125.09	1,511.91	36.11	43.88	1,898.73	4.12
1993:03	33.13	125.59	1,516.83	36.34	44.12	1,908.80	4.13
1993:04	33.11	126.09	1,521.75	36.57	44.37	1,918.87	4.14
1993:05	33.08	126.59	1,526.68	36.80	44.61	1,928.94	4.15
1993:06	33.06	127.09	1,531.60	37.04	44.85	1,939.01	4.16
1993:07	33.04	127.54	1,536.08	37.14	45.03	1,948.24	4.16
1993:08	33.01	127.98	1,540.56	37.25	45.20	1,957.48	4.17
1993:09	32.99	128.43	1,545.04	37.35	45.38	1,966.72	4.17
1993:10	32.97	128.87	1,549.51	37.46	45.56	1,975.95	4.17
1993:11	32.95	129.32	1,553.99	37.56	45.73	1,985.19	4.17
1993:12	32.93	129.76	1,558.47	37.67	45.91	1,994.42	4.17
1994:01	32.90	130.20	1,562.95	37.78	46.09	2,003.66	4.17
1994:02	32.88	130.65	1,567.43	37.88	46.26	2,012.90	4.17
1994:03	32.86	131.09	1,571.91	37.99	46.44	2,022.13	4.18
1994:04	32.84	131.54	1,576.38	38.09	46.62	2,031.37	4.18
1994:05	32.82	131.98	1,580.86	38.20	46.79	2,040.60	4.18
1994:06	32.80	132.43	1,585.34	38.30	46.97	2,049.84	4.18



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
1994:07	32.85	132.89	1,592.73	38.46	47.11	2,063.61	4.17
1994:08	32.90	133.36	1,600.12	38.61	47.26	2,077.38	4.16
1994:09	32.94	133.82	1,607.50	38.76	47.41	2,091.16	4.16
1994:10	32.99	134.28	1,614.89	38.91	47.55	2,104.93	4.15
1994:11	33.04	134.75	1,622.28	39.06	47.70	2,118.70	4.14
1994:12	33.09	135.21	1,629.67	39.22	47.84	2,132.47	4.14
1995:01	33.13	135.68	1,637.05	39.37	47.99	2,146.24	4.13
1995:02	33.18	136.14	1,644.44	39.52	48.13	2,160.02	4.12
1995:03	33.23	136.61	1,651.83	39.67	48.28	2,173.79	4.11
1995:04	33.27	137.07	1,659.22	39.82	48.43	2,187.56	4.11
1995:05	33.32	137.53	1,666.60	39.98	48.57	2,201.33	4.10
1995:06	33.36	138.00	1,673.99	40.13	48.72	2,215.11	4.09
1995:07	33.40	138.73	1,685.51	40.45	49.03	2,240.91	4.09
1995:08	33.43	139.45	1,697.02	40.77	49.35	2,266.72	4.09
1995:09	33.46	140.18	1,708.54	41.09	49.66	2,292.53	4.09
1995:10	33.50	140.91	1,720.05	41.41	49.97	2,318.33	4.09
1995:11	33.53	141.63	1,731.57	41.73	50.29	2,344.14	4.09
1995:12	33.56	142.36	1,743.09	42.05	50.60	2,369.95	4.10
1996:01	33.59	143.09	1,754.60	42.37	50.92	2,395.75	4.10
1996:02	33.62	143.81	1,766.12	42.69	51.23	2,421.56	4.10
1996:03	33.65	144.54	1,777.63	43.01	51.54	2,447.37	4.10
1996:04	33.68	145.27	1,789.15	43.33	51.86	2,473.17	4.10
1996:05	33.71	145.99	1,800.67	43.65	52.17	2,498.98	4.10
1996:06	33.74	146.72	1,812.18	43.97	52.49	2,524.79	4.10
1996:07	33.78	147.49	1,824.65	44.32	52.82	2,554.20	4.10
1996:08	33.81	148.26	1,837.12	44.67	53.16	2,583.62	4.10
1996:09	33.84	149.04	1,849.58	45.02	53.50	2,613.03	4.10
1996:10	33.88	149.81	1,862.05	45.37	53.84	2,642.45	4.10
1996:11	33.91	150.58	1,874.52	45.72	54.18	2,671.86	4.10
1996:12	33.94	151.35	1,886.98	46.07	54.52	2,701.28	4.10
1997:01	33.97	152.13	1,899.45	46.42	54.85	2,730.69	4.10
1997:02	34.00	152.90	1,911.92	46.77	55.19	2,760.11	4.10
1997:03	34.03	153.67	1,924.38	47.12	55.53	2,789.52	4.10
1997:04	34.07	154.45	1,936.85	47.48	55.87	2,818.94	4.10
1997:05	34.10	155.22	1,949.32	47.83	56.21	2,848.35	4.10
1997:06	34.13	155.99	1,961.78	48.18	56.55	2,877.76	4.10
1997:07	34.16	156.81	1,975.28	48.56	56.91	2,911.29	4.11
1997:08	34.19	157.63	1,988.77	48.95	57.28	2,944.82	4.11
1997:09	34.23	158.45	2,002.27	49.33	57.64	2,978.35	4.11



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
1997:10	34.26	159.28	2,015.77	49.71	58.00	3,011.87	4.11
1997:11	34.29	160.10	2,029.26	50.10	58.37	3,045.40	4.11
1997:12	34.33	160.92	2,042.76	50.48	58.73	3,078.93	4.11
1998:01	34.36	161.74	2,056.25	50.87	59.10	3,112.45	4.11
1998:02	34.39	162.56	2,069.75	51.25	59.46	3,145.98	4.11
1998:03	34.42	163.38	2,083.24	51.64	59.83	3,179.51	4.11
1998:04	34.45	164.20	2,096.74	52.02	60.19	3,213.03	4.11
1998:05	34.48	165.03	2,110.24	52.40	60.56	3,246.56	4.11
1998:06	34.51	165.85	2,123.73	52.79	60.92	3,280.09	4.11
1998:07	34.55	166.72	2,138.34	53.21	61.31	3,318.30	4.11
1998:08	34.58	167.59	2,152.95	53.63	61.71	3,356.52	4.11
1998:09	34.62	168.47	2,167.56	54.05	62.10	3,394.73	4.11
1998:10	34.65	169.34	2,182.17	54.47	62.49	3,432.95	4.11
1998:11	34.68	170.21	2,196.78	54.89	62.88	3,471.16	4.11
1998:12	34.72	171.09	2,211.39	55.32	63.28	3,509.37	4.11
1999:01	34.75	171.96	2,226.00	55.74	63.67	3,547.59	4.11
1999:02	34.78	172.83	2,240.61	56.16	64.06	3,585.80	4.11
1999:03	34.81	173.71	2,255.22	56.58	64.46	3,624.02	4.12
1999:04	34.84	174.58	2,269.83	57.00	64.85	3,662.23	4.12
1999:05	34.87	175.45	2,284.44	57.42	65.24	3,700.44	4.12
1999:06	34.90	176.33	2,299.05	57.84	65.63	3,738.66	4.12
1999:07	34.94	177.26	2,314.87	58.30	66.06	3,782.22	4.12
1999:08	34.97	178.18	2,330.68	58.76	66.48	3,825.77	4.12
1999:09	35.01	179.11	2,346.50	59.23	66.90	3,869.33	4.12
1999:10	35.04	180.04	2,362.32	59.69	67.33	3,912.89	4.12
1999:11	35.08	180.97	2,378.13	60.15	67.75	3,956.44	4.12
1999:12	35.11	181.90	2,393.95	60.61	68.17	4,000.00	4.12
2000:01	35.14	182.83	2,409.76	61.07	68.60	4,043.56	4.12
2000:02	35.17	183.76	2,425.58	61.53	69.02	4,087.11	4.12
2000:03	35.21	184.68	2,441.40	61.99	69.44	4,130.67	4.12
2000:04	35.24	185.61	2,457.21	62.46	69.86	4,174.23	4.12
2000:05	35.27	186.54	2,473.03	62.92	70.29	4,217.78	4.12
2000:06	35.30	187.47	2,488.84	63.38	70.71	4,261.34	4.12
2000:07	35.34	188.24	2,502.84	63.73	71.09	4,305.47	4.13
2000:08	35.38	189.02	2,516.83	64.08	71.47	4,349.61	4.13
2000:09	35.42	189.80	2,530.82	64.43	71.85	4,393.74	4.13
2000:10	35.46	190.57	2,544.82	64.78	72.22	4,437.88	4.13
2000:11	35.50	191.35	2,558.81	65.13	72.60	4,482.01	4.14
2000:12	35.54	192.12	2,572.80	65.48	72.98	4,526.15	4.14



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
2001:01	35.57	192.90	2,586.80	65.84	73.36	4,570.28	4.14
2001:02	35.61	193.67	2,600.79	66.19	73.74	4,614.41	4.14
2001:03	35.65	194.45	2,614.78	66.54	74.11	4,658.55	4.15
2001:04	35.69	195.22	2,628.78	66.89	74.49	4,702.68	4.15
2001:05	35.72	196.00	2,642.77	67.24	74.87	4,746.82	4.15
2001:06	35.76	196.77	2,656.77	67.59	75.25	4,790.95	4.15
2001:07	35.80	197.59	2,671.70	67.96	75.65	4,840.57	4.16
2001:08	35.84	198.40	2,686.64	68.34	76.05	4,890.19	4.16
2001:09	35.88	199.22	2,701.58	68.71	76.46	4,939.81	4.16
2001:10	35.92	200.03	2,716.52	69.09	76.86	4,989.43	4.16
2001:11	35.96	200.84	2,731.45	69.46	77.26	5,039.05	4.17
2001:12	36.00	201.66	2,746.39	69.84	77.66	5,088.67	4.17
2002:01	36.03	202.47	2,761.33	70.21	78.07	5,138.29	4.17
2002:02	36.07	203.28	2,776.27	70.58	78.47	5,187.91	4.18
2002:03	36.11	204.10	2,791.20	70.96	78.87	5,237.53	4.18
2002:04	36.15	204.91	2,806.14	71.33	79.27	5,287.15	4.18
2002:05	36.18	205.73	2,821.08	71.71	79.68	5,336.77	4.18
2002:06	36.22	206.54	2,836.02	72.08	80.08	5,386.39	4.19
2002:07	36.26	207.39	2,851.96	72.48	80.51	5,442.17	4.19
2002:08	36.30	208.25	2,867.91	72.88	80.93	5,497.96	4.19
2002:09	36.34	209.10	2,883.85	73.28	81.36	5,553.74	4.19
2002:10	36.38	209.96	2,899.80	73.68	81.79	5,609.53	4.20
2002:11	36.42	210.81	2,915.74	74.08	82.22	5,665.32	4.20
2002:12	36.46	211.67	2,931.69	74.48	82.65	5,721.10	4.20
2003:01	36.50	212.52	2,947.63	74.88	83.08	5,776.89	4.20
2003:02	36.54	213.37	2,963.58	75.28	83.50	5,832.68	4.21
2003:03	36.58	214.23	2,979.52	75.67	83.93	5,888.46	4.21
2003:04	36.62	215.08	2,995.47	76.07	84.36	5,944.25	4.21
2003:05	36.65	215.94	3,011.41	76.47	84.79	6,000.04	4.21
2003:06	36.69	216.79	3,027.36	76.87	85.22	6,055.82	4.22
2003:07	36.73	217.69	3,044.38	77.30	85.67	6,118.54	4.22
2003:08	36.77	218.58	3,061.40	77.72	86.13	6,181.26	4.22
2003:09	36.81	219.48	3,078.42	78.15	86.58	6,243.98	4.22
2003:10	36.86	220.38	3,095.45	78.58	87.04	6,306.70	4.23
2003:11	36.90	221.27	3,112.47	79.00	87.50	6,369.42	4.23
2003:12	36.93	222.17	3,129.49	79.43	87.95	6,432.14	4.23
2004:01	36.97	223.07	3,146.51	79.85	88.41	6,494.86	4.24
2004:02	37.01	223.96	3,163.53	80.28	88.86	6,557.58	4.24
2004:03	37.05	224.86	3,180.55	80.70	89.32	6,620.30	4.24



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
2004:04	37.09	225.76	3,197.57	81.13	89.78	6,683.02	4.24
2004:05	37.13	226.65	3,214.59	81.56	90.23	6,745.74	4.25
2004:06	37.17	227.55	3,231.61	81.98	90.69	6,808.46	4.25
2004:07	37.21	228.49	3,249.78	82.44	91.17	6,878.97	4.25
2004:08	37.25	229.43	3,267.95	82.89	91.66	6,949.49	4.25
2004:09	37.29	230.37	3,286.12	83.34	92.14	7,020.00	4.26
2004:10	37.33	231.32	3,304.29	83.80	92.63	7,090.52	4.26
2004:11	37.37	232.26	3,322.46	84.25	93.11	7,161.03	4.26
2004:12	37.41	233.20	3,340.63	84.71	93.60	7,231.55	4.26
2005:01	37.45	234.14	3,358.80	85.16	94.08	7,302.06	4.27
2005:02	37.49	235.08	3,376.97	85.61	94.57	7,372.58	4.27
2005:03	37.53	236.02	3,395.14	86.07	95.05	7,443.09	4.27
2005:04	37.57	236.96	3,413.31	86.52	95.54	7,513.60	4.27
2005:05	37.61	237.90	3,431.48	86.98	96.02	7,584.12	4.28
2005:06	37.65	238.84	3,449.65	87.43	96.51	7,654.63	4.28
2005:07	37.73	239.72	3,471.49	87.85	96.96	7,741.72	4.28
2005:08	37.82	240.60	3,493.33	88.27	97.42	7,828.81	4.28
2005:09	37.90	241.48	3,515.17	88.69	97.88	7,915.90	4.28
2005:10	37.98	242.36	3,537.01	89.12	98.34	8,002.99	4.28
2005:11	38.07	243.24	3,558.84	89.54	98.80	8,090.08	4.28
2005:12	38.15	244.12	3,580.68	89.96	99.25	8,177.17	4.28
2006:01	38.23	245.00	3,602.52	90.38	99.71	8,264.26	4.28
2006:02	38.31	245.88	3,624.36	90.80	100.17	8,351.35	4.28
2006:03	38.39	246.76	3,646.20	91.22	100.63	8,438.44	4.28
2006:04	38.47	247.64	3,668.04	91.64	101.08	8,525.53	4.28
2006:05	38.55	248.52	3,689.88	92.07	101.54	8,612.62	4.28
2006:06	38.62	249.39	3,711.72	92.49	102.00	8,699.71	4.28
2006:07	38.71	250.31	3,735.22	92.93	102.48	8,798.68	4.28
2006:08	38.80	251.23	3,758.71	93.38	102.97	8,897.66	4.28
2006:09	38.88	252.15	3,782.21	93.82	103.45	8,996.64	4.28
2006:10	38.97	253.07	3,805.71	94.27	103.93	9,095.62	4.28
2006:11	39.05	253.98	3,829.21	94.72	104.42	9,194.60	4.28
2006:12	39.14	254.90	3,852.71	95.16	104.90	9,293.58	4.28
2007:01	39.22	255.82	3,876.20	95.61	105.38	9,392.56	4.28
2007:02	39.30	256.74	3,899.70	96.05	105.87	9,491.54	4.28
2007:03	39.38	257.66	3,923.20	96.50	106.35	9,590.52	4.28
2007:04	39.47	258.57	3,946.70	96.95	106.84	9,689.50	4.28
2007:05	39.55	259.49	3,970.20	97.39	107.32	9,788.48	4.28
2007:06	39.63	260.41	3,993.69	97.84	107.80	9,887.46	4.28



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
2007:07	39.72	261.37	4,018.98	98.31	108.31	9,999.95	4.28
2007:08	39.80	262.33	4,044.26	98.78	108.83	10,112.44	4.28
2007:09	39.89	263.29	4,069.54	99.25	109.34	10,224.94	4.28
2007:10	39.98	264.25	4,094.83	99.72	109.85	10,337.43	4.28
2007:11	40.07	265.20	4,120.11	100.20	110.36	10,449.92	4.28
2007:12	40.15	266.16	4,145.39	100.67	110.87	10,562.41	4.28
2008:01	40.24	267.12	4,170.67	101.14	111.38	10,674.91	4.28
2008:02	40.32	268.08	4,195.96	101.61	111.89	10,787.40	4.28
2008:03	40.41	269.04	4,221.24	102.08	112.40	10,899.89	4.27
2008:04	40.49	270.00	4,246.52	102.55	112.91	11,012.39	4.27
2008:05	40.57	270.96	4,271.81	103.03	113.43	11,124.88	4.27
2008:06	40.65	271.91	4,297.09	103.50	113.94	11,237.37	4.27
2008:07	40.74	272.91	4,324.29	104.00	114.48	11,365.22	4.27
2008:08	40.84	273.92	4,351.50	104.50	115.02	11,493.07	4.27
2008:09	40.93	274.92	4,378.70	104.99	115.56	11,620.92	4.27
2008:10	41.02	275.92	4,405.91	105.49	116.10	11,748.78	4.27
2008:11	41.10	276.92	4,433.11	105.99	116.64	11,876.63	4.27
2008:12	41.19	277.92	4,460.31	106.49	117.18	12,004.48	4.27
2009:01	41.28	278.92	4,487.52	106.99	117.72	12,132.33	4.27
2009:02	41.37	279.92	4,514.72	107.49	118.26	12,260.18	4.27
2009:03	41.45	280.92	4,541.93	107.99	118.80	12,388.03	4.27
2009:04	41.54	281.92	4,569.13	108.49	119.34	12,515.88	4.27
2009:05	41.62	282.92	4,596.33	108.99	119.88	12,643.73	4.27
2009:06	41.71	283.92	4,623.54	109.49	120.42	12,771.59	4.27
2009:07	41.80	284.97	4,652.81	110.01	120.99	12,916.89	4.27
2009:08	41.89	286.02	4,682.08	110.54	121.56	13,062.20	4.27
2009:09	41.99	287.06	4,711.35	111.07	122.13	13,207.50	4.27
2009:10	42.08	288.11	4,740.62	111.60	122.71	13,352.81	4.27
2009:11	42.17	289.15	4,769.89	112.12	123.28	13,498.12	4.27
2009:12	42.26	290.20	4,799.16	112.65	123.85	13,643.42	4.27
2010:01	42.35	291.24	4,828.43	113.18	124.42	13,788.73	4.27
2010:02	42.44	292.29	4,857.70	113.71	124.99	13,934.04	4.27
2010:03	42.53	293.33	4,886.97	114.24	125.56	14,079.34	4.27
2010:04	42.62	294.38	4,916.24	114.76	126.13	14,224.65	4.27
2010:05	42.70	295.42	4,945.51	115.29	126.70	14,369.96	4.27
2010:06	42.79	296.47	4,974.78	115.82	127.27	14,515.26	4.27
2010:07	42.88	297.46	5,003.40	116.33	127.82	14,665.33	4.27
2010:08	42.96	298.45	5,032.02	116.83	128.37	14,815.40	4.26
2010:09	43.05	299.44	5,060.64	117.34	128.92	14,965.47	4.26



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
2010:10	43.14	300.43	5,089.26	117.85	129.47	15,115.54	4.26
2010:11	43.22	301.42	5,117.88	118.36	130.02	15,265.61	4.26
2010:12	43.31	302.42	5,146.50	118.86	130.56	15,415.67	4.25
2011:01	43.39	303.41	5,175.12	119.37	131.11	15,565.74	4.25
2011:02	43.47	304.40	5,203.73	119.88	131.66	15,715.81	4.25
2011:03	43.56	305.39	5,232.35	120.39	132.21	15,865.88	4.24
2011:04	43.64	306.38	5,260.97	120.89	132.76	16,015.95	4.24
2011:05	43.72	307.37	5,289.59	121.40	133.31	16,166.02	4.24
2011:06	43.80	308.37	5,318.21	121.91	133.85	16,316.08	4.24
2011:07	43.89	309.40	5,348.81	122.44	134.43	16,484.77	4.23
2011:08	43.98	310.43	5,379.40	122.98	135.01	16,653.46	4.23
2011:09	44.07	311.46	5,409.99	123.51	135.59	16,822.14	4.23
2011:10	44.16	312.49	5,440.59	124.04	136.16	16,990.83	4.22
2011:11	44.24	313.52	5,471.18	124.58	136.74	17,159.52	4.22
2011:12	44.33	314.56	5,501.78	125.11	137.32	17,328.20	4.22
2012:01	44.42	315.59	5,532.37	125.65	137.89	17,496.89	4.21
2012:02	44.50	316.62	5,562.97	126.18	138.47	17,665.58	4.21
2012:03	44.59	317.65	5,593.56	126.71	139.05	17,834.26	4.21
2012:04	44.67	318.68	5,624.16	127.25	139.62	18,002.95	4.21
2012:05	44.75	319.71	5,654.75	127.78	140.20	18,171.64	4.20
2012:06	44.84	320.74	5,685.35	128.32	140.78	18,340.32	4.20
2012:07	44.93	321.82	5,718.05	128.88	141.38	18,529.94	4.20
2012:08	45.02	322.89	5,750.76	129.44	141.99	18,719.55	4.19
2012:09	45.11	323.96	5,783.47	130.00	142.60	18,909.17	4.19
2012:10	45.20	325.04	5,816.17	130.56	143.20	19,098.78	4.19
2012:11	45.29	326.11	5,848.88	131.13	143.81	19,288.40	4.19
2012:12	45.38	327.18	5,881.59	131.69	144.42	19,478.01	4.18
2013:01	45.47	328.25	5,914.29	132.25	145.02	19,667.63	4.18
2013:02	45.56	329.33	5,947.00	132.81	145.63	19,857.24	4.18
2013:03	45.64	330.40	5,979.71	133.38	146.24	20,046.85	4.17
2013:04	45.73	331.47	6,012.41	133.94	146.84	20,236.47	4.17
2013:05	45.81	332.55	6,045.12	134.50	147.45	20,426.08	4.17
2013:06	45.90	333.62	6,077.83	135.06	148.06	20,615.70	4.17
2013:07	45.99	334.73	6,112.79	135.65	148.69	20,828.84	4.16
2013:08	46.09	335.85	6,147.76	136.25	149.33	21,041.98	4.16
2013:09	46.18	336.97	6,182.72	136.84	149.97	21,255.11	4.16
2013:10	46.27	338.08	6,217.69	137.43	150.61	21,468.25	4.15
2013:11	46.36	339.20	6,252.65	138.02	151.25	21,681.39	4.15
2013:12	46.45	340.31	6,287.62	138.61	151.88	21,894.53	4.15



Historical and Projected Energy and Demand Forecast Variables							
Year/Month	HINCPERHH	HPOPA	HRYTOT	HSERVICES	HTS	HYTOT	LGOODS
2014:01	46.54	341.43	6,322.58	139.20	152.52	22,107.67	4.15
2014:02	46.63	342.55	6,357.54	139.80	153.16	22,320.81	4.14
2014:03	46.72	343.66	6,392.51	140.39	153.80	22,533.95	4.14
2014:04	46.81	344.78	6,427.47	140.98	154.44	22,747.09	4.14
2014:05	46.90	345.89	6,462.44	141.57	155.07	22,960.23	4.13
2014:06	46.99	347.01	6,497.40	142.16	155.71	23,173.36	4.13
2014:07	47.08	348.17	6,534.78	142.78	156.38	23,412.95	4.13
2014:08	47.18	349.33	6,572.16	143.41	157.05	23,652.53	4.13
2014:09	47.27	350.49	6,609.54	144.03	157.72	23,892.11	4.12
2014:10	47.37	351.65	6,646.92	144.65	158.40	24,131.69	4.12
2014:11	47.46	352.81	6,684.29	145.28	159.07	24,371.27	4.12
2014:12	47.55	353.97	6,721.67	145.90	159.74	24,610.86	4.11
2015:01	47.65	355.14	6,759.05	146.52	160.41	24,850.44	4.11
2015:02	47.74	356.30	6,796.43	147.14	161.08	25,090.02	4.11
2015:03	47.83	357.46	6,833.81	147.77	161.75	25,329.60	4.14
2015:04	47.92	358.62	6,871.19	148.39	162.42	25,569.18	4.10
2015:05	48.01	359.78	6,908.57	149.01	163.09	25,808.76	4.10
2015:06	48.10	360.94	6,945.94	149.64	163.76	26,048.35	4.10
2015:07	48.19	362.04	6,982.50	150.23	164.41	26,294.72	4.09
2015:08	48.28	363.15	7,019.06	150.83	165.05	26,541.09	4.09
2015:09	48.37	364.25	7,055.61	151.43	165.70	26,787.46	4.08
2015:10	48.45	365.36	7,092.17	152.03	166.35	27,033.83	4.07
2015:11	48.54	366.46	7,128.72	152.63	166.99	27,280.20	4.07
2015:12	48.63	367.57	7,165.28	153.23	167.64	27,526.58	4.06
2016:01	48.72	368.67	7,201.83	153.83	168.28	27,772.95	4.05
2016:02	48.80	369.78	7,238.39	154.43	168.93	28,019.32	4.05
2016:03	48.89	370.88	7,274.95	155.03	169.57	28,265.69	4.04
2016:04	48.97	371.98	7,311.50	155.63	170.22	28,512.06	4.04
2016:05	49.06	373.09	7,348.06	156.23	170.87	28,758.43	4.03
2016:06	49.14	374.19	7,384.61	156.83	171.51	29,004.81	4.02
2016:07	49.23	375.34	7,423.48	157.46	172.19	29,279.14	4.02
2016:08	49.33	376.48	7,462.34	158.09	172.86	29,553.47	4.01
2016:09	49.42	377.63	7,501.21	158.72	173.54	29,827.81	4.01
2016:10	49.51	378.77	7,540.07	159.35	174.22	30,102.14	4.00
2016:11	49.60	379.92	7,578.94	159.97	174.89	30,376.48	4.00
2016:12	49.69	381.06	7,617.80	160.60	175.57	30,650.81	3.99



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LYTOT	LSERVICES	LTS	LYTOT
1985:01	23.45	28.52	32.79	76.76	935.05	19.93	18.72	857.58
1985:02	23.61	28.73	32.83	77.35	943.20	20.08	18.85	867.71
1985:03	23.77	28.94	32.88	77.93	951.35	20.23	18.98	877.85
1985:04	23.92	29.14	32.92	78.52	959.51	20.37	19.12	887.98
1985:05	24.08	29.35	32.97	79.11	967.66	20.52	19.25	898.11
1985:06	24.24	29.56	33.01	79.70	975.81	20.67	19.38	908.24
1985:07	24.45	29.71	33.11	80.13	983.86	20.86	19.58	918.34
1985:08	24.66	29.86	33.22	80.56	991.90	21.05	19.77	928.44
1985:09	24.87	30.01	33.32	80.99	999.94	21.24	19.96	938.54
1985:10	25.08	30.16	33.42	81.43	1,007.98	21.43	20.16	948.63
1985:11	25.29	30.31	33.52	81.86	1,016.02	21.62	20.35	958.73
1985:12	25.50	30.46	33.62	82.29	1,024.07	21.81	20.55	968.83
1986:01	25.71	30.61	33.71	82.73	1,032.11	22.00	20.74	978.93
1986:02	25.92	30.76	33.81	83.16	1,040.15	22.19	20.93	989.03
1986:03	26.13	30.91	33.91	83.59	1,048.19	22.38	21.13	999.13
1986:04	26.34	31.07	34.00	84.03	1,056.24	22.57	21.32	1,009.23
1986:05	26.55	31.22	34.09	84.46	1,064.28	22.76	21.52	1,019.33
1986:06	26.76	31.37	34.19	84.89	1,072.32	22.96	21.71	1,029.43
1986:07	27.00	31.54	34.23	85.38	1,079.39	23.17	21.95	1,040.07
1986:08	27.24	31.71	34.27	85.87	1,086.45	23.39	22.19	1,050.71
1986:09	27.48	31.88	34.31	86.36	1,093.52	23.60	22.43	1,061.35
1986:10	27.72	32.05	34.34	86.85	1,100.59	23.82	22.67	1,071.99
1986:11	27.96	32.22	34.38	87.33	1,107.65	24.03	22.90	1,082.63
1986:12	28.20	32.39	34.42	87.82	1,114.72	24.25	23.14	1,093.27
1987:01	28.43	32.56	34.46	88.31	1,121.79	24.46	23.38	1,103.91
1987:02	28.67	32.73	34.49	88.80	1,128.85	24.68	23.62	1,114.55
1987:03	28.91	32.90	34.53	89.29	1,135.92	24.90	23.86	1,125.20
1987:04	29.15	33.07	34.57	89.77	1,142.99	25.11	24.10	1,135.84
1987:05	29.39	33.24	34.60	90.26	1,150.05	25.33	24.34	1,146.48
1987:06	29.63	33.41	34.64	90.75	1,157.12	25.54	24.58	1,157.12
1987:07	29.88	33.57	34.68	91.23	1,164.32	25.73	24.95	1,168.69



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
1987:08	30.12	33.73	34.73	91.71	1,171.51	25.92	25.32	1,180.27
1987:09	30.36	33.90	34.77	92.18	1,178.71	26.12	25.70	1,191.84
1987:10	30.60	34.06	34.82	92.66	1,185.91	26.31	26.07	1,203.42
1987:11	30.85	34.23	34.86	93.14	1,193.10	26.50	26.45	1,214.99
1987:12	31.09	34.39	34.90	93.62	1,200.30	26.69	26.82	1,226.57
1988:01	31.33	34.55	34.95	94.10	1,207.50	26.88	27.19	1,238.14
1988:02	31.58	34.72	34.99	94.58	1,214.69	27.07	27.57	1,249.72
1988:03	31.82	34.88	35.03	95.05	1,221.89	27.26	27.94	1,261.29
1988:04	32.06	35.05	35.07	95.53	1,229.09	27.45	28.32	1,272.87
1988:05	32.31	35.21	35.11	96.01	1,236.28	27.64	28.69	1,284.44
1988:06	32.55	35.37	35.15	96.49	1,243.48	27.84	29.06	1,296.02
1988:07	32.79	35.50	35.21	96.87	1,249.86	28.05	29.39	1,308.85
1988:08	33.02	35.63	35.26	97.25	1,256.24	28.27	29.72	1,321.69
1988:09	33.26	35.75	35.31	97.63	1,262.61	28.49	30.05	1,334.52
1988:10	33.50	35.88	35.37	98.00	1,268.99	28.71	30.38	1,347.36
1988:11	33.74	36.01	35.42	98.38	1,275.37	28.93	30.71	1,360.19
1988:12	33.97	36.13	35.47	98.76	1,281.75	29.15	31.04	1,373.03
1989:01	34.21	36.26	35.52	99.14	1,288.12	29.37	31.37	1,385.86
1989:02	34.45	36.39	35.57	99.52	1,294.50	29.59	31.70	1,398.70
1989:03	34.69	36.52	35.63	99.90	1,300.88	29.81	32.03	1,411.53
1989:04	34.92	36.64	35.68	100.28	1,307.26	30.03	32.36	1,424.37
1989:05	35.16	36.77	35.73	100.66	1,313.63	30.25	32.69	1,437.21
1989:06	35.40	36.90	35.78	101.04	1,320.01	30.47	33.02	1,450.04
1989:07	35.53	37.14	35.67	101.75	1,324.93	30.63	33.35	1,461.28
1989:08	35.67	37.39	35.56	102.46	1,329.85	30.79	33.68	1,472.52
1989:09	35.81	37.64	35.46	103.18	1,334.78	30.95	34.01	1,483.76
1989:10	35.94	37.89	35.36	103.89	1,339.70	31.11	34.34	1,494.99
1989:11	36.08	38.14	35.25	104.60	1,344.62	31.28	34.67	1,506.23
1989:12	36.21	38.39	35.15	105.31	1,349.54	31.44	34.99	1,517.47
1990:01	36.35	38.64	35.06	106.03	1,354.46	31.60	35.32	1,528.71
1990:02	36.48	38.89	34.96	106.74	1,359.38	31.76	35.65	1,539.95
1990:03	36.62	39.14	34.86	107.45	1,364.31	31.92	35.98	1,551.18
1990:04	36.76	39.38	34.77	108.16	1,369.23	32.09	36.31	1,562.42
1990:05	36.89	39.63	34.67	108.88	1,374.15	32.25	36.64	1,573.66
1990:06	37.03	39.88	34.58	109.59	1,379.07	32.41	36.97	1,584.90
1990:07	36.99	40.08	34.45	110.13	1,380.83	32.41	37.15	1,592.52
1990:08	36.96	40.28	34.32	110.67	1,382.59	32.41	37.33	1,600.14
1990:09	36.92	40.48	34.20	111.21	1,384.35	32.42	37.51	1,607.76
1990:10	36.88	40.68	34.07	111.74	1,386.10	32.42	37.69	1,615.38



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
1990:11	36.85	40.88	33.95	112.28	1,387.86	32.42	37.87	1,623.00
1990:12	36.81	41.08	33.83	112.82	1,389.62	32.42	38.05	1,630.62
1991:01	36.78	41.28	33.71	113.36	1,391.38	32.43	38.23	1,638.25
1991:02	36.74	41.48	33.59	113.90	1,393.14	32.43	38.41	1,645.87
1991:03	36.70	41.68	33.47	114.44	1,394.90	32.43	38.60	1,653.49
1991:04	36.67	41.88	33.35	114.98	1,396.65	32.43	38.78	1,661.11
1991:05	36.63	42.08	33.23	115.52	1,398.41	32.44	38.96	1,668.73
1991:06	36.60	42.28	33.12	116.06	1,400.17	32.44	39.14	1,676.35
1991:07	36.74	42.43	33.14	116.47	1,406.20	32.59	39.37	1,688.17
1991:08	36.88	42.59	33.16	116.89	1,412.23	32.74	39.61	1,699.99
1991:09	37.02	42.75	33.18	117.31	1,418.26	32.90	39.84	1,711.81
1991:10	37.17	42.90	33.20	117.73	1,424.29	33.05	40.08	1,723.63
1991:11	37.31	43.06	33.22	118.15	1,430.32	33.20	40.31	1,735.45
1991:12	37.45	43.21	33.24	118.57	1,436.35	33.35	40.54	1,747.27
1992:01	37.60	43.37	33.26	118.98	1,442.37	33.50	40.78	1,759.09
1992:02	37.74	43.52	33.28	119.40	1,448.40	33.66	41.01	1,770.91
1992:03	37.88	43.68	33.30	119.82	1,454.43	33.81	41.25	1,782.73
1992:04	38.02	43.83	33.32	120.24	1,460.46	33.96	41.48	1,794.55
1992:05	38.17	43.99	33.34	120.66	1,466.49	34.11	41.72	1,806.36
1992:06	38.31	44.15	33.36	121.08	1,472.52	34.26	41.95	1,818.18
1992:07	38.55	44.33	33.33	121.58	1,477.44	34.49	42.19	1,828.25
1992:08	38.79	44.51	33.30	122.08	1,482.37	34.73	42.43	1,838.32
1992:09	39.03	44.69	33.28	122.58	1,487.29	34.96	42.67	1,848.39
1992:10	39.27	44.87	33.25	123.08	1,492.21	35.19	42.92	1,858.46
1992:11	39.51	45.06	33.23	123.58	1,497.14	35.42	43.16	1,868.53
1992:12	39.75	45.24	33.20	124.08	1,502.06	35.65	43.40	1,878.60
1993:01	40.00	45.42	33.18	124.59	1,506.98	35.88	43.64	1,888.67
1993:02	40.24	45.60	33.15	125.09	1,511.91	36.11	43.88	1,898.73
1993:03	40.48	45.78	33.13	125.59	1,516.83	36.34	44.12	1,908.80
1993:04	40.72	45.97	33.11	126.09	1,521.75	36.57	44.37	1,918.87
1993:05	40.96	46.15	33.08	126.59	1,526.68	36.80	44.61	1,928.94
1993:06	41.20	46.33	33.06	127.09	1,531.60	37.04	44.85	1,939.01
1993:07	41.31	46.50	33.04	127.54	1,536.08	37.14	45.03	1,948.24
1993:08	41.41	46.67	33.01	127.98	1,540.56	37.25	45.20	1,957.48
1993:09	41.52	46.83	32.99	128.43	1,545.04	37.35	45.38	1,966.72
1993:10	41.63	47.00	32.97	128.87	1,549.51	37.46	45.56	1,975.95
1993:11	41.73	47.17	32.95	129.32	1,553.99	37.56	45.73	1,985.19
1993:12	41.84	47.33	32.93	129.76	1,558.47	37.67	45.91	1,994.42
1994:01	41.95	47.50	32.90	130.20	1,562.95	37.78	46.09	2,003.66



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
1994:02	42.06	47.67	32.88	130.65	1,567.43	37.88	46.26	2,012.90
1994:03	42.16	47.83	32.86	131.09	1,571.91	37.99	46.44	2,022.13
1994:04	42.27	48.00	32.84	131.54	1,576.38	38.09	46.62	2,031.37
1994:05	42.38	48.17	32.82	131.98	1,580.86	38.20	46.79	2,040.60
1994:06	42.48	48.34	32.80	132.43	1,585.34	38.30	46.97	2,049.84
1994:07	42.63	48.49	32.85	132.89	1,592.73	38.46	47.11	2,063.61
1994:08	42.77	48.64	32.90	133.36	1,600.12	38.61	47.26	2,077.38
1994:09	42.92	48.80	32.94	133.82	1,607.50	38.76	47.41	2,091.16
1994:10	43.06	48.95	32.99	134.28	1,614.89	38.91	47.55	2,104.93
1994:11	43.21	49.10	33.04	134.75	1,622.28	39.06	47.70	2,118.70
1994:12	43.35	49.26	33.09	135.21	1,629.67	39.22	47.84	2,132.47
1995:01	43.50	49.41	33.13	135.68	1,637.05	39.37	47.99	2,146.24
1995:02	43.64	49.56	33.18	136.14	1,644.44	39.52	48.13	2,160.02
1995:03	43.79	49.71	33.23	136.61	1,651.83	39.67	48.28	2,173.79
1995:04	43.93	49.87	33.27	137.07	1,659.22	39.82	48.43	2,187.56
1995:05	44.07	50.02	33.32	137.53	1,666.60	39.98	48.57	2,201.33
1995:06	44.22	50.17	33.36	138.00	1,673.99	40.13	48.72	2,215.11
1995:07	44.23	50.18	33.36	138.02	1,674.38	40.14	48.73	2,215.98
1995:08	44.24	50.19	33.37	138.05	1,674.77	40.15	48.74	2,216.85
1995:09	44.25	50.20	33.37	138.07	1,675.15	40.16	48.75	2,217.72
1995:10	44.26	50.21	33.37	138.10	1,675.54	40.17	48.76	2,218.58
1995:11	44.28	50.22	33.37	138.12	1,675.93	40.18	48.77	2,219.45
1995:12	44.29	50.23	33.37	138.15	1,676.32	40.19	48.78	2,220.32
1996:01	44.30	50.24	33.37	138.17	1,676.71	40.20	48.79	2,221.19
1996:02	44.31	50.25	33.37	138.19	1,677.09	40.21	48.80	2,222.06
1996:03	44.32	50.26	33.37	138.22	1,677.48	40.22	48.81	2,222.93
1996:04	44.33	50.27	33.38	138.24	1,677.87	40.23	48.82	2,223.80
1996:05	44.34	50.28	33.38	138.27	1,678.26	40.25	48.83	2,224.67
1996:06	44.35	50.29	33.38	138.29	1,678.65	40.26	48.84	2,225.54
1996:07	44.37	50.30	33.38	138.32	1,679.03	40.27	48.85	2,226.41
1996:08	44.38	50.31	33.38	138.34	1,679.42	40.28	48.87	2,227.29
1996:09	44.39	50.32	33.38	138.37	1,679.81	40.29	48.88	2,228.16
1996:10	44.40	50.33	33.38	138.39	1,680.20	40.30	48.89	2,229.03
1996:11	44.41	50.34	33.38	138.42	1,680.59	40.31	48.90	2,229.91
1996:12	44.42	50.35	33.38	138.44	1,680.98	40.32	48.91	2,230.78
1997:01	44.43	50.36	33.39	138.46	1,681.37	40.33	48.92	2,231.65
1997:02	44.45	50.37	33.39	138.49	1,681.76	40.34	48.93	2,232.53
1997:03	44.46	50.38	33.39	138.51	1,682.15	40.35	48.94	2,233.40
1997:04	44.47	50.39	33.39	138.54	1,682.54	40.36	48.95	2,234.27



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPRHH	LPOPA	LYTOT	LSERVICES	LTS	LYTOT
1997:05	44.48	50.40	33.39	138.56	1,682.92	40.38	48.96	2,235.15
1997:06	44.49	50.41	33.39	138.59	1,683.31	40.39	48.97	2,236.02
1997:07	44.50	50.42	33.39	138.61	1,683.70	40.40	48.98	2,236.90
1997:08	44.51	50.43	33.39	138.64	1,684.09	40.41	48.99	2,237.78
1997:09	44.52	50.44	33.39	138.66	1,684.48	40.42	49.00	2,238.65
1997:10	44.54	50.45	33.40	138.69	1,684.87	40.43	49.01	2,239.53
1997:11	44.55	50.46	33.40	138.71	1,685.26	40.44	49.02	2,240.41
1997:12	44.56	50.47	33.40	138.73	1,685.65	40.45	49.04	2,241.29
1998:01	44.57	50.48	33.40	138.76	1,686.04	40.46	49.05	2,242.16
1998:02	44.58	50.49	33.40	138.78	1,686.43	40.47	49.06	2,243.04
1998:03	44.59	50.50	33.40	138.81	1,686.82	40.48	49.07	2,243.92
1998:04	44.60	50.51	33.40	138.83	1,687.21	40.49	49.08	2,244.80
1998:05	44.62	50.52	33.40	138.86	1,687.60	40.51	49.09	2,245.67
1998:06	44.63	50.53	33.40	138.88	1,687.99	40.52	49.10	2,246.55
1998:07	44.64	50.54	33.41	138.91	1,688.39	40.53	49.11	2,247.43
1998:08	44.65	50.55	33.41	138.93	1,688.78	40.54	49.12	2,248.32
1998:09	44.66	50.56	33.41	138.96	1,689.17	40.55	49.13	2,249.20
1998:10	44.67	50.57	33.41	138.98	1,689.56	40.56	49.14	2,250.08
1998:11	44.68	50.58	33.41	139.01	1,689.95	40.57	49.15	2,250.96
1998:12	44.70	50.59	33.41	139.03	1,690.34	40.58	49.16	2,251.84
1999:01	44.71	50.60	33.41	139.05	1,690.73	40.59	49.17	2,252.72
1999:02	44.72	50.61	33.41	139.08	1,691.12	40.60	49.18	2,253.61
1999:03	44.73	50.62	33.41	139.10	1,691.52	40.61	49.19	2,254.49
1999:04	44.74	50.63	33.42	139.13	1,691.91	40.63	49.21	2,255.37
1999:05	44.75	50.64	33.42	139.15	1,692.30	40.64	49.22	2,256.25
1999:06	44.76	50.65	33.42	139.18	1,692.69	40.65	49.23	2,257.13
1999:07	44.78	50.66	33.42	139.20	1,693.08	40.66	49.24	2,258.02
1999:08	44.79	50.67	33.42	139.23	1,693.47	40.67	49.25	2,258.90
1999:09	44.80	50.68	33.42	139.25	1,693.87	40.68	49.26	2,259.79
1999:10	44.81	50.69	33.42	139.28	1,694.26	40.69	49.27	2,260.68
1999:11	44.82	50.70	33.42	139.30	1,694.65	40.70	49.28	2,261.56
1999:12	44.83	50.71	33.43	139.33	1,695.04	40.71	49.29	2,262.45
2000:01	44.84	50.72	33.43	139.35	1,695.44	40.72	49.30	2,263.33
2000:02	44.86	50.73	33.43	139.38	1,695.83	40.73	49.31	2,264.22
2000:03	44.87	50.74	33.43	139.40	1,696.22	40.75	49.32	2,265.10
2000:04	44.88	50.75	33.43	139.42	1,696.61	40.76	49.33	2,265.99
2000:05	44.89	50.76	33.43	139.45	1,697.00	40.77	49.34	2,266.88
2000:06	44.90	50.77	33.43	139.47	1,697.40	40.78	49.36	2,267.76
2000:07	44.94	50.80	33.44	139.56	1,698.77	40.81	49.39	2,271.15



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
2000:08	44.97	50.84	33.44	139.64	1,700.15	40.84	49.43	2,274.53
2000:09	45.01	50.87	33.45	139.72	1,701.52	40.88	49.47	2,277.91
2000:10	45.04	50.90	33.45	139.81	1,702.90	40.91	49.51	2,281.30
2000:11	45.08	50.94	33.46	139.89	1,704.27	40.94	49.55	2,284.68
2000:12	45.11	50.97	33.46	139.97	1,705.65	40.97	49.58	2,288.06
2001:01	45.15	51.00	33.47	140.06	1,707.02	41.01	49.62	2,291.45
2001:02	45.18	51.03	33.48	140.14	1,708.40	41.04	49.66	2,294.83
2001:03	45.22	51.07	33.48	140.22	1,709.77	41.07	49.70	2,298.22
2001:04	45.25	51.10	33.49	140.31	1,711.15	41.10	49.74	2,301.60
2001:05	45.29	51.13	33.49	140.39	1,712.52	41.14	49.77	2,304.98
2001:06	45.32	51.17	33.50	140.47	1,713.90	41.17	49.81	2,308.37
2001:07	45.36	51.20	33.50	140.56	1,715.28	41.20	49.85	2,311.81
2001:08	45.39	51.23	33.51	140.64	1,716.67	41.23	49.89	2,315.25
2001:09	45.43	51.26	33.51	140.72	1,718.06	41.27	49.93	2,318.70
2001:10	45.46	51.30	33.52	140.81	1,719.45	41.30	49.97	2,322.14
2001:11	45.50	51.33	33.52	140.89	1,720.84	41.33	50.00	2,325.59
2001:12	45.54	51.36	33.53	140.97	1,722.22	41.37	50.04	2,329.03
2002:01	45.57	51.40	33.54	141.06	1,723.61	41.40	50.08	2,332.48
2002:02	45.61	51.43	33.54	141.14	1,725.00	41.43	50.12	2,335.92
2002:03	45.64	51.46	33.55	141.22	1,726.39	41.46	50.16	2,339.36
2002:04	45.68	51.50	33.55	141.31	1,727.78	41.50	50.20	2,342.81
2002:05	45.71	51.53	33.56	141.39	1,729.17	41.53	50.23	2,346.25
2002:06	45.75	51.56	33.56	141.48	1,730.55	41.56	50.27	2,349.70
2002:07	45.78	51.60	33.57	141.56	1,731.96	41.60	50.31	2,353.20
2002:08	45.82	51.63	33.57	141.64	1,733.36	41.63	50.35	2,356.71
2002:09	45.86	51.66	33.58	141.73	1,734.76	41.66	50.39	2,360.21
2002:10	45.89	51.70	33.58	141.81	1,736.16	41.70	50.43	2,363.72
2002:11	45.93	51.73	33.59	141.90	1,737.56	41.73	50.47	2,367.23
2002:12	45.96	51.76	33.60	141.98	1,738.96	41.76	50.50	2,370.73
2003:01	46.00	51.80	33.60	142.07	1,740.37	41.79	50.54	2,374.24
2003:02	46.03	51.83	33.61	142.15	1,741.77	41.83	50.58	2,377.74
2003:03	46.07	51.86	33.61	142.23	1,743.17	41.86	50.62	2,381.25
2003:04	46.11	51.90	33.62	142.32	1,744.57	41.89	50.66	2,384.76
2003:05	46.14	51.93	33.62	142.40	1,745.97	41.93	50.70	2,388.26
2003:06	46.18	51.96	33.63	142.49	1,747.37	41.96	50.74	2,391.77
2003:07	46.21	52.00	33.63	142.57	1,748.79	41.99	50.78	2,395.34
2003:08	46.25	52.03	33.64	142.66	1,750.21	42.03	50.82	2,398.90
2003:09	46.29	52.06	33.64	142.74	1,751.62	42.06	50.85	2,402.47
2003:10	46.32	52.10	33.65	142.83	1,753.04	42.09	50.89	2,406.04



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LYTOT	LSERVICES	LTS	LYTOT
2003:11	46.36	52.13	33.66	142.91	1,754.45	42.13	50.93	2,409.61
2003:12	46.39	52.16	33.66	143.00	1,755.87	42.16	50.97	2,413.18
2004:01	46.43	52.20	33.67	143.08	1,757.28	42.20	51.01	2,416.75
2004:02	46.47	52.23	33.67	143.17	1,758.70	42.23	51.05	2,420.32
2004:03	46.50	52.26	33.68	143.25	1,760.11	42.26	51.09	2,423.89
2004:04	46.54	52.30	33.68	143.34	1,761.53	42.30	51.13	2,427.45
2004:05	46.57	52.33	33.69	143.42	1,762.94	42.33	51.17	2,431.02
2004:06	46.61	52.36	33.69	143.51	1,764.36	42.36	51.21	2,434.59
2004:07	46.65	52.40	33.70	143.59	1,765.79	42.40	51.25	2,438.22
2004:08	46.68	52.43	33.70	143.68	1,767.22	42.43	51.28	2,441.86
2004:09	46.72	52.47	33.71	143.76	1,768.65	42.46	51.32	2,445.49
2004:10	46.76	52.50	33.72	143.85	1,770.08	42.50	51.36	2,449.12
2004:11	46.79	52.53	33.72	143.93	1,771.50	42.53	51.40	2,452.75
2004:12	46.83	52.57	33.73	144.02	1,772.93	42.57	51.44	2,456.39
2005:01	46.87	52.60	33.73	144.10	1,774.36	42.60	51.48	2,460.02
2005:02	46.90	52.64	33.74	144.19	1,775.79	42.63	51.52	2,463.65
2005:03	46.94	52.67	33.74	144.28	1,777.22	42.67	51.56	2,467.28
2005:04	46.98	52.70	33.75	144.36	1,778.65	42.70	51.60	2,470.92
2005:05	47.01	52.74	33.75	144.45	1,780.08	42.73	51.64	2,474.55
2005:06	47.05	52.77	33.76	144.53	1,781.51	42.77	51.68	2,478.18
2005:07	47.05	52.77	33.76	144.53	1,781.40	42.77	51.68	2,477.92
2005:08	47.04	52.77	33.76	144.52	1,781.30	42.76	51.67	2,477.65
2005:09	47.04	52.76	33.76	144.52	1,781.19	42.76	51.67	2,477.39
2005:10	47.04	52.76	33.76	144.51	1,781.08	42.76	51.67	2,477.12
2005:11	47.04	52.76	33.76	144.51	1,780.98	42.76	51.67	2,476.86
2005:12	47.04	52.76	33.76	144.50	1,780.87	42.76	51.67	2,476.59
2006:01	47.03	52.76	33.75	144.50	1,780.77	42.75	51.66	2,476.33
2006:02	47.03	52.75	33.75	144.49	1,780.66	42.75	51.66	2,476.06
2006:03	47.03	52.75	33.75	144.49	1,780.56	42.75	51.66	2,475.80
2006:04	47.03	52.75	33.75	144.48	1,780.45	42.75	51.66	2,475.53
2006:05	47.03	52.75	33.75	144.48	1,780.34	42.75	51.65	2,475.27
2006:06	47.02	52.75	33.75	144.47	1,780.24	42.74	51.65	2,475.00
2006:07	47.02	52.74	33.75	144.47	1,780.13	42.74	51.65	2,474.74
2006:08	47.02	52.74	33.75	144.46	1,780.03	42.74	51.65	2,474.48
2006:09	47.02	52.74	33.75	144.46	1,779.92	42.74	51.64	2,474.21
2006:10	47.01	52.74	33.75	144.45	1,779.81	42.74	51.64	2,473.95
2006:11	47.01	52.74	33.75	144.45	1,779.71	42.74	51.64	2,473.68
2006:12	47.01	52.73	33.75	144.44	1,779.60	42.73	51.64	2,473.42
2007:01	47.01	52.73	33.75	144.44	1,779.50	42.73	51.64	2,473.15



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYSOT	LSERVICES	LTS	LYTOT
2007:02	47.01	52.73	33.75	144.43	1,779.39	42.73	51.63	2,472.89
2007:03	47.00	52.73	33.74	144.43	1,779.29	42.73	51.63	2,472.62
2007:04	47.00	52.73	33.74	144.42	1,779.18	42.73	51.63	2,472.36
2007:05	47.00	52.72	33.74	144.42	1,779.07	42.72	51.63	2,472.10
2007:06	47.00	52.72	33.74	144.41	1,778.97	42.72	51.62	2,471.83
2007:07	47.00	52.72	33.74	144.41	1,778.86	42.72	51.62	2,471.57
2007:08	46.99	52.72	33.74	144.40	1,778.76	42.72	51.62	2,471.30
2007:09	46.99	52.72	33.74	144.40	1,778.65	42.72	51.62	2,471.04
2007:10	46.99	52.71	33.74	144.39	1,778.54	42.71	51.62	2,470.77
2007:11	46.99	52.71	33.74	144.39	1,778.44	42.71	51.61	2,470.51
2007:12	46.99	52.71	33.74	144.38	1,778.33	42.71	51.61	2,470.25
2008:01	46.98	52.71	33.74	144.38	1,778.23	42.71	51.61	2,469.98
2008:02	46.98	52.71	33.74	144.37	1,778.12	42.71	51.61	2,469.72
2008:03	46.98	52.70	33.74	144.37	1,778.02	42.70	51.60	2,469.45
2008:04	46.98	52.70	33.74	144.36	1,777.91	42.70	51.60	2,469.19
2008:05	46.97	52.70	33.73	144.36	1,777.80	42.70	51.60	2,468.93
2008:06	46.97	52.70	33.73	144.35	1,777.70	42.70	51.60	2,468.66
2008:07	46.97	52.70	33.73	144.35	1,777.59	42.70	51.59	2,468.40
2008:08	46.97	52.69	33.73	144.34	1,777.49	42.69	51.59	2,468.13
2008:09	46.97	52.69	33.73	144.34	1,777.38	42.69	51.59	2,467.87
2008:10	46.96	52.69	33.73	144.33	1,777.28	42.69	51.59	2,467.61
2008:11	46.96	52.69	33.73	144.33	1,777.17	42.69	51.59	2,467.34
2008:12	46.96	52.69	33.73	144.32	1,777.06	42.69	51.58	2,467.08
2009:01	46.96	52.68	33.73	144.32	1,776.96	42.68	51.58	2,466.82
2009:02	46.96	52.68	33.73	144.31	1,776.85	42.68	51.58	2,466.55
2009:03	46.95	52.68	33.73	144.31	1,776.75	42.68	51.58	2,466.29
2009:04	46.95	52.68	33.73	144.30	1,776.64	42.68	51.57	2,466.02
2009:05	46.95	52.68	33.73	144.30	1,776.54	42.68	51.57	2,465.76
2009:06	46.95	52.67	33.72	144.29	1,776.43	42.68	51.57	2,465.50
2009:07	46.95	52.67	33.72	144.29	1,776.32	42.67	51.57	2,465.23
2009:08	46.94	52.67	33.72	144.28	1,776.22	42.67	51.56	2,464.97
2009:09	46.94	52.67	33.72	144.28	1,776.11	42.67	51.56	2,464.71
2009:10	46.94	52.67	33.72	144.27	1,776.01	42.67	51.56	2,464.44
2009:11	46.94	52.66	33.72	144.27	1,775.90	42.67	51.56	2,464.18
2009:12	46.94	52.66	33.72	144.26	1,775.80	42.66	51.56	2,463.92
2010:01	46.93	52.66	33.72	144.26	1,775.69	42.66	51.55	2,463.65
2010:02	46.93	52.66	33.72	144.25	1,775.59	42.66	51.55	2,463.39
2010:03	46.93	52.66	33.72	144.25	1,775.48	42.66	51.55	2,463.13
2010:04	46.93	52.65	33.72	144.24	1,775.37	42.66	51.55	2,462.86



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
2010:05	46.92	52.65	33.72	144.24	1,775.27	42.65	51.54	2,462.60
2010:06	46.92	52.65	33.72	144.23	1,775.16	42.65	51.54	2,462.34
2010:07	46.88	52.61	33.70	144.14	1,773.20	42.62	51.50	2,457.43
2010:08	46.84	52.58	33.69	144.05	1,771.23	42.58	51.46	2,452.53
2010:09	46.81	52.54	33.68	143.95	1,769.26	42.54	51.41	2,447.62
2010:10	46.77	52.50	33.66	143.86	1,767.29	42.51	51.37	2,442.72
2010:11	46.73	52.46	33.65	143.77	1,765.33	42.47	51.33	2,437.81
2010:12	46.69	52.43	33.64	143.67	1,763.36	42.44	51.28	2,432.91
2011:01	46.65	52.39	33.62	143.58	1,761.39	42.40	51.24	2,428.00
2011:02	46.61	52.35	33.61	143.49	1,759.42	42.36	51.20	2,423.10
2011:03	46.57	52.31	33.60	143.40	1,757.46	42.33	51.16	2,418.19
2011:04	46.53	52.28	33.58	143.30	1,755.49	42.29	51.11	2,413.29
2011:05	46.49	52.24	33.57	143.21	1,753.52	42.26	51.07	2,408.38
2011:06	46.46	52.20	33.55	143.12	1,751.55	42.22	51.03	2,403.48
2011:07	46.42	52.16	33.54	143.02	1,749.61	42.18	50.99	2,398.69
2011:08	46.38	52.13	33.53	142.93	1,747.67	42.15	50.94	2,393.91
2011:09	46.34	52.09	33.51	142.84	1,745.73	42.11	50.90	2,389.12
2011:10	46.30	52.05	33.50	142.75	1,743.79	42.08	50.86	2,384.33
2011:11	46.26	52.01	33.49	142.66	1,741.85	42.04	50.82	2,379.54
2011:12	46.22	51.98	33.47	142.56	1,739.90	42.01	50.77	2,374.76
2012:01	46.19	51.94	33.46	142.47	1,737.96	41.97	50.73	2,369.97
2012:02	46.15	51.90	33.45	142.38	1,736.02	41.93	50.69	2,365.18
2012:03	46.11	51.87	33.43	142.29	1,734.08	41.90	50.65	2,360.39
2012:04	46.07	51.83	33.42	142.19	1,732.14	41.86	50.60	2,355.61
2012:05	46.03	51.79	33.41	142.10	1,730.20	41.83	50.56	2,350.82
2012:06	45.99	51.75	33.39	142.01	1,728.26	41.79	50.52	2,346.03
2012:07	45.95	51.72	33.38	141.92	1,726.34	41.76	50.48	2,341.36
2012:08	45.92	51.68	33.37	141.83	1,724.43	41.72	50.44	2,336.69
2012:09	45.88	51.64	33.35	141.74	1,722.51	41.69	50.39	2,332.01
2012:10	45.84	51.61	33.34	141.64	1,720.59	41.65	50.35	2,327.34
2012:11	45.80	51.57	33.33	141.55	1,718.68	41.62	50.31	2,322.67
2012:12	45.76	51.53	33.31	141.46	1,716.76	41.58	50.27	2,317.99
2013:01	45.73	51.50	33.30	141.37	1,714.85	41.55	50.23	2,313.32
2013:02	45.69	51.46	33.29	141.28	1,712.93	41.51	50.18	2,308.65
2013:03	45.65	51.42	33.27	141.19	1,711.02	41.47	50.14	2,303.97
2013:04	45.61	51.39	33.26	141.10	1,709.10	41.44	50.10	2,299.30
2013:05	45.57	51.35	33.25	141.00	1,707.19	41.40	50.06	2,294.63
2013:06	45.53	51.31	33.23	140.91	1,705.27	41.37	50.02	2,289.96
2013:07	45.50	51.28	33.22	140.82	1,703.38	41.33	49.97	2,285.39



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
2013:08	45.46	51.24	33.21	140.73	1,701.49	41.30	49.93	2,280.83
2013:09	45.42	51.20	33.19	140.64	1,699.60	41.26	49.89	2,276.27
2013:10	45.38	51.17	33.18	140.55	1,697.71	41.23	49.85	2,271.71
2013:11	45.35	51.13	33.17	140.46	1,695.82	41.19	49.81	2,267.15
2013:12	45.31	51.09	33.15	140.37	1,693.93	41.16	49.77	2,262.59
2014:01	45.27	51.06	33.14	140.28	1,692.04	41.12	49.73	2,258.03
2014:02	45.23	51.02	33.13	140.19	1,690.15	41.09	49.68	2,253.47
2014:03	45.19	50.98	33.11	140.09	1,688.26	41.05	49.64	2,248.90
2014:04	45.16	50.95	33.10	140.00	1,686.37	41.02	49.60	2,244.34
2014:05	45.12	50.91	33.09	139.91	1,684.48	40.98	49.56	2,239.78
2014:06	45.08	50.87	33.07	139.82	1,682.59	40.95	49.52	2,235.22
2014:07	45.04	50.84	33.06	139.73	1,680.73	40.92	49.48	2,230.77
2014:08	45.01	50.80	33.05	139.64	1,678.86	40.88	49.44	2,226.32
2014:09	44.97	50.77	33.03	139.55	1,677.00	40.85	49.39	2,221.86
2014:10	44.93	50.73	33.02	139.46	1,675.13	40.81	49.35	2,217.41
2014:11	44.89	50.69	33.01	139.37	1,673.27	40.78	49.31	2,212.96
2014:12	44.86	50.66	32.99	139.28	1,671.40	40.74	49.27	2,208.51
2015:01	44.82	50.62	32.98	139.19	1,669.54	40.71	49.23	2,204.05
2015:02	44.78	50.58	32.97	139.10	1,667.67	40.67	49.19	2,199.60
2015:03	44.78	50.55	32.95	139.01	1,665.81	40.64	49.15	2,195.15
2015:04	44.71	50.51	32.94	138.92	1,663.94	40.60	49.11	2,190.70
2015:05	44.67	50.48	32.93	138.83	1,662.08	40.57	49.07	2,186.24
2015:06	44.63	50.44	32.91	138.74	1,660.21	40.54	49.02	2,181.79
2015:07	44.55	50.36	32.89	138.55	1,656.28	40.46	48.94	2,172.51
2015:08	44.47	50.29	32.86	138.36	1,652.35	40.39	48.85	2,163.23
2015:09	44.40	50.21	32.83	138.17	1,648.42	40.32	48.76	2,153.95
2015:10	44.32	50.13	32.80	137.98	1,644.49	40.24	48.68	2,144.67
2015:11	44.24	50.06	32.77	137.79	1,640.56	40.17	48.59	2,135.39
2015:12	44.16	49.98	32.75	137.60	1,636.64	40.10	48.50	2,126.11
2016:01	44.08	49.90	32.72	137.40	1,632.71	40.02	48.42	2,116.83
2016:02	44.00	49.83	32.69	137.21	1,628.78	39.95	48.33	2,107.55
2016:03	43.92	49.75	32.66	137.02	1,624.85	39.88	48.24	2,098.27
2016:04	43.84	49.67	32.63	136.83	1,620.92	39.80	48.16	2,088.99
2016:05	43.76	49.60	32.60	136.64	1,616.99	39.73	48.07	2,079.71
2016:06	43.68	49.52	32.57	136.45	1,613.06	39.66	47.98	2,070.43
2016:07	43.61	49.45	32.55	136.26	1,609.24	39.59	47.90	2,061.62
2016:08	43.53	49.37	32.52	136.07	1,605.42	39.52	47.81	2,052.82
2016:09	43.45	49.29	32.49	135.89	1,601.61	39.44	47.73	2,044.01
2016:10	43.37	49.22	32.46	135.70	1,597.79	39.37	47.64	2,035.20



Historical and Projected Energy and Demand Forecast Variables								
Year/Month	LGOODSERV	LHH	LINCPERHH	LPOPA	LRYTOT	LSERVICES	LTS	LYTOT
2016:11	43.30	49.14	32.43	135.51	1,593.97	39.30	47.56	2,026.40
2016:12	43.22	49.07	32.41	135.32	1,590.15	39.23	47.47	2,017.59

Appendix 1B.16.3

**Kissimmee Utility Authority
Request for Power Supply Proposal
RFP #004-97**

KISSIMMEE UTILITY AUTHORITY
Request for Power Supply Proposals
RFP #004-97

May 28, 1997

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KISSIMMEE UTILITY AUTHORITY
Request for Power Supply Proposals

May 28, 1997

1. Introduction

The Kissimmee Utility Authority ("KUA" or "Authority") is issuing this Request for Proposals ("RFP") as an invitation to qualified companies to submit proposals for the supply of electric capacity and energy to satisfy up to 80 MW of KUA's projected requirements for the period 2001 -2030. Details of KUA's system requirements for the period are shown in Section 3.

KUA will consider proposals for base, intermediate and/or peaking generating resources and will accept bids that propose a minimum capacity of 10 MW and an agreement term of at least three years. The power supply commencement date is June 1, 2001. Proposals received in response to this RFP will be evaluated in comparison with (i) the options that are available to KUA under existing power supply arrangements; and/or (ii) a self-build alternative that may be developed jointly by KUA and Florida Municipal Power Agency ("FMPA").

The deadline for receipt of proposals by KUA is Wednesday, August 6, 1997.

2. KUA Description

The KUA is a public body corporate and politic, duly organized and legally existing as part of the government of the City of Kissimmee ("City"), Florida, under the Constitution and laws of the State of Florida, particularly the Charter of the City. At a special referendum election held in the City on March 26, 1985, the qualified electors residing in the City approved Amended City Ordinance No. 1285 (the "Ordinance"), amending the charter of the City to create the Authority with powers and immunities set forth in the Ordinance. On October 1, 1985, the City transferred to the Authority ownership and operational control of the electric generation, transmission and distribution system (the "System"), including all generation, transmission, interconnection, and distribution facilities thereof.

3. The SYSTEM

KUA's peak demand, which occurs during the summer months, is projected to be 209 MW for 1997 and the net system energy requirement is expected to be 985 GWh in calendar year 1997.

The Authority's power supply needs are currently satisfied by a combination of KUA-owned generating resources and contracted power supply resources. Details of the annual capacity nominations for each existing resource available to KUA under existing arrangements are shown in Table 1. Partial Requirements Service ("PR") is provided by Florida Power Corporation ("FPC") under its stratified PR rate. No nominations have been made for the FPC PR resource after 2001.

Table 2 provides a summary of KUA's projections of annual net energy requirement, summer peak demand, system capacity requirement, committed capacity resources and required capacity resources for the period 2001 through 2030 which KUA is seeking to satisfy at least in part through this RFP process.

TABLE 1
Committed Capacity Resources

Year (Ending Dec. 31)	KUA-Owned Capacity Resources (MW)							Contracted Capacity Resources (MW)					
	Hansel Plant (Diesel)	Hansel Plant (Gas CC)	Cane Island Plant 1 (Gas CT)	Cane Island Plant 2 (Gas CC)	Crystal River #3 (Nuclear)	Stanton No. 1 (Coal)	Indian River (Gas CT)	St. Lucie Nos 1 & 2 (Nuclear)	OUC Sched. D (Syst. Pur.)	OUC Stanton #1 (Coal)	OUC Stanton #2 (Coal)	OUC Unit Purchase	FFC Stratified PR
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
2001	15	41.9	15.2	54.5	5.2	21.0	10.2	6.8	20.0	7.9	33.3	0.0	0.0
2002	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	20.0	7.9	33.3	0.0	0.0
2003	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	20.0	7.9	33.3	0.0	0.0
2004	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2005	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2006	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2007	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2008	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2009	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2010	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2011	0	41.9	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2012	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2013	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2014	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2015	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2016	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2017	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2018	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2019	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2020	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2021	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2022	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2023	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2024	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2025	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2026	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2027	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2028	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2029	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0
2030	0	0.0	15.2	54.5	5.2	21.0	10.2	6.8	0.0	7.9	33.3	0.0	0.0

TABLE 2**System Projections**

Year	Energy Requirements (GWh)	Summer Peak Demand (MOO)	System Capacity Requirements (MOO)	Committed Capacity Resources (MOO)	Required Capacity Resources (MW)
(a)	(b)	(c)	(d)	(e)	(f)
2001	1,158	243	279	231	48
2002	1,205	252	290	216	74
2003	1,253	261	300	216	84
2004	1,301	271	312	196	115
2005	1,349	280	322	196	126
2006	1,391	288	331	196	135
2007	1,431	296	340	196	144
2008	1,473	304	350	196	154
2009	1,514	313	360	196	164
2010	1,557	321	369	196	172
2011	1,598	330	380	196	184
2012	1,641	138	389	154	235
2013	1,684	347	399	154	245
2014	1,729	356	409	154	255
2015	1,773	365	420	154	266
2016	1,806	373	429	154	275
2017	1,859	383	440	154	286
2018	1,913	393	452	154	298
2019	1,968	403	463	154	309
2020	2,025	414	476	154	322
2021	2,084	425	489	154	335
2022	2,145	436	501	154	347
2023	2,207	447	514	154	360
2024	2,271	459	528	154	374
2025	2,337	471	542	154	388
2026	2,405	483	555	154	401
2027	2,475	496	570	154	416
2028	2,547	509	585	154	431
2029	2,621	522	600	154	446
2030	2,698	536	616	154	462

4. RFP Schedule

KUA's timetable for this Request For Proposal ("RFP" process is shown below. Note that all times shown are based on the prevailing eastern time on the scheduled dates; however, the dates shown are only estimates and may be modified at any time by KUA.

Public Notice of RFP	May 27, 1997	
RFP Available for Distribution	May 28, 1997	
Notification of Conference Attendance Due	June 18, 1997	[12:00 Noon EDT]
Pre-Bid Conference	June 24, 1997	[9:30 A.M. EDT]
Notice of Intent to Bid Form Due to FMPA	June 30, 1997	[5 :00 P.M. EDT]
Deadline for Bidders' Questions	July 2, 1997	[5:00 P.M. EDT]
Sealed Proposal(s) Due Date	August 6, 1997	[3:00 P.M. EDT]
Publish Short List/Commence Negotiations	October 8, 1997	
Complete Negotiations	December 4, 1997	
Contract(s) Approved	December 12, 1997	
Commencement of Power Supply Service	June 1, 2001	

5. Potential Power Supply Requirements

KUA initiated the development of an Integrated Resource Plan ("IRP") to ensure that it's customers are provided with reliable and economic energy, both in the short and long terms. In developing the IRP, a wide assortment of supply-side and demand-side alternatives were considered as a means of satisfying KUA's future demand for electricity. KUA's primary objective was to develop a plan (or plans) that blends the short-term and long-term objectives and fairly and reasonably assigns risks associated with the resources set forth in the plan(s). In meeting this objective, it was important that KUA consider its competitive position in the industry in order to maintain customer base while adding those resources which minimize prices and total cost to KUA's customers.

After evaluating a variety of different plans using a risk analysis model, the most robust resources were identified based on the frequency of selection of the resources in the most robust plans. A robust plan is a plan that consistently performs well over a variety of different futures. The lowest cost arrangement of the most robust resources formed the most robust plan. KUA's IRP is being used as the basis for this RFP and the possible selection of the joint project with Florida Municipal Power Agency ("FMPA") at the "Cane Island Site" as the self-build alternative. A copy of the IRP Summary Report dated April, 1996 is included as Attachment C.

KUA is accepting proposals for capacity and energy in whole megawatt quantities for part or all of the capacity requirements with a minimum bid amount of 10 MW. As previously mentioned,

KUA currently has the option to increase its power purchase amounts under existing purchase agreements as well as the option to build and jointly own new generating capacity on the existing Cane Island Site. Accordingly, KUA will consider proposals for the sale of short-term or long-term firm power supply from (i) existing specified resources, (ii) a portfolio of supply resources with appropriate guarantees, and/or (iii) a generating facility to be constructed for a unit power sale or joint ownership participation between KUA and the bidder at the bidder's location. In any event, all proposals must identify the specific resources at a specific site. Proposals that include supply resources located outside the State of Florida must also identify the transmission contracts for the

transmission path that will be utilized from the resources up to KUA's transmission network as more fully described in Section 9.

6. Proposals for Capacity/Energy Sales

Proposals involving a unit or power plant capacity/energy sale should include all available data including equivalent availability factor ("EAF"), maintenance schedules, net capacity, heat rate, fuel type, and other pertinent data for the specific unit(s). Proposals involving a system or portfolio capacity and energy sale to KUA should include information for all generating units and purchase contracts required to make the sale to KUA. All proposals for a capacity/energy sale shall be on a non-recallable basis equivalent to native load delivered to the KUA transmission grid. Details of the information required for each proposal are specified in Attachment B.

If the capacity/energy sale proposal is based on a pass-through fuel cost arrangement, the fuel forecast prices presented in Attachment A of this RFP shall be used by the bidder to project the cost of energy. As an option, bidders may also present energy prices based on their own forecast of fuel prices along with suitable explanations. If the proposal is based on a contractually fixed total energy cost, the proposal must include all information pertinent to the pricing and its escalation. If any of this information is Proprietary Confidential Business Information, it should be clearly noted and KUA will maintain confidentiality per Section 14.

All proposals shall include scheduling provisions of the sale. For proposals that include peaking type resources or peaking type energy pricing, the schedule shall be established hourly with the availability to change up to 10 minutes before the schedule commences. For all other resources, the schedule should be established no more than 1 day in advance with the ability to change the schedule within 2-3 hours before the schedule commences except under KUA emergency conditions when changes may be required as soon as physically possible if the resource is available. The proposal shall not include any contractual limitations on energy usage (MWhs) by day, month or year. As part of the scheduling provisions, the supplier will be required to fax daily to KUA's dispatchers (currently contracted to the Florida Municipal Power Pool (" FMPP")) a schedule of estimated prices for the energy to be delivered for that day and the next day.

7. Proposals for Construction and/or Joint Ownership in Generation

Proposals that involve the construction of a generating unit(s) with KUA as sole owner or a joint owner must include all of the information specified in Attachment B, Section B-1. In addition, the proposals should include details of the terms and conditions of the ownership offer to KUA. KUA prefers proposals that do not utilize the existing Cane Island Site for the construction of generating capacity in excess of that which will be provided to KUA and/or FMPPA. Any proposal that offers construction of generating facilities at the Cane Island Site must include provisions to transfer 100% ownership after construction to KUA or to KUA and a qualified joint participant identified by KUA. Federal tax law and State law requirements may place further constraints on eligible partners or specific projects. Proposals involving ownership by KUA are subject to KUA's agreement on the detailed plant specifications and design. Bidders presenting such proposals are encouraged to include detailed specifications and performance guarantees upon which their proposals are based.

8. Cane Island Site

The Cane Island Site is located in Osceola County, Florida. The site comprises 1,027 acres that is owned by KUA and is located near the KUA service area. It is situated on uplands known as Cane Island.

Currently there are two generating units in operation at the Cane Island Site. The first is a 40 MW General Electric model LM6000 combustion turbine ("CT") unit which was placed into commercial operation on January 1, 1995. The second unit is a 120 MW combined cycle ("CC") General Electric Model 107 EA comprised of a 80 MW CT and a 40 MW steam turbine unit. This unit entered commercial operation service on November 1, 1995. The Cane Island Site was designed for the installation of up to a total of 1,000 MW of generating capacity.

KUA and FMPA are joint owners of the existing "Cane Island Project," each with a 50 percent ownership share. Both KUA and FMPA have joint ownership of the land specific to the units constructed at the site; however, KUA will continue to own the balance of the site with FMPA paying a user's fee. In addition, KUA has the responsibility for construction, operation and maintenance of the plant.

The Cane Island Site is being served by three new 230 kV transmission lines. Two of the 230 kV circuits result from looping OUC's McIntosh-Taft 230 kV transmission line into the Cane Island Site. The line has been constructed on double circuit towers along the Bonnet Creek Canal. The third 230 kV transmission line is a single circuit line which extends east from the site to the new Clay Street substation where it interconnects with KUA's 69 kV transmission system. The transmission lines and substation are jointly owned by KUA and FMPA.

If KUA decides to participate in the self-build alternative with FMPA, the project will probably consist of a 240 MW combined cycle generating plant located at the Cane Island Site. The main equipment will comprise one combustion turbine and one heat recovery steam generator and associated steam turbine generator. Detailed cost estimates for the self-build project will be prepared by a design consultant and submitted to KUA and FMPA prior to the Proposal Due Date. In the initial stages of the evaluation process, this cost estimate will be used as a benchmark for screening alternatives. During the final evaluation stages KUA and FMPA may obtain firm "not to exceed" bids for the self-build project before making a final decision to select a proposal versus the self-build alternative. The design consultant will not have access to the proposals submitted in response to this RFP. Bidders are encouraged to provide their lowest cost offer on August 6, 1997, since repricing is not currently anticipated.

KUA has included a gas fuel forecast in Attachment A for use by bidders. However, KUA will seek bids to confirm market pricing coincident with this RFP process and may use the updated pricing in evaluating the bids.

9. Transmission Arrangements

Electric power supplied from KUA-owned generation and purchased power supplied by other entities are delivered through 21.9 miles of 230 kilovolt and 36.4 miles of 69 kilovolt transmission lines to ten distribution substations. KUA has the following interconnections with area electric utility companies:

- (I) FPC - One 69 kV circuit at FPC's Lake Bryan Substation
- (ii) OUC - One 230 kV circuit at OUC's Taft Substation
- One 69 kV circuit at OUC's Taft substation
- (iii) City of Lakeland - One 230 kV through the interconnection with the Taft-McIntosh Circuit
- (iv) City of St. Cloud - One 69 kV with St. Cloud's Transmission System
- (v) TECO - One 230 kV circuit through the interconnection with the Osceola and Lake Jewell Circuits.

Where resources originate outside the State of Florida, proposals must consider the limits and allocation of interface capacity among the owners of the transmission lines that make up the Florida-Southern interface. At this writing, KUA believes the total reported import capacity is 3,600 MW. All of that capacity may not be available for firm transmission.

It is KUA's understanding that the current allocation of this import capability is 200 MW to the City of Tallahassee, Florida ("Tallahassee"), 438 MW to FPC, 1,228 MW to the Jacksonville Electric Authority ("JEA") and 1,734 MW to Florida Power & Light Company ("FPL"). The firm commitments of FPC and FPL are believed to be very close to their maximum allocation and KUA does not expect any firm transmission capacity to be available from those utilities.

The bidder should confirm this conclusion on its own. The Tallahassee amount may not be fully committed but may not be available for firm transmission service south of Tallahassee. JEA reportedly has 400 MW of its import allocation committed. Imports through JEA may have a contract path through Seminole Electric Cooperative, Inc. ("Seminole") to the Silver Springs North station which is a tie point for Seminole, Ocala Electric Utility and FPC. The exact amount of firm transmission that may be available through JEA for delivery to FPL's or FPC's transmission system will need to be established and may require agreement of all affected parties. It is the bidders' responsibility to determine that firm transmission and interface capability is available for the resources proposed. Proposals should include the cost of all transmission related services required to deliver the power supply to KUA's transmission system.

Bidders should provide backup information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source(s) of supply to the high voltage transmission grid of KUA. KUA prefers proposals that include detailed analyses which show all assumptions, including, among other things, contract paths, contracting parties, interface capability, intervening parties, and transfer capabilities. KUA may verify the transmission studies provided by the bidder by performing its own load flow studies. Therefore, bidders are encouraged to submit a hard copy of the transmission analysis results plus the load flow cases in raw data ASCII IBM compatible format (i.e., PTI's PSS/E, (GE's PSLF, IEEE common) along with all assumptions used in creating each case and any special instructions for reading the data. To the extent uncertainty exists regarding whether the bidder has appropriately

accounted for transmission limitations and associated costs in the proposal, KUA may reflect this in its evaluation or reject the proposal.

10. Notice to Bidders

KUA is coordinating the schedule of this RFP process with a similar process that is being followed by FMPA so that the activities for both processes are executed in parallel. In this way, both entities are able to maximize the benefits of their existing relationship. KUA and FMPA will accept proposals that are made to KUA and FMPA jointly for capacity sharing as stipulated by the bidder. Proposals that are submitted to KUA and FMPA jointly may be eliminated from further consideration if either KUA's or FMPA's requirements are not met. To ensure that the applicable components of the joint proposal are eligible to be considered by KUA and FMPA separately, bidders must also submit individual proposals to each entity in addition to the joint proposal which must be submitted to both entities.

KUA has scheduled a Pre-Bid Conference jointly with FMPA for Tuesday, June 24, 1997 at 9:30 A.M. EDT at the KUA offices, 1701 W. Carroll Street, Kissimmee, Florida 34742. Only qualified bidders will be permitted to attend the Pre-Bid Conference. The purpose of the conference is to answer all questions that bidders may have about KUA's solicitation. Only written questions and written responses will be considered official. Companies that intend to submit proposals are requested to use this forum to obtain answers about the RFP and the form of the response to the RFP. Companies must register for the Pre-Bid Conference by submitting a list of attendees via mail to the address given in Section 12, via the Internet to E-Mail address rpf9720@kna.dst.fl.us, or via facsimile to the attention of Mr. A. K. (Ben) Sharma at (407) 847-0787 [fax] to arrive, on or before Noon EDT, Wednesday, June 18, 1997. After the Pre-Bid Conference, a tour of the Cane Island Site will be conducted by KUA for interested bidders. The tour group is scheduled to leave KUA offices for the Cane Island Site at 2:00 P.M. Bidders must indicate on their Pre-Bid Conference registrations whether or not they wish to participate in the tour.

All bidders are required to provide written notification of their intent to submit a proposal no later than 5:00 P.M. EDT on Monday, June 30, 1997. Such notification should be sent by facsimile or mail (not via the Internet) to Ms Barbara Layton, Contract Administrator to the address given in Section 12. A Notice of Intent to Bid Form is included in Section 22 as RFP Form 1. Bidders must complete the form in full, stating the agreement term on which their proposal(s) is planned to be based and sign it prior to submitting it to KUA.

Sealed proposal packages will be received until 3:00 P.M. EDT on Wednesday, August 6, 1997 ("Proposal Due Date") at the offices of KUA. Each bidder is required to submit a Proposal Summary (RFP Form 2), a checklist (RFP Form 5), and other completed forms as applicable (RFP Form 3 to RFP Form 5) as part of the proposal package. The forms are included in Section 22 of this RFP. Registered bidders will be notified through the issue of RFP addenda of any change in the Proposal Due Date or other necessary revision to information contained in this RFP. KUA reserves the right to reject all proposals received after the Proposal Due Date.

One original and six (6) copies of each proposal should be sealed and delivered to the following address:

Director of Materials Management
Kissimmee Utility Authority
2850 N. Bermuda Avenue
Kissimmee, Florida 34741

Phone Number: (407) 933-7777 -- Ext. 3100

The name of the company submitting the proposal should be clearly marked on the outside of each package. In addition, each package should be marked as follows: "Proposal for Supply of Electric Capacity and Energy - RFP #004-97."

An electronic copy of the completed proposal pricing forms and all other spreadsheets included in the proposal should be submitted in Microsoft Excel 5.0/95 or compatible format on a 3-1/2 inch diskette.

Proposals with agreement terms of 5 years or less should remain in effect until December 31, 1997 or later if the purchase is to be finalized pending a transmission service request, and

Proposals offering agreement terms of more than 5 years should remain in effect until March 31, 1997 or later if the purchase is to be finalized pending a transmission service request. The proposal packages will be opened after the Proposal Due Date. Each proposal package must be accompanied by a non-refundable Proposal Fee (in the form of a cashiers check made payable to KUA) in the amount of \$100 per proposal per year of the proposed agreement term or part thereof up to a maximum of \$1,500 per proposal.

11. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

KUA reserves the right to:

- Reject any and all proposals received in response to this RFP;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement or power supply with more than one bidder at a time;
- Not select the proposal with the lowest price; and
- Request clarifications from bidders at any time.

12. Interpretations and Addenda

All questions of a technical nature regarding interpretation of this RFP must be submitted in writing or by the Internet to the following:

By Fax: Mr. A. K. (Ben) Sharma
(407) 847-0787
By E-Mail: rfp9720@koa.dst.fl.us
Attn: Mr. A. K. (Ben) Sharma

By Mail or Courier: Mr. A. K. (Ben) Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 W. Carroll Street
Kissimmee, Florida 34741

All questions regarding terms, conditions and other non-technical matters should be submitted in writing or by the Internet to:

By Fax: Ms. Barbara Layton
(407) 933-2823
By E-Mail: rfp9720@kua.dst.fl.us
Attn: Ms. Barbara Layton

By Mail or Courier: Ms. Barbara Layton
Contract Administrator
Kissimmee Utility Authority
2850 N. Bermuda Avenue
Kissimmee, Florida 34741

Only written or Internet transmitted responses provided by KUA to bidders' questions will be considered official. A verbal response by KUA will not be considered an official response. Written responses to all questions and requests for interpretations will be provided only to the company posing the question or making the request unless the question and answer are applicable to the RFP process in general, in which case, at KUA's discretion the question and answer will be provided to all bidders. All written questions must be received by KUA on or before Wednesday, July 2, {397 (5:00 P.M. EDT). Inquiries after this date may not receive responses. All addenda issued in connection with this RFP will be placed in the "Important Updates" page on the Internet Website www.rwb.com/fmpa-kna at the time of issue, and it shall be the responsibility of those bidders that download the RFP from the Internet to regularly check the "Important Updates" file to receive addenda. Copies of all issued addenda will also be sent to all companies that directly obtained a copy of the RFP from KUA, by facsimile and/or mail, and after June 30, 1997, those direct purchase companies that submitted a timely Notice of Intent to Bid form.

13. Errors, Modifications or Withdrawal of Proposal

Each bidder should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which should be followed by all bidders. Modifications to proposals already received by KUA will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice (no Internet notices) to KUA prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by KUA. Proposals withdrawn after the Proposal Due Date will result in forfeiture of the proposal fees.

14. Proprietary Confidential Business Information

All proposals shall become the property of KUA. KUA will not disclose to third parties any information that is clearly labeled "Proprietary Confidential Business Information" in a proposal unless such disclosures are required by law or by order of a court or government agency having-appropriate jurisdiction. Each page of Proprietary Confidential Business Information must be clearly labeled "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" at the top of the page. KUA reserves the right to disclose information contained in proposals to its consultant(s) for the sole purpose of assisting in the proposal evaluation process. KUA will require the consultant(s) to maintain the confidentiality of the document.

15. Bidder Qualifications

KUA will accept bids from any electric utility, independent power producer ("IPP"), qualifying facility ("QF"), exempt wholesale generator, or non-utility generator, or electric power marketer who has received certification as such by the Federal Energy Regulatory Commission ("FERC"). Bidders unfamiliar to KUA may be required to provide proof of experience. Bidders that propose to develop a power generating project to provide power to KUA must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Bidders proposing to provide KUA with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

Bidders offering capacity/energy sales or ownership proposals from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. KUA may require proof of such contracts as well as proof of contracts for sales from a portfolio of sources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to KUA.

Bidders offering to construct generating unit(s) for KUA's sole or joint ownership must provide sufficient details in accordance with Attachment B, Section 1.19.

Electric power plant operators of a unit, plant or system capacity proposal must provide proof of operating experience as requested in Attachment B.

Respondents are encouraged to provide the following information with their proposals: most recent audited financial statement; Form 10 K of parent company, where appropriate; most recent Dunn & Bradstreet report; description of pending litigation; summary of project experience; and annual report.

16. Capacity

Resources providing the proposed capacity, whether unit, plant or system, or portfolio sale or construction of a joint ownership proposal must be in commercial operation at least two months prior to the start date of the proposed power supply.

17. Bid Security

KUA may require the short-listed bidder(s) to provide adequate bid security prior to short-list negotiations. Bidders are therefore requested to propose an appropriate bid security.

18. Default and Damages Provisions

KUA will negotiate the conditions of default and damages with the successful bidder(s). Bidders should include default and damage provisions in their proposals.

19. Disqualification of Proposals

A bidder's proposal may be disqualified at any point if bribery, conflict of interest, or interference in the evaluation process is determined, at KUA's sole discretion, to be involved with the proposal.

20. Evaluation Process

The proposal evaluation process will be performed on a bid and negotiate basis. Information provided from each bidder by the Proposal Due Date will be used to develop a short list of proposals from which selection(s) could be made for direct negotiations. No additional data may be considered after the Proposal Due Date, except for clarifications requested by KUA and possible transmission study results. KUA will evaluate the proposals in terms of price and non-price factors. The first stage of the evaluation process for qualified bidders will consist of a check of each proposal against the minimum requirements, as listed in this section of the RFP. After the minimum requirements screening, initial price screening of proposals may be accomplished by comparing proposals using a capacity factor analysis. Such proposals may then be screened by comparison with options that are available to KUA under existing power purchase arrangements. Proposals for long-term arrangements may be screened by comparison with KUA's self-build project and/or other proposals. Both screenings will be performed on a present value busbar cost basis. Detailed price and non-price evaluations may be conducted next. From this detailed analysis a short-list of bidder(s) will be selected and notified for participation in negotiations. Selection and rejection of proposals and notification of bidders at all stages will remain entirely with KUA's discretion. KUA intends to notify bidders not selected under this solicitation within a reasonable amount of time.

Minimum Requirements For All Proposals

Each proposal must satisfy certain minimum requirements before it will receive any further evaluation. The bidder must demonstrate in its submittal that the following minimum requirements have been met:

1. Although capacity is required during all months, proposal must provide for capacity for either one or both of the following peak load periods: (I) June through September; or (ii) December through March for a minimum of three (3) calendar years.

2. The capacity and energy proposed are on a first call, non-recallable basis, i.e., as long as the unit(s) from which the capacity is purchased is available, KUA has the right to the output of the unit(s) for the duration of the contract. KUA's rights must be equal to or superior to any other party's rights to such unit(s) output.
3. Proposals that contain agreement terms of 5 years or less must remain in effect through December 31, 1997, or later if the purchase is to be finalized pending a transmission service request. All other proposals must remain effective until March 31, 1998, or later if the purchase is to be finalized pending a transmission service request.
4. The minimum capacity amount offered to KUA shall be 10 MW.
5. All generating units providing the proposed capacity must be in operation at least two months prior to the delivery commencement date of the term of the proposed power supply.
6. Proposals must identify and include the location of each capacity resource, and name the originating control area and identify the firm transmission contract path.
7. The bidder must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.
8. The bidder must declare ownership or contractual status of the unit, plant or system capacity as described in Section 15.
9. The bidder must complete the appropriate RFP Forms 1 through 5 and provide the information requested in Attachment B. All forms requiring a signature must be signed by a duly authorized official.
10. Bidders offering power that impacts any transmission interface must provide a letter of intent from the owner(s) of the systems forming the interface stating that the required power transfer capability is available on a firm (non-recallable) basis.
11. The bidder must be willing to provide adequate bid security prior to entering short-list negotiations.
12. The bidder must not include any contractual limits on energy utilization (as opposed to price) by day, month or year.
13. The proposal must include scheduling provisions for the sale.
14. Each proposal must contain the appropriate proposal fee in accordance with Section IO.

Price Criteria

KUA will evaluate the firm power supply proposal(s) as alternatives to increasing the amount of purchases for certain period under the terms of its existing power purchase arrangements and/or developing a self-build project. The net present value of the total system power cost for KUA with each proposal included in the resource mix separately will be compared to the net present value of

the total system power cost for KUA with increased purchases under existing arrangements and/or the self-build option included in the resource mix. Scores will then be applied to each proposal to reflect the projected cost differential between the proposal and the benchmark option.

Non-Price Criteria

Each proposal will be evaluated on a list of non-price criteria which KUA has developed. A score will be assigned to each criteria based on the extent to which the proposal satisfies KUA's preferences. The total non-price score will be added to price related score for each proposal to obtain an overall score which will be used to determine the ranking of proposals.

The proposals will be evaluated in accordance with the following non-price criteria:

Components of Power Cost -	To evaluate risk, KUA prefers bidders that identify the true fixed and variable costs for the resources providing the power (e.g., the bidder should identify the amount of fixed cost in the capacity charge and the amount of variable costs [fuel, variable operation and maintenance expenses, etc.] in the energy charge).
Flexibility -	KUA prefers flexible proposals with reasonable notice provisions that give KUA sole rights (e.g., adjust the contract term, the amount of purchases, type of purchase, payment provisions, price, etc.).
Dispatchability -	KUA prefers provisions that would permit KUA to dispatch the resources off-line during periods when KUA deems it economical to do so. Dispatchability may also encompass the concept of scheduling power deliveries for economy transactions in a manner that contributes favorably to KUA's needs.
Fuel Risk -	KUA prefers proposals that have firm fuel supply contracts (vs. spot purchases). KUA also prefers proposals that improve the diversity of KUA's fuel mix. Multiple suppliers are preferred.
Firm Supply -	Proposals will be evaluated on the availability of generating resources, arrangements for firming or reserved capacity, and penalties for nonperformance.
Transmission-	KUA prefers location of generating resources that minimize the number of intermediate transmission systems.
Technology-	Proposals utilizing commercially proven technologies are preferable.
Environmental Effects-	KUA prefers proposals that minimize potential adverse environmental impacts including water supply and waste water discharge.

21. Final Contract

Any final contract(s) that result from the proposal evaluation and negotiation processes will be submitted to the Board of Directors of KUA for approval. The tentative date for approval of contract(s) for the purchases is shown in Section 4, RFP Schedule.

22. RFP Forms and Attachments

Form 1	-	Notice of Intent to Bid Form
Form 2	-	Proposal Summary Form
Form 3	-	Minimum Requirements Form
Form 4	-	Pricing Proposal Form
Form 5	-	Checklist
Attachment A	-	Fuel Price Forecast
Attachment B	-	Required Data
Attachment C	-	IRP Summary Report

23. Reserved Rights

The KUA reserves the right to accept or reject any and/or all proposals, to waive irregularities and technicalities, and to request re-submission. Also, the KUA reserves the right to accept all or any part of the proposal. Any sole response received the first submission date may or may not be rejected by the KUA depending on available competition and timely needs of the KUA. To be a responsible bidder the bidder shall have the capability in all respects to perform fully the contract requirements, and the tenacity, perseverance, experience, integrity, reliability, capacity, facilities, equipment, and credit which will assure good faith performance. Also, the KUA reserves the right to make such investigation as it deems necessary. To make this determination, the information shall be provided by the bidder. Such information may include but shall not be limited to: current financial statement; verification of availability of equipment and personnel; and past performance records.

24. Collusion

By offering a submission to this request for proposal, the bidder certifies the bidder has not divulged, discussed, or compared his proposal with other bidders and has not colluded with any other bidder or parties to this proposal whatsoever. The bidder also certifies, that in connection with this proposal:

- (i) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and/or cost data, with any other bidder or with any competitor;

- (ii) Any prices and/or cost data quoted for this proposal have not knowingly been disclosed by the bidder and will not knowingly be disclosed by the bidder prior to the scheduled opening directly or indirectly to any other bidder or to any competitor;
- (iii) No attempt has been made or will be made by the bidder to induce any other person or firm to submit or not to submit a proposal for the purpose of restricting competition;
- (iv) The only person or persons interested in this proposal, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this proposal or in the contract to be entered into and;
- (v) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee excepting bona fide employees or established commercial agencies maintained by KUA for the purpose of doing business.

25. Indemnity

After notification of award, the successful bidder shall indemnify and save harmless the KUA from and against all claims, suits, actions, damages, or causes of action arising during the terms of the resulting agreement for any personal injury, loss of life, or damage to property sustained by reason of a result of the performance of the services or delivery of goods for which the resulting agreement was entered into, or its agents, employees, invitees, and all other persons, and for and against any orders, judgments, or decrees, which may be entered thereto, and from and against all costs, attorney's fees, expenses and liabilities incurred in or by reason of the defense of any such claim, suit or action, and the investigation thereof. Nothing in the award, resulting agreement, contract of Purchase Order shall be deemed to affect the rights, privileges and immunities of the KUA as set forth in Florida Statute 768.28.

26. Equal Employment Opportunity Clause

The Kissimmee Utility Authority of Kissimmee, in accordance with the provision of Title VI of the Civil Rights Act of 1964 (78 Stat. 252) and the Regulations of the Department of Commerce (15 CFR Part 8) issued pursuant to such Act, hereby notifies all proposers that it will affirmatively ensure that in any contract entered into pursuant to this advertisement minority business will be afforded full opportunity to submit proposals in response to this advertisement and will not be discriminated against on the grounds of race, color, or national origin in consideration for an award.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

**MISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS****Notice of Intent to Bid Form****Due: June 30, 1997 (5:00 PM)**

Date: _____

Project Bidder

Name: _____

Title: _____

Company Name: _____

Address: _____

Telephone: _____

Fax: _____

E-Mail: _____

Project Name: _____

Project Location: _____

Agreement Term: _____

Power Generation Technology: _____

Primary Fuel: _____

Specific Entity to Contract With KUA: _____

Respondent Classification:

(Utility, Qualified Facility, Exempt Wholesale Generator,
Power Marketer, etc.)

Respondent Qualifications:

Describe similar projects developed by bidder, noting project capacity,
location, contract commencement date, contract term, etc.*(Attach additional sheets as needed)*

Bidder's Signature: _____

(Duly Authorized)

**KISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS**

Proposal Summary Form

1. Company/Bidder

2. Name of Contact

3. Mailing Address

4. Telephone

Fax

E-Mail

5. Proposed Contract Start Date

6. Proposed Contract End Date

7. Proposed Contract Capacity Listing by Resource

Unit Name and Number	Summer MW Rating	Winter MW Rating	Fuel Type	Location	Proposed Capacity Delivered [1] (MW)	System Delivered to (FPC or FPL)
Total Capacity (MW)						

[1] Capacity delivered to KUA's transmission system.

8. Certification: Bidder hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the bidder's knowledge and belief. Bidder agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: _____

(Typed): _____

Title: _____

(Duly Authorized)

Date: _____

**KISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS**

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below.

Duly Authorized Signature: _____ (Date)

If the bidder is an entity proposing a capacity sale from existing resources the bidder must provide sufficient documentation to demonstrate that over time the source utility, or entity will have sufficient capacity to sell to FMPA as well as to serve its own load, if applicable, and other commitments.

All bidders must demonstrate the following by attaching appropriate information to this form:

1. Although capacity is required during all months, proposal must provide for capacity for either one or both of the following peak load periods: (i) June through September; or (ii) December through March for a minimum of 3 calendar years.
2. The capacity and energy proposed are on a first call, non-recallable basis, i.e., as long as the unit(s) from which the capacity is purchased is available, KUA has the right to the output of the unit(s) for the duration of the contract. KUA's rights must be equal to or superior to any other party's rights to such unit(s) output.
3. The proposal for capacity sales for terms of five years or less must remain in effect until December 31, 1997, or later if the purchase is to be finalized pending a transmission service request. All other proposals must remain effective until March 31, 1998, or later if the purchase is to be finalized pending a transmission service request.
4. The minimum capacity amount offered to KUA shall be 10 MW.
5. All generating units providing the proposed capacity must be in operation at least two months prior to the delivery commencement date of the term of the proposed power supply.
6. Proposals must identify and include the location of each capacity resource, name the originating control area and identify the firm transmission contract path.
7. The bidder must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.
8. The bidder must declare ownership or contractual status of unit, plant or system capacity as described in Section 15.

**KISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS**

**Minimum Requirements Form
(Continued)**

9. The bidder must complete the appropriate RFP Forms 1 through 5 and provide the information requested in Attachment B. All forms requiring a signature must be signed by a duly authorized official.
10. Bidders offering power that impacts any transmission interface must provide a letter of intent from the owner(s) of the systems forming the interface stating that the required power transfer capability is available on a firm (non-recallable) basis.
11. The bidder must be willing to provide adequate bid security prior to entering short-list negotiations.
12. The bidder must not include any contractual limits on energy utilization (as opposed to price) by day, month or year.
13. The proposal must include scheduling provisions for the sale.
14. Each proposal must contain the appropriate proposal fee in accordance with Section 10.

**KISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS**

Proposal Pricing Form
Capacity Pricing

Delivered Capacity Rate								
Period 12 Mo. Ending Dec. 31	A \$/kW-yr	B \$/kW-yr	C \$/kW-yr	D \$/kW-yr	E \$/kW-yr	Total A-E \$/kW-yr	Capacity kW	Total \$000
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								

Describe the components of and the methodology for determining the capacity rates.

[illegible]

**KISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS**

Proposal Pricing Form

Energy Pricing

Delivered Energy Rate									
Period (2 Mo. Ending Dec. 31)	Fuel Cost \$/MMBtu	Heat Rate mmBtu/ MWh	F \$/MWh	G \$/MWh	H \$/MWh	I \$/MWh	Total F-I \$/MWh	Project d Energy MWh	Total \$000
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
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2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									

KISSIMMEE UTILITY AUTHORITY REQUEST FOR POWER SUPPLY PROPOSALS

Proposal Pricing Form

Describe the components of and the methodology for determining the energy rates.

[illegible]

**KISSIMMEE UTILITY AUTHORITY
REQUEST FOR POWER SUPPLY PROPOSALS**

Checklist

All RFP Forms checked below have been included as part of the response package *.

RFP Form 2 - Proposal Summary Form

RFP Form 3 - Minimum Requirements Form

RFP Form 4 - Pricing Proposal Form

Signature of Bidder:

Name of Project:

() RFP Form 1 is the Notice of Intent to Bid Form which is sent to KUA prior to, and separately from, the proposal package.*

ATTACHMENT A
Commodity Only Natural Gas Price Forecast
(No Transportation Included)

<u>Year</u>	<u>\$/MMBtu</u>
2001	\$2.30
2002	\$2.35
2003	\$2.40
2004	\$2.45
2005	\$2.50
2006	\$2.60
2007	\$2.70
2008	\$2.80
2009	\$2.95
2010	\$3.10
2011	\$3.22
2012	\$3.35
2013	\$3.49
2014	\$3.63
2015	\$3.77

ATTACHMENT B

Required Supply Proposal Data

The following is required for all supply proposals as is applicable. The required data should be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided, but not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, 'boiler plate', etc.) may be provided with the proposal, but only the formatted information will be considered in the event of conflicting data. Any proposal that lacks requested information may be deemed incomplete and may be rejected in KUA's sole discretion. KUA may request additional data or clarifying information from respondents.

Information requirements are specified separately for two types of proposal, (i) Section B-1 for those involving sales from specific generating unit(s) with or without capacity reserves, separate reserves or firming service contracts to provide firm power (a "Generating Unit Sale"), or (ii) B-2 for a firm sale from a utility system which will provide sufficient system reserves for its total load, including this sale, (a "System Sale"), or (iii) Section B-1 for those involving sole or joint ownership in a generating facility.

B-1 Generating Unit Power Sale and/or Sole/Joint Ownership

B-1.1 Identity of Bidder Contact

Provide the full name, business address, telephone, E-Mail address if available, and facsimile number of contact person from whom additional information can be requested.

B-1.2 General Description of Supply Proposals

- (a) Provide a general overall executive summary of the Supply Proposals. The description must include identification of each major component of involved electric generating unit, including unit type, unit manufacturer, date of manufacture, manufacturer's nameplate capacity rating, any reratings that have occurred since date of manufacture, location of resources, primary and secondary fuel type, term of contract, sites where similar units have been installed for commercial operation, and other relevant information.
- (b) Fully describe the dispatchability and dependable capacity of the proposed resource, how reserves or firming service, voltage support, operating reserves, load following capability and dispatching will be provided. All limitations on dispatchability must be disclosed.

B-1.3 Location of Generating Unit(s)

Identify the geographic location of the project and indicate whether or not such area is an attainment or a non-attainment air quality area. If no specific location has been identified, so state. Provide a

segment of a USGS map showing geographical location of each generating unit relative to KUA's service territory and surrounding area with interconnections and transmission lines indicated.

B-1.4 Capacity and Expected Energy Production

- (a) Specify the amount of firm capacity offered. Please specify net electrical output at 59 degrees Fahrenheit and 95 degrees Fahrenheit available for four (4) continuous hours at the most efficient level of operation. Also, indicate the additional output (if any) which can be obtained through power augmentation (i.e., steam injection, water injection, duct firing, etc.). Indicate the amount of additional capacity obtained for each type of augmentation at 59 degrees and 95 degrees Fahrenheit.
- (b) Indicate the expected total net kilowatt-hours to be delivered to the interface with KUA's transmission system under the contract, by hour, for a typical day's operation. Take into account step-up transformer losses, transmission losses to the interface, capacity degradation, and auxiliary loads. Identify limiting conditions (if any).
- (c) Show separately, the amount of capacity provided for reserves, or firming service. KUA may wish to purchase unreserved capacity and reserves, or firming service, separately.

B-1.5 Schedule

Specify the time frame when capacity is available. If capacity is provided by a new generating facility, include a schedule for environmental permitting, design, procurement, construction and commissioning of the project, as applicable.

B-1.6 Proposed Agreement Term

- (a) Specify proposed contract term.
- (b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

B-1.7 Operating Parameters

- (a) Provide performance characteristics of the proposed facility at most efficient full load capacity, including capacity and heat rate, for operation with the following ambient air temperatures:

8° F, 17° F, 37° F, 59° F, 69° F, 77° F, 95° F

- (b) Provide heat rate data for the following percentages, as applicable, of the proposed contract capacity at (a) 59°F and (b) 95°F:

20%, 40%, 60%, 80%, 100 %, 110 %

- (c) Provide start-up fuel requirements for (1) cold start (off-line 12 hours or longer) and (2) warm start (off-line less than 12 hours) conditions.
- (d) Provide heat rate performance coefficients (A, B and C, as shown below) for the unit(s) operating at ambient air temperatures of (a) 59° F and (b) 95° F, as available. The preferred format for such equation is:

$$F = A + B * P + c * P^2$$

where,

F = fuel used by the unit, in millions of Btu per hour (MMbtu/hr); P = net power output by the unit, in megawatts.

- (e) If an alternate format for the heat rate performance equation is used, provide sufficient explanation of all parameters represented including values, units, etc.

All performance must be expressed on a higher heating value (HHV) basis and identified as such.

- (f) If heat rate is guaranteed over the proposed contract term, please include degradation and indicate the percentage assumed for degradation. If the heat rate is guaranteed for new and clean state only and not over the contract period, please so state.
- (g) Specify: (1) annual availability in hours; (2) annual planned maintenance in hours; (3) expected annual full forced outages in hours; (4) expected annual partial forced outages in hours; (5) frequency, in months, and duration, in days, of periodic (less frequently than annually) major overhauls and/or recommended hours of operation between major overhauls.
- (h) Specify the expected calendar months for annual planned maintenance to occur.

B-1.8 History of Existing Facilities

- (a) If the proposed facility is an existing generator, provide a narrative describing the project's operating history. Include construction start date, test operation start date, commercial operation date, monthly, capacity factors, non-fuel operations and maintenance expenses, and net heat rates by month, - for at least three (3) years or since commercial operation date. Also include major equipment additions and enhancements and associated costs.
- (b) If the proposed facility is comprised of an existing generator(s), provide a narrative describing the project's maintenance history, including: (i) monthly and annual scheduled outages, (ii) number and duration of forced outages, (iii) forced and planned outage rates, (iv) dates and causes of all major equipment breakdowns by year, etc., and (v) all known equipment deficiencies.

B-1.9 Control Area Services

Please describe methodology for dispatching unit(s) and other resources (if any) to meet KUA's load each hour, provide operating reserves (including spinning reserves and ready reserves), load following, load regulation and other Control Area Services. Please separately identify the cost for such services.

B-1.10 Project Dispatchability

Please specify:

- (a) maximum and minimum net electrical output at 95° F;
- (b) time notice required to attain maximum and minimum operating levels;
- (c) time notice required to attain contract capacity output from shut-down condition (assuming unit is available);
- (d) technical or contractual limitations with respect to ability and willingness or project to operate at part load conditions, including load following;
- (e) technical or contractual limitations with respect to ability and willingness of project to operate on electronic automatic generation control (AGC) signals provided by KUA designated dispatch computer;
- (f) technical or contractual limitations with respect to ability and willingness to operate generating unit(s) at levels above contract capacity (include capacity delivery level(s) and duration of operation at each indicated level);
- (g) technical or contractual limitations with respect to ability and willingness to periodically cycle electric production off-line; including limits on number and frequency of start-ups, minimum duration of on-line and off-line periods;
- (h) output level obtainable within 10-minutes from cold start (quick start capability); and
- (i) is unit capable of black-start (capable of starting with no external power available)?

B-1.11 Environmental Considerations

- (a) Provide the expected level of air emissions from the generating unit(s) for the following compounds:

	<u>Lbs./Hour</u> <i>(@ Max Output)</i>	<u>Tons/Year</u> <i>(Annual Average)</i>
Carbon Dioxide		
Carbon Monoxide		
Nitrous Oxides		
Sulfur Dioxide		
Ozone		

Volatile Organic Compounds
Particulate Matter
Solid Waste Discharge (By Type)

(b) Other Environmental Impacts

	<u>Gallons/Hours</u>	<u>Gallons/Year</u>
Water Usage		
Waste Water Discharge		

(c) Other (please specify)

- (d) If the project is an existing facility, include levels of emission allowed under existing permits along with actual emission data as described in B-1.1 l(a)-(c) for the three most recent years of operation.
- (e) If the project is an existing facility, include a record of each permit violation, notice of violation, civil or criminal penalties related to environmental permits, licenses and registrations.
- (f) Provide a statement of bidder's responsibility for compliance with all environmental regulations indicating that the owner of the generating facility will retain responsibility for environmental compliance and absolve KUA of any and all environmental responsibility - associated with operation of the unit(s) providing power under the proposed agreement.
- (g) Provide copies of all environmental permits, licenses and registrations and related correspondence associated with the generating unit(s) designated to perform under the proposal. :
- (h) If a new facility is to be constructed, provide status of site including permitting, land acquisition, etc.

B-1.12 Third Party Information

Identify any other firm capacity and energy commitments during the proposed contract term from the project to other parties, and provide a description of KUA's rights compared to the rights of the other parties. KUA may require bidders to provide copies of contracts associated with sale of power to other parties.

B-1.13 Fuel Information

- (a) Fully describe the fuel source for any proposed generating facility, and any fuel supply contracts, including price and escalation provisions, interruptibility, obligation to deliver, penalties for non-delivery, and dispatchability. Specify project fuel type(s), and associated fuel supply information to the extent known, including number and delivery capability of suppliers. If the fuel source requires any emission allowances, the bidder shall specify if entitlements are now held for the required allowances. If

entitlements to required allowances are not held, the bidder shall identify the source from which allowances will be obtained, and any separate charge proposed to be assessed.

- (b) Specify backup fuel arrangements, including type(s) of backup fuel and expected ability (duration and net electrical output level) to deliver power when supplied solely by backup fuel supply.
- (c) If the proposal is based on a pass-through fuel cost arrangement, the fuel forecast prices in Attachment A must be used by the bidder to calculate the cost of energy.

B-1.14 Thermal Host

If a thermal host is involved, identify the thermal host and provide a complete description of contractual arrangements with the thermal host, such as term, description of waste heat steam takes, quantities, delivery patterns, and pricing and credit information sufficient to permit KUA to evaluate project viability given the proposed power pricing. If a steam cycle is used to increase the efficiency of the project, provide a heat balance diagram showing steam requirements for the thermal host and calculation of the net heat rate of project. Limitations on the operation of the project due to steam hosts requirements should be described in detail.

B-1.15 Financial Information

- (a) Provide a detailed description of the proposed financing plan, including, but not limited to, the identification of expected sources of debt and equity, proposed guarantor, proposed dollar amounts, issuer and rating of performance bonds, the anticipated level and duration of equity involvement by the bidder, and any and all conditions (including revocation, expiration, etc.), if applicable. Provide a sample of each proposed security instrument along with the name of the institution proposed as the issuer of the instrument.
- (b) Provide pro forma income statements, balance sheets, and after tax cash flow statements with applicable debt coverage ratios consistent with cost estimation and price bid forecasted on an annual bases for the life of the proposal.
- (c) Identify any and all bidder affiliates.
- (d) Provide audited financial statements, if available, or other financial statements for the last three years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum, FERC Form l's and SEC 10K Forms. Bidders should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation, and the most recent annual report.

B-1.16 Pricing Information

- (a) Specify on RFP Form 4 - Proposal Pricing form all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such

provisions. KUA requires that proposals clearly distinguish energy and capacity pricing components. Please include all costs for transmission services, reserves or firming service, dispatching, load following, load regulation, telecommunication, and metering.

- (b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is to represent (e.g., general inflation, general economic growth, etc.), and the proposed index or other source data to define the escalator (e.g., CPI change in GDP, etc.). Unless the escalation factors are contractually fixed, bidders must use the factor specified in Attachment A.
- (c) Provide itemized installed costs for project and ancillary equipment including the power block, substation equipment, balance of plant, spare parts, environmental, site costs, land, step-up transformer, electrical interconnection, high side breaker), transmission system upgrades, gas line, gas compression, gas line interconnection, alternate fuel storage tanks, ancillary equipment to provide Control Area Services, contingencies, interest during construction, financing costs, working capital, owner's engineer costs, development fees, legal fees, start-up, training, mobilization, etc. Please indicate which of these installed costs the proposal will cover with payments indicated in items B-1.16 (a) and (b), and which will be the responsibility of KUA (if any).

B-1.17 Proposed Financial Security Arrangements

Indicate proposed financial security arrangements specifying, at a minimum:

Proposed Form of Security Instrument	
Corporate Guaranty	Proposed guarantor, any and all conditions, including revocation, expiration, etc.
Letter of Credit	Name of issuer proposed dollar amount; any and all conditions, including revocation, expiration, etc.
Performance Bond	Name of issuer and rating; proposed dollar amount; any and all conditions, including revocation, expiration, etc.
Project Take-over Rights	Mechanics and limitations on the exercise of such rights.
Other	Please describe in detail.

B-1.18 Wheeling

Any bidder proposing to wheel power and energy over the facilities of a third party will be required by KUA to provide:

- (a) A detailed description of the proposed wheeling and interconnection arrangements, including, but not limited to, contract path and estimated cost of such wheeling services.
- (b) Point(s) of delivery of firm capacity and energy into KUA's transmission system.
- (c) A description of interconnection facilities and estimated cost and cost responsibility for such facilities.
- (d) A description of upgrades in the third party transmission system which may be required to accommodate the project and an estimate of costs.
- (e) Back-up information that would verify the reasonableness of assumptions and cost data associated with transmission ;service required for delivery of the proposed capacity and energy from the source of the supply to the transmission grid of KUA. Also, detailed analyses which show all assumptions, including, among other things, contract paths, contracting parties, interface capability intervening parties, and transfer capabilities. KUA may verify the transmission studies provided by the bidder by performing its own load flow studies. Therefore, bidders are encouraged to submit a hard copy of the transmission analysis results plus the load flow cases in raw data ASCII IBM compatible format (i.e., PTT's PSS/E, GE's PSLF, IEEE common), along with all assumptions used in creating each case and any special instructions for reading the data

B-1.19 Summary of Bidder's Qualification

- (a) Provide a description of the bidder's qualifications and experience applicable to the developing, designing, financing, constructing, operating and maintaining of the proposed project.
- (b) Identify and describe existing generation facilities currently in commercial service on which bidder has contracted, including (i) the name, address, telephone number, and specific contact of the owner of such facilities; (ii) a description of the facility and its location; (iii) the bidder's scope of work relating to the project; and (iv) total contract value and duration.

B-1.20 Additional Information

Please provide any additional information which bidder believes will assist KUA in an accurate and fair evaluation of the proposed project.

B-1.21 Guaranty For Firm Power

Describe the formula or mechanism whereby the power and energy will be compensated or replaced, and/or the capacity or energy payments reduced when or if the project fails to provide firm power when required by KUA.

B-2 System Sale

B-2.1 Identity of Bidder Contract

Provide the full name, business address, telephone, and facsimile number of contract person from whom additional information can be requested.

B-2.2 General Description of Supply Proposals

- (a) Provide a general overall summary of the Supply Proposals. The description must include identification of each resource in the electric system from which sale is being made (the "System").
- (b) Describe the amount of capacity to be provided, the amount of total resources, and projected loads (including the proposal sale) on the System for each year of the proposed contract. Describe the dispatchability of the resource, and how reserves, firm services, load following, load regulation, operating reserves and other Control Area Services which will be provided to KUA.

B-2.3 Location Of Generating Facilities

Identify the geographic location of the generating resources on the System and the transmission system which interconnects these resources. Identify the transmission path and intervening transmission systems required to deliver the power to KUA's transmission system.

B-2.4 Capacity and Expected Energy Production

- (a) Specify the amount of delivered capacity and maximum energy offered on typical days, months and years, taking into account seasonality of supply (if any) and transmission losses.
- (b) Please indicate the firmness of the sale (i.e. will KUA have equal priority to the native load and other wholesale customers of the System.). If not, explain. Also describe limiting conditions (if any).

B-2.5 Schedule

Specify the time frame when capacity will be available (or unavailable).

B-2.6 Proposed Agreement Term

- (a) Specify proposed contract term.
- (b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

B-2.7 Dispatchability

Indicate all scheduling, and dispatch constraints applicable to the proposed system sale including but not limited to the following:

- (a) Scheduling requirements.
- (b) Notice requirements for the start-up of units to supply purchased power.
- (c) Minimum up-time requirements for units to supply purchased power.
- (d) Minimum load requirement (if any).
- (e) Ramp-up or ramp-down limitations and notice requirements.

B-2.8 Control Area Services

Please provide a description of how these services could be provided for KUA's load. The service could include dispatching, load following, load regulation, operating reserves (Spinning and ready reserves) and other services.

B-2.9 Environmental Considerations

- (a) Provide the expected level of air emissions associated with the proposed system sale for the following compounds:

	<u>Lbs./Hour</u> <i>(@ Max Output)</i>	<u>Tons/Year</u> <i>(Annual Average)</i>
Carbon Dioxide		
Carbon Monoxide		
Nitrous Oxides		
Ozone		
Sulfur Dioxide		
Volatile Organic Compounds		
Particulate Matter		
Solid Waste Discharge (By Type)		

- (b) Other Environmental Impacts

	<u>Gallons/Houris</u>	<u>Gallons/Year</u>
Water Usage		
Waste Water Discharge		

- (c) Other (please specify)
- (d) Provide a statement of bidder's responsibility for compliance with all environmental regulations and that bidder will retain responsibility for environmental compliance and

absolve KUA of any and all environmental responsibility associated with the system sale.

B-2.10 Third Party Information

Identify any other firm capacity and energy commitments during the proposed contract term from the system to other parties, and provide a description of KUA's rights compared to the rights of the other parties. Provide contracts for sale of power to other parties from the system.

B-2.11 Fuel Information

Please describe the following:

- (a) Primary and alternate fuel source for each generating unit on the system.
- (b) Relationship of energy pricing for system sale to actual fuel costs (show example calculations).
- (c) Historical monthly average fuel prices in \$/MMBtu for each generating unit on the system for the last three (3) years.
- (d) Average monthly heat rate by unit including separately MMBtu's and net generation for the last three (3) years.
- (e) If the proposal is based on a pass-through fuel cost arrangement, the fuel forecast prices in Attachment A must be used to calculate the projected cost of energy.

B-2.12 Financial Information

- (a) Identify any and all bidder affiliates.
- (b) Provide audited financial statements, if available, or other financial statements for the last three years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum FERC Forms l's and SEC 10K Forms. For investor owned utilities, this would include as a minimum, FERC Form l's and SEC 10K Forms. Bidders should also provide where appropriate, the most recent Dunn and Bradstreet' report, a "description of pending litigation,;and the most recent annual report.

B-2.13 Pricing Information

- (a) Specify on the RFP Form 4 - Proposal-Pricing form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. KUA requires that proposals clearly distinguish energy and capacity pricing components. Please include all costs for reserves or firming service, transmission service, dispatching, load following, load regulations telecommunications and metering.

- (c) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is to represent (e.g., general inflation, general economic growth, etc.), and proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.). Unless the escalation factors are contractually fixed, bidders must use the factors specified in Attachment A.

B-2.14 Proposed Financial Security Arrangements

Indicate proposed financial security arrangements specifying, at a minimum:

Proposed From of Security Instrument	
Corporate Guaranty	Proposed guarantor; any and all conditions, including revocation, expiration, etc.
Letter of Credit	Name of issuer; proposed dollar amount; any and all conditions, including revocation, expiration, etc.
Performance Bond	Name of issuer and rating; proposed dollar amount; any and all conditions, including revocation, expiration, etc.
Project Take-over Rights	Mechanics and limitations on the exercise of such rights.
Other	Please describe in detail.

B-2.15 Wheeling

Any bidder proposing to wheel power and energy over the facilities of a third party will be required by KUA to provide:

- (a) A detailed description of the proposed wheeling and interconnection arrangements, including, but not limited to, contract path and estimated cost of such wheeling services.
- (b) Point(s) of delivery of firm capacity and energy into KUA's transmission system.
- (c) A description of interconnection facilities, and estimated costs and cost responsibility for such facilities.
- (d) A description of upgrades in third party transmission system(s) which may be required to accommodate the purchase and an estimate of costs.
- (e) Back-up information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source of the supply to the transmission grid of KUA. Also, detailed analyses which show all assumptions, including, among other things,

contract paths, contracting parties, interface capability, intervening parties, and transfer capabilities. FMPA may verify the transmission studies provided by the bidder by performing its own load flow studies. Therefore, bidders are encouraged to submit a hard copy of the transmission analysis results plus the load flow cases in raw data ASCII IBM compatible format (i.e., PTI's PSSIE, GE's PSLF, IEEE common) along with all assumptions used in creating each case and any special instructions for reading the data.

B-2.16 Additional Information

Please provide any additional information which the bidder believes will assist KUA in an accurate and fair evaluation of the proposed project.

B-2.17 Guaranty For Firm Power

Describe the formula or mechanism whereby the power and energy will be compensated or replaced, and/or the capacity or energy payments reduced when or if the project fails to provide firm power when required by KUA.

Attachment C

IRP Summary

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I. INTRODUCTION

The Kissimmee Utility Authority (KUA) retained the services of Stone & Webster Management Consultants, Inc. (Stone & Webster) to develop an integrated resource plan (IRP). This **Summary Report** contains the key assumptions and findings associated with the IRP study. Attached to this Summary Report are two additional volumes. Volume I is the **Assumptions Document** which contains all the underlying data assumptions used for the study. Volume II is the **Technical Report** which contains methodology and results of the screening and sensitivity analyses, as well as the risk assessment.

A. Background

KUA initiated the development of an IRP to ensure that its customers are provided with reliable and economic energy both in the short and the long term. Due primarily to increased competition, utilities now face a multitude of options for assuring an adequate and reliable future supply of electricity for their customers.

On the **supply-side**, these options include conventional fossil-fuel-fired central station generation (in both a self-build and joint ownership status), as well as emerging technologies expected to be available in the near future such as fluidized bed, coal gasification, and alternative technologies such as wind and solar. Independent power producers, cogenerators and small power producers are another means of supplying electricity. Purchased power from other utilities is also an option, particularly as deregulation removes constraints to transmitting power from one geographical area to another. New purchased power alternatives were explicitly solicited and investigated as part of this IRP.

Utilities also can use **demand-side** alternatives as a means of satisfying the future demand for electricity. In some cases it may be less expensive to implement a conservation program that reduces load than to add new capacity to serve the same load. In addition to a broad array of conservation programs currently being implemented in the utility industry, load shifting, peak shaving, and strategic marketing programs must also be considered. If a utility can more efficiently use its current generating capacity by selling firm and/or economy energy, it can reduce the cost of electricity to all customers. These options have been considered in KUA's IRP.

While conservation, load management, and marketing functions have existed in the utility industry for many years, these concepts now called demand-side management (DSM) resources have been added to the resource mix. The simultaneous consideration of supply and DSM resources resulted in the emergence of integrated resource planning (IRP) as a common planning approach.

Integrated resource planning (sometimes referred to as least-cost planning or "value-based planning") involves integrating the activities of forecasting, generation expansion, marketing, and conservation into a comprehensive plan. In most cases, the goal is not to achieve a true least-cost plan but to

provide customers with the **most cost-effective plan** while assuring adequate reliability given changing business and economic conditions.

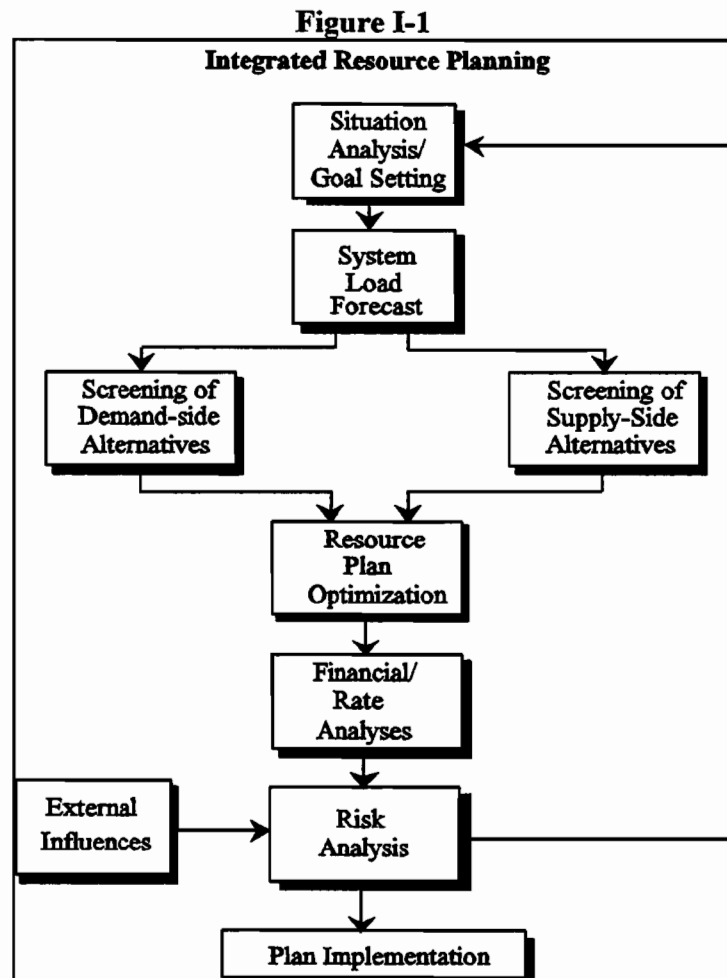


Figure I-1 shows the various components that comprise a thorough integrated resource planning process.

The IRP process for KUA began with a **load forecast** (described in Volume I: Assumptions Document). The forecast was also performed for alternative scenarios of future economic conditions so the flexibility of various resource plans under these conditions could be evaluated. The second major component of IRP is **demand-side planning** (discussed in Volume I, Section 2.0). The DSM analysis adds another dimension to resource planning and KUA considers it important in managing the efficiency of its electric system and providing “choice” to its customers. Cost-effectiveness of all resources is therefore very important, and the IRP process undertaken by KUA provides a framework designed to identify the most cost-effective resource plan.

Supply resource evaluation is the third component of the IRP process. In this step, all available technologies appropriate to KUA were considered in addition to purchases from other utilities. The ultimate number of planning alternatives is a subset of a much larger group which has been selected.

In the fourth major step, **integration**, both the supply and demand resources were evaluated together so that they can compete based on cost-effectiveness and load-serving capability. Following the integration analysis, a **sensitivity analysis** was performed on a range of uncertainty variables aggregated in meaningful combinations to produce a wide range of scenarios. The development of this wide range of scenarios is the foundation of the sensitivity analysis.

The final step of the IRP process is to evaluate all of the decision variables in the **risk analysis**: the objectives and plans are brought together to derive a preferred plan. The risk assessment approach and methodology are discussed in greater detail in Volume II.

B. Models

The models used for the resource evaluation are components of the Resource Planning Workstation (RPW) which is commercially supported by Stone & Webster Management Consultants, Inc. The EGEAS (Electric Generation Expansion Analysis System) model, available from the Electric Power Research Institute (EPRI) and the major component of the RPW models, uses a probabilistic load duration curve based production cost methodology similar to other production costing models. EGEAS is a planning model with a static screening module, a Bender's decomposition optimization module, and a dynamic programming optimization module.

The demand-side programs were developed using the Synergic Resource Company (SRC) model COMPASS[®]. The results of the COMPASS[®] program were then used by DSMLINK to create the data for the EGEAS program.

The supply-side screening analysis, the resource integration, and the sensitivity analysis were carried out using EGEAS. The risk analysis was performed using RISKMIN, also developed by EPRI and part of the Resource Planning Workstation.

C. Objectives of the Preferred Plan(s)

Short-term performance is an important part of developing the best long-term plan. KUA's primary objective is to develop a plan (or plans) that blends the short-term and long-term objectives and fairly and reasonably assigns risks associated with the resources and actions set forth in the plan(s). In meeting this objective it is important that KUA consider its competitive position in the industry in order to maintain customer base while adding those resources which minimize prices and total costs to KUA customers.

D. Summary Report Structure

This Summary Report contains seven sections. In addition to the Introduction, there are the following six sections.

- II. Core Assumptions
- III. Planning Alternatives Retained
- IV. Integration Analysis
- V. Risk Analysis
- VI. Preferred Plans
- VII. Recommended Action Plan

The actual IRP was developed for KUA in a non-pool environment. The pool is an operating pool and requires each of its members to perform their own capacity expansion analysis. Unless the pool decides to pursue a joint planning effort KUA is prudent to base its future expansion solely on its own needs. The resulting expansion plan does not reflect any economy energy purchases or sales to the Florida Municipal Power Pool (FMPP) members. The need for capacity and surrounding economic impacts are based solely on KUA's own system needs.

II. CORE ASSUMPTIONS

Load and fuel forecasts tend to dominate the results of the IRP process. Environmental factors can also be strong determining factors in many IRPs, but for KUA they do not dominate the process due to the similarity of fuel types for the planning alternatives and the amount of purchase power available.

The load forecast in conjunction with the existing resource base defines the timing and need for new capacity. The fuel forecasts generally tend to be the deciding factor in the choice of new capacity.

Detailed discussion of both the load and fuel forecasts is found in the Volume I: Assumption Document in Section 3 and 4, respectively. This section summarizes the core assumptions in order to frame the results contained later in this report.

A. Load Forecast

KUA's load forecast is summer peak driven. Table II-1 and Figure II-1 provide both a tabular and graphical representation of the load growth under forecasted base conditions in relation to KUA's existing resources. The KUA peak load is forecasted to increase at a 5.5% annual rate during the next ten years and then slow to a 3.6% growth rate for the subsequent ten-year period.

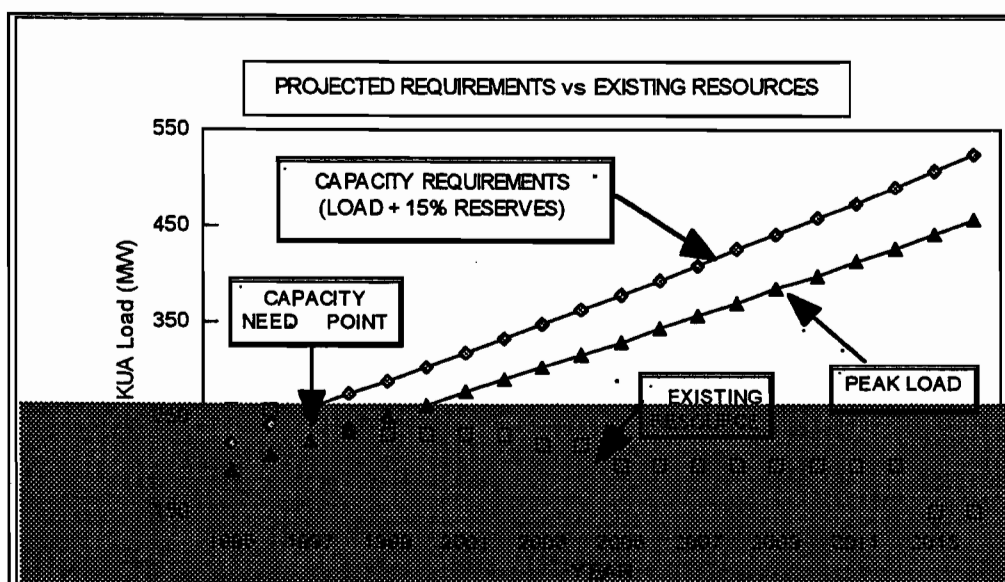
KUA has an immediate need for new capacity. In 1997, 3 MW of additional capacity will be needed to meet load growth plus a 15% reserve margin. In the short term, purchased power is available under the existing Stratified Purchase Agreement contract with Florida Power Corporation. In conjunction with this IRP additional short-term bids for purchased power were requested from regional utilities. (The excellent response to KUA's request for new purchased power will be discussed in Section III). Long-term capacity can also be obtained under the Stratified Purchase Agreement or through a host of alternatives. Table II-1 indicates that, due to continued load growth and the retirement of capacity, a total of 373 MW will have to be added through 2014. The complete list of planning alternatives that were analyzed and screened is contained in Section 2 and Section 12 of the Assumptions Document while the planning alternatives retained for detailed evaluation are shown in Section III of this Summary Report.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Table II-1 and Figure II-1
Load Projection and Resource Requirements

Year	Existing Resources (MW)	Forecasted Peak Load (MW)	Capacity Requirements (MW)	Annual New Capacity Needed (MW)	Cumulative New Capacity Needed (MW)
1995	258	195	224	0	0
1996	257	211	243	0	0
1997	257	226	260	3	3
1998	234	238	274	37	40
1999	231	251	288	17	57
2000	231	263	302	14	71
2001	231	276	318	15	87
2002	231	290	333	15	102
2003	221	303	349	26	128
2004	221	317	364	15	143
2005	201	330	379	35	179
2006	201	343	394	15	194
2007	201	356	410	15	209
2008	201	370	425	16	225
2009	201	384	442	16	241
2010	201	399	458	17	258
2011	201	412	474	16	274
2012	201	427	491	16	290
2013	152	441	507	66	356
2014	152	456	525	17	373



B. Fuel Forecast

Table II-2 below summarizes the 1995 fuel prices and the long-term price escalation forecast for each of KUA's fuels. Figure II-2 shows the 1996 KUA fuel mix (with Stanton 2 included). On a capacity basis, natural gas provides just over 50% of KUA's needs, and with the current projections, fuel prices and availability, natural gas continues to look attractive as the primary fuel for expansion.

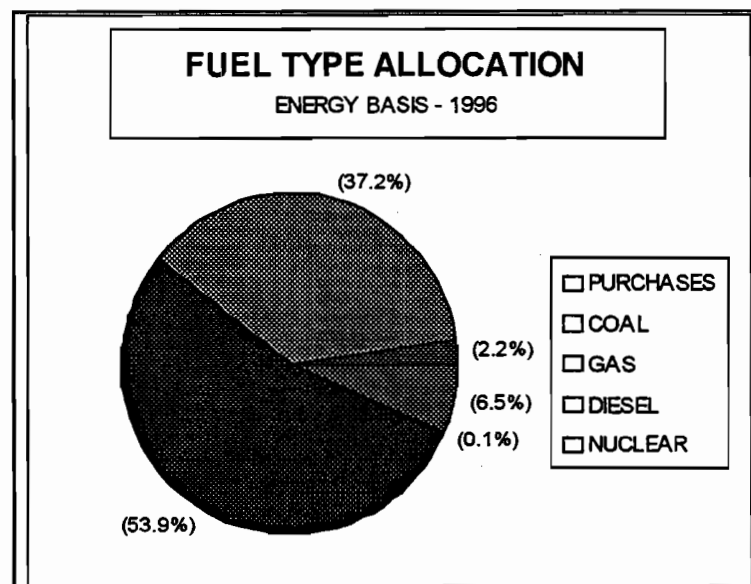
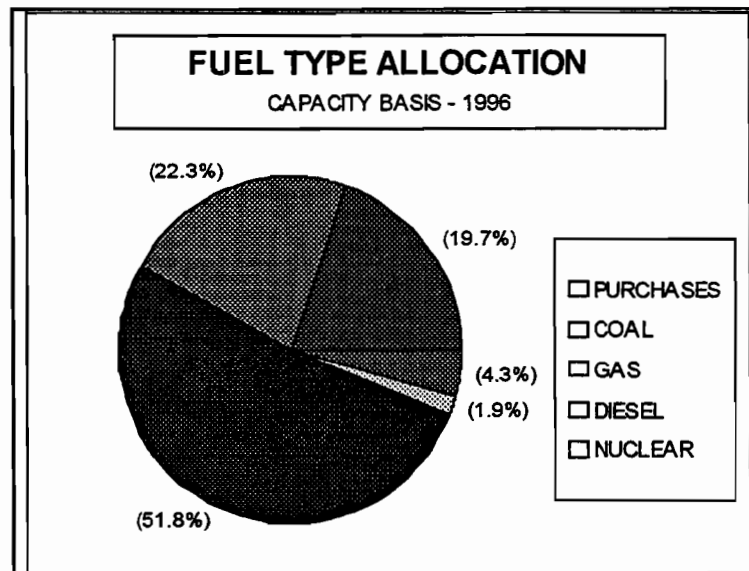
In addition to the traditional fuels (coal, gas, oil and nuclear), municipal solid waste was also investigated in the IRP. The advantage of using municipal solid waste (MSW) is its negative fuel cost (i.e., tipping fee): municipalities pay the utility to use municipal solid waste as the fuel for generating electricity up to the level or cost that would have been incurred to dispose of the solid waste in an approved landfill. Another advantage of considering MSW is the fuel diversity it offers to a heavily gas-dominated system. In the IRP, the initial tipping fee used for MSW is \$40/ton with a modest 1.5% annual increase.

Table II-2
Summary of Fuel & Purchase Power Escalators

Fuel Type	1995 Price	Unit	Annual Escalation (1) (%)
Gas	\$2.18	\$/MBtu	5.23
Coal	1.94	\$/MBtu	1.75
Nuclear	0.63	\$/MBtu	3.00
Diesel	4.00	\$/MBtu	4.58
Peak Capacity	61.6	\$/kW-yr.	0.74
Peak Energy	57.3	\$/MWh	2.19
Intermediate Capacity	107.3	\$/kW-yr.	0.73
Intermediate Energy	32.9	\$/MWh	4.03
Baseload Capacity	168.0	\$/kW-yr.	0.79
Baseload Energy	22.3	\$/MWh	4.25
Municipal Solid Waste	-40.0	\$/ton	1.50

⁽¹⁾ The escalation rates reflect the annual compound rate over the period 1995 through 2015.

Figure II-2
Fuel Type Allocation



III. PLANNING ALTERNATIVES RETAINED

After screening the comprehensive list of supply-side planning alternatives (see Table 12.2 of the Assumptions Document), eleven supply-side alternatives were carried forward into the evaluation phase of the IRP. Four demand-side management alternatives were also incorporated into the evaluation, making a total of fifteen planning alternatives. The alternatives range in size from less than 1 MW up to 80 MW and represent both KUA self- and joint-ownership alternatives. Table III-1 lists the fifteen planning alternatives and some of their key parameters.

Table III-1
Planning Alternatives Considered in IRP Optimization
(All Costs in 1995 Dollars)

Planning Alternative	Type	Size (MW)	Ownership Status	Capital Cost 1995 (\$/kW)	Fixed O&M 1995 \$/kW-yr	Variable O&M 1995 \$/MWh	Full Load Heat Rate Btu/kWh
Commercial Cooling	DSM	2.8	KUA	N/A	0	63.2	N/A
Residential Appliance	DSM	1	KUA	N/A	0	1,148	N/A
Residential Fix-up	DSM	0.6	KUA	N/A	0	965.7	N/A
Direct Load Control	DSM	41.7	KUA	N/A	0	25,979	N/A
Peak Purchase	PURC	10	KUA	N/A	61.56	57.31	N/A
Intermediate Purchase	PURC	10	KUA	N/A	107.56	32.85	N/A
Base Purchase	PURC	10	KUA	N/A	168	22.34	N/A
Aero Derivative CT	Supply	40	KUA	497	0.56	9.96	10,410
Cane Island CT	Supply	80	KUA	335	1.03	4.33	11,751
Large CT	Supply	77	Joint	345	0.15	2.22	11,210
Coal	Supply	44	Joint	925	39.09	8.22	9,880
Hansel Repowering	Supply	58.3	KUA	*957	30.0	1.10	7,370
Conventional CC	Supply	62	Joint	600	16.92	1.81	8,100
Advanced CC	Supply	80	Joint	500	10.86	1.08	7,450
Municipal Solid Waste	Supply	40	KUA	5,500	140	19.84	16,400

* Represents cost of incremental 14 MW of new capacity.

Along with the fifteen demand-side and supply-side alternatives, additional firm purchases were investigated. Based upon initial findings of the IRP process, KUA invited three regional utilities (Tampa Electric Company, Orlando Utilities Commission and Florida Power Corporation) to provide new bids for both short- and long-term power. The response to KUA's request for bids was excellent and the resulting bids have been incorporated in the IRP analysis, but, because they are considered confidential, have not been illustrated in this Summary Report.

The size indicated for the demand-side alternatives represents the maximum potential for that alternative. Tables 2-1 to 2-4 in the Assumptions Document contain the growth patterns (i.e., penetration rates) along with the costs for each of the demand-side alternatives.

The costs for each of the DSM alternatives have been modeled as variable O&M. For each alternative the O&M values shown in Table III-1 above are for the first year only. The rates decline over time in response to obtaining ongoing benefits associated with one-time prior costs. The year-by-year O&M rates associated with each of the four alternatives is shown in Table III-2.

Table III-2
Year by Year Rates for DSM Program
(\$/MWh)

Year	Commercial Cooling	Residential Appliance	Direct Load Control	Residential Fix-up
1996	63	1,148	25,978	965
1997	32	391	16,696	498
1998	22	201	13,615	339
1999	17	124	12,085	262
2000	14	84	11,178	216
2001	12	62	10,582	186
2002	10	48	10,164	164
2003	9	38	9,857	148
2004	8	31	9,626	135
2005	8	26	9,446	125
2006	0	0	8,940	0
2007	0	0	8,848	0
2008	0	0	8,776	0
2009	0	0	8,718	0
2010	0	0	8,638	0
2012	0	0	8,612	0
2013	0	0	8,593	0
2014	0	0	8,580	0
2015	0	0	8,572	0

All of the fixed and variable O&M costs for the supply-side units were escalated at 3% annually.

Four supply-side alternatives are listed as having a joint ownership status. To investigate the efficiencies of larger units, Stone & Webster used the price and heat rate parameters for larger units and allocated a portion of the capacity to KUA. For example, the 44 MW coal alternative is based on an actual unit size of 440 MW. The assumption is that KUA can obtain a 10% share of the 440 MW coal unit. Table III-3 shows each of the joint planning alternatives and the actual size unit.

Table III-3
Jointly-Owned Planning Alternatives

Planning Alternative	Planning Size (MW)	KUA Ownership (%)	Actual Size (MW)
Large CT	77	50	155
Conventional CC	62	50	125
Advanced CC	80	32	250
Coal	44	10	440

Jointly-owned units can align resource additions more closely with load growth at a lower cost. The larger units used as jointly-owned planning alternatives have lower capital costs, lower fixed and variable O&M, and more efficient heat rates. The drawback to jointly-owned units is the need to find a suitable partner and the time necessary to negotiate the contracts. Given KUA's ongoing relationship with FMPPA, however, joint ownership issues may not be substantial.

IV. INTEGRATION ANALYSIS

Virtually all of the underlying economic parameters associated with the resource options considered by the IRP analysis are to some degree uncertain. An optimal resource strategy therefore depends on a discrete set of assumptions. That is, while a single plan might be optimal for a given set of assumptions, the introduction of uncertainty could result in a drastically different optimal plan. Therefore, the integration analysis dynamically considers a spectrum of likely scenarios for key variables and determines optimal resource strategies for each scenario. To take account of these conditions the analysis was performed using the following process.

Specification of Significant Variables

It is important to identify the variables that significantly influence optimization results. For example, if the optimal plan under base assumptions indicates a preference for gas-fired combustion turbines, the integration analysis should consider natural gas prices as an uncertainty variable, since changes in gas prices will likely result in changes to the optimal resource plan. On the other hand, because variable O&M typically represents a fraction of the total production costs of a combustion turbine, the uncertainty in variable O&M costs most likely will not affect the optimized resource plan, and therefore need not be considered. The uncertainty variables used in the IRP were developed jointly by KUA management and Stone & Webster and are shown in Table IV-1.

Specification of Uncertainty States

Using the list of uncertainty variables, the range of values to address the uncertainty governing each variable was developed. Defining ranges involved the definition of uncertainty boundaries around the base value. Each of these values (base, mid-high, high, mid-low and low) for a particular variable is defined as an **uncertainty state**.

Table IV-1
Kissimmee Utility Authority 1995 IRP

		Definition of Uncertainty Values				
Uncertainties		Low	Mid Low	Base	Mid High	High
1	Load Growth	2.40%		5.60%		8.00%
2	Cost of Money	5.50%		6.50%	8.00%	12.00%
3	Combustion Turbine Capital Costs	300		335		400
4	Combined Cycle Capital Costs	540		600		720
5	Gas Prices Escalation (Average)	5.23%		5.23%		7.00%
6	Gas Supply Availability (80%)	4.4216		Unlimited		Unlimited
7	Purc Power Prices (Peak) - Esc.	0.00%		0.74%	1.50%	2.25%
	Purc Energy Prices (Peak) - Esc.	2.19%		2.19%	3.25%	4.50%
8	Purc Power Prices (Int) - Esc.	0.00%		0.74%	1.50%	2.25%
	Purc Energy Prices (Int) - Esc.	2.50%		4.03%	5.00%	6.00%
9	Purc Power Prices (Base) - Esc.	0.00%		0.79%	1.50%	2.25%
	Purc Energy Prices (Base) - Esc.	2.00%		4.25%	4.50%	5.00%
10	Purc Power Availability (Peak)	75%	90%	Unlimited		Unlimited

Definition of Futures

The next step in the process is the combination of uncertainties into meaningful combinations which represent possible "futures." Table IV-2 defines each of the seven futures which KUA and Stone & Webster jointly decided were applicable and appropriate to consider. Each future represents a realistic possibility, and not simply an exhaustive permutation of all combinations of variable uncertainty states.

When developing a future, each uncertainty variable is assigned one of its uncertainty values which reflects how the variable is expected to perform under the specified set of conditions. For example, the underlying assumption behind Future #4 (the over-subscribed gas market case) is that due to the headlong switch to natural gas in the U.S. supplies will not be able to keep up with demand and, correspondingly, gas prices will rise while availability will decrease. Under this premise, a related assumption is that peak and intermediate purchase power costs will increase because these types of transactions are normally made from gas-fired units. By developing reasonable futures, the entire set of uncertainty variables is changed in a cohesive manner to represent the expected impact associated with that future.

Integration

The integration analysis optimizes resource options for each of the futures, with the objective of either minimizing present value of revenue requirements or minimizing the levelized system average rate over the study period. The integration analysis derives optimal and sub-optimal resource strategies for each of the futures defined above. For each of the seven futures, the top two to three plans were initially retained and analyzed, which provided a total of eighteen plans. It is important to note, however, that some of these plans might be duplicates. For example, the best resource plan under Future #1 might be the third-best plan under Future #5. This plan would be reflected twice in the list of plans and it would be redundant to continue analyzing it. Accordingly, the last step in the integration process determines *unique plans* by eliminating duplicate plans from the list. A plan is defined as being unique if either the amount of each resource options and/or the timing of installation of these options is different from all other plans. Two plans are duplicates if the following three conditions hold: (1) the same types of resource options are selected, (2) the same number of each of the resource options is selected, and (3) the timing of these resource options is the same. Due to the large number of purchased power alternatives being studied, all of the eighteen plans retained were determined to be unique. Seven additional plans were later incorporated in the analysis framework to test for different timing and resource mix characteristics.

The integration analysis results in a number of unique resource strategies that consider the full spectrum of uncertainties. However, each of these plans was derived based on an optimization of a *single future*. In the next step, the Risk Analysis, each unique plan is simulated under *all* of the futures. This process exposes the consequences of implementing each plan in the event that a different future than the one for which the plan was derived

occurs. The risk analysis identifies the unique plan(s) which perform best over *all* futures and is the point in the IRP process where the majority of the analysis is involved. Therefore, a total of twenty-five plans were carried forward to the risk analysis.

Table IV-2
Definition of Futures

Futures	Uncertainty Variables and Levels									
	Load Forecast	Cost of Money	Turbine Capital Cost	CC Capital Cost	Gas Price	Gas Avail.	Peak Purch Power Prices	Int Purch Power Prices	Base Purch Power Prices	Peak Power Avail.
1.) Existing Conditions	B	B	B	B	B	B	B	B	B	B
2.) Impacts of Wholesale Wheeling	B	MH	B	B	B	B	L	L	L	ML
3.) Florida Limited Transfer Capability	B	B	B	B	B	B	L	L	L	L
4.) Over-subscribed Gas Market	B	B	L	L	H	L	H	H	MH	L
5.) Increased Regulation of Municipals	B	H	B	B	B	B	B	B	B	B
6.) Regional High Economic Growth	H	MH	H	H	MH	B	MH	MH	B	B
7.) Regional Low Economic Growth	L	L	B	B	B	B	L	L	L	H

V. RISK ANALYSIS

The risk analysis is a critical aspect of the IRP process because it pays particular attention to the strategic implications of implementing the resource plans derived in the Integration Analysis, and highlights the situational tradeoffs between each of the plans. In short, the risk analysis assesses the robustness of each of the unique resource plans, aiming to identify the plan(s) which best meet the IRP objectives over the broadest possible spectrum of likely futures. In this step, we defined the attributes by which competing resource strategies are ranked. An *attribute* is a performance measure for a particular plan simulated under a particular future. Attributes are selected such that the subsequent ranking of plans accurately reflects the ability of each plan to meet the IRP objectives. Table V-1 contains the list of attributes used in the IRP and the objective for using it.

Table V-1
List of Attributes

Decision Variables (Attribute)	Objectives
Levelized Average System Rates	Low Customer Rates
NO _x and SO ₂ per megawatt hour	Environmental Compliance
Present Worth of Revenue Requirements	Low Total Electric Power Costs
Gas supply constraints	Effective use of fuels
KUA-owned new generation costs and purchase power costs per megawatt hour	Balance capital and purchase power costs

Simulation of Scenarios

In this step, each of the unique plans derived in the integration analysis is systematically simulated under each of the futures defined. This expands the number of scenarios considered to a number equal to the number of unique plans times the number of futures (i.e., $25 \times 7 = 175$ scenarios). For each of these scenarios, the values for the attributes defined in the previous step are tracked and then compared to discern which plans perform best over all futures.

Specification of Attribute Tolerances

In this step, tolerances are established for the attributes defined above. These tolerances establish cutoffs by which a given plan may be deemed “not significantly better” or “worse than” an alternate plan. These tolerance levels are modeled as two inputs to the RISKMIN model, and by establishing them, the best plans can quickly be highlighted from the list of unique plans.

Analysis of Plan Robustness

A **robust** plan is a plan that consistently performs well over all of the futures. This step of the risk analysis assesses the relative robustness of the unique resource strategies.

A plan's robustness is determined by the number of futures which "support the plan." A future is said to support a plan only if the plan's attributes are within the tolerance levels of the corresponding attributes for all the other plans simulated for that same future.

The analysis of plan robustness is systematically accomplished as follows:

- 1) Examine the attributes for each plan under future #1.
- 2) Identify the plans for which each attribute is lowest under future #1. It is likely that two different plans will have the lowest values for the different attributes.
- 3) Calculate the incremental deltas in attribute values between the plans identified in step 2 and other plans for future #1. These deltas measure the "inferiority" of each plan as compared to the plans identified in step 2, assuming future #1 were to occur. If the deltas for all attributes of a given plan are within the defined tolerance levels, then future #1 supports that plan.
4. Repeat steps 1-3 for each of the remaining futures.

The more futures that support a plan, the more robust that plan is deemed.

VI. PREFERRED PLANS

A total of twenty-five plans were evaluated in the risk analysis, seven of which were the optimal (i.e. the lowest cost plan from each of the seven futures) and the remaining eighteen being sub-optimal plans (higher cost plans). The sub-optimal plans were evaluated to investigate timing and resource mix considerations. These plans were considered in order to cover a wide spectrum of resource plans that were not entirely based upon the lowest present worth revenue requirements over a fifty year period. For example, the municipal solid waste unit was never chosen in any of the seven optimal plans, however, it may have had advantages to KUA due to fuel diversity concerns. Volume 2: Technical Report (Section IV) discusses the methodology and results of the sensitivity and risk analysis in detail.

The desired outcome of the risk analysis is to obtain the preferred plan or plans for KUA. The preferred plan(s) will be the ones which support the most futures (i.e. are the most robust) using the defined attributes which are contained in Table V-1 of this report. In determining the most robust plan, certain planning alternatives appeared with greater regularity than the others. The resources that are selected the most frequently in the most robust plans are the most robust resources. This result provides justification for them to be preferred over other resources. The most robust resources are shown in Table VI-1. Other than purchases, the most favored resources across all plans are: Hansel refurbishing, Cane Island combustion turbine, and 80 MW combined-cycle, the residential appliances DSM program, and the commercial cooling DSM program.

Table VI-1
The Most Robust Resources

Planning Alternative	Capacity (MW)
Commercial Cooling DSM	2.8
Residential Appliance	1.0
OUC Base Purchases (1997-2000)	10 - 40
Hansel CC Repower	58
Cane Island CT	80
CC 80 MW (32% Ownership)	80
FPC Base Purchases (2001-2010)	10
TECO Peak Purchases (2001-2007)	10
FPC Base Purchases (2007-2010)	10

Based upon the RISKMIN evaluation, there were ten plans which were supported in 100% of the futures. The plans contained in this group are considered to be the most robust plans. The lowest cost plan within the robust group is the plan derived for the "Increased Regulation" future and is described in Table VI-2. This plan is characterized as the most robust plan.

**Table VI-2
Resource Additions of the Most Robust Plan
(Preferred Plan 1)**

Planning Alternative	Capacity (MW)	Year
DSM Commercial Cooling	Variable	1996
DSM Residential Appliances	Variable	
DSM Residential Load Control	Variable	
Base Purchase (OUC)	30	1998
Hansel CC Repower	58	1999
Base Purchase (OUC)	30	
Base Purchase (OUC)	40	2000
Combined Cycle (32% Ownership)	80	2001
Peak Purchase (TECO)	30	2004
Peak Purchase (TECO)	40	2005
Peak Purchase (TECO)	50	2006
Combined Cycle (32% Ownership)	80	2007
Peak Purchase (TECO)	10	2009
Peak Purchase (TECO)	20	2010
Total Capacity Added	218	
Total Maximum Summer DSM Added	46	

This plan contains many of the most robust planning alternatives contained in Table VI-1. One important difference between this most robust plan and the other plans is that it incorporates the residential direct load control in lieu of increased purchases and a combustion turbine at Cane Island. By improving KUA's fuel mix, the addition of the direct load control program helps offset the impact associated with the over-subscribed gas market future.

The implementation of the direct load control program does not effect the near term capacity expansion alternatives being proposed for the Hansel repowering in 1999 or the Cane Island Combined Cycle in 2001. The impact of the direct load control program is to reduce the near-term

and mid-term level of purchases required; and, to also avoid adding a combustion turbine in the 2004 timeframe. If the level of residential direct load control does not materialize then preferred Plan 2 described in Table VI-3 should be implemented.

Table VI-3
Resource Additions of Preferred Plan 2

Planning Alternative	Capacity (MW)	Year
DSM Commercial Cooling DSM Residential Appliances	Variable	1996
Base Purchase (OUC)	10	1997
Base Purchase (OUC)	50	1998
Base Purchase (OUC) Hansel Repowering	40 58	1999
Base Purchase (OUC)	60	2000
Combined Cycle (32% Ownership)	80	2001
Peaking Purchase (TECO)	10	2002
Peaking Purchase (TECO)	30	2003
Cane Island CT	80	2004
Peaking Purchase (TECO)	10	2005
Base Purchase (FPC)	20	2006
Combined Cycle (32% Ownership)	80	2007
Base Purchase (FPC)	10	2010
Cane Island CT	80	2011
Base Purchase (FPC)	20	2015

VII. ACTION PLAN

As a result of the IRP process, it is recommended that KUA pursue the following short-term action plan:

- Develop the implementation plan for the new residential direct load control program which provides up to 78 MW (winter) and 41 MW (summer).
- Pursue development of the implementation plan for the residential appliances program.
- Finalize the purchase power agreement with OUC and negotiate the contract to extend through the year 2000 instead of the currently proposed date of 1999.
- Initiate an engineering study to refine the cost of repowering the Hansel combined cycle. Repowering of the unit needs to be completed in early 1999.
- Enter into discussions with FMPA or another party to build a 250 MW combined cycle at Cane Island for installation in early 2001.
- Initiate competitive bid evaluation for the 250 MW combined cycle unit.
- Conduct customer surveys at both the residential and commercial levels to gather information to develop end-use forecasts.

In addition to the recommended short-term action plan, the following intermediate-to-long-term action plan should be undertaken:

- Continued monitoring of the purchase power market for the 2001 and onward time frame.
- Review and periodically assess municipal solid waste tipping fees. As tipping fees approach \$50/ton this alternative becomes economic to KUA and also provides fuel diversity.
- Review after 1-2 years the results of the residential direct load control program to determine if the program is being accepted at the level modeled. If the program is smaller than expected then that program will need to be reevaluated and possibly eliminated. Preferred Plan 2 described in Table VI-3 can quickly be implemented if the direct load control program does not meet expectations.

VIII. RECOMMENDATIONS FOR KUA IRP PROCESS

The development of an IRP is not a one-time event, in fact it must be a living process. In today's utility environment the key to maintaining a healthy company is the ability to quickly recognize and adapt to changing conditions. The IRP process should be used to take the pulse of the utility environment on an on-going basis in order to assure the continued health of KUA. The IRP process provides the fundamental mechanism by which future power purchase bids, capacity bids and special projects will be evaluated. To this end Stone & Webster recommends that KUA implements the following actions to support and improve the IRP process.

- Conduct customer surveys to provide the necessary information to develop end-use forecasts.
- Obtain necessary modeling tools to effectively analyze DSM. COMPASS, DSManager or Resource Planning Guide are candidates.
- Obtain the necessary modeling tools to be able to dynamically evaluate the financial impact associated with the plans developed under the IRP. Stone & Webster recommends Finance+ be obtained.
- Obtain database for in-house investigation of the cost and performance of the full range of planning alternatives. Stone & Webster's Cost & Performance Database or EPRI's Technical Assessment Guide (TAG) are good examples.
- Increased KUA staff involvement in the ongoing IRP process. In addition to increased involvement by Planning staff, involvement of Finance and Operations is desirable.

Kissimmee Utility Authority
Florida Municipal Power Agency
Cane Island – Unit 3

NEED FOR POWER APPLICATION

Volume 1C

Kissimmee Utility Authority
Florida Municipal Power Agency



Cane Island Power Park Unit 3



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1C.1.0 Overview and Summary

1C.1.1 Overview

Cane Island Unit 3 is planned as a new combined cycle addition to the existing Cane Island site, located in Osceola County. Cane Island Units 1 and 2, a combustion turbine and combined cycle burning natural gas, are currently operating. The Cane Island Site was licensed for an ultimate capacity of approximately 1,000 MW. Cane Island Unit 3 will provide very economical power for the Florida Municipal Power Agency (FMPA or Agency) All-Requirements Project members with a minimal environmental impact. Cane Island Unit 3 will be a 1x1 "F" class combined cycle unit. The actual output of the unit will depend upon the combustion turbine vendor selected and the design and size of the steam turbine. Output will also vary with degradation and ambient conditions. FMPA will be a 50 percent joint owner in Cane Island Unit 3. FMPA's portion of the nominal 250 MW of generation from Cane Island Unit 3 will be approximately 125 MW. Details specific to the project are presented in Volume 1A. This volume, Volume 1C, contains information specific to FMPA's need for the project.

FMPA strives to meet their responsibility to supply their member's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. FMPA's rates to its All-Requirements members are among the lowest in the state due to strategic planning and ability to provide economies of scale to its smaller members.

FMPA is committed to meet its All-Requirements customers' needs and identify projects that will provide economical power to Peninsular Florida residents through the combination of demand-side and supply-side resources. Through the member cities, FMPA has been a strong supporter of conservation and demand-side programs where cost-effective. With FMPA's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

A diversified mix of fuels for generation provides methods to reduce risk associated with fuel price volatility and supply risk. Cane Island Unit 3 provides the best alternative for fuel diversification for FMPA with the price of natural gas projected to remain low and the availability of natural gas to remain high throughout the planning horizon.



FMPP achieves savings through economy interchange and central dispatch which are obtained through participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, Kissimmee, and the FMPP All-Requirements Project. Since 1988, FMPP has saved its members an estimated \$101.8 million.

FMPP's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with the Cane Island Unit 3 project. Cane Island Unit 3 will burn natural gas as the primary fuel with dry low NO_x burners providing a very clean burning high efficiency unit.

As discussed in the remainder of this application, FMPP has evaluated appropriate alternatives to Cane Island Unit 3 to determine if they are lower in cumulative present worth revenue requirements. As part of the evaluation process, FMPP together with KUA, issued a joint request for proposals (RFP) for power supply as an alternative to Cane Island Unit 3 in May 1997. FMPP's RFP requested bids for short-, mid-, and long-term power. Numerous bids were received and evaluated. All long-term bids received, that were feasible under current regulations in Peninsular Florida, resulted in an increase in present worth revenue requirements over Cane Island Unit 3. As a result, FMPP rejected all long-term bids and is pursuing the construction of Cane Island Unit 3. Short- and mid-term bids were evaluated from the RFP resulting in their selection for purchase power for short- and mid-term periods. Contracts for the purchase power are currently being pursued by FMPP.

FMPP believes that Cane Island Unit 3 represents the minimal cost and performance risk to its members due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Cane Island Unit 3 represents FMPP's least cost alternative that has been demonstrated through exhaustive evaluations as well as a thorough test of the marketplace.

1C.1.2 Summary

FMPP's All-Requirements has been growing rapidly through the addition of new members with Lake Worth projected to join in 1999. FMPP's peak demand is projected to grow at a 1.5 percent average annual rate from 1999 through the end of the planning period in 2017. The projected load growth assumes no new members will join after Lake Worth in 1999.



FMPA uses an 18 percent reserve margin as a reliability criteria. FMPA's reserve margin is projected to drop to 7.4 percent during the summer of 2001, dictating the need to add capacity.

FMPA received 33 proposals from 17 bidders from their May 1997 request for proposals (RFP) for purchase power. Proposals were received for short-, medium-, and long-term power. After an extensive evaluation, two of the bidders were short-listed for long-term power. Ultimately, both long-term bidders were rejected because both bidders proposed merchant plant projects using Westinghouse 501G combined cycle units. Recent FPSC decisions regarding requests for Declaratory Statements regarding merchant plants draw into serious question the ability of merchant plants to be constructed in time to meet FMPA's need for capacity in the summer of 2001. Furthermore, the Westinghouse 501G combustion turbine is not yet in commercial operation in the United States resulting in significant reliability and performance risk. As a result, FMPA selected Cane Island 3 to provide long-term power requirements.

After evaluation, FMPA short-listed six short- and medium-term bidders for negotiations. Ultimately, three of the bidders were eliminated since their proposals involved the development of merchant plants. FMPA is currently negotiating for short- and medium-term power with Lakeland Electric & Water, Lee County Solid Waste Management, and Orlando Utilities Commission representing all of the short-listed bidders that were not proposing merchant plants. In addition, FMPA is also negotiating with Tampa Electric Company for purchase power.

FMPA evaluated 10 generating unit alternatives with the EGEAS optional generation expansion model. EGEAS selected the installation of Cane Island 3 as a 501F combined cycle as the least cost alternative for the base case. In addition, FMPA evaluated seven sensitivity cases and EGEAS selected the 501F combined cycle in 2001 for all the sensitivity cases as the least cost alternative.

**1C.2.0 Description of Existing
Facilities**



1C.2.0 Description of Existing Facilities

The Florida Municipal Power Agency (FMPA) was created on February 24, 1978, by signing of the Interlocal Agreement among its 27 members, which specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution, Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each city commission or authority which is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of the Agency. The Board has the responsibility for developing and approving the Agency's budget, hiring a General Manager, and establishing both bylaws which govern how the Agency operates and policies which implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary-Treasurer, Assistant Secretary-Treasurer, and Executive Committee. The Executive Committee consists of nine representatives elected by the Board plus the then-current Chairman and Vice Chairman of the Board.

The Executive Committee meets regularly to control the Agency's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

1C.2.1 Generation System

FMPA is a project-oriented, joint action agency where each project stands on its own. FMPA currently has five power supply projects in operation: (i) the St. Lucie Project, (ii) the Stanton Project, (iii) the Tri-City Project, (iv) the All-Requirements Project, and (v) the Stanton II Project. Each of the projects is summarized in Sections 1C.2.1.1 through 1C.2.1.5.



Table 1C.2-1 provides a summary of the member participation for each project. Figure 1C.2-1 illustrates the location of the FMPA member cities within Peninsular Florida. Table 1C.2-2 provides a summary for the existing FMPA generating facilities with project capacities combined where appropriate.

The 50 percent ownership share of Cane Island Unit 3 will be owned by the All-Requirements Project as is the 50 percent ownership share of Cane Island Units 1 and 2. As such, the need for Cane Island Unit 3 will be demonstrated by the All-Requirements Project.

1C.2.1.1 St. Lucie Project

On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie Unit 2 was declared in commercial operation August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the Agency's members are participants in the St. Lucie Project and seven of the fifteen are also members of the All-Requirements Project.

1C.2.1.2 Stanton Project

On August 13, 1984, the Agency purchased from Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit 1, a coal fired electric generation unit with a nominally rated, net high dispatch capacity of 465 MW. Stanton Unit 1 went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project and three of the six are also members of the All-Requirements Project.

1C.2.1.3 Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three of the Agency's members are participants in the Tri-City Project and two of the three are also members of the All-Requirements Project.

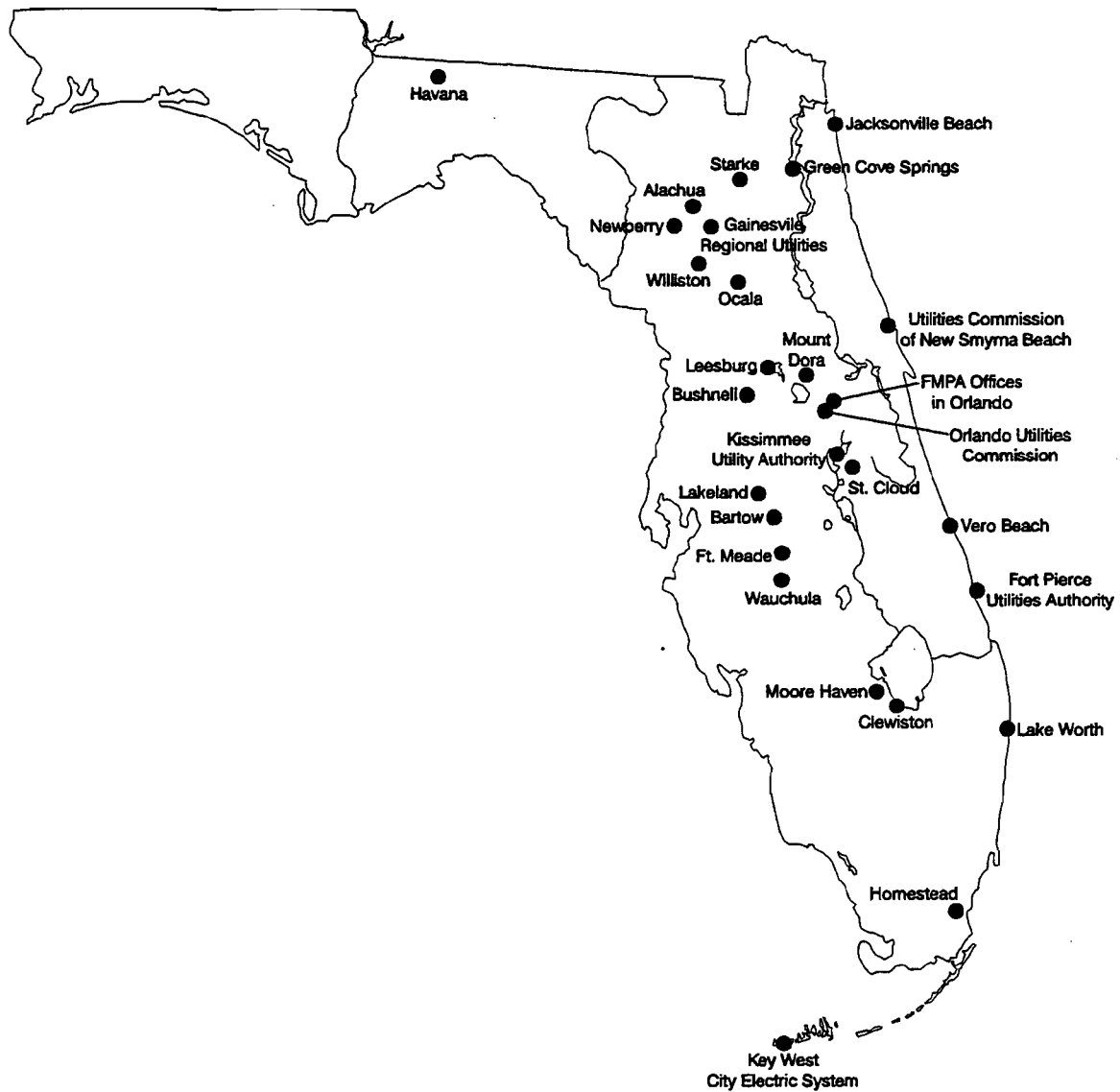
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Table 1C.2-1
Summary of Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bartow					
City of Bushnell				X	
City of Clewiston	X			X	
City of Ft. Meade	X				
Ft. Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana					
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X			X
City of Lakeland					
City of Lake Worth	X	X		P (1999)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt. Dora					
City of Newberry	X				
Utilities Commission of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utility Commission					
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X
City of Wauchula					
City of Williston					
P - Planned addition of new member.					



Member Cities
Figure 1C.2-1



Table 1C.2-2
Existing FMPA Generating Facilities
As of December 31, 1997 (1)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Net Capability ²	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
St. Lucie	2	St. Lucie	NP	UR	--	TK	--	8/83	Unknown	839,000	74.0	75.0
Stanton Energy Center	1	Orange	ST	BIT	--	RR	--	7/87	Unknown	464,580	115.0	115.0
	2		ST	BIT	--	RR	--	6/96	Unknown	464,580	122.0	122.0
Indian River	CT A	Brevard	GT	NG	FO2	PL	TK	6/89	Unknown	41,400	14.0	18.5
	CT B		GT	NG	FO2	PL	TK	7/89	Unknown	41,400	14.0	18.5
	CT C		GT	NG	FO2	PL	TK	8/92	Unknown	112,040	22.0	27.0
	CT D		GT	NG	FO2	PL	TK	10/92	Unknown	112,040	22.0	27.0
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	1/95	Unknown	42,000	15	20
	2		GT	NG	FO2	PL	TK	6/95	Unknown	120,000	54	60
Key West	2	Monroe	GT	FO2	--	WA	--	6/98	Unknown	19,000	17.7	17.7
	3		GT	FO2	--	WA	--	6/98	Unknown	19,000	17.7	17.7
Total											487.4	518.4

1. Also includes Key West GT's 2 and 3 with planned commercial operation dates in June 1998.

2. FMPA ownership share.



1C.2.1.4 All-Requirements Project

The All-Requirements Project was formed on May 1, 1986, with five members; other members have joined through the years. The All-Requirements Project participants now consist of City of Bushnell, City of Clewiston, Fort Pierce Utilities Authority, City of Green Cove Springs, City of Jacksonville Beach, City of Key West, City of Leesburg, Ocala Electric Utility, City of Starke, City of Vero Beach, with the City of Lake Worth Utilities planned to join in 1999. Under the All-Requirements Project, the Agency currently serves all the power requirements (above certain excluded resources) for the 10 members. In May 1991, the City of Clewiston became a member of the All-Requirements Project. In 1997, the Cities of Vero Beach and Starke joined, with Fort Pierce joining in January 1998 and Key West in April 1998. The City of Lake Worth is anticipated to join the All-Requirements Project sometime in 1999. Table 1C.2-3 shows the date that each member joined the All-Requirements Project. The current supply resources of the Project include: (i) the purchase of a 6.5060 percent undivided ownership interest in Stanton Unit 1 from OUC; (ii) capacity and energy from FMPA's 39 percent undivided ownership interest in two 41 MW combustion turbines (Units A and B) at the OUC Indian River Plant; (iii) capacity and energy from FMPA's 21 percent undivided ownership interest in two 112 MW combustion turbines (Units C and D) at the OUC Indian River Plant; (iv) capacity and energy from FMPA's 50 percent undivided interest in the 42 MW Cane Island Unit 1 combustion turbine and the 120 MW Cane Island Unit 2 combined cycle at the Cane Island Power Park; (v) the purchase of a 5.1724 percent undivided ownership interest in Stanton Unit 2 from OUC, (vi) capacity and energy purchases from other utilities including OUC, FPL, Florida Power Corporation (FPC), Tampa Electric Company (TECO), City of Lake Worth, and Gainesville Regional Utilities; (vii) necessary transmission arrangements; and (viii) required dispatching services. With Key West's recent decision to join the All-Requirements Project, FMPA awarded a contract for the turnkey purchase of two reconditioned combustion turbine generating units that total 38 MW nameplate that will be located at an existing Key West site. Both combustion turbines are Frame 5 GE models reconditioned back to zero hours of operation. With the addition of four generating cities to the All-Requirements Project in 1997 and 1998, the supply resources of the All-Requirements Project now include capacity and energy purchases from the



Table 1C.2-3 Summary of All-Requirements Project Participants Date Member Joined	
Agency Member	Date Member Joined
City of Bushnell	May 1, 1986
City of Clewiston	May 8, 1991
Ft. Pierce Utilities Authority	January 1, 1998
City of Green Cove Springs	May 1, 1986
City of Jacksonville Beach	May 1, 1986
Key West City Electric System	April 1, 1998
City of Lake Worth	1999
City of Leesburg	May 1, 1986
City of Ocala	May 1, 1986
City of Starke	October 1, 1997
City of Vero Beach	June 1, 1997

generation owned by each of these cities and/or firm power resources. Table 1C.2-4 provides a summary of the generating resources of the All-Requirements Project. This table does not include member generating resources, which are considered firm capacity purchases. The member generating resources are included in Section 1C.2.2.1. Table 1C.2-4 indicates 18 MW of generating capacity from Crystal River Unit 3 for the All-Requirements Project. This capacity in Crystal River Unit 3 is actually owned by several of the individual All-Requirements Project members, but FMPA is responsible for dispatching its capacity along with all other FMPA All-Requirement Project resources. Table 1C.2-4 indicates St. Lucie Unit 2 generating capacity which is also actually owned by several of the individual All-Requirements Project members and is also dispatched by FMPA. Table 1C.2-4 also indicates capacity from St. Lucie Unit 1. Certain All-Requirements Project members actually have ownership in St. Lucie Unit 2, but power is supplied equally from Units 1 and 2 through a reliability exchange agreement. The Stanton 1 and 2 capacity shown in Table 1C.2-4 includes the capacity owned by individual members as well as the capacity owned directly by the All-Requirements Project itself.



Table 1C.2-4
Existing All-Requirements Generating Facilities
As of December 31, 1997 (1)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate MW	Net Capability ²	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
Crystal River	3	Citrus	N	UR	--	TK	--	3/77	Unknown	890	18.0	18.0
Stanton Energy Center	1	Orange	ST	BIT	--	RR	--	7/87	Unknown	465	83	83
	2		ST	BIT	--	RR	--	6/96	Unknown	465	65	65
St. Lucie	1	St. Lucie	N	UR	--	TK	--	8/83	Unknown	839	17.5	18.0
	2		N	UR	--	TK	--		Unknown	839	17.5	18.0
Indian River	CT A	Brevard	GT	NG	FO2	PL	TK	6/89	Unknown	41.40	14.0	18.5
	CT B		GT	NG	FO2	PL	TK	7/89	Unknown	41.40	14.0	18.5
	CT C		GT	NG	FO2	PL	TK	8/92	Unknown	112.0	22.0	27.0
	CT D		GT	NG	FO2	PL	TK	10/92	Unknown	112.0	22.0	27.0
Cane Island	1	Osceola	GT	NG	FO2	PL	TK	1/95	Unknown	42	15	20
	2		CC	NG	FO2	PL	TK	6/95	Unknown	120	54	60
Key West	2	Monroe	GT	FO2	--	WA	--	6/98	Unknown	19.0	17.7	17.7
	3		GT	FO2	--	WA	--	6/98	Unknown	19.0	17.7	17.7
Total											377.4	408.4

1. Also includes Key West GT's 2 and 3 with planned commercial operation dates in June 1998.

2. All-Requirements Project ownership share.



The All-Requirements Project provides its members with all of their capacity and energy requirements above excluded resources which are the members' ownership in Crystal River Unit 3 and St. Lucie Unit 2. All-Requirements Project members which have joint ownership in other FMPP projects make available their joint ownership interests to the All-Requirements Project and the All-Requirements Project incorporates the capacity into the total project power supply. For All-Requirements Project members that own on-system generation, the All-Requirements Project purchases the capacity and energy from the on-system generation for use by the All-Requirements Project and then, in turn, supplies the members their full capacity and energy requirements. The All-Requirements Project members are responsible for maintenance and operation of their on-system generating units. The All-Requirements Project schedules the commitment and dispatch of the units. As a member of the Florida Municipal Power Pool (FMPP), the actual commitment and dispatch of units is conducted by FMPP for the All-Requirements Project.

1C.2.1.5 Stanton II Project

On June 6, 1991, the Agency, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton Unit 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of the Agency's members are participants in the Stanton II Project and four of the seven are also members of the All-Requirements Project.

1C.2.1.6 All-Requirements Project Participants

A brief description of each of the participants is provided in the following subsections.

1C.2.1.6.1 City of Bushnell. Bushnell, "Seat of Sumter County," is located in west central Florida, 55 miles from Orlando and 50 miles north of Tampa. The City operates under a Council-Manager form of government. Bushnell owns and operates its own electric and water system, the revenues from which are combined for financial purposes; thus, these utility services are integrated for purposes of the All-Requirements Power Supply Project Contract.

Bushnell is predominantly a rural community and local employment is mostly provided through retail establishments, government agencies, light manufacturing, service companies



and agriculture. Bushnell usually has a slight population growth during the winter months due to returning visits of part-time residents from northern states.

The City of Bushnell entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Energy is delivered through a delivery point in the City at 12 kV. Excluded Power Supply Resources for the City of Bushnell include only its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 0.0388 percent of that unit (or 306 kW based on current net summer rating).

The City of Bushnell's electric utility service area covers approximately 3 square miles and has a territorial agreement with a neighboring cooperative. Ninety-two percent of the customers served reside within the city limits.

1C.2.1.6.2 City of Clewiston. The City of Clewiston is located in Hendry County on the southwest tip of Lake Okeechobee, mid-way between West Palm Beach on the east and Fort Myers on the west. Clewiston is the headquarters of the United States Sugar Corporation. The City operates and maintains electric, water, and wastewater utilities.

The City of Clewiston purchased its electric system in May 1942, from U.S. Sugar Corporation. On May 8, 1991, Clewiston became an All-Requirements Project Participant. Excluded Power Supply Resources for the City of Clewiston include only its entitlement share in the Agency's St. Lucie Project (approximately 1,624 kW). The City's 138 kV transmission system interconnects with FPL. One substation supplies voltage at 12 kV to a predominantly overhead distribution system.

The City's electric utility service area encompasses approximately 8.5 square miles with 70 percent of the customers served residing within city limits. Clewiston has a territorial agreement with Glades Electric Cooperative and has a franchise from Hendry County to serve its current service area.

1C.2.1.6.3 City of Fort Pierce Utilities Authority. The City of Fort Pierce is located in St. Lucie County on the east coast of Florida approximately 125 miles north of Miami. The Fort Pierce Utilities Authority was established in 1972 for the purpose of governing and operating the City's electric, water, wastewater, and natural gas distribution utilities as a separate unit of City government. The City Commission appoints Utility Authority Members to overlapping 4 year terms, and each Authority Member is limited to two consecutive terms of office. The Authority employs the Director of Utilities.



The Fort Pierce Utilities Authority owns and operates electric generating facilities capable of supplying a portion of its system requirements. The existing on-system capacity, which amounts to 119 MW (excluding units on extended cold standby), is primarily fueled by natural gas (99.85 percent) pursuant to a contract with Florida Gas Transmission Company (FGT). On January 1, 1998, Fort Pierce became an All-Requirements Project participant. Additionally, the Authority has the right to receive up to 11.217 MW from FMPA's St. Lucie Project. The Fort Pierce Utilities Authority is also a participant in FMPA's Stanton Project and Tri-City Project with a total interest of approximately 20 MW from Stanton 1 for both projects. Fort Pierce's electric utility service area encompasses approximately 40 square miles with 78 percent of electric utility customers residing within the City limits. Fort Pierce's transmission system includes a 138 kV interconnection with FPL, a 138 kV line connecting Fort Pierce with the City of Vero Beach, and a 69 kV line completely looping the Fort Pierce service area. Six major substations supply voltage at 13 kV to a predominantly overhead distribution system.

1C.2.1.6.4 City of Green Cove Springs. The City of Green Cove Springs is located on the St. John's River in Clay County, 26 miles south of Jacksonville. The City operates and maintains the electric, water, and wastewater utilities. The City operates under the City Council/Manager form of government. The five member City Council is elected at large and appoints the City Manager, who serves as the City's chief administrative officer and directs the operation of the City's utility service.

Green Cove Springs became an All-Requirements Project Participant when the project was originally implemented on May 1, 1986. The City's electric utility service area encompasses approximately 10 square miles with 85 percent of customers residing within city limits and 15 percent residing outside of city limits. The City has a territorial agreement with a neighboring cooperative utility.

1C.2.1.6.5 City of Jacksonville Beach. The City of Jacksonville Beach is located in Duval County approximately 18 miles east of Jacksonville. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water, and wastewater utility operations. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities.



Jacksonville Beach is predominantly a residential community whose citizens, for the most part, work in the metropolitan Jacksonville area. Additionally, the City is a major recreation area for the people of Duval County, Florida.

The City of Jacksonville Beach entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Jacksonville Beach include only its entitlement share in the Agency's St. Lucie Project (approximately 5,406 kW). Jacksonville Beach owns one 230 kV transmission substation that ties to Florida Power & Light and has available a transmission tie to Jacksonville Electric Authority. They also have 12 distribution substations, which deliver energy at 26 kV, 12 kV, and 4 kV levels. Approximately 50 percent of the distribution circuits are underground installations.

The City of Jacksonville Beach electric utility service area encompasses approximately 45 square miles including the neighboring town of Neptune Beach, and the unincorporated areas of Ponte Vedra and Palm Valley located in St. Johns County. Portions of this territory have been assigned to the City by the Florida PSC. Forty-four percent of the customers served reside within City limits.

1C.2.1.6.6 City of Key West Utilities Board. The City of Key West was first incorporated in 1828 and is the county seat of Monroe County, Florida. It is located near the southern extreme of the Florida keys, a string of coral islands extending in a southwesterly arc from Biscayne Bay to the Dry Tortugas, and lies further south than any other point in the continental United States. The Utility Board of the City of Key West operates the municipally owned electric generating and distribution system of the City. The Utility Board is composed of a chairman who is elected for a term of two years and four members who are elected for a term of four years by the voters of the City of Key West. The Utility Board employs the Manager of the Electric System.

The Utility Board operates and maintains the on-system electric generating facilities of the electric system which consist of diesel generating units and one combustion turbine generating unit, with a total capacity of 50.4 MW. On April 1, 1998, the Utility Board became a member of the All-Requirements Project. The Utility Board is also a participant in FMPA's Tri-City Project and Stanton II Project with entitlements of approximately 12 MW from Stanton 1 and 10 MW from Stanton 2.



The electric system currently uses No. 2 and No. 6 fuel oil for all of its on-system generation facilities. The generating units of the system are not capable of using alternative fuels.

Key West obtains a major portion of its power via a 138 kV transmission line that extends up the causeway through Florida Keys Electric Cooperative Association, Inc. (FKEC) service territory and ties in with FPL on the mainland. Key West's portion of this main transmission line consists of 46.11 miles of 138 kV overhead line from Key West's Stock Island Substation to FKEC's Marathon Key Substation. Subtransmission is provided in Key West through various 69 kV overhead transmission lines with an aggregate total of 15.2 miles. Transformation between the 138 kV and 69 kV transmission lines is obtained by a 105 MVA autotransformer at the Stock Island Substation.

Key West's distribution system is comprised of approximately 202 miles of 13.8 kV and 19 miles of three-phase equivalent 4.16 kV feeder lines from Key West's power generation units and substation power transformers. In order to reduce system losses, Key West has an ongoing program to convert all of its 4.16 kV distribution lines to 13.8 kV.

Key West's service area consists of the lower Florida Keys, extending approximately 44 miles in an east-west direction from Pigeon Key, adjacent to the service area of FKEC to the City of Key West. Within its area, the electric system currently services the area between Ohio Key and the City. The FKEC and Key West have a Florida Public Service Commission approved territorial agreement.

Two additional 17.7 MW combustion turbines are planned to go into service at Key West's Stock Island Plant, but they will be owned by FMPA's All-Requirements Project.

1C.2.1.6.7 City of Leesburg. The City of Leesburg is located in Lake County, 41 miles north of Orlando and 36 miles south of Ocala. The City operates under a Commission/Manager form of government. The five member City Commission is elected at large and employs the City Manager, who serves as the City's chief administrative officer. The City operates and maintains electric, water, sewer, and natural gas distribution utilities. Each of the City's utility operations is supervised by a Director.

The City of Leesburg entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Leesburg include its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 0.8244 percent of that unit (or 6,496 kW



based on current net summer rating), and its entitlement in the Agency's St. Lucie Project (approximately 1,716 kW). The City owns four substations which convert the 69 kV voltage delivered by Florida Power Commission (FPC) down to the system distribution voltage of 13 kV. These substations and their attendant transmission systems completely loop the service area and assure dependable system operation. The city-owned distribution system has a 190 MVA capacity and delivers all the system energy at the 13 kV level. Approximately 15 percent of electric service is provided in underground circuits. A load management and SCADA system was installed during 1985.

The City's electric utility service area includes the incorporated cities of Leesburg and Fruitland Park and encompasses approximately 59 square miles with 40 percent of the customers served residing within the 23.5 square mile city limits of Leesburg. The City has received Florida PSC approval of a territorial agreement with FPC and the local electric cooperative.

1C.2.1.6.8 Ocala Electric Utility. The City of Ocala is located in Marion County near the geographic center of the State of Florida, approximately 35 miles south of Gainesville and 75 miles north of Orlando. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water, and wastewater utility operations which are not integrated for purposes of the All-Requirements Power Supply Project Contract. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities.

The economy of Ocala and Marion County is diversified. The three major payroll classifications in the private sector are: services (tourism), manufacturing, and retail trade, in that order. Next are wholesale trade and construction. Agriculture and the thoroughbred horse industry are also major contributors to the area economy. As the center of retail trade for a four county area, the City of Ocala and Marion County have each experienced significant growth in both retail sales and in the number of establishments catering to the retail sector.

The City of Ocala entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Ocala include only its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 1.3333 percent of that unit (or 10,504 kW based on current net summer rating). The City owns and operates its bulk power supply system



which consists of 70 miles of 230 kV transmission line, three 230 kV to 69 kV substations, an 80 mile 69 kV transmission loop, and 15 distribution substations delivering power at 12 kV. The distribution system consists of approximately 800 miles of overhead lines and 100 miles of underground.

The City's service area encompasses approximately 171 square miles. The service area is generally rectangular in shape, extending approximately 21 miles east and west and 17 miles north and south. The City of Ocala has received Florida PSC approval of territorial agreements with Clay Electric Cooperative and Sumter Electric Cooperative. Sixty-one percent of the customers served reside within the City limits.

1C.2.1.6.9 City of Starke. The City of Starke, in Bradford County, is located in northeast Florida, approximately 50 miles southwest of the City of Jacksonville. The City, established in 1875, operates under the Mayor/Commissioner form of government. The City operates and maintains electric, water, sewer, and gas distribution utilities. An elected city clerk serves as the City's chief administrative officer, and utility operations are under the supervision of an appointed Electric System Director.

The City of Starke owns and operates electric distribution facilities. The City receives up to 1.634 MW from FMPA's St. Lucie Project and up to approximately 1.5 MW from FMPA's Stanton Project. In order to meet its total electric system requirements, the City is a member of the All-Requirements Project. The City has one 13 kV interconnection with FPL and one substation reduces this voltage to 4 kV for predominantly overhead delivery to electric system customers.

1C.2.1.6.10 City of Vero Beach. The City of Vero Beach, the county seat of Indian River County, is located on the east coast of Florida midway between Miami and Jacksonville. The City was incorporated in 1919 and established a City Council/City Manager organization in 1951. The City Manager also serves as the Director of Utilities. The City owns and operates electric, water, and sewer utilities.

The City of Vero Beach owns and operates on-system electric generating facilities. The existing on-system capacity amounts to 150 MW (excluding units on extended cold standby) of oil and gas fired units predominantly fueled by natural gas. The City paid FGT to expand the fuel gas pipeline to allow the City's existing capacity to be totally gas fired. Natural gas is currently supplied pursuant to a contract with FGT. In addition to its existing on-system generating capacity, the City has entitlements of 11.214 MW of nuclear power and 20 MW



of coal fired power from Stanton 1 from FMPA's St. Lucie and Stanton Projects, respectively. The City's 69 kV transmission system includes interconnections with FPL and the Fort Pierce Utilities Authority. The transmission system completely loops the service area, enhancing service reliability. Eight substations supply voltage at 13 kV to a predominantly overhead distribution system.

1C.2.1.6.11 City of Lake Worth. The City of Lake Worth is located in Palm Beach County on the east coast of Florida, 7 miles south of West Palm Beach and 61 miles north of Miami. The City was incorporated in 1913 and has been supplying electric power to the area since 1916. The City of Lake Worth assumed the operation of, and all obligations for, the electric, water, and wastewater utilities in 1985 through state of Florida legislative action.

Lake Worth owns on-system electric generating facilities. The existing on-system capacity amounts to 89.8 MW (excluding units on extended cold standby), primarily fueled by natural gas (98 percent). Lake Worth purchases gas pursuant to a contract for interruptible gas service with Florida Public Utilities Company. Lake Worth has entitlements of 18.347 MW of nuclear power and approximately 10 MW of coal fired power from FMPA's St. Lucie and Stanton Projects, respectively. Lake Worth is interconnected with the transmission facilities of FPL and, through them, to the State transmission grid. Five 26 kV transmission lines presently serve nine 26/4 kV distribution substations; however, the distribution system in the western portion of the service area has been upgraded to 26 kV concurrent with the transmission system improvement program and is served by a 138/26 kV substation. While the distribution system is predominantly overhead, new installations, serving platted developments, are installed underground. FMPA is planning for Lake Worth to join the All-Requirements Project in 1999.

1C.2.2 Purchased Power

FMPA currently has several power purchase contracts. These contracts exist with members as firm power purchases, from other utilities as firm power purchases, and from other utilities as partial requirements contracts. Subsections 1C.2.2.1 through 1C.2.2.3 outline the purchase power contracts in detail.

**1C.2.2.1 Firm Power Purchases from All-Requirements Project Members**

Generating members of the All-Requirements Project have firm purchase power contracts with FMPA for the purchase of capacity and energy from the members' generating units. Generating members of the All-Requirements Project consist of City of Vero Beach, City of Fort Pierce, and Key West City Utility Board. Table 1C.2-5 displays the generating units each of the member cities owns and operates. The total capacity of the firm power purchases from the generating members is 410 MW in summer and 427 MW in the winter after the addition of Lake Worth. FMPA is currently planning to add the City of Lake Worth as a member to the All-Requirements Project sometime in the year 1999. Lake Worth will be a generating member at the time of addition. The generation capacity of Lake Worth's units is also shown in Table 1C.2-5.

1C.2.2.2 Firm Power Purchases from Other Utilities

The All-Requirements Project has six firm purchase power contracts with other utilities as of June 1, 1998. The contracts exist with Lake Worth, Gainesville Regional Utilities, Orlando Utility Commission, and Tampa Electric Company. Each of the firm purchase power contracts is discussed in detail below and displayed in Table 1C.2-6.

1C.2.2.2.1 Lake Worth. The All-Requirements Project currently has a firm power purchase for capacity and energy through 2001. The capacity is for 15 MW for the years 1998 through 2000 and for 10 MW in 2001. The contract falls under Schedule D of the interchange agreements. While the existing contract extends through 2001, effectively, the contract will terminate from a power supply standpoint when Lake Worth joins the All-Requirements Project in 1999.

1C.2.2.2.2 Gainesville Regional Utilities Contracts. The All-Requirements Project currently has two contracts with GRU for firm power purchase capacity and energy that total 23 MW for the summer period of 1998. The first contract for 3 MW is a firm power purchase contract that the All-Requirements Project took over with the addition of the City of Starke to the Project. This contract is for 3 MW annually until the year 2004, after which time FMPA does not plan on extending the contract. The second contract is for 20 MW, reducing to 10 MW in 1999, and terminating thereafter.

1C.2.2.2.3 Orlando Utilities Commission Contracts. FMPA currently has two contracts with OUC for firm capacity and energy. The contracts extend through the year



Table 1C.2-5
Existing All-Requirements On-System Generating Facilities
As of December 31, 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Plant Name	Unit No.*	Location	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate MW	Net Capability	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
Vero Beach	1	Indian River	ST	NG	FO6	PL	TK	11/61	Unknown	12.5	12.0	12.0
	3		ST	NG	FO6	PL	TK	9/71	Unknown	33.0	34.0	34.0
	4		ST	NG	FO6	PL	TK	8/76	Unknown	55.0	56.0	56.0
	5		GT	NG	FO2	PL	TK	12/92	Unknown	57.9	52.0	60.0
Henry D. King	2	St. Lucie	ST	FO2	NG	TK	PL	4/70	Unknown	5.0	5.0	5.0
	7		ST	FO6	NG	TK	PL	1/64	Unknown	32.0	32.0	32.0
	8		ST	FO6	NG	TK	PL	5/76	Unknown	50.0	50.0	50.0
	9		ST	FO2	NG	TK	PL	5/90	Unknown	31.0	31.0	31.0
Big Pine Cudjoe	1	Monroe	DS	FO2	--	TK	WA	2/64	Unknown	2.5	2.5	2.5
	3		DS	FO2	--	TK	WA	8/68	Unknown	4.5	4.5	4.5
	GT		GT	FO2	--	WA	--	11/78	Unknown	20.0	20.0	20.0
	IC 1-3		DS	FO2	--	WA	--	1/65	Unknown	6.0	6.0	6.0
Stock Island	MS 1-2		DS	FO2	--	WA	--	6/91	Unknown	18.0	17.4	17.4
Smith	1-5 D**	Palm Beach	DS	FO2	--	TK	--	12/65	Unknown	10.0	10.0	10.0
	GT 1**		GT	FO2	--	TK	--	12/76	Unknown	30.8	26.0	31.0
	GT 2**		GT	NG	FO2	PL	TK	3/78	Unknown	21.41	21.0	23.0
	3**		ST	NG	FO6	PL	TK	11/67	Unknown	26.5	22.0	24.0
	5**		CW	WH	--	--	--	3/78	Unknown	10.0	9.0	9.0
										Total	410.4	427.4

*Units are generating utility members units. Capacity and energy sold to All-Requirements members under a firm purchase contract.

**Units are generating units from City of Lake Worth anticipated to be incorporated into the All-Requirements Project in 1999. Capacity will not show until January 1999 as firm purchase.

Table 1C.2-6
Purchase Power Capacity

	1998		1999		2000		2001		2002		2003		2004		2005		2006		2007		2008	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	
Lake Worth D	15	15*	15*	15*	10*	10*	10*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Starke (GRU)	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	
GRU	20	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
OUC	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	
OUC	130	130	130	130	130	130	130	108	108	87	87	65	65	43	43	22	22	0	0	0	0	
TECO	85	105	105	150	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total	273	268	268	303	303	303	153	131	131	110	110	85	85	63	63	22	22	0	0	0	0	
FPC PR	100	120	120	80	80	40	40	40	40	2	2	0	0	0	0	0	0	0	0	0	0	
FPL PR	55	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	
Total	155	165	165	125	125	85	85	85	85	47	47	45	45	45	45	45	45	45	45	45	45	
OUC	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	
Lee CO.	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0	
Lakeland	0	0	0	0	0	0	0	60	35	125	125	165	155	185	190	235	270	260	250	282	255	
TECO	0	0	0	0	0	0	0	50	55	75	75	75	75	90	90	100	100	100	100	100	100	
Total	0	0	0	0	0	70	70	180	160	270	270	310	300	345	350	405	370	360	350	382	355	
Total Purchase Power	428	433	433	428	428	458	308	396	376	427	427	440	430	453	458	472	437	405	395	427	400	

*Lake Worth D contract capacity not in totals beginning in 1999 when they become members in the All-Requirements Project.

Table 1C.2-6 (Continued)
Purchase Power Capacity

	2009		2010		2011		2012		2013		2014		2015		2016		2017	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
Lake Worth D	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Starke (GRU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPC PR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PR	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0
Total	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lee CO.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakeland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Purchase Power	45	45	45	45	45	45	45	45	45	0	0	0	0	0	0	0	0	0



2006 and total 150 MW in 1998. The first contract is for 20 MW and extends through 2003. The second contract is for 130 MW through 2001. Thereafter, the capacity is decreased by 1/6 of the 130 MW (21.667 MW) annually through 2006. Table 1C.2-6 displays the contract capacities for these two purchases.

1C.2.2.2.4 Tampa Electric Company Contract. The All-Requirements Project currently has one contract with TECO for firm capacity and energy. The contract is for an escalating capacity and energy amount through the month of March 2001. The contract specifies that 85 MW of capacity is available for 1998 escalating to 105 MW in 1999, and 150 MW thereafter until the contract is terminated.

1C.2.2.3 Partial Requirements Purchases

The All-Requirements Project has two partial requirements purchases: one from Florida Power & Light (FPL) and the other from Florida Power Corporation. The partial requirements purchase through FPL is for 45 MW through the winter season of 2013, except the capacity for 1998 is 55 MW. The contract for partial requirements with FPC is for an escalating/declining capacity through 2003. FMPA may choose to increase/decrease capacity under these contracts in increments of 25 MW per contract each year on May 1. FMPA has identified the capacities in Table 1C.2-6 as the optimal amount under this contract. Table 1C.2-6 displays the values for the partial requirements purchases.

1C.2.2.4 New Purchases Identified in 1997 RFP

FMPA identified three purchases for the All-Requirements Project as part of the process of economic evaluation of the 1997 RFP. The three purchases would include the purchase power from an existing unit from Lee County, sales from existing OUC units, and sales from a new unit to be installed by the City of Lakeland. A purchase from TECO was identified in parallel to the RFP process.

The purchase of power from Lee County for 20 MW starting in 2001 through 2006 would be from Lee County's municipal solid waste burner which produces power in the range of 21 to 24 MW from a single steam generator with two boilers. Currently, Lee County sells the power to FPL on an as-available basis. Lee County has proposed that FMPA buy the entire output of the plant.

The purchase from Lakeland would be from the construction of two new units, McIntosh Unit 4 and 5. The City of Lakeland would have excess capacity to sell as a result of building



Unit 5, a simple cycle 501G combustion turbine in 1999, and Unit 4, a pressurized fluidized bed unit in 2003.

The capacity from these purchases would begin in 2001 and escalate over time. Table 1C.2-6 displays the proposed capacities for the planned new purchases. While these firm purchases are not under contract, FMPA is in the process of pursuing the contracts, and therefore included the purchases in the expansion plan. Tables 1C.2-7 and 1C.2-8 display a summary of the total All-Requirements Project capacity for summer and winter, respectively.

1C.2.3 Transmission System

Electric capacity and energy for the All-Requirements Project will be transmitted to the All-Requirements members utilizing the transmission systems of FPL, FPC, and OUC. FMPA divides the All-Requirements members into two categories: members east of Orlando and members west of Orlando. Members east of Orlando include: Jacksonville Beach, Green Cove Springs, Clewiston, Vero Beach, Starke, Fort Pierce, Key West, and Lake Worth. Members west of Orlando include Ocala, Leesburg, and Bushnell.

Network transmission service for east members is provided under an existing agreement FMPA currently has in place with FPL. FMPA began purchasing network transmission service from FPL effective April 1, 1996, culminating a six-year battle in the courts and regulatory forums. FMPA strived to obtain network service in order to integrate the operations of several members. Details of the network transmission service agreement are on file with the FPSC.

Network transmission for the west members is provided under an agreement with FPC. Network transmission service is also purchased under an agreement with OUC. The capacity from Cane Island Unit 3 will be delivered to west members through FPC.



Table 1C.2-7
All-Requirements Total Capacity - Summer (MW)

Year	All-Requirements Capacity	Generating Member Firm Purchases	Existing Firm Purchases	Partial Requirements Purchase	New Purchases	Total Capacity
1998	377	325	273	155	0	1130
1999	377	410	268	165	0	1220
2000	377	410	303	125	0	1215
2001	377	410	153	85	70	1095
2002	377	410	131	85	160	1163
2003	377	410	110	47	270	1214
2004	377	410	85	45	300	1217
2005	377	410	63	45	350	1245
2006	377	410	22	45	370	1224
2007	377	410	0	45	350	1182
2008	377	410	0	45	355	1187
2009	377	410	0	45	0	832
2010	377	410	0	45	0	832
2011	377	410	0	45	0	832
2012	377	410	0	45	0	832
2013	377	410	0	0	0	787
2014	377	410	0	0	0	787
2015	377	410	0	0	0	787
2016	377	410	0	0	0	787
2017	377	410	0	0	0	787



Table 1C.2-8
All-Requirements Total Capacity - Winter (MW)

Year	All-Requirements Capacity	Generating Member Firm Purchases	Existing Firm Purchases	Partial Requirements Purchase	New Purchases	Total Capacity
1997/98	373	330	273	155	0	1131
1998/99	411	427	268	165	0	1271
1999/00	411	427	303	125	0	1266
2000/01	411	427	303	85	70	1296
2001/02	411	427	131	85	180	1234
2002/03	411	427	110	47	270	1265
2003/04	411	427	85	45	310	1278
2004/05	411	427	63	45	345	1291
2005/06	411	427	22	45	405	1310
2006/07	411	427	0	45	360	1243
2007/08	411	427	0	45	382	1265
2008/09	411	427	0	45	0	883
2009/10	411	427	0	45	0	883
2010/11	411	427	0	45	0	883
2011/12	411	427	0	45	0	883
2012/13	411	427	0	45	0	883
2013/14	411	427	0	45	0	883
2014/15	411	427	0	0	0	838
2015/16	411	427	0	0	0	838
2016/17	411	427	0	0	0	838



1C.3.0 Methodology

This section provides a general description of the methodology used to analyze the Cane Island Unit 3 expansion for FMPA's All-Requirements Project power supply requirements and is arranged according to the sequence of the remaining sections of this volume. The purpose of the power supply planning study and determination of need is to develop evaluation criteria, a range of load and fuel forecasts, and potential capacity additions that will meet the least-cost power generation needs of its consumers while providing consideration for reliability, fuel diversity, environmental impacts, strategic goals, and regulatory requirements. To this end, FMPA has provided in-depth analysis and evaluation of supply-side and demand-side resources to determine the least-cost plan which is in the collective best interest of all parties involved.

1C.3.1 Evaluation Criteria

The first step in the power supply planning process is to establish evaluation criteria, that is, to identify the assumptions about important parameters used in the analysis. Evaluation criteria presented in Section 1C.4.0 include the following:

- Economic forecast assumptions.
- Financial assumptions.
- Natural gas availability assumptions.
- Fuel price projections.

1C.3.2 Forecast of Electrical Power Demand and Energy Consumption

The load forecast for the FMPA All-Requirements members is summarized in Section 1C.5.0 and shown in detail in Appendix 1C.16.1. The Appendix describes the development of the econometric models which forecast system peak demands and energy requirements. The load forecast takes into account FMPA members' existing conservation plans. Demand-side program reductions are forecast separately.



1C.3.3 Conservation and Demand-Side Management

The FMPA All-Requirements members conservation and demand-side management programs are discussed in Section 1C.6.0. Estimates of capacity avoided by the various programs are provided.

1C.3.4 Reliability Criteria

Section 1C.7.0 presents the reliability criteria used to identify timing of capacity additions. The All-Requirements Project uses an 18 percent minimum reserve margin for summer peak as the reliability criteria.

1C.3.5 Supply-Side Alternatives

Supply-side alternatives that are candidates for meeting the All-Requirements Projects capacity expansion requirements are outlined in Volume 1A.6.0. A variety of plant sizes, capital costs, and operating parameters of conventional alternatives as well as advanced and renewable technologies are considered.

1C.3.6 Supply-Side Screening

The economics of the supply-side alternatives were evaluated on a screening level before modeling in detail in production cost programs. The screening analysis provides a method to eliminate alternatives that possess no potential of being economically viable under any operating parameters for the All-Requirements Project. The details of the screening analysis are provided in Volume 1A.6.0.

1C.3.7 Economic Analyses

In Section 1C.10.0, the economics of the expansion alternatives are evaluated from the characteristics in Section 1A.6.0. The plans are evaluated on a comparative basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components:

- Fuel costs.
- Purchased power costs.



- Operation and maintenance (O&M) costs.
- Capital costs for new generation.
- Transmission costs for new units.

An optimization program, EGEAS, is used to model the All-Requirements Project system for the expansion alternatives developed in Section 1C.8.0. Annual system fuel and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions.

The objective of the economic analysis is to determine the total present worth of the annual comparative revenue requirements. This refers to the sum of the annual comparative revenue requirements discounted to 1998 using FMPA's present worth discount rate.

1C.3.8 Sensitivity Analyses

Several sensitivity analyses were conducted to verify the robustness of the least-cost plan to altered conditions. The sensitivity analyses include a high load and energy forecast, low load and energy forecast, high fuel price forecast, low fuel price forecast, a case where the differential fuel prices of coal versus natural gas/oil are held constant over the planning horizon, a 15 percent reserve margin case, and a case where the cost of Cane Island Unit 3 is increased. The results of the analysis are included in Section 1C.11.0.

1C.3.9 Strategic Considerations

Section 1C.12.0 outlines the strategic considerations involved in the alternative power supply plans. Such considerations include fuel mix, fuel supply, and availability of sites. The strategic considerations factor heavily into the analysis of the least-cost plan. While the least-cost plan might provide the least-cost under the applied assumptions, the "best" plan may be different depending on strategic considerations.

1C.3.10 Consequences of Delay

Section 1C.13.0 addresses the adverse consequences of not building or delaying Cane Island Unit 3. This section addresses the adverse impacts on system reliability, system cumulative present worth costs, and emission impacts of a delay.



1C.3.11 Financial Analysis

Section 1C.14.0 addresses the financial feasibility of constructing Cane Island 3 with FMPA's current financial position. This section highlights FMPA's strong standing among Florida utilities and high outlook for future growth.

1C.3.12 Analysis of 1990 Clean Air Act Amendments

Section 1C.15.0 addresses the impact of the 1990 Clean Air Act Amendments on the Cane Island 3 project. This section discusses FMPA's strategy for compliance with the amendments.





1C.4.0 Evaluation Criteria

Economic evaluation is conducted over a 20 year period from 1998 through 2017. The economic evaluation is based on the cumulative present worth of annual costs for capital costs, non-fuel O&M costs, fuel costs, purchase power demand, energy, and transmission costs. Costs that are common to all expansion alternatives, such as demand charges for existing power purchases or existing transmission and distribution system costs, and administrative and general costs are not included.

1C.4.1 Economic Parameters and Evaluation Criteria

1C.4.1.1 Escalation Rate

The general inflation rate applied in the economic evaluation is 2.5 percent. A 3.0 percent annual escalation rate is applied for operation and maintenance (O&M) costs. The escalation rate applied to capital costs is 2.5 percent.

1C.4.1.2 Bond Interest Rate

The bond interest rate is assumed to be 5.50 percent for FMPA.

1C.4.1.3 Bond Issuance Fee

A bond issuance fee of 2.90 percent is assumed to apply to FMPA bond issues.

1C.4.1.4 Interest During Construction

Interest during construction is assumed to be equal to the bond interest rate of 5.50 percent.

1C.4.1.5 Present Worth Discount Rate

The base case present worth discount rate is equal to the bond interest rate of 5.50 percent.



1C.4.1.6 Fixed Charge Rate

The fixed charge rate is 8.2 percent. The fixed charge rate was developed based upon a 30 year bond term including principal and interest, a 1 year debt service reserve fund, interest earnings credit based on the bond interest rate, a 2.9 percent bond issuance rate, and 1.0 percent for property insurance.

1C.4.2 Fuel Price Projections

Fuel price projections for FMPA are based on the projections in Section 1A.3.2 of Volume 1A. The fuel price escalation rates for coal, gas, and oil were developed by DRI. With fuel expenses representing the largest portion of the FMPA budget, reliable fuel price forecasts are of great importance. Table 1C.4-1 provides a summary of the base case fuel forecast that is developed in Volume 1A.

Three fuel price sensitivity projections were developed. The first two are high and low price projections. The description of the high and low fuel price projections is presented in 1A.3.2. The third fuel price sensitivity projection is based on holding natural gas/oil versus coal prices constant throughout the planning period. For this sensitivity, coal prices from the base case were chosen as the fixed component. Fuel prices were held at a constant differential (same as differential in base year) over the forecast horizon.

1C.4.3 Fuel Availability

Fuel availability for FMPA, including coal, natural gas, oil, and nuclear fuel are discussed in detail in Volume 1A with this subsection presenting a brief overview of information specific to FMPA.

FMPA is currently a member of Florida Gas Utility (FGU) which is a joint action agency gas supply organization. Membership in FGU allows aggregation of member contracts which provides better economy for purchases, mitigates demand changes, and simplifies the problems of individual systems balancing consumption against supply. FMPA plans to purchase commodity for Cane Island Unit 3 under FGU. The portion of natural gas that will be purchased under spot purchases or under contract is still being evaluated.

FMPA currently receives transportation from Florida Gas Transmission Company (FGT) for its existing unit share in Cane Island 1 and 2. Since FMPA is a member in FGU, it has the



Table 1C.4-1
Delivered Fuel Price Forecast—Base Case
(\$/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas ⁽¹⁾ Existing Units	Natural Gas ⁽²⁾ New Units
1998	1.70	2.68	4.47	0.55	2.39	3.20
1999	1.71	2.66	4.45	0.56	2.31	3.12
2000	1.74	2.75	4.59	0.57	2.22	3.03
2001	1.77	2.89	4.82	0.59	2.25	3.06
2002	1.81	3.03	5.05	0.60	2.38	3.19
2003	1.86	3.16	5.28	0.62	2.46	3.27
2004	1.90	3.31	5.52	0.63	2.53	3.34
2005	1.93	3.49	5.82	0.65	2.61	3.42
2006	1.97	3.65	6.09	0.67	2.70	3.51
2007	2.02	3.82	6.37	0.68	2.79	3.60
2008	2.06	4.00	6.68	0.70	2.92	3.73
2009	2.10	4.18	6.99	0.72	3.02	3.83
2010	2.15	4.36	7.29	0.73	3.17	3.98
2011	2.20	4.57	7.63	0.75	3.32	4.13
2012	2.23	4.78	7.98	0.77	3.45	4.26
2013	2.29	5.00	8.34	0.79	3.59	4.40
2014	2.34	5.23	8.72	0.81	3.77	4.58
2015	2.40	5.46	9.12	0.83	3.92	4.73
2016	2.46	5.70	9.52	0.85	4.09	4.90
2017	2.51	5.97	9.96	0.87	4.30	

(1) Delivered natural gas price less demand reservation costs.

(2) Includes demand reservation costs



ability to supply additional volumes of gas to other locations by utilizing members' firm transportation rights when available. This allows FMPA flexibility to schedule and run units more efficiently. FMPA has firm transportation rights from FGT under FTS-1 and FTS-2. Table 1C.4-2 displays FMPA's totaled fixed transportation on a monthly basis. The existing transportation volumes are generally adequate to operate Cane Island Unit 3 at full load around the clock. As part of FGT's open season to schedule firm transportation for new supplies under FTS-3, FMPA requested an additional 25,000 MBtu/day.

Table 1C.4-2 FMPA's Total Firm Transportation (MBtu/day)		
	Totals	
	FTS-1	FTS-2
January	14,121	26,500
February	14,121	26,500
March	14,421	26,500
April	17,789	26,500
May	20,139	26,500
June	20,139	26,500
July	20,139	26,500
August	20,139	26,500
September	20,139	26,500
October	23,084	26,500
November	14,271	26,500
December	14,121	26,500

1CE.0 Forecast of Elect Power
Demand and Energy Consumption



1C.5.0 Forecast of Electrical Power Demand and Energy Consumption

Under the All-Requirements Project structure, FMPA agrees to meet its members resource planning requirements. The forecast of electrical power demand and energy consumption includes current member cities and identified future cities that will become members to the All-Requirements Project. FMPA forecasts each of its members loads on an individual basis and integrates the results into a FMPA forecast of electrical power demand and energy consumption. The results of the forecast are provided in this section and Appendix 1C.16.1.

1C.5.1 Load Forecasting Assumptions

The load forecast attempts to predict how certain changes within the members cities will affect power consumption. This is accomplished by reviewing and analyzing these changes and their impact on load growth. Changes evaluated include: population, historical trends, weather patterns, conservation programs, account types, economic conditions, and number of customers. Several techniques were applied for the load forecast including:

- By-class econometric modeling,
- Aggregate econometric modeling,
- Time series / Time trend modeling.

By-class econometric modeling forecasts kilowatt hour sales for individual rate classifications. Economics and demographics for each city are used as determinates for projection of energy sales. The total kilowatt hour sales for the system can then be determined by summing all individual rate classifications and losses.

Aggregate econometric modeling attempts to forecast net energy for load for a system. This technique projects total net energy for load without segregating energy usage into individual rate classifications. One equation is developed using independent variables to predict net energy for load for a system.

Time series/Time trend modeling attempts to use past trends in net energy for load to forecast future net energy for load.

The FMPA forecasting process involves applying some or all of these models to develop individual forecasts for each All-Requirements Project member. FMPA uses Forecast Pro to



forecast loads for its member cities. Forecast Pro is a commercially developed software package that conducts analysis considering moving averages, exponential smoothing, Box-Jenkins, event models, and multiple level models. The model considers the statistical relevance of input variables and forecasts based on the highest correlation. The forecasts are then compared and checked for reasonableness. Finally, any unusual incremental load additions or reductions are integrated into the forecast.

1C.5.2 Base Case Load Forecast

Based on the data from the member cities, The Kiplinger Washington Letter, The Florida Outlook, Florida Statistical Abstract, Florida Estimates of Population, and Monthly Energy Review, it is concluded that Florida will remain one of the fastest growing states in the United States. The economy will remain strong with the unemployment rate declining and the price of electricity projected to remain steady. In the following subsections details of the net energy for load summer peak demand and winter peak demand are discussed.

1C.5.2.1 Net Energy for Load Forecast

FMPA forecasts net energy for load for each member taking into account all conservation programs that were active over the historical period. The forecast methodology, as outlined in the previous subsection, varies from member to member to provide the most reliable forecast possible consistent with available data. For forecasts using regression analysis the minimum coefficient of determination was 93 percent, implying a strong correlation of historical information. Once the net energy for load forecasts are compiled for all the member cities, the loads are integrated into an FMPA net energy for load forecast. The FMPA projected net energy for load including conservation for the base case is presented in Tables 1C.5-1 through 1C.5-3. The projected average annual growth rate (AAGR) for the base case is 1.5 percent for 1999 after the addition of the City of Lake Worth through 2017. Table 1C.5-4 displays each member's net energy for load forecast for the planning horizon. Details of each member's forecast are described in detail in Appendix 1C.A.

1C.5.2.2 Summer Peak Demand Forecast

Summer peak demand forecasts are conducted in a similar fashion to the net energy for load forecast. To forecast the summer peak demand for each member city average annual

IMAGE QUALITY

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PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Table 1C.5-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
All-Requirements Project

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	Residential Sales GWh	Residential Average No. of Customers	Residential Average MWh Consumption Per Customer	Commercial and Industrial Sales GWh	Commercial and Industrial Average No. of Customers	Commercial and Industrial Average MWh Consumption Per Customer
1992	857	72,303	11.86	1,000	13,082	76.44
1993	910	73,460	12.39	1,044	13,259	78.71
1994	962	74,817	12.86	1,091	14,179	76.96
1995	1,041	76,070	13.69	1,146	13,766	83.25
1996	1,072	77,423	13.84	1,163	14,141	82.21
1997	1,229	98,726	12.45	1,380	18,510	74.54
1998*	1,847	147,511	12.52	2,152	26,832	80.19
1999*	2,170	170,702	12.71	2,434	30,390	80.11
2000*	2,221	172,723	12.86	2,493	30,822	80.88
2001*	2,271	174,727	13.00	2,550	31,238	81.64
2002*	2,319	176,651	13.13	2,606	31,634	82.38
2003*	2,365	178,545	13.25	2,659	32,005	83.08
2004*	2,410	180,338	13.36	2,711	32,361	83.78
2005*	2,451	182,060	13.46	2,761	32,695	84.46
2006*	2,489	183,667	13.55	2,809	33,005	85.11
2007*	2,525	185,197	13.63	2,855	33,294	85.75

* Forecast includes new All-Requirements Project members.



Table 1C.5-2 History and Forecast of Energy Consumption and Number of Customers by Customer Class All-Requirements Project			
(1)	(2)	(3)	(4)
Year	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales Ultimate Consumers GWh
1992	52	7	1,916
1993	48	9	2,011
1994	59	10	2,122
1995	65	11	2,263
1996	57	10	2,302
1997	60	14	2,683
1998*	78	14	4,091
1999*	76	14	4,694
2000*	77	14	4,805
2001*	78	15	4,915
2002*	78	15	5,018
2003*	79	15	5,118
2004*	80	15	5,216
2005*	81	15	5,308
2006*	81	15	5,394
2007*	82	15	5,477
* Forecast includes new all requirements projects members.			



Table 1C.5-3 History and Forecast of Energy Consumption and Number of Customers by Customer Class All-Requirements Project			
(1)	(2)	(3)	(4)
Year	Utility Use & Losses GWh	Net Energy for Load GWh	Total No. of Customers
1992	127	2,043	85,385
1993	134	2,145	86,719
1994	66	2,188	88,996
1995	80	2,343	89,836
1996	103	2,405	91,564
1997	167	2,850	117,236
1998*	226	4,317	174,343
1999*	271	4,965	201,092
2000*	276	5,081	203,545
2001*	280	5,194	205,965
2002*	287	5,305	208,285
2003*	293	5,411	210,550
2004*	297	5,513	212,699
2005*	303	5,611	214,755
2006*	309	5,703	216,672
2007*	313	5,790	218,491
* Forecast includes new all requirements projects members.			



Table 1C.5-4
Net Energy for Load for each of All-Requirements Members (MWh)

Year	City of Bushnell	City of Clewiston	Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	Ocala	City of Starke	City of Vero Beach	City of Lake Worth	Total
1998	21,456	116,978	560,120	128,838	646,019	481,657	430,983	1,158,645	71,390	647,684	0	4,317,436
1999	21,843	119,401	572,150	131,472	670,502	696,100	441,799	1,185,277	73,485	668,139	387,003	4,965,171
2000	22,226	121,800	583,845	134,066	695,252	708,179	452,461	1,211,527	75,569	684,460	391,442	5,080,827
2001	22,607	124,158	595,008	136,642	719,196	720,433	463,016	1,237,213	77,637	702,622	395,615	5,194,147
2002	22,988	126,453	605,223	139,170	742,536	732,864	473,361	1,262,268	79,683	720,584	399,512	5,304,642
2003	23,354	128,681	613,798	141,663	765,183	744,783	483,586	1,287,133	81,704	737,589	403,051	5,410,525
2004	23,713	130,853	621,931	144,159	787,011	756,158	493,920	1,311,911	83,641	753,558	406,527	5,513,382
2005	24,062	132,967	628,952	146,610	807,419	766,957	504,118	1,336,071	85,511	768,390	409,701	5,610,758
2006	24,409	135,006	635,174	148,963	826,164	777,150	514,166	1,359,434	87,338	781,998	412,801	5,702,603
2007	24,745	136,989	640,918	151,261	843,108	786,708	524,050	1,382,423	89,029	794,684	415,685	5,789,600
2008	25,077	138,893	645,808	153,550	858,966	795,604	533,595	1,405,168	90,663	806,785	418,490	5,872,596
2009	25,405	140,777	650,461	155,740	873,131	803,806	543,064	1,427,487	92,204	818,283	421,309	5,951,667
2010	25,720	142,602	654,784	157,862	885,904	811,296	552,373	1,449,313	93,621	828,727	423,729	6,025,931
2011	26,031	144,342	658,855	159,963	897,997	818,493	561,514	1,470,244	94,931	838,085	426,160	6,096,615
2012	26,327	146,011	662,301	161,936	909,363	824,940	570,477	1,490,092	96,165	846,717	428,356	6,162,685
2013	26,618	147,592	665,769	163,844	919,982	830,619	579,251	1,509,543	97,319	856,785	430,460	6,227,782
2014	26,894	149,157	668,954	165,667	929,243	835,964	588,082	1,528,357	98,328	860,078	432,319	6,283,043
2015	27,163	150,657	671,863	167,362	937,674	840,512	596,696	1,546,900	99,248	865,561	434,183	6,337,819
2016	27,425	152,132	674,118	168,980	945,256	844,705	605,096	1,564,316	100,042	870,659	435,797	6,388,526
2017	27,681	153,448	676,383	170,448	951,966	848,536	613,271	1,582,223	100,742	874,936	437,419	6,437,055



summer load factors are determined from the historical information and applied to the forecasted net energy for load to arrive at the forecasted summer peak demand. Table 1C.5-5 shows the projected summer peak demand for the individual All-Requirements Project members. The summer peak demands are for non-coincidental peak demand. For the forecast of summer peak demand for FMPA's All-Requirements Project, considering diversity among the individual members, FMPA applies seasonal factors to the All-Requirement Project net energy for load forecast to arrive at the summer peak demand forecast. Table 1C.5-6 displays the FMPA forecasted summer peak demand for the base case. Table 1C.5-6 also presents the projected demand reduction due to residential load management. The projected AAGR for summer peak demand from 1999 after the addition of the City of Lake Worth to 2017 is 1.5 percent.

1C.5.2.3 Winter Peak Demand Forecast

Winter peak demand forecasts are conducted in a similar fashion to the net energy for load forecast. To forecast the winter peak demand for each member city, average annual winter load factors are determined from the historical information and applied to the forecasted net energy for load to arrive at the forecasted winter peak demand. Table 1C.5-7 shows the projected winter peak demand for the individual All-Requirements Project members. The winter peak demands are for non-coincidental peak demand. For the forecast of winter peak demand for FMPA's All-Requirements Project, considering diversity among the individual members, FMPA applies seasonal factors to the All-Requirements Project net energy for load forecast to arrive at the winter peak demand forecast. Table 1C.5-8 displays the FMPA forecasted winter peak demand for the base case. Table 1C.5-8 also presents the projected demand reduction due to residential load management. The projected AAGR for winter peak demand from 1999 after the addition of the City of Lake Worth to 2017 is 1.5 percent.

1C.5.3 Sensitivities

FMPA develops the most accurate base case load forecast possible based on the data available. However, uncertainty in the assumptions for future conditions dictate the development of high and low band forecasts to ensure that the addition of Cane Island Unit 3 results in the least cost under the full range of conditions that might be encountered in the future.



Table 1C.5-5
All-Requirements Project Members Projected Summer Peak Demand

Year	City of Bushnell	City of Clewiston	Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	Ocala	City of Starke	City of Vero Beach	City of Lake Worth
1998	4.5	23.1	102.6	23.8	140.8	116.3	95.7	247.4	13.2	131	72.0
1999	4.5	23.6	104.8	24.3	146.1	118.5	98.1	253.0	13.6	135	72.8
2000	4.6	24.0	106.9	24.8	151.5	120.5	100.5	258.6	14.0	139	73.7
2001	4.7	24.5	109.0	25.2	156.7	122.6	102.8	264.1	14.4	142	74.5
2002	4.8	25.0	110.9	25.7	161.8	124.7	105.1	269.5	14.8	146	75.2
2003	4.9	25.4	112.4	26.2	166.8	126.8	107.4	274.8	15.1	149	75.9
2004	4.9	25.8	113.9	26.6	171.5	128.7	109.7	280.1	15.5	153	76.5
2005	5.0	26.2	115.2	27.1	176.0	130.5	112.0	285.2	15.8	156	77.1
2006	5.1	26.7	116.3	27.5	180.0	132.3	114.2	290.2	16.2	158	77.7
2007	5.2	27.0	117.4	27.9	183.7	133.9	116.4	295.1	16.5	161	78.2
2008	5.2	27.4	118.3	28.4	187.2	135.4	118.5	300.0	16.8	164	78.8
2009	5.3	27.8	119.1	28.8	190.3	136.8	120.6	304.7	17.1	166	79.3
2010	5.4	28.2	119.9	29.2	193.1	138.1	122.7	309.4	17.3	168	79.8
2011	5.4	28.5	120.7	29.5	195.7	139.3	124.7	313.9	17.6	170	80.2
2012	5.5	28.8	121.3	29.9	198.2	140.4	126.7	318.1	17.8	172	80.6
2013	5.5	29.1	122.0	30.3	200.5	141.4	128.7	322.3	18.0	173	81.0
2014	5.6	29.4	122.5	30.6	202.5	142.3	130.6	326.3	18.2	174	81.4
2015	5.7	29.7	123.1	30.9	204.3	143.1	132.5	330.2	18.4	175	81.7
2016	5.7	30.0	123.5	31.2	206.0	143.8	134.4	334.0	18.5	176	82.0
2017	5.8	30.3	123.9	31.5	207.5	144.4	136.2	337.8	18.7	177	82.3



Table 1C.5-6
Forecast of Summer Peak Demand--Base Case

Year	Total Demand MW	Residential Load Management MW	Net Firm Demand MW
1998	896	3.6	892
1999	992	3.8	988
2000	1,015	4.0	1,011
2001	1,038	4.2	1,034
2002	1,061	4.5	1,056
2003	1,082	4.7	1,077
2004	1,103	4.8	1,098
2005	1,123	5.0	1,118
2006	1,141	5.1	1,136
2007	1,159	5.2	1,154
2008	1,176	5.3	1,171
2009	1,192	5.4	1,187
2010	1,207	5.4	1,202
2011	1,222	5.5	1,217
2012	1,235	5.6	1,229
2013	1,248	5.6	1,242
2014	1,260	5.7	1,254
2015	1,271	5.7	1,265
2016	1,282	5.7	1,276
2017	1,292	5.8	1,286



Table 1C.5-7
All-Requirements Project Members Projected Winter Peak Demand

Year	City of Bushnell	City of Clewiston	Fort Pierce	City of Green Cove Springs	City of Jacksonville Beach	City of Key West	City of Leesburg	Ocala	City of Starke	City of Vero Beach	City of Lake Worth
1997/98	5.6	21.8	119.3	23.7	176.6	80.4	91.0	236.4	11.6	165.7	73.4
1998/99	5.7	22.2	121.8	24.2	183.3	81.8	93.3	241.8	12.0	170.4	74.3
1999/00	5.8	22.7	124.3	24.6	190.0	83.3	95.5	247.2	12.3	175.1	75.2
2000/01	5.9	23.1	126.7	25.1	196.6	84.7	97.8	252.4	12.7	179.8	76.0
2001/02	6.0	23.6	128.9	25.6	203.0	86.2	100.0	257.5	13.0	184.4	76.7
2002/03	6.1	24.0	130.7	26.0	209.2	87.6	102.1	262.6	13.3	188.7	77.4
2003/04	6.2	24.4	132.4	26.5	215.1	88.9	104.3	267.6	13.6	192.8	78.1
2004/05	6.2	24.8	133.9	26.9	220.7	90.2	106.5	272.6	14.0	196.6	78.7
2005/06	6.3	25.2	135.3	27.4	225.8	91.4	108.6	277.3	14.2	200.1	79.3
2006/07	6.4	25.5	136.5	27.8	230.5	92.5	110.7	282.0	14.5	203.3	79.8
2007/08	6.5	25.9	137.5	28.2	234.8	93.5	112.7	286.7	14.8	206.4	80.4
2008/09	6.6	26.2	138.5	28.6	238.7	94.5	114.7	291.2	15.0	209.4	80.9
2009/10	6.7	26.6	139.4	29.0	242.2	95.4	116.6	295.7	15.3	212.0	81.4
2010/11	6.8	26.9	140.3	29.4	245.5	96.2	118.6	299.9	15.5	214.4	81.9
2011/12	6.8	27.2	141.0	29.8	248.6	97.0	120.5	304.0	15.7	216.6	82.3
2012/13	6.9	27.5	141.8	30.1	251.5	97.6	122.3	307.9	15.9	218.4	82.7
2013/14	7.0	27.8	142.5	30.4	254.0	98.3	124.2	311.8	16.0	220.0	83.0
2014/15	7.1	28.1	143.1	30.8	256.3	98.8	126.0	315.6	16.2	221.4	83.4
2015/16	7.1	28.3	143.6	31.1	258.4	99.3	127.8	319.1	16.3	222.8	83.7
2016/17	7.2	28.6	144.0	31.3	260.2	99.8	129.5	322.8	16.4	223.8	84.0



Table 1C.5-8
Forecast of Winter Peak Demand--Base Case

Year	Total Demand MW	Residential Load Management MW	Net Firm Demand MW
1997/98	852	5.9	846
1998/99	1,031	6.3	1,025
1999/00	1,056	6.8	1,049
2000/01	1,081	7.2	1,074
2001/02	1,105	7.6	1,097
2002/03	1,128	7.9	1,120
2003/04	1,150	8.2	1,142
2004/05	1,171	8.5	1,163
2005/06	1,191	8.7	1,182
2006/07	1,210	8.9	1,201
2007/08	1,227	9.0	1,218
2008/09	1,244	9.2	1,235
2009/10	1,260	9.3	1,251
2010/11	1,275	9.4	1,266
2011/12	1,289	9.5	1,280
2012/13	1,303	9.6	1,293
2013/14	1,315	9.7	1,305
2014/15	1,327	9.8	1,317
2015/16	1,338	9.9	1,328
2016/17	1,348	10.0	1,338



FMPA's load forecasts reported in FMPA Ten Year Site Plans have been very accurate compared to actual net energy for load and peak demand. Forecasts for net energy for load and summer peak demand have always been within 5 percent of the actual net energy for load and summer peak demand. Actual winter peak demand which is much more temperature dependent has varied as much as almost 20 percent from projected values. The larger level of variation is primarily due to different temperatures occurring at the time of peak instead of inaccuracy with the forecast. Therefore, for purposes of selecting high and low bands for sensitivity analysis, a difference of ± 5 percent from the base forecast has been selected. The high and low forecasts are presented in Tables 1C.5-9 and 1C.5-10, respectively.



Table 1C.5-9
Forecast of Summer and Winter Peak Demand with NEL--High Case

Year	Net Firm Summer Demand MW	Net Firm Winter Demand MW	Net Energy For Load GWH
1998	938	889	4,533
1999	1,038	1,076	5,213
2000	1,062	1,102	5,335
2001	1,086	1,128	5,454
2002	1,109	1,153	5,570
2003	1,132	1,176	5,681
2004	1,154	1,200	5,789
2005	1,174	1,221	5,891
2006	1,194	1,242	5,988
2007	1,212	1,261	6,079
2008	1,230	1,280	6,166
2009	1,247	1,298	6,249
2010	1,263	1,314	6,327
2011	1,278	1,330	6,401
2012	1,292	1,345	6,471
2013	1,305	1,359	6,539
2014	1,318	1,371	6,597
2015	1,329	1,384	6,655
2016	1,340	1,395	6,708
2017	1,351	1,405	6,759



Table 1C.5-10
Forecast of Summer and Winter Peak Demand with NEL--Low Case

Year	Net Firm Summer Demand MW	Net Firm Winter Demand MW	Net Energy For Load GWH
1998	849	805	4,112
1999	940	975	4,729
2000	962	999	4,839
2001	984	1,022	4,947
2002	1,005	1,044	5,052
2003	1,025	1,056	5,153
2004	1,045	1,087	5,251
2005	1,064	1,106	5,344
2006	1,081	1,125	5,431
2007	1,098	1,143	5,514
2008	1,114	1,159	5,593
2009	1,130	1,175	5,668
2010	1,144	1,190	5,739
2011	1,158	1,205	5,806
2012	1,170	1,218	5,869
2013	1,183	1,231	5,931
2014	1,194	1,242	5,984
2015	1,205	1,253	6,036
2016	1,215	1,263	6,084
2017	1,224	1,273	6,131

1C.6.0 Demand-side Programs



1C.6.0 Demand-Side Programs

1C.6.1 Existing Conservation Programs

FMPA is a strong supporter of the conservation of energy and promotes effective programs to its members. FMPA will continue to expand services as needed to assist members in increasing the promotion and use of conservation programs to retail customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness. FMPA members promote their conservation programs by providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. Additionally, bill inserts are utilized to keep customers aware of available conservation programs.

FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a 89-member non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers.

FMPA's All-Requirements Project members offer some or all of the following conservation programs:

- Residential Energy Audits including the 5-Star Award
- High-Pressure Sodium Outdoor Lighting Conservation
- Assistance for Commercial/ Industrial Audits
- Commercial Time-of-Use Program
- Natural Gas Promotion
- Fix-Up Program for the Elderly and Handicapped

A brief description of each of the conservation programs is provided in the following subsections.

1C.6.1.1 Residential Energy Audits Including the 5-Star Award

Residential energy audits are offered to residential customers. Audits are conducted in accordance with FPSC rules. The audits consist of a walk-through Home Energy Survey with the following materials available upon customer request.

- Electric outlet gaskets
- Socket protectors



- Water flow restrictors
- Electric water heater jacket
- Low flow shower heads

Home Energy Surveys also include water heater temperature reduction and the installation of the water heater insulating blanket upon customer request.

1C.6.1.2 High Pressure Sodium Outdoor Lighting Conversion

This program involves eliminating mercury vapor street and yard lighting. The fixtures are converted whenever maintenance is required.

1C.6.1.3 Assistance for Commercial/ Industrial Audits

On-site audits are available to industrial and commercial customers with the intention of shifting demand from peak to off-peak periods.

1C.6.1.4 Commercial Time-of-Use Program

Time-of-Use rates are offered to commercial and industrial customers with the intention of shifting demand from peak to off-peak periods.

1C.6.1.5 Natural Gas Promotion

This program was established to replace older electric heat and water heaters with natural gas when the conversion would benefit the customers.

1C.6.1.6 Fix-Up Program for the Elderly and Handicapped

The program seeks and receives grants for the Community Block Development Program and Weatherization Program. This is a low-income program with participants as directed by the grants. Energy auditors submit homes for the weatherization program.

1C.6.2 Residential Load Management Program

Residential Load Management Program is intended for customers that have electric water heaters, central air conditioning units, and central heating units. This program allows the city to regulate the usage of the appliances as a way to reduce weather sensitive peak demands. Two of the All-Requirements members currently have direct load control programs in place.



The members are City of Ocala and City of Leesburg. The City of Leesburg's load management program was analyzed and started under the direction of the City. The City of Ocala's load management program was analyzed and started under the direction of FMPA. Table 1C.6-1 provides the forecasted load management projections for the two programs for both summer and winter periods. The savings from the two programs are shared among all All-Requirements members when activated.

1C.6.3 New Conservation and Demand-Side Programs

FMPA along with KUA evaluated approximately 70 new conservation and demand-side programs in order to ensure that Cane Island Unit 3 is the least cost alternative. Details of the evaluations are contained in Volume 1A.5.0. Each of the programs were evaluated using the FPSC approved Florida Integrated Resource Evaluator (FIRE) model. The analysis indicates that none of the demand-side alternatives are cost effective at this juncture. Therefore FMPA is not pursuing new conservation or demand-side management programs at this time.



Table 1C.6-1
All-Requirements Total Forecast Load Management Capability
(As of January 1997)

Year	Summer						Winter		Total MW
	Ocala MW	Ocala Gwh	Leesburg MW	Leesburg Gwh	Total MW	Total GWh	Ocala MW	Leesburg MW	
1997	1.7	0.017	1.5	0.015	3.2	0.03	2.6	2.8	5.4
1998	1.9	0.019	1.7	0.017	3.6	0.04	2.9	3.0	5.9
1999	2.0	0.020	1.8	0.018	3.8	0.04	3.1	3.2	6.3
2000	2.1	0.021	1.9	0.019	4.0	0.04	3.3	3.4	6.8
2001	2.2	0.022	2.0	0.020	4.2	0.04	3.6	3.6	7.2
2002	2.4	0.024	2.1	0.021	4.5	0.04	3.8	3.8	7.6
2003	2.5	0.025	2.2	0.022	4.7	0.05	4.0	3.9	7.9
2004	2.6	0.026	2.3	0.023	4.8	0.05	4.2	4.1	8.2
2005	2.7	0.027	2.3	0.023	5.0	0.05	4.4	4.2	8.5
2006	2.7	0.027	2.4	0.024	5.1	0.05	4.4	4.3	8.7
2007	2.8	0.028	2.4	0.024	5.2	0.05	4.5	4.4	8.9
2008	2.8	0.028	2.5	0.025	5.3	0.05	4.5	4.5	9.0
2009	2.8	0.028	2.5	0.025	5.4	0.05	4.6	4.6	9.2
2010	2.8	0.028	2.6	0.026	5.4	0.05	4.6	4.7	9.3
2011	2.9	0.029	2.6	0.026	5.5	0.06	4.7	4.7	9.4
2012	2.9	0.029	2.7	0.027	5.6	0.06	4.7	4.8	9.5
2013	2.9	0.029	2.7	0.027	5.6	0.06	4.8	4.8	9.6
2014	3.0	0.030	2.7	0.027	5.7	0.06	4.8	4.9	9.7
2015	3.0	0.030	2.7	0.027	5.7	0.06	4.9	4.9	9.8
2016	3.0	0.030	2.7	0.027	5.7	0.06	4.9	4.9	9.9
2017	3.0	0.030	2.7	0.027	5.7	0.06	4.9	4.9	9.9



1C.7.0 Reliability Criteria

1C.7.1 Development of Reliability Criteria

There are two basic methods used in the utility industry to calculate a system's reliability indices. The two methods are deterministic and probabilistic methods. The most often used deterministic method is reserve margin which is calculated as the system net capacity less system net peak demand, divided by the system peak demand.

The probabilistic method of system planning incorporates the probability of individual unit outages and emergency assistance from other systems and involves calculations that are more mathematically complex. The probabilistic index most frequently used is the loss of load probability (LOLP) which is the expected number of days per year when the utility is projected to have insufficient capacity on-line with tie-line assistance to meet its peak daily load. The calculation of LOLP is very strongly driven by the values of tie-line assistance. For systems with multiple interconnections these tie-line assistance values are very difficult to develop and as such comparisons to commonly accepted LOLP values such as 1 day in 10 years are very hard to develop for individual systems. The use of a LOLP criteria is much better suited to a larger integrated system with limited tie-line assistance such as Peninsular Florida. For a diverse transmission system dependent system like the All-Requirements Project, LOLP would likely result in a misleading reliability criteria since the tie-line assistance would likely overpower the influence of generating capacity in the LOLP calculation. For these reasons, FMPA does not use LOLP as a reliability criterion.

FMPA is a member of the Florida Reliability Coordinating Council (FRCC). FRCC has specific criteria for determining each utility's operating and spinning reserve requirements, but does not have specific planning reserve requirements. The selection of specific planning reserve requirements is up to the individual utility.

The Florida Public Service Commission (FPSC) has set a minimum planned reserve margin criteria of 15 percent in 25-6.035 (1,) Fla. Admin. Code, for the purposes of sharing reserves. The 15 percent planned reserve margin criteria is generally consistent with utility practice throughout the industry. Many pools and reliability councils require reserve margins ranging from 15 to 20 percent. FMPA is currently using an 18 percent minimum reserve criteria for determining the need for capacity additions. The 18 percent criteria is slightly



more conservative than the FPSC's 15 percent criteria, and is consistent with general utility practice throughout the industry.

1C.7.2 Reliability Need for Cane Island Unit 3

Applying the base case forecast for electrical demand, FMPA will need additional capacity by the year 2001 to maintain a 18 percent reserve margin for summer. Table 1C.7-1 presents the projected reliability levels for FMPA's system without resource additions (excluding projected contract power purchase capacity) for summer, while Table 1C.7-2 is for winter. Table 1C.7-1 clearly indicates that capacity is needed in 2001.



Table 1C.7-1
Projected Reliability Levels with
Demand-Side Management and Conservation - Summer

Year	Total Installed Capacity (MW)	Power Purchases (MW)	Total Capacity (MW)	Peak Demand (MW)	Reserve Margin (1) (percent)
1998	377	753	1,130	892	29.81
1999	377	843	1,220	988	26.49
2000	377	838	1,215	1,011	22.40
2001	377	718	1,095	1,034	7.38
2002	377	786	1,163	1,056	11.58
2003	377	837	1,214	1,077	13.51
2004	377	840	1,217	1,098	11.58
2005	377	868	1,245	1,118	12.08
2006	377	847	1,224	1,136	8.46
2007	377	805	1,182	1,154	3.13
2008	377	810	1,187	1,171	2.06
2009	377	455	832	1,187	(29.22)
2010	377	455	832	1,202	(30.11)
2011	377	455	832	1,217	(30.97)
2012	377	455	832	1,229	(31.64)
2013	377	410	787	1,242	(36.63)
2014	377	410	787	1,254	(37.24)
2015	377	410	787	1,265	(37.79)
2016	377	410	787	1,276	(38.32)
2017	377	410	787	1,286	(38.80)

(1) Reserve margin includes reserves associated with PR purchases.



Table 1C.7-2
Projected Reliability Levels with
Demand-Side Management and Conservation - Winter

Year	Total Installed Capacity (MW)	Power Purchases (MW)	Total Capacity (MW)	Peak Demand (MW)	Reserve Margin (1) (percent)
1997/98	373	758	1,131	846	36.99
1998/99	408	860	1,268	1,025	26.43
1999/00	408	855	1,263	1,049	23.06
2000/01	408	885	1,293	1,074	22.99
2001/02	408	823	1,231	1,097	14.76
2002/03	408	854	1,262	1,120	15.17
2003/04	408	867	1,275	1,142	14.09
2004/05	408	880	1,288	1,163	13.15
2005/06	408	899	1,307	1,182	12.94
2006/07	408	832	1,240	1,201	5.57
2007/08	408	854	1,262	1,218	5.90
2008/09	408	472	880	1,235	(26.49)
2009/10	408	472	880	1,251	(27.43)
2010/11	408	472	880	1,266	(28.29)
2011/12	408	472	880	1,280	(29.07)
2012/13	408	472	880	1,293	(29.78)
2013/14	408	472	880	1,305	(30.43)
2014/15	408	472	880	1,317	(31.06)
2015/16	408	427	835	1,328	(35.02)
2016/17	408	427	835	1,338	(35.51)

(1) Reserve margin includes reserves associated with PR purchases.



1C.8.0 Supply-Side Alternatives

FMPA conducted a very thorough search for supply-side alternatives that would best fit the planning needs for future demands. The alternatives considered and briefly discussed below included self-build generation alternatives and purchased power alternatives. Details of the self-build generation alternatives are provided in Section 1A.6.0.

1C.8.1 Self-Build Generation Alternatives

Self-build generation alternatives were identified based on system characteristics, existing generating alternatives, and projected need for capacity. The alternatives identified in Section 1A.6.0 were developed to be applied jointly by KUA and FMPA in the economic evaluation of potential resources. FMPA has applied the supply-side resources that passed the screening analysis in its economic modeling of system production costs over the 20 year planning horizon. There were ultimately 10 self-build generating alternatives modeled in the EGEAS evaluations. The alternatives are listed in Section 1C.9.0. Details of the generating unit alternative characteristics and performance are contained in Section 1A.6.0.

1C.8.2 Purchase Power Alternatives

FMPA conducted a three-phase evaluation of several power supply proposals received in response to a request for proposals (RFP), RFP # 9720 issued May 28, 1997, for supply of capacity and energy in various quantities for different time periods. The RFP was issued concurrent with a similar RFP by KUA. The comparison of power supply bids took into consideration many applicable pricing parameters including fixed and variable O&M charges, fuels commodity and transportation costs, applicable transmission rates, transmission upgrade costs, and system losses. Certain non-price parameters were also considered in the evaluation including contract term, firmness of supply and commercial viability.

The Stage I evaluation focused on the completeness of each proposal package and satisfaction of specified minimum requirements but did not address the price and non-price substantive criteria in each bid.

The Stage II evaluation centered primarily on the relative pricing of each proposal as compared to each of the other similar proposals. A busbar analysis was conducted to determine the cumulative present value on a \$/MWH basis relative to each other similar term



bid and a) for the short- and medium-term proposals, to the cost of purchased power based on projected market based rates and b) for the long-term proposals, the cost of FMPA's self-build project alternative.

In the Stage III evaluation, both price and non-price factors were considered in the evaluation of the most competitive remaining proposals in each of the short, medium and long-term categories. Non-price factors considered at this stage included contract term, dispatchability, existing generation versus planned, ability to finance new facilities, fuel risk, firmness of supply, transmission capability/availability, viability of technology, environmental considerations, and regulatory considerations. Each of these items represented an important risk factor in selecting both the short-list of proposals and, ultimately, the companies with which FMPA desired to contract.

FMPA received 33 proposals from 17 different bidders in response to the RFP for up to 360 MW of power from 2001 through 2021. The capacity of all proposals in the initial screening phase totaled approximately 3,500 MW. The RFP specified that FMPA was seeking three separate purchases each for up to 120 MW with varying contract periods. Table 1C.8-1 displays the contract periods requested.

Table 1C.8-1 FMPA Power Supply RFP		
Capacity	Commence Service	Contract Period
120 MW	Dec. 16, 2000	Apprx. 5 yrs. ("short-term")
120 MW	Dec. 16, 2001	Apprx. 7 yrs. ("medium-term")
120 MW	June 1, 2001	Min. 20 yrs. ("long-term")

The following entities submitted responses to the RFP issued by FMPA:

- | | |
|--|---------------------------------|
| 1. Constellation Power Development | 6. LS Power, LLC |
| 2. Indeck Energy Services | 7. NorAm Energy Services |
| 3. Lakeland Electric & Water Utilities | 8. NP Energy |
| 4. Lee County Solid Waste Management | 9. Orlando Utilities Commission |
| 5. LG&E Power Marketing | 10. Panda Energy International |



- | | |
|---------------------------------|-------------------------------|
| 11. PECO Energy Company | 15. Southern Wholesale Energy |
| 12. Polsky Energy Corporation | 16. Tarpon Power Partners |
| 13. Progress Energy Corporation | 17. Tenaska Energy Partners |
| 14. SEMCOR Energy | |

Once the Stage III evaluations were complete, a short-list of bidders was prepared with seven bidders representing nine separate proposals being selected for further negotiations:

Long-Term Proposals

Constellation Power Development
Tarpon Power Partners

Medium-Term Proposals

Constellation Power Development
Lakeland Electric & Water Utilities
Panda Energy International
Progress Energy Corporation

Short-Term Proposals

Lee County Solid Waste Management
Orlando Utilities Commission
Panda Energy International

The two entities that were short-listed as possible providers of long-term capacity, i.e. Constellation Power Development and Tarpon Power Partners, both proposed building a 2 x 1 "G" class combined cycle to be located in Hardee County. FMPPA eliminated these two long-term bids due primarily to two very important factors: questionable viability of the proposed new generation technology and a negative regulatory atmosphere regarding "merchant plants", as were both proposals.

The "G" class technology is one of the latest technologies available from Westinghouse with very little demonstrated operating time. There is one such "G" class machine now operating in Japan and there are two more being installed: one in Europe and one at the City



of Lakeland, but neither is in operation today. From a strategic point of view, although this new technology promises greater efficiencies and potentially lower cost power, the lack of operating experience with this new design raises serious questions about plant reliability and poses a significant risk to the FMPA All-Requirements Project participants. The reported efficiency improvements as compared to the commercially proven "F" class technology does not in FMPA's opinion outweigh the higher risk with the new "G" class combustion turbines.

Regarding regulatory considerations, last year the Florida Public Service Commission (FPSC) formally decided to not address the question of whether or not independent power producers (IPPs) would be allowed to build "merchant plants" in Florida. If approved, merchant plants could simply be constructed, without necessarily demonstrating an actual need to meet load growth in Florida, for the primary purpose of competing in the generation market against other existing power suppliers. The FPSC turned down a recommendation from the FPSC staff to issue a declaratory statement that would have allowed IPPs building merchant plants to qualify as applicants under the Power Plant Siting Act. If nothing else, the FPSC decision will definitely delay the possibility of "merchant plants" becoming a reality in Florida. This makes the start and completion dates for the two long-term RFP proposals most uncertain.

Three of the six medium- and short-term bidders, i.e. Constellation Power Development, Panda Energy International and Progress Energy Corporation, were also eliminated from the RFP process primarily due to the fact that their proposals were also based on the construction of "merchant plants".

The remaining short-listed medium- and short-term bidders, i.e. Lakeland Electric & Water, Lee County Solid Waste Management and Orlando Utilities Commission are currently in negotiations with FMPA for possible power supply agreements based on their respective RFP.

In summary, all of the short-listed bidders whose proposals were not based on construction of a "merchant plant" are currently involved in contract discussions with FMPA.



1C.9.0 Supply-Side Screening

A detailed supply-side screening analysis was conducted in Section 1A.6.8 of Volume 1A to reduce the number of alternatives to be modeled in the economic evaluation. The conventional alternatives from Section 1A.6.0 which were considered appropriate for modeling with EGEAS are presented on Tables 1C.9-1 through 1C.9-10.



Table 1C.9-1
Estimated Cost and Performance of 250 MW Pulverized Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 \$1,000	194,115
Indirect Capital Cost, 2001 \$1,000	84,958
Total Capital Cost, 2001 \$1,000	279,073 (1)
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2001 \$/kW-y	33.83
Variable O&M Cost, 2001 \$/MWh	4.71
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,750
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	240,749/10,157
75 Percent of Full Load	180,562/10,275
50 Percent of Full Load	120,374/10,967
25 Percent of Full Load	60,187/13,302
1. Includes interest during construction.	



Table 1C.9-2
Estimated Cost and Performance of 250 MW Fluidized Bed Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 \$1,000	180,415
Indirect Capital Cost, 2001 \$1,000	81,710
Total Capital Cost, 2001 \$1,000	262,125 (1)
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2001 \$/kW-y	28.69
Variable O&M Cost, 2001 \$/MWh	4.87
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	4,800
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	242,794/10,250
75 Percent of Full Load	182,095/10,353
50 Percent of Full Load	121,397/11,025
25 Percent of Full Load	60,698/13,295
1. Includes interest during construction.	



Table 1C.9-3
Generating Unit Characteristics
7EA 1 x 1 Combined Cycle

Item			
Steam Pressure, psia		1,250	
Steam Temperature, °F		940	
Reheat Steam Temperature, °F		—	
Direct Capital Cost, 2001 \$1,000		56,981	
Indirect Capital Cost, 2001 \$1,000		20,923	
Total Capital Cost, 2001 \$1,000		77,904 (1)	
O&M Cost-Baseload Duty			
Fixed O&M Cost, 2001 \$/kW-y		3.59	
Variable O&M Cost, 2001 \$/MWh		2.59	
Equivalent Availability, percent		92.1	
Equivalent Forced Outage Rate, percent		3.7	
Planned Maintenance Outage, weeks/y		2.25	
Startup Fuel (cold start), MBtu		59	
Construction Period, months		20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh		95° F	59° F
100 Percent of Full Load		109,939/8,114	124,166/7,849
79 Percent of Full Load		86,852/8,454	98,091/8,100
59 Percent of Full Load		64,864/9,219	73,258/8,738
35 Percent of Full Load		38,479/11,288	43,458/10,478
1. Includes interest during construction.			



Table 1C.9-4
Generating Unit Characteristics
7EA 2 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	95,069	
Indirect Capital Cost, 2001 \$1,000	39,115	
Total Capital Cost, 2001 \$1,000	134,184 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 \$/kW-y	2.45	
Variable O&M Cost, 2001 \$/MWh	2.36	
Equivalent Availability, percent	94.1	
Equivalent Forced Outage Rate, percent	1.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	119	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	222,096/7,938	250,416/7,791
75 Percent of Full Load	166,572/8,258	187,812/8,025
50 Percent of Full Load	111,048/8,178	125,208/7,869
25 Percent of Full Load	55,524/9,865	62,604/9,309
1. Includes interest during construction.		



Table 1C.9-5
Generating Unit Characteristics
Westinghouse 1 x 1 501F Combined Cycle

Item		
Steam Pressure, psia	1,800	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 \$1,000	83,622	
Indirect Capital Cost, 2001 \$1,000	33,944	
Total Capital Cost, 2001 \$1,000	117,566 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 \$/kW-y	2.27	
Variable O&M Cost, 2001 \$/MWh	2.82	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	84	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	236,630/6,945	261,792/6,815
75 Percent of Full Load	175,106/7,483	196,344/7,141
52 Percent of Full Load	123,048/8,011	138,750/7,699
27 Percent of Full Load	63,890/10,474	73,302/9,894
1. Includes interest during construction.		



Table 1C.9-6
Generating Unit Characteristics
Westinghouse 1 x 1 501G Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 \$1,000	107,386	
Indirect Capital Cost, 2001 \$1,000	39,976	
Total Capital Cost, 2001 \$1,000	147,362 (1) (2)	
O&M Cost-BaseLoad Duty		
Fixed O&M Cost, 2001 \$/kW-y	2.13	
Variable O&M Cost, 2001 \$/MWh	2.48 (3)	
Equivalent Availability, percent	83.0	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	294,960/7,062	333,456/6,784
75 Percent of Full Load	221,220/7,437	250,092/7,083
50 Percent of Full Load	147,480/8,190	166,728/7,714
25 Percent of Full Load	73,740/10,788	83,364/9,967
1. Includes interest during construction.		
2. After 2001, SCR is not included and total capital cost is reduced to \$145,157 in 2001 dollars.		
3. After 2001, SCR is not included and variable O&M is reduced to \$2.33 in 2001 dollars.		



Table 1C.9-7
Generating Unit Characteristics
General Electric LM6000 Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	16,209	
Indirect Capital Cost, 2001 \$1,000	5,956	
Total Capital Cost, 2001 \$1,000	22,165 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 \$/kW-y	5.96	
Variable O&M Cost, 2001 \$/MWh	7.56	
Equivalent Availability, percent	95.8	
Equivalent Forced Outage Rate, percent	2.3	
Planned Maintenance Outage, weeks/y	1	
Startup Fuel (cold start), MBtu	6	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	33,360/9,893	41,664/9,417
75 Percent of Full Load	25,020/10,475	31,248/9,806
50 Percent of Full Load	16,680/11,639	20,832/10,650
25 Percent of Full Load	8,340/15,136	10,416/13,183
1. Includes interest during construction.		



Table 1C.9-8
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	22,527	
Indirect Capital Cost, 2001 \$1,000	8,924	
Total Capital Cost, 2001 \$1,000	31,451 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 \$/kW-y	3.63	
Variable O&M Cost, 2001 \$/MWh	25.74	
Equivalent Availability, percent	95.6	
Equivalent Forced Outage Rate, percent	2.1	
Planned Maintenance Outage, weeks/y	1.25	
Startup Fuel (cold start), MBtu	12	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	72,432/12,335	81,552/11,959
75 Percent of Full Load	54,324/13,504	61,164/13,050
50 Percent of Full Load	36,216/15,844	40,776/15,300
25 Percent of Full Load	18,108/23,515	20,388/22,097
1. Includes interest during construction.		



Table 1C.9-9
Generating Unit Characteristics
Westinghouse 501G Simple Cycle

Table 1C.9-9 Generating Unit Characteristics Westinghouse 501G Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	51,871	
Indirect Capital Cost, 2001 \$1,000	22,823	
Total Capital Cost, 2001 \$1,000	74,694 (1) (2)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 \$/kW-y	2.33	
Variable O&M Cost, 2001 \$/MWh	12.68 (3)	
Equivalent Availability, percent	84.2	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	18	
Construction Period, months	15	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	197,040/10,502	223,872/10,047
75 Percent of Full Load	147,780/11,377	167,904/10,854
50 Percent of Full Load	98,520/13,128	111,936/12,470
25 Percent of Full Load	49,260/18,757	55,968/17,322
1. Includes interest during construction.		
2. After 2001, SCR is not included and total capital cost is reduced to \$72,522 in 2001 dollars.		
3. After 2001, SCR is not included and variable O&M is reduced to \$11.19/Mwh in 2001 dollars.		



Table 1C.9-10
Generating Unit Characteristics
General Electric 7FA Simple Cycle

Table 1C.9-10 Generating Unit Characteristics General Electric 7FA Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 \$1,000	35,300	
Indirect Capital Cost, 2001 \$1,000	13,457	
Total Capital Cost, 2001 \$1,000	48,757 (1)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2001 \$/kW-y	2.70	
Variable O&M Cost, 2001 \$/MWh	11.33	
Equivalent Availability, percent	94.5	
Equivalent Forced Outage Rate, percent	2.7	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	35	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	147,168/11,063	165,312/10,698
75 Percent of Full Load	110,376/12,030	123,984/11,546
50 Percent of Full Load	73,584/14,090	82,656/13,400
25 Percent of Full Load	36,792/20,339	41,328/19,122
1. Includes interest during construction.		



1C.10.0 Economic Analysis

The economic analysis for the All-Requirements Project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of its participants. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

1C.10.1 Methodology

The economic analysis consists of essentially three phases: demand-side, supply-side, and sensitivity analysis. Supply-side and demand-side are discussed in this subsection, whereas, sensitivity analysis will be addressed in Section 1C.11.0

Demand-side alternatives evaluated in 1A.5.0 using the FIRE model did not prove to be cost effective. Therefore, no further analysis will be considered in the production cost modeling. Details of the FIRE modeling are discussed in 1A.5.0.

Supply-side alternatives are evaluated using the Electric Generation Expansion Analysis System (EGEAS) modeling software. EGEAS evaluates all combinations of generating unit alternatives and purchase power options to determine the combination of alternatives that exhibit the lowest cumulative present worth revenue requirements while maintaining user-defined reliability criteria. The reserve criteria utilized is a minimum of 18 percent reserves and a maximum of 30 percent reserves.

The supply-side alternatives that passed the screening analysis in Section 1A.6.8 were analyzed on a comparative cost basis. Comparative costs include only those costs which are affected by differences in the plans. The comparative cost analysis will yield the optimal alternative, but should not be used to project actual total costs.

The plans were analyzed over twenty year period from 1998 to 2017. FMPA views this planning horizon to reflect the appropriate time interval for resource evaluation in today's energy market. While resources are evaluated over a 20 year period, FMPA does not formally plan beyond a 10 year period. With load growth, economic parameters, technology development, regulatory issues, and all other future conditions changing rapidly it is very uncertain what future conditions will be like. Therefore, FMPA has forecasted what it expects as reasonable assumptions for the future, but views the period beyond 2007 as too uncertain to begin formal planning. Because an EGEAS 20 year resource optimization study



needs capacity to fulfill the reserve margin requirements in the years beyond 2007, generating units were selected by the model based upon EGEAS's least-cost analysis to meet future load growth. It is uncertain whether FMPA would actually pursue the construction of the selected units beyond 2007, but such options will be frequently reviewed as the 10 year planning horizon encompasses those future years.

Several sensitivities are addressed in Section 1C.11.0 to demonstrate the robustness of the expansion plan. Sensitivities addressed include: low load growth, high load growth, low fuel prices, high fuel prices, constant differential between natural gas/oil and coal, 15 percent reserve margin criteria, and an increase in the capital cost of Cane Island Unit 3.

1C.10.2 Expansion Candidates

The expansion candidates for the EGEAS evaluation were taken directly from the screening analysis in Section 1A.6.8. The expansion candidates were developed to be applied jointly by KUA and FMPA. Table 1C.10-1 provides a summary of the expansion alternatives considered, with details provided in Section 1C.9.0. FMPA evaluated all of the expansion candidates in the year 2001 as 50 percent ownership with KUA, after which time the units were modeled as 100 percent ownership. The expansion candidates represent generic unit performance and characteristics and are subject to slight increases and/or decreases in specific parameters. The performance is dependent upon configurations and equipment utilized.

1C.10.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case FMPA All-Requirements load forecast, base case fuel price forecast, and minimum reserve margin for FMPA at 18 percent. Results of the base case scenario economic evaluation are summarized in this subsection.

Based upon the cost and performance characteristics described in detail in Section 1C.9.0 and summarized in Table 1C.10-1, the expansion plan outlined in Table 1C.10-2 represents the least-cost plan for FMPA under the base case scenario. The least-cost plan consists of the construction of an "F" class combined cycle turbine in which FMPA will share 50 percent ownership, purchase power opportunities identified from the 1997 RFP process as well as additional purchase power for which FMPA is negotiating, the construction of a 7EA simple

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Table 1C.10-1
Summary of Generation Alternatives (2001 \$)

Description	Capital Costs **	Capacity**		O&M Costs**		Fuel Type	Full Load Heat Rate*	Forced Outage Rate	Planned Maintenance	First Year Available
		Summer	Winter	Variable	Fixed					
	\$1,000	MW	MW	\$/MWh	\$/W-Yr		Btu/kWh	percent	weeks	
Pulverized Coal	279,073	240.75	240.75	4.71	33.83	Coal	10,157	9.0	4.00	2002
Fluidized Bed	262,125	242.78	242.78	4.87	28.69	Coal	10,250	9.0	4.00	2002
7EA 1x1 CC	77,904	109.94	124.166	2.59	3.59	Nat. Gas	7,849	3.7	2.25	2001
7EA 2x1 CC	134,184	222.10	250.42	2.36	2.45	Nat. Gas	7,791	1.7	2.25	2001
501F 1x1 CC	117,566	236.63	261.79	2.82	2.27	Nat. Gas	6,815	4.1	2.25	2001
501G 1x1 CC ***	147,362/ 145,157	294.96	333.46	2.48/ 2.34	2.13	Nat. Gas	6,784	13.3	2.25	2001/ 2002
LM6000 SC	22,165	33.36	41.66	7.56	5.96	Nat. Gas	9,417	2.3	1.00	2000
7EA SC	31,451	72.43	81.55	25.74	3.63	Nat. Gas	11,959	2.1	1.25	2001
501G SC ***	74,694 / 72,522	197.04	223.87	12.69/ 11.19	2.33	Nat. Gas	10,047	13.3	1.50	2001/ 2002
7FA SC	48,757	147.17	165.31	11.33	2.70	Nat. Gas	10,698	2.7	1.50	2001
*At ISO conditions including degradation.										
** FMPA would retain 50 percent ownership in the expansion alternative for additions through 2001; beyond 2001 it is assumed that FMPA would have full ownership.										
*** Capital and operating costs assume SCR through 2001; beyond 2001 SCR is not included in capital and operating costs.										



Table 1C.10-2
Base Case Expansion Plan

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011		278,201	2,058,727
2012	Build 7EA Simple Cycle (72 MW)	291,706	2,196,578
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,336,520
2014		324,860	2,474,450
2015		341,307	2,611,808
2016	Build 7EA Simple Cycle (72 MW)	355,717	2,747,502
2017		373,919	2,882,703

* Indicates FMPPA share of 50 percent ownership with KUA



cycle combustion turbine in 2007, and several other resources beyond 2007. All capacities listed in the tables are summer capacities. Table 1C.10-3 displays the reserve margins for the base case after the construction of the resources identified.

Tables 1C.10-4 through 1C.10-6 provide the top three expansion plans that were runner-ups to the top plan with their associated higher cumulative present worth revenue requirements. These plans were very similar in nature to the base case plan with minor changes in the years beyond 2007. All of the top plans selected the construction of the combined cycle "501F" machine in the year 2001 and the "7EA" combustion turbine in 2007 as the least-cost alternative.

The capacities listed next to the generating unit expansion units are summer capacities. The economic evaluation modeled the generating alternatives using their respective summer and winter ratings for the two seasons. Since the All-Requirements project is a system that is driven by summer peak demand for reserve criteria, the associated summer capacity is listed for convenience. The modeling of the capacities for seasonal variations provides a more accurate estimate for the least-cost expansion plan for FMPPA.



Table 1C.10-3
Projected Reliability Levels with
Demand-Side Management and Conservation
Including Identified Generating Alternatives - Base Case

Year	Total Installed Capacity (MW)	Power Purchases (MW)	Total Capacity (MW)	Peak Demand (MW)	Reserve Margin (percent)
1998	377	753	1,130	892	29.81
1999	377	843	1,220	988	26.49
2000	377	838	1,215	1,011	22.40
2001	495	718	1,213	1,034	18.79
2002	495	786	1,281	1,056	22.76
2003	495	837	1,332	1,077	24.46
2004	495	840	1,335	1,098	22.32
2005	495	868	1,363	1,118	22.64
2006	495	847	1,342	1,136	18.85
2007	567	805	1,372	1,154	19.59
2008	567	810	1,377	1,171	18.28
2009	934	455	1,389	1,187	18.31
2010	934	455	1,389	1,202	18.15
2011	934	455	1,389	1,217	18.01
2012	1006	455	1,461	1,229	19.54
2013	1078	410	1,488	1,242	19.81
2014	1078	410	1,488	1,254	18.66
2015	1078	410	1,488	1,265	18.01
2016	1150	410	1,560	1,276	22.26
2017	1150	410	1,560	1,286	21.31



Table 1C.10-4
Base Case Expansion Plan - Runner-Up #1

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011		278,201	2,058,727
2012	Build 7EA Simple Cycle (72 MW)	291,706	2,196,578
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,336,520
2014		324,860	2,474,450
2015	Build 7EA Simple Cycle (72 MW)	344,127	2,612,943
2016		355,717	2,748,637
2017		373,919	2,883,838

* Indicates FMPA share of 50 percent ownership with KUA



Table 1C.10-5
Base Case Expansion Plan - Runner-Up #2

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011	Build 7EA Simple Cycle (72 MW)	280,919	2,060,082
2012		291,706	2,197,934
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,337,875
2014		324,860	2,475,805
2015		341,307	2,613,163
2016	Build 7EA Simple Cycle (72 MW)	355,717	2,748,857
2017		373,919	2,884,059

* Indicates FMPP share of 50 percent ownership with KUA



Table 1C.10-6
Base Case Expansion Plan - Runner-Up #3

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001	Build 501F 1x1 Combined Cycle (118 MW) *	179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007	Build 7EA Simple Cycle (72 MW)	246,145	1,488,590
2008		256,765	1,638,908
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	255,415	1,780,641
2010		265,002	1,920,027
2011		278,201	2,058,727
2012	Build 7EA Simple Cycle (72 MW)	291,706	2,196,578
2013	Build 7EA Simple Cycle (72 MW)	312,416	2,336,520
2014		324,860	2,474,450
2015		341,307	2,611,808
2016	Build 7EA Simple Cycle (72 MW)	355,717	2,747,502
2017	Build 7EA 1x1 Combined Cycle (109 MW)	380,983	2,885,257

* Indicates FMPA share of 50 percent ownership with KUA.

TC.1.0 Sensitivity Analysis



1C.11.0 Sensitivity Analyses

FMPA performed several sensitivities to measure the impact of key assumptions on the least-cost plan. The sensitivities are presented in Sections 1C.11.1 through 1C.11.7 which include: low load and energy growth, high load and energy growth, low fuel price escalation, high fuel price escalation, constant differential between oil/gas and coal prices over the planning horizon, fifteen percent reserve margin sensitivity, and a case where Cane Island 3 capital cost is increased. For each sensitivity the least-cost plan over the planning horizon is identified.

The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs. While the tables indicate the resources necessary to maintain system reserve margins above 18 percent in all years (excluding the 15 percent reserve margin sensitivity), FMPA does not formally plan for resource additions beyond 10 years due to the large uncertainties of the future. Therefore, the resources identified by EGEAS as least-cost resources beyond 2007 represent units that are place holders in the economic analysis.

All capacities listed in the expansion plan summary tables are the summer ratings of the units. The summer capacity is listed because reserve margins are driven by the summer peak demand. The modeling of the units applied both the summer and winter ratings of the units in their respective seasons. As demonstrated in the sensitivities and the base case expansion plans, the construction of Cane Island 3 is the best resource addition for the All-Requirements Project.

1C.11.1 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth are less than the expected base case forecast. The low load and energy growth requires less generation resources than the base case forecast. Table 1C.11-1 indicates the need for power based upon the low load and energy forecast. Capacity is still required in 2001 for the low load and energy forecast. Table 1C.11-2 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity. With the lower load and energy projections, EGEAS still selects the 501F combined cycle in 2001.



Table 1C.11-1
Projected Reserve Margin Levels with
Demand-Side Management and Conservation
Before Expansion Plan - Low Growth

Year	Summer Total Installed Capacity (MW)	Summer Power Purchases (MW)	Summer Total Capacity (MW)	Summer Peak Demand (MW)	Summer Reserve Margin ⁽¹⁾ (percent)
1998	377	753	1,130	849	36.38
1999	377	843	1,220	940	32.95
2000	377	838	1,215	962	28.64
2001	377	718	1,095	984	12.84
2002	377	786	1,163	1,005	17.24
2003	377	837	1,214	1,025	19.26
2004	377	840	1,217	1,045	17.23
2005	377	868	1,245	1,064	17.77
2006	377	847	1,224	1,081	13.98
2007	377	805	1,182	1,098	8.39
2008	377	810	1,187	1,114	7.28
2009	377	455	832	1,130	(25.65)
2010	377	455	832	1,144	(26.56)
2011	377	455	832	1,158	(27.45)
2012	377	455	832	1,170	(28.20)
2013	377	410	787	1,183	(33.47)
2014	377	410	787	1,194	(34.09)
2015	377	410	787	1,205	(34.69)
2016	377	410	787	1,215	(35.23)
2017	377	410	787	1,224	(35.70)

(1) Reserve margin includes reserves associated with PR purchases.



Table 1C.11-2
Low Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118 MW *)	129,256	129,256
1999		141,613	263,486
2000		147,649	396,142
2001		171,260	541,989
2002		182,205	689,068
2003		193,558	837,166
2004		200,730	982,745
2005		211,304	1,128,003
2006		220,791	1,271,870
2007		231,175	1,414,651
2008	Build 501G 1x1 Combined Cycle (295 MW) Build 7FA Simple Cycle (147 MW)	241,138	1,555,820
2009		242,101	1,690,165
2010		250,820	1,822,092
2011		262,748	1,953,088
2012	Build 7EA Simple Cycle (72 MW)	272,358	2,081,796
2013		287,545	2,210,597
2014		298,524	2,337,345
2015		315,527	2,464,327
2016		325,480	2,588,487
2017		341,331	2,711,905

* Indicates FMPPA share of 50 percent ownership with KUA



1C.11.2 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth are greater than the expected forecast. The high load and energy growth requires the addition of more generation and thus the increase in cumulative present worth for the supply plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Subsection 1C.5.4.1. Table 1C.11-3 indicates the need for power based upon the high load and energy forecast.

As indicated in Table 1C.11-3, the need for power to maintain an 18 percent reserve margin occurs in 2000. Since the planning alternatives evaluated are not available until 2001, purchased power from an existing partial requirements purchase is assumed be made in 2000 to maintain system reserves. The least-cost plan selected for the high load sensitivity is a combination of units in 2001, a 501G 1x1 combined cycle and a 7EA 1x1 combined cycle that FMPA would retain 50 percent ownership. Table 1C.11-4 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity.

A sensitivity analysis was conducted for the high load case to determine what the cumulative present worth impact would be if FMPA proceeded with the construction of the 501F 1x1 combined cycle in 2001. Table 1C.11-5 displays the results of the analysis. As indicated in the cumulative present worth, a savings of 12.5 million dollars is achieved by constructing the 501G 1x1 combined cycle for the high load case. With the unproven results of the 501G, FMPA feels that the construction of the 501G in 2001 will present high risks on availability, operating costs, and potential system reserves. Therefore, FMPA will proceed with the construction of Cane Island 3 501F 1x1 combined cycle.

1C.11.3 Low Fuel Price Escalation

The low fuel price scenario applies the low fuel price forecast to the generation planning assumptions. The low fuel price forecast is provided in Section 1A.3.2. With the low fuel price forecast, the resource plan indicates increased amounts of energy from generation resources and decreased reliance on purchased power as low cost power sources. Table 1C.11-6 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity.



Table 1C.11-3
Projected Reserve Margin Levels with
Demand-Side Management and Conservation
Before Expansion Plan - High Load Growth

Year	Summer Total Installed Capacity (MW)	Summer Power Purchases (MW)	Summer Total Capacity (MW)	Summer Peak Demand (MW)	Summer Reserve Margin ⁽¹⁾ (percent)
1998	377	753	1,130	938	23.44
1999	377	843	1,220	1,038	20.40
2000	377	838	1,215	1,062	16.53
2001	377	718	1,095	1,086	2.24
2002	377	786	1,163	1,109	6.25
2003	377	837	1,214	1,132	7.99
2004	377	840	1,217	1,154	6.16
2005	377	868	1,245	1,174	6.74
2006	377	847	1,224	1,194	3.19
2007	377	805	1,182	1,212	(1.81)
2008	377	810	1,187	1,230	(2.84)
2009	377	455	832	1,247	(32.63)
2010	377	455	832	1,263	(33.48)
2011	377	455	832	1,278	(34.26)
2012	377	455	832	1,292	(34.98)
2013	377	410	787	1,305	(39.69)
2014	377	410	787	1,318	(40.29)
2015	377	410	787	1,329	(40.78)
2016	377	410	787	1,340	(41.27)
2017	377	410	787	1,351	(41.75)

(1) Reserve Margin includes reserves associated with PR purchases.



Table 1C.11-4
High Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		142,779	142,779
1999		156,540	291,158
2000	Increase Partial Requirements (25MW)	163,844	438,364
2001	Build 501G 1x1 Combined Cycle (147 MW)* Build 7EA 1x1 Combined Cycle (55 MW) *	187,711	598,221
2002		199,228	759,041
2003		211,092	920,555
2004		218,912	1,079,320
2005		230,033	1,237,454
2006		240,226	1,393,985
2007		251,292	1,549,190
2008		262,113	1,702,639
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	264,935	1,849,655
2010		274,635	1,994,108
2011		287,579	3,137,484
2012		298,186	2,278,397
2013	Build 7EA Simple Cycle (72 MW)	317,046	2,420,413
2014		329,202	2,560,186
2015		344,625	2,698,879
2016	Build 7EA Simple Cycle (72 MW)	358,488	2,835,630
2017		375,692	2,971,472

* Indicates FMPA share of 50 percent ownership with KUA



Table 1C.11-5
High Load and Energy Growth Sensitivity - 501F Installed

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		142,779	142,779
1999		156,540	291,158
2000	Increase Partial Requirements (25MW)	163,844	438,364
2001	Build 501F 1x1 Combined Cycle (118 MW) * Build 7EA 1x1 Combined Cycle (55 MW)* Build 7EA Simple Cycle (36 MW)*	189,147	599,444
2002		200,660	761,420
2003		212,610	924,095
2004		220,485	1,084,001
2005		231,686	1,243,270
2006		241,944	1,400,921
2007		253,038	1,557,205
2008		263,857	1,711,675
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7FA Simple Cycle (147 MW)	265,981	1,859,270
2010		275,688	2,004,277
2011		288,664	2,148,194
2012		299,296	2,289,632
2013	Build 7EA Simple Cycle (72 MW)	318,229	2,432,178
2014		330,351	2,572,439
2015		345,796	2,711,603
2016		356,891	2,847,745
2017	Build 7EA Simple Cycle (72 MW)	376,836	2,984,001
* Indicates FMPA share of 50 percent ownership with KUA			



Table 1C.11-6
Low Fuel Price Escalation Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118 MW) *	134,063	134,063
1999		146,070	272,518
2000		151,194	408,358
2001		172,075	554,900
2002		180,775	700,824
2003		190,871	846,867
2004		196,940	989,697
2005		204,766	1,130,460
2006		212,601	1,268,991
2007	Build 7EA Simple Cycle (72 MW)	223,191	1,406,840
2008	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	230,938	1,542,038
2009		226,966	1,667,984
2010		232,277	1,790,158
2011	Build 7EA Simple Cycle (72 MW)	241,271	1,910,446
2012		249,295	2,028,256
2013		264,651	2,146,802
2014	Build 7EA Simple Cycle (72 MW)	271,669	2,262,147
2015		282,846	2,375,978
2016		293,258	2,487,846
2017		304,566	2,597,970

* Indicates FMPA share of 50 percent ownership with KUA



1C.11.4 High Fuel Price Escalation

The high fuel price scenario applies the high fuel price forecast to the generation planning assumptions. The high fuel price forecast is provided in Section 1A.3.2. Table 1C.11-7 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity.

1C.11.5 Constant Differential of Oil/Gas Price Versus Coal Price

This scenario assumes the differential price between oil/gas and coal remains constant over the planning horizon based on current fuel prices. This fuel price sensitivity is outlined in Section 1A.3.2 with the fuel prices used are shown in Table 1C.11-8. The evaluation results indicate the following plan in Table 1C.11-9.

1C.11.6 Fifteen Percent Minimum Reserve Margin

FMPA maintains a system minimum reserve margin of 18 percent to provide adequate system reliability. If FMPA chose to lower the minimum reserve margin to 15 percent, the level the FPSC has identified as the general minimum reserve margin, additional capacity would still be required in 2001. This is demonstrated in the base case load forecast and system reliability criteria in Sections 1C.5.0 and 1C.7.0. Table 1C.11-10 summarizes the economic evaluation for the 15 percent minimum reserve margin scenario.

1C.11.7 Cane Island Unit 3 Capital Cost Increase

FMPA analyzed a scenario where the capital cost of a new 501F 1x1 combined cycle plant would increase in total capital cost by 20 percent. The increase in cost would be the result of increasing equipment or construction costs. After increasing the total capital costs by 20 percent the economic evaluation in EGEAS chose the expansion plan in Table 1C.11-12 which results in the least-cost supply plan. The expansion plan still indicates that the construction of Cane Island 3 with the 501F 1x1 combined cycle results in the least-cost expansion plan for the All-requirements Project.

The increase in capital cost also serves as a sensitivity analysis for an increase in interest rates. The 20 percent increase in capital costs is equivalent to a 20 percent increase in the fixed charge rate applied to the base case capital cost of the 501F 1x1 combined cycle. The 20 percent increase in the fixed charge rate represents an increase from 8.2 percent to 9.8 percent. The 20 percent increase in fixed charge rate corresponds to an increase in the bond rate from 5.5 percent to 7.5 percent.



Table 1C.11-7
High Fuel Price Escalation Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118 MW) *	137,632	137,632
1999		151,543	281,275
2000		159,627	424,692
2001		187,651	584,498
2002		202,192	747,711
2003		216,322	913,227
2004		227,011	1,077,866
2005		239,412	1,242,447
2006		252,138	1,406,740
2007	Build 7EA Simple Cycle (72 MW)	268,406	1,572,515
2008		281,629	1,737,389
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	290,137	1,898,390
2010		304,148	2,058,366
2011		323,911	2,219,855
2012	Build 7EA Simple Cycle (72 MW)	343,068	2,381,979
2013	Build 7EA Simple Cycle (72 MW)	376,083	2,550,439
2014		395,988	2,718,568
2015		422,844	2,888,741
2016	Build 7EA Simple Cycle (72 MW)	445,527	3,058,694
2017		475,481	3,230,618

* Indicates FMPA share of 50 percent ownership with KUA



Table 1C.11-8
Delivered Fuel Price Forecast—
Constant Differential Between Coal versus Natural Gas/Oil
(\$/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas ⁽¹⁾ <i>Existing Units</i>	Natural Gas ⁽²⁾ <i>New Units</i>
1998	1.70	2.68	4.47	0.55	2.39	3.20
1999	1.71	2.69	4.48	0.56	2.40	3.21
2000	1.74	2.72	4.51	0.59	2.43	3.24
2001	1.77	2.75	4.54	0.62	2.46	3.27
2002	1.81	2.79	4.58	0.66	2.50	3.31
2003	1.86	2.84	4.63	0.71	2.55	3.36
2004	1.90	2.88	4.67	0.75	2.59	3.40
2005	1.93	2.91	4.70	0.78	2.62	3.43
2006	1.97	2.95	4.74	0.82	2.66	3.47
2007	2.02	3.00	4.79	0.87	2.71	3.52
2008	2.06	3.04	4.83	0.91	2.75	3.56
2009	2.10	3.08	4.87	0.95	2.79	3.60
2010	2.15	3.13	4.92	1.00	2.84	3.65
2011	2.20	3.18	4.97	1.05	2.89	3.70
2012	2.23	3.21	5.00	1.08	2.92	3.73
2013	2.29	3.27	5.06	1.14	2.98	3.79
2014	2.34	3.32	5.11	1.19	3.03	3.84
2015	2.40	3.38	5.17	1.25	3.09	3.90
2016	2.46	3.44	5.23	1.31	3.15	3.96
2017	2.51	3.49	5.28	1.36	3.20	4.01

(1) Delivered natural gas price less demand reservation.

(2) Includes demand reservation costs.



Table 1C.11-9
Constant Differential of Oil/Gas Versus Coal Sensitivity

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118 MW) *	135,731	135,731
1999		149,663	277,700
2000		158,662	420,250
2001		185,429	578,164
2002		195,095	735,648
2003		206,275	893,476
2004		213,289	1,048,163
2005		222,885	1,201,383
2006		231,441	1,352,190
2007	Build 7EA Simple Cycle (72 MW)	244,098	1,502,952
2008		251,784	1,650,354
2009	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	247,826	1,787,876
2010		254,246	1,921,605
2011		263,395	2,052,923
2012	Build 7EA Simple Cycle (72 MW)	273,050	2,181,958
2013	Build 7EA Simple Cycle (72 MW)	288,161	2,311,035
2014		295,437	2,436,472
2015		306,663	2,559,888
2016	Build 7EA Simple Cycle (72 MW)	316,959	2,680,797
2017		327,093	2,799,067

* Indicates FMPA share of 50 percent ownership with KUA



Table 1C.11-10
Projected Reserve Margin Levels with
Demand-Side Management and Conservation - 15 Percent Reserve Margin

Year	Summer Total Installed Capacity (MW)	Summer Power Purchases (MW)	Summer Total Capacity (MW)	Summer Peak Demand (MW)	Summer Reserve Margin ⁽¹⁾ (percent)
1998	377	753	1,130	892	29.81
1999	377	843	1,220	988	26.49
2000	377	838	1,215	1,011	22.40
2001	377	718	1,095	1,034	7.38
2002	377	786	1,163	1,056	11.58
2003	377	837	1,214	1,077	13.51
2004	377	840	1,217	1,098	11.58
2005	377	868	1,245	1,118	12.08
2006	377	847	1,224	1,136	8.46
2007	377	805	1,182	1,154	3.13
2008	377	810	1,187	1,171	2.06
2009	377	455	832	1,187	(29.22)
2010	377	455	832	1,202	(30.11)
2011	377	455	832	1,217	(30.97)
2012	377	455	832	1,229	(31.64)
2013	377	410	787	1,242	(36.63)
2014	377	410	787	1,254	(37.24)
2015	377	410	787	1,265	(37.79)
2016	377	410	787	1,276	(38.32)
2017	377	410	787	1,286	(38.80)

(1) Reserve margin includes reserves associated with PR purchases.



Table 1C.11-11
Fifteen Percent Minimum Reserve Margin

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118 MW) *	135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001		179,812	569,355
2002		191,489	723,928
2003		203,341	879,511
2004		211,012	1,032,547
2005		222,148	1,185,260
2006		232,203	1,336,563
2007		243,270	1,486,814
2008	Build 501G 1x1 Combined Cycle (295 MW) Build 7FA Simple Cycle (147MW)	253,883	1,635,446
2009		253,338	1,776,025
2010		262,819	1,914,263
2011		275,770	2,051,752
2012	Build 7FA Simple Cycle (147 MW)	286,366	2,187,079
2013		306,731	2,324,474
2014		318,769	2,459,818
2015		334,366	2,594,382
2016		345,538	2,726,193
2017		362,914	2,857,416

* Indicates FMPA share of 50 percent ownership with KUA



Table 1C.11-12
Cane Island Unit 3 Capital Cost Increase by 20 Percent

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998	Build 501F 1x1 Combined Cycle (118 MW) *	135,731	135,731
1999		148,625	276,609
2000		155,396	416,225
2001		180,776	570,176
2002		192,453	725,527
2003		204,305	881,848
2004		211,976	1,035,583
2005		223,112	1,188,959
2006		233,167	1,340,890
2007	Build 7EA Simple Cycle (72 MW)	247,109	1,493,512
2008	Build 501G 1x1 Combined Cycle (295 MW) Build 7EA Simple Cycle (72 MW)	257,729	1,644,395
2009		256,379	1,786,662
2010		265,966	1,926,556
2011	Build 7EA Simple Cycle (72 MW)	279,165	2,065,736
2012		292,670	2,204,043
2013		313,380	2,344,417
2014	Build 7EA Simple Cycle (72 MW)	325,824	2,482,756
2015		342,271	2,620,502
2016		356,681	2,756,563
2017		374,883	2,892,113

* Indicates FMPP share of 50 percent ownership with KUA





1C.12.0 Strategic Considerations

In selecting a power supply alternative, a utility must consider certain strategic factors which reflect the utility's long-term ability to provide economical and reliable electric capacity and energy to its consumers. There are a number of strategic considerations which favor the installation of Cane Island 3 over other alternatives. The strategic considerations include low installation cost on a \$/kW basis, low operating costs, domestically produced fuel, existing site which can support the project capacity, electric industry deregulation, environmental benefits, and efficiency.

Cane Island 3 is one of the lowest cost alternatives on a \$/kW basis in comparison to other resource additions. Unit No. 3 enjoys the lower cost of an existing site, a point in time where capital costs for combined cycle "F" technology are at the lowest price in history, and funds available for financing are at a low interest rate. These factors contribute to Cane Island 3 having a lower installed cost over other alternatives.

Cane Island Unit 3's "F" technology has the lowest heat rate of any of the generating units that are in commercial operation in the United States. The proposed "G" technology only has a slightly better heat rate than the "F" technology and is not yet in commercial operation in the United States. The efficiency of the "F" technology ensures that Cane Island Unit 3 will produce competitively priced generation for many years. If deregulation were to happen in Florida, Cane Island Unit 3 with its low heat rate would remain a competitive resource.

The ability to utilize the existing Cane Island site offers many strategic advantages. Only two additional personnel will be required for the operation and maintenance of Cane Island Unit 3 which will result in very low fixed O&M costs. Cane Island Unit 3 will also have the advantage of a skilled and trained staff for operation and maintenance.

The use of the existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions with Cane Island Unit 3 provides assurance from risk from future environmental regulations while reducing emissions within the state.

Cane Island Unit 3 will utilize domestic natural gas which minimizes risks from interruption of supply that can be associated with imported fuels.





1C.13.0 Consequences of Delay

The initial consequences of delaying the proposed generating plant is the cost impact of construction costs due to price escalation, the need to supply an alternative resource or purchase to maintain the same level of system reliability that would be provided to the system, and the potential for capital costs to rise above escalation.

With the equipment costs for "F" technology combined cycles at their lowest point in history and industry expert opinions indicating cost may begin to increase again, there could be significant impacts to the cumulative present worth revenue requirements on the project.

Cane Island 3 provides generation from a low cost fuel source of natural gas that will in part displace higher cost, higher emission output oil burning units. Potentially if Cane Island 3 is delayed, FMPA will be required to obtain additional purchased power to meet the needs of its All-Requirements Project members. This could provide significant impacts to cumulative present worth revenue requirements due to the potential for unavailability of new purchase power opportunities.

Peninsula Florida's need for power is growing at one of the fastest rates in the nation; thus supply of power is decreasing. To maintain a reliable system for the FMPA All-Requirements Project additional sources of power are required. With the lack of available purchased power on the market, FMPA must build a new facility. The consequence's of delaying the project could have potentially large impacts on system reliability.

1C.13.1 Economic Benefits

If the construction of Cane Island 3 was delayed or canceled, there would be several consequences that would occur. Some of the consequences would include: impacts on possible escalation of capital costs above inflation, the need to purchase power on the market or under emergency conditions, the higher fuel costs associated with running older units, and the environmental impacts of the emissions from the older units.

Ignoring the very realistic possibility of increasing costs for equipment and the effects of higher emissions on the environment, FMPA has conducted an economic evaluation to provide the impact on cumulative present worth if the project was delayed 1 year and purchased power was required to maintain the 18 percent reserve margin.



Without the construction of Cane Island Unit 3 in 2001, FMPA will be presented with a shortfall of capacity. With Florida's reserve margin projected to fall below 15 percent for 2001, the impact on system reliability could be large.

With the delay of Cane Island 3, FMPA would need to reserve capacity either from the market or under existing power purchase contracts. With the projections from Florida Reliability Coordinating Councils 1997 Ten-Year Plan for Peninsular Florida's reserve margin for summer of 2001 to be 15% after exercising all of the load management and interruptible loads, it is uncertain if purchase power from the market will be available. Therefore, FMPA analyzed a one year delay of Cane Island 3 to 2002 by assuming that capacity for 2001 would be supplied from existing partial requirements contracts with FPC and FPL. The contracts state that FMPA can reserve additional capacity in increments of up to 25 MW per contract each May 1. Therefore FMPA would need to begin requiring additional capacity for 2000 for both contracts to build up to the need in 2001 of approximately 93 MW to maintain an 18 percent reserve margin. Table 1C.13-1 displays the results of the economic evaluation if a delay in the construction of Cane Island 3 occurred. The delay would result in an increased present worth cost of \$1.8 million.



Table 1C.13-1
Consequences of Delay

Year	Expansion Plan	Annual Costs (\$1,000)	Cumulative Present Worth (\$1,000)
1998		135,731	135,731
1999		148,625	276,609
2000	Secure additional 43 MW from FPC and FPL	156,021	416,785
2001	Secure additional 50 MW from FPC and FPL	175,666	566,385
2002	Build 501F 1x1 Combined Cycle (118 MW)* Remove 50 MW from FPC and FPL contracts	196,525	725,023
2003	Remove 43 MW from FPC and FPL contracts	204,251	881,303
2004		211,012	1,034,338
2005		222,148	1,187,051
2006		232,203	1,338,354
2007	Build 7EA Simple Cycle (81 MW)	246,145	1,490,380
2008		256,765	1,640,698
2009	Build 501F 1x1 Combined Cycle (262 MW) Build 7EA 1x1 Combined Cycle (124 MW)	255,415	1,782,431
2010		265,002	1,921,817
2011		278,201	2,060,517
2012	Build 7EA Simple Cycle (81 MW)	291,706	2,198,368
2013		312,416	2,338,310
2014	Build 7EA Simple Cycle (81 MW)	324,860	2,476,239
2015		341,307	2,613,597
2016		355,717	2,749,291
2017	Build 7EA Simple Cycle (81 MW)	373,919	2,884,492

*Indicates FMPA share of 50 percent ownership with KUA.



1C.14.0 Financial Analysis

The All-Requirements Project is in its 13th year of operation and continuing a very strong financial performance while supplying low-cost power to its members. The project has a track record of strong financial performance which has exceeded projections. Since its inception, the All-Requirements Project has reduced its participants' annual power supply costs by 10 to 20 percent, compared to what they would have paid their previous power suppliers. For the foreseeable future, FMPA expects its rates to remain below regional power costs medians and below what the state's investor-owned utilities charge for comparable service. Table 1C.14-1 displays the All-Requirements Project historical cost per kilowatt-hour power costs.

Table 1C.14-1 All-Requirements Project Power Costs	
Year	Power Costs (cents/kWh)
1992	4.34
1993	4.56
1994	4.55
1995	4.89
1996	4.51
1997	4.50

Fitch Investors Service reviewed the project's outstanding bonds in 1997 and issued a credit rating of "A+" up from "A, positive outlook." Fitch said "The ratings reflect a sound management team, competitive wholesale rates, court-validated power supply contracts and Florida's slower transition to deregulation, which allows FMPA time to better position itself for competition. Other strengths include management's debt reduction plan and historically



good financial performance.” Fitch stated the rating increase was a result of several factors. The two main factors included the addition of new members to the project and the diversified mix of resources. The All-Requirements Project maintains a diverse portfolio of energy sources to serve its members most cost-effectively. Section 2.0 describes the portfolio of energy sources in detail for the Project.

Based upon FMPA’s All-Requirements historical performance and positive outlook for future power supply opportunities, the financial ability to finance the construction of new generating facilities is very good.



1C.15.0 Analysis of 1990 Clean Air Act Amendments

1C.15.1 Compliance Strategy

Cane Island Unit 3 will emit small amounts of sulfur dioxide while running on either natural gas or fuel oil. As an affected unit, Unit 3 must have allowances available for emissions of sulfur dioxide to comply with its Title IV Acid Rain permit. FMPA All-Requirements Project is proposing to limit sulfur dioxide emissions to 40 tons per year for Unit 3. The 40 ton per year maximum emissions level minimizes permitting requirements for Unit 3. Forty tons per year of sulfur dioxide emissions for Unit 3 is equivalent to approximately 720 hours of full load operation on distillate oil (0.05 percent sulfur) and 8,040 hours of full load operation on fuel gas. The current operating plan for the Cane Island Power Park, including Unit 3, includes operation on fuel oil only during emergency situations. To date Cane Island Units 1 and 2 have not had to operate on fuel oil.

FMPA All-Requirements Project has identified two possible sulfur dioxide emissions compliance strategies. The first and preferred compliance strategy involves re-allocation of excess allowances currently maintained by the OUC Stanton Energy Center to cover the Cane Island Unit 3 sulfur dioxide emissions. FMPA All-Requirements Project owns 17.84 percent of Stanton Unit 1 and 13.97 percent of Stanton Unit 2. Therefore, FMPA All-Requirements Project has entitlements to a proportionate amount of the excess allowances of the Stanton Energy Center. Stanton Unit 1 currently receives 11,199 allowances per year while Stanton Unit 2 receives 0 allowances per year. Current operation of Stanton Unit 1 and Unit 2 results in a combined sulfur dioxide emissions rate of approximately 10,200 tons per year, leaving approximately 1,000 excess allowances. Therefore, in accordance with the FMPA All-Requirements Project ownership entitlements, over 318 allowances per year are currently available for reallocation from Stanton to Cane Island by FMPA All-Requirements Project. The second possible compliance strategy involves purchasing allowances. Purchasing allowances will be the compliance strategy utilized if, for any reason, re-allocation proves to supply insufficient quantities of allowances.



Appendix 1C.16.1

Energy and Demand Forecast

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Florida
Municipal
Power
Agency

Energy and Demand Forecast

All-Requirements Project

March 10, 1998



Florida
Municipal
Power
Agency

Energy and Demand Forecast

City of Bushnell

March 10, 1998





7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744



March 10, 1998

Mr. Vince Ruano
City Manager
City of Bushnell
P.O. Box 115
Bushnell, FL 33513

Introduction	For your information, attached is a report for the City of Bushnell Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

**City of Bushnell, Florida
Electric System**

**Customers, Sales, Energy and Demand Forecast
1998 – 2017**

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Bushnell for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 1.6% for the period of 1998-2007 and 1.1% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1988 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service demand sales is general service demand customers. The series is trended and seasonal; therefore the model used is exponential smoothing.

City Usage

The series for city usage is trend and seasonal. Exponential smoothing is used to project future sales.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. Box-Jenkins model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988	563	5,411	9.61
	1989	588	5,726	9.74
	1990	601	5,869	9.77
	1991	615	5,888	9.57
	1992	636	6,283	9.88
	1993	644	6,493	10.08
	1994	653	6,293	9.64
	1995	658	6,981	10.61
	1996	688	7,251	10.54
	1997	[1] 702	6,292	8.96
AGGR '88 - '97		2.5%	1.7%	-0.8%
Projected:				
	1998	717	6,449	9.00
	1999	731	6,612	9.04
	2000	746	6,776	9.08
	2001	761	6,941	9.12
	2002	776	7,111	9.16
	2003	790	7,272	9.20
	2004	804	7,432	9.24
	2005	818	7,588	9.28
	2006	830	7,740	9.32
	2007	843	7,887	9.36
AGGR '98 - '07		1.8%	2.3%	0.4%
	2008	854	8,029	9.40
	2009	865	8,165	9.44
	2010	875	8,296	9.48
	2011	885	8,421	9.52
	2012	893	8,538	9.56
	2013	901	8,649	9.60
	2014	908	8,753	9.64
	2015	914	8,850	9.68
	2016	920	8,938	9.72
	2017	924	9,018	9.76
AGGR '08 - '17		0.9%	1.3%	0.4%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988	182	3,975	21.84
	1989	179	3,796	21.21
	1990	176	4,146	23.56
	1991	169	3,700	21.90
	1992	177	3,852	21.76
	1993	180	4,125	22.92
	1994	184	4,182	22.73
	1995	215	4,955	23.05
	1996	220	6,447	29.30
	1997	[1] 219	6,754	30.84
AGGR '88 - '97		2.1%	6.1%	3.9%
Projected:	1998	220	6,889	31.38
	1999	221	7,020	31.78
	2000	222	7,146	32.18
	2001	223	7,268	32.58
	2002	224	7,384	32.98
	2003	225	7,495	33.38
	2004	226	7,600	33.68
	2005	227	7,699	33.98
	2006	228	7,799	34.23
	2007	229	7,892	34.48
AGGR '98 - '07		0.4%	1.5%	1.1%
	2008	230	7,987	34.73
	2009	231	8,083	34.98
	2010	232	8,172	35.23
	2011	233	8,262	35.48
	2012	234	8,344	35.73
	2013	235	8,428	35.93
	2014	236	8,504	36.09
	2015	237	8,580	36.25
	2016	238	8,657	36.41
	2017	239	8,735	36.57
AGGR '08 - '17		0.4%	1.0%	0.6%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988	6	4,385	731
	1989	7	4,809	687
	1990	7	4,946	707
	1991	7	5,014	716
	1992	7	5,236	748
	1993	7	5,172	739
	1994	7	5,137	734
	1995	6	4,984	831
	1996	6	5,305	884
	1997	[1] 7	5,809	830
AGGR '88 - '97		1.7%	3.2%	1.4%
Projected:				
	1998	7	5,867	838
	1999	7	5,926	847
	2000	7	5,985	855
	2001	7	6,045	864
	2002	7	6,105	872
	2003	7	6,166	881
	2004	7	6,228	890
	2005	7	6,290	899
	2006	7	6,353	908
	2007	7	6,417	917
AGGR '98 - '07		0.0%	1.0%	1.0%
	2008	7	6,481	926
	2009	7	6,546	935
	2010	7	6,611	944
	2011	7	6,677	954
	2012	7	6,744	963
	2013	7	6,812	973
	2014	7	6,880	983
	2015	7	6,948	993
	2016	7	7,018	1,003
	2017	7	7,088	1,013
AGGR '08 - '17		0.0%	1.0%	1.0%

[1] October, November, and December are estimated.

	CY Year	Lighting Sales MWh	City Usage MWh
Historical	1988	95	390
	1989	96	402
	1990	101	434
	1991	102	428
	1992	100	429
	1993	103	413
	1994	107	591
	1995	110	646
	1996	108	666
	1997 [1]	107	676
AGGR '88 - '97		1.3%	6.3%
Projected:			
	1998	108	683
	1999	109	690
	2000	110	697
	2001	111	704
	2002	112	711
	2003	113	718
	2004	115	725
	2005	116	732
	2006	117	740
	2007	118	747
AGGR '98 - '07		1.0%	1.0%
	2008	119	754
	2009	120	762
	2010	122	770
	2011	123	777
	2012	124	785
	2013	125	793
	2014	127	801
	2015	128	809
	2016	129	817
	2017	130	825
AGGR '08 - '17		1.0%	1.0%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1988	14,257	15,402	3.5	4.3
	1989	14,829	16,320	3.8	4.5
	1990	15,496	16,654	3.7	4.3
	1991	15,131	16,571	3.6	3.4
	1992	15,901	17,251	3.7	4.5
	1993	16,306	17,718	3.6	4.3
	1994	16,310	17,694	3.8	4.5
	1995	17,676	19,514	4.5	5.1
	1996	19,776	20,408	4.4	5.7
	1997	[1] 19,638	21,078	4.6	5.0
AGGR '88 - '97		3.6%	3.8%	3.2%	1.7%
Projected:	1998	19,997	21,456	4.6	5.6
	1999	20,357	21,843	4.7	5.7
	2000	20,714	22,226	4.8	5.8
	2001	21,069	22,607	4.9	5.9
	2002	21,424	22,988	4.9	6.0
	2003	21,765	23,354	5.0	6.1
	2004	22,100	23,713	5.1	6.2
	2005	22,425	24,062	5.2	6.3
	2006	22,748	24,409	5.2	6.4
	2007	23,061	24,745	5.3	6.5
AGGR '98 - '07		1.6%	1.6%	1.6%	1.6%
	2008	23,371	25,077	5.4	6.6
	2009	23,676	25,405	5.5	6.7
	2010	23,970	25,720	5.5	6.8
	2011	24,260	26,031	5.6	6.8
	2012	24,536	26,327	5.7	6.9
	2013	24,807	26,618	5.7	7.0
	2014	25,064	26,894	5.8	7.1
	2015	25,315	27,163	5.8	7.1
	2016	25,559	27,425	5.9	7.2
	2017	25,797	27,681	6.0	7.3
AGGR '08 - '17		1.1%	1.1%	1.1%	1.1%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	1,715.9	1,746.8	1,777.4	1,807.9	1,838.3
FEBRUARY	1,500.1	1,527.1	1,553.9	1,580.6	1,607.2
MARCH	1,634.5	1,663.9	1,693.1	1,722.2	1,751.1
APRIL	1,476.8	1,503.4	1,529.7	1,556.0	1,582.2
MAY	1,893.5	1,927.6	1,961.4	1,995.1	2,028.7
JUNE	1,920.5	1,955.1	1,989.4	2,023.6	2,057.6
JULY	2,117.0	2,155.1	2,193.0	2,230.6	2,268.1
AUGUST	2,223.7	2,263.8	2,303.5	2,343.0	2,382.4
SEPTEMBER	2,017.9	2,054.2	2,090.2	2,126.1	2,161.9
OCTOBER	1,746.5	1,778.0	1,809.2	1,840.2	1,871.2
NOVEMBER	1,583.5	1,612.0	1,640.3	1,668.4	1,696.5
DECEMBER	1,626.3	1,655.6	1,684.6	1,713.5	1,742.4
TOTAL	21,456.3	21,842.5	22,225.9	22,607.1	22,987.6
FY	21,127.1	21,753.3	22,137.3	22,519.0	22,899.7

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	5.6	5.7	5.8	5.9	6.0
FEBRUARY	4.9	5.0	5.0	5.1	5.2
MARCH	4.1	4.1	4.2	4.3	4.4
APRIL	3.6	3.6	3.7	3.8	3.8
MAY	4.4	4.5	4.5	4.6	4.7
JUNE	4.5	4.6	4.6	4.7	4.8
JULY	4.5	4.6	4.7	4.8	4.8
AUGUST	4.6	4.7	4.8	4.9	4.9
SEPTEMBER	4.5	4.6	4.7	4.8	4.8
OCTOBER	3.8	3.9	4.0	4.0	4.1
NOVEMBER	3.8	3.9	3.9	4.0	4.1
DECEMBER	4.4	4.5	4.6	4.7	4.8
TOTAL	52.7	53.7	54.6	55.6	56.5
FY	53.0	53.5	54.4	55.4	56.3

Florida
Municipal
Power
Agency

Energy and Demand Forecast

City of Clewiston

March 10, 1998





7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744



March 10, 1998

Mr. George Mathis
Utilities Director
City of Clewiston
141 Central Avenue
Clewiston, FL 33440

Introduction	For your information, attached is a report for the City of Clewiston Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Clewiston, Florida Electric System

Customers, Sales, Energy and Demand Forecast 1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Clewiston for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP- MW) are projected to increase at compound annual growth rates of approximately 1.8% for the period of 1998-2007 and 1.1% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1983 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the-year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

General Service Non-Demand

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and nonseasonal; therefore the exponential smoothing model is used to project future sales.

General Service Demand

The explanatory variable used to determine general service demand sales is general service demand customers. The series is trended and nonseasonal; therefore an exponential smoothing model is used to project future sales.

US Sugar Corp

The series is stationary and nonseasonal; therefore the Box-Jenkins model is used to project future sales.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. The Box-Jenkins model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986	3,007	38,278	12.73
	1987	3,036	38,720	12.75
	1988	3,043	40,194	13.21
	1989	3,066	41,626	13.58
	1990	3,137	42,712	13.61
	1991	3,162	42,863	13.56
	1992	3,191	42,290	13.25
	1993	3,215	43,267	13.46
	1994	3,238	46,580	14.39
	1995	3,272	48,392	14.79
	1996	3,268	49,110	15.03
	1997	[1]	49,857	15.11
		1.2%	2.4%	2.0%
AGGR '86 - '97				
Projected:				
	1998	3,335	50,754	15.22
	1999	3,373	51,668	15.32
	2000	3,410	52,546	15.41
	2001	3,444	53,387	15.50
	2002	3,476	54,188	15.59
	2003	3,506	54,947	15.67
	2004	3,534	55,661	15.75
	2005	3,563	56,329	15.81
	2006	3,588	56,948	15.87
	2007	3,613	57,518	15.92
AGGR '98 - '07				
		0.9%	1.4%	0.5%
	2008	3,634	58,036	15.97
	2009	3,655	58,558	16.02
	2010	3,673	59,026	16.07
	2011	3,690	59,440	16.11
	2012	3,705	59,796	16.14
	2013	3,719	60,095	16.16
	2014	3,733	60,396	16.18
	2015	3,743	60,637	16.20
	2016	3,753	60,880	16.22
	2017	3,760	61,062	16.24
AGGR '08 - '17				
		0.4%	0.6%	0.2%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer NCP's
Historical	1986	113	25,734	227.23
	1987	114	26,241	230.19
	1988	115	27,264	237.42
	1989	116	29,829	256.41
	1990	119	30,523	257.04
	1991	122	31,776	261.00
	1992	127	31,126	245.89
	1993	131	31,582	241.85
	1994	129	32,843	255.26
	1995	131	33,394	255.07
	1996	127	33,316	262.68
	1997	[1]	36,118	282.17
AGGR '86 - '97		2.4%	4.4%	2.0%
Projected:				
	1998	129	37,165	288.10
	1999	130	38,206	293.89
	2000	131	39,276	299.82
	2001	132	40,356	305.72
	2002	133	41,433	311.53
	2003	134	42,509	317.23
	2004	135	43,583	322.83
	2005	136	44,654	328.34
	2006	137	45,724	333.75
	2007	138	46,792	339.07
AGGR '98 - '07		0.8%	2.6%	1.8%
	2008	139	47,858	344.30
	2009	140	48,922	349.44
	2010	141	49,984	354.50
	2011	142	51,044	359.46
	2012	143	52,102	364.35
	2013	144	53,158	369.15
	2014	145	54,212	373.88
	2015	146	55,265	378.52
	2016	147	56,315	383.09
	2017	148	57,329	387.35
AGGR '08 - '17		0.7%	2.0%	1.3%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer NCP's
Historical	1986	409	5,198	12.71
	1987	426	5,259	12.34
	1988	427	5,611	13.15
	1989	455	5,863	12.79
	1990	430	5,563	12.93
	1991	434	5,556	12.81
	1992	425	4,984	11.73
	1993	431	5,487	12.73
	1994	446	6,111	13.70
	1995	433	6,026	13.92
	1996	441	5,938	13.46
	1997	[1]	449	6,817
AGGR '86 - '97		1.0%	3.2%	2.1%
Projected:				
	1998	455	6,919	15.21
	1999	461	7,023	15.23
	2000	467	7,121	15.25
	2001	473	7,221	15.27
	2002	478	7,315	15.29
	2003	483	7,403	15.31
	2004	488	7,484	15.33
	2005	492	7,559	15.35
	2006	496	7,627	15.37
	2007	500	7,696	15.39
AGGR '98 - '07		1.1%	1.2%	0.1%
	2008	503	7,757	15.41
	2009	506	7,812	15.43
	2010	509	7,866	15.45
	2011	511	7,913	15.47
	2012	513	7,953	14.49
	2013	515	7,985	15.51
	2014	516	8,017	15.53
	2015	517	8,049	15.55
	2016	518	8,073	15.57
	2017	519	8,097	15.59
AGGR '08 - '17		0.3%	0.5%	0.1%

[1] October, November, and December are estimated.

	CY Year	US Sugar Corp Sales MWh	Lighting Sales MWh
Historical	1986	4,297	1,140
	1987	3,378	1,005
	1988	4,302	1,003
	1989	5,118	1,008
	1990	5,014	967
	1991	4,588	965
	1992	5,135	1,094
	1993	7,290	1,097
	1994	8,809	1,140
	1995	9,063	1,124
	1996	8,281	1,429
	1997	[1] 11,790	1,099
AGGR '86 - '97		9.4%	-0.3%
Projected:			
	1998	11,967	1,108
	1999	12,134	1,117
	2000	12,292	1,126
	2001	12,440	1,133
	2002	12,576	1,141
	2003	12,702	1,149
	2004	12,829	1,156
	2005	12,958	1,163
	2006	13,074	1,170
	2007	13,192	1,176
AGGR '98 - '07		1.1%	0.7%
	2008	13,297	1,182
	2009	13,390	1,187
	2010	13,484	1,191
	2011	13,565	1,195
	2012	13,646	1,199
	2013	13,715	1,202
	2014	13,770	1,205
	2015	13,825	1,207
	2016	13,866	1,209
	2017	13,894	1,212
AGGR '08 - '17		0.5%	0.3%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989	82,388	89,224	18.0	17.7
	1990	83,813	89,916	18.2	21.4
	1991	85,748	88,562	18.8	16.8
	1992	84,628	90,786	18.5	15.3
	1993	88,724	95,643	20.4	15.5
	1994	95,484	101,533	19.3	18.5
	1995	97,999	105,035	20.8	21.0
	1996	98,074	103,949	21.4	22.4
	1997	[1] 105,681	114,533	23.0	21.6
AGGR '89 - '97		3.2%	3.4%	3.2%	1.3%
Projected:	1998	107,914	116,978	23.9	22.2
	1999	110,148	119,401	24.4	22.7
	2000	112,361	121,800	24.8	23.1
	2001	114,537	124,158	25.3	23.6
	2002	116,654	126,453	25.8	24.0
	2003	118,710	128,681	26.3	24.4
	2004	120,713	130,853	26.7	24.9
	2005	122,663	132,967	27.1	25.3
	2006	124,544	135,006	27.5	25.7
	2007	126,374	136,989	27.9	26.0
AGGR '98 - '07		1.8%	1.8%	1.8%	1.8%
	2008	128,130	138,893	28.3	26.4
	2009	129,868	140,777	28.7	26.7
	2010	131,552	142,602	29.1	27.1
	2011	133,157	144,342	29.4	27.4
	2012	134,696	146,011	29.8	27.7
	2013	136,155	147,592	30.1	28.0
	2014	137,599	149,157	30.4	28.3
	2015	138,982	150,657	30.7	28.6
	2016	140,343	152,132	31.0	28.9
	2017	141,594	153,448	31.3	29.2
AGGR '08 - '17		1.1%	1.1%	1.1%	1.1%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	9,089.7	9,277.9	9,464.3	9,647.5	9,825.9
FEBRUARY	8,755.8	8,937.1	9,116.7	9,293.2	9,465.0
MARCH	8,600.3	8,778.4	8,954.7	9,128.1	9,296.9
APRIL	8,372.7	8,546.1	8,717.8	8,886.6	9,050.9
MAY	10,299.7	10,513.0	10,724.2	10,931.8	11,133.9
JUNE	10,635.6	10,855.8	11,074.0	11,288.4	11,497.0
JULY	11,235.4	11,468.0	11,698.4	11,924.9	12,145.3
AUGUST	11,691.0	11,933.0	12,172.8	12,408.5	12,637.8
SEPTEMBER	10,987.8	11,215.3	11,440.7	11,662.2	11,877.8
OCTOBER	10,456.8	10,673.3	10,887.7	11,098.5	11,303.7
NOVEMBER	8,277.9	8,449.3	8,619.0	8,785.9	8,948.3
DECEMBER	8,575.9	8,753.4	8,929.3	9,102.2	9,270.4
TOTAL	116,978.5	119,400.6	121,799.6	124,157.9	126,452.9
FY	113,567.8	118,835.1	121,239.5	123,607.3	125,917.1

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	22.2	22.7	23.1	23.6	24.0
FEBRUARY	22.1	22.6	23.0	23.5	23.9
MARCH	19.3	19.7	20.1	20.5	20.9
APRIL	19.3	19.7	20.1	20.5	20.9
MAY	21.8	22.3	22.7	23.2	23.6
JUNE	21.9	22.4	22.8	23.3	23.7
JULY	22.0	22.5	22.9	23.4	23.8
AUGUST	23.9	24.4	24.8	25.3	25.8
SEPTEMBER	22.9	23.3	23.8	24.3	24.7
OCTOBER	22.2	22.7	23.1	23.6	24.0
NOVEMBER	20.0	20.4	20.8	21.2	21.6
DECEMBER	18.8	19.2	19.5	19.9	20.3
TOTAL	256.5	261.8	267.1	272.2	277.3
FY	251.9	260.5	265.8	271.0	276.1

Florida
Municipal
Power
Agency

Energy and Demand Forecast

Fort Pierce Utilities Authority

March 10, 1998





7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744



March 10, 1998

Mr. Elie J. Boudreaux III, P.E.
Director of Utilities
Fort Pierce Utilities Authority
P.O. Box 3191
Fort Pierce, FL 34948

Introduction	For your information, attached is a report for the Fort Pierce Utilities Authority Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y



7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744



March 10, 1998

Mr. Thomas Richards
Director of Operations
Fort Pierce Utilities Authority
P.O. Box 3191
Fort Pierce, FL 34948

Introduction	For your information, attached is a report for the Fort Pierce Utilities Authority Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

**Fort Pierce Utilities Authority, Florida
Electric System**

**Customers, Sales, Energy and Demand Forecast
1998 – 2017**

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the Fort Pierce Utilities Authority for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 1.5% for the period of 1998-2007 and 0.5% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1986 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is nonstationary and seasonal; therefore the model used is dynamic regression.

General Service

The explanatory variable used to determine general service sales is general service customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. A exponential smoothing is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986	18,988	189,830	10.00
	1987	19,443	196,436	10.10
	1988	19,576	200,931	10.26
	1989	19,726	210,757	10.68
	1990	19,721	207,688	10.53
	1991	19,582	219,144	11.19
	1992	19,575	205,084	10.48
	1993	19,732	205,658	10.42
	1994	19,790	210,082	10.62
	1995	20,018	216,604	10.82
	1996	20,137	223,330	11.09
	1997	[1]	210,387	10.41
		0.6%	0.9%	0.4%
AGGR '86 - '97				
Projected:				
	1998	20,337	216,699	10.66
	1999	20,459	222,983	10.90
	2000	20,582	229,226	11.14
	2001	20,706	234,957	11.35
	2002	20,830	240,361	11.54
	2003	20,955	245,409	11.71
	2004	21,060	250,071	11.87
	2005	21,165	254,323	12.02
	2006	21,271	258,137	12.14
	2007	21,377	261,493	12.23
AGGR '98 - '07				
		0.6%	2.1%	1.5%
	2008	21,463	264,370	12.32
	2009	21,548	267,013	12.39
	2010	21,635	269,684	12.47
	2011	21,721	272,111	12.53
	2012	21,786	274,288	12.59
	2013	21,852	276,482	12.65
	2014	21,895	278,417	12.72
	2015	21,939	280,088	12.77
	2016	21,983	281,488	12.80
	2017	22,027	282,896	12.84
AGGR '08 - '17				
		0.3%	0.8%	0.5%

[1] October, November, and December are estimated.

General Service

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986	3,671	216,712	59.03
	1987	3,790	224,589	59.25
	1988	3,829	233,037	60.86
	1989	3,989	254,112	63.70
	1990	3,980	253,003	63.57
	1991	3,933	260,873	66.33
	1992	3,896	271,191	69.61
	1993	3,935	283,202	71.97
	1994	3,923	290,530	74.06
	1995	3,830	295,922	77.26
	1996	3,960	299,516	75.64
	1997	[1]	295,489	73.60
		0.8%	2.9%	2.0%
AGGR '86 - '97				
Projected:				
	1998	4,062	301,103	74.13
	1999	4,106	306,523	74.65
	2000	4,147	311,734	75.17
	2001	4,188	316,410	75.55
	2002	4,227	320,523	75.83
	2003	4,259	323,729	76.01
	2004	4,287	326,642	76.19
	2005	4,307	328,929	76.37
	2006	4,327	330,902	76.48
	2007	4,346	332,888	76.59
AGGR '98 - '07				
		0.8%	1.1%	0.4%
	2008	4,362	334,552	76.70
	2009	4,377	336,225	76.81
	2010	4,389	337,570	76.92
	2011	4,400	338,920	77.03
	2012	4,410	339,937	77.09
	2013	4,419	340,957	77.15
	2014	4,429	341,979	77.21
	2015	4,439	343,005	77.27
	2016	4,444	343,691	77.33
	2017	4,450	344,379	77.39
AGGR '08 - '17				
		0.2%	0.3%	0.1%

[1] October, November, and December are estimated.

	CY Year	Lights Sales MWh
Historical	1986	6,952
	1987	7,140
	1988	7,253
	1989	7,608
	1990	7,986
	1991	8,160
	1992	8,503
	1993	8,944
	1994	9,098
	1995	9,292
	1996	9,685
	1997	[1] 9,480
AGGR '86 - '97		2.9%
Projected:	1998	9,618
	1999	9,749
	2000	9,877
	2001	9,996
	2002	10,112
	2003	10,218
	2004	10,313
	2005	10,400
	2006	10,482
	2007	10,559
AGGR '98 - '07		1.0%
	2008	10,631
	2009	10,704
	2010	10,767
	2011	10,830
	2012	10,888
	2013	10,945
	2014	10,992
	2015	11,040
	2016	11,081
	2017	11,122
AGGR '08 - '17		0.5%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989	486,643	513,000	100.0	111.0
	1990	483,543	507,467	99.0	121.0
	1991	486,896	510,598	101.0	98.0
	1992	484,778	504,650	102.0	102.0
	1993	497,804	524,564	104.0	101.0
	1994	509,710	536,258	102.0	92.0
	1995	522,112	554,189	108.0	128.0
	1996	532,825	544,589	104.0	126.0
	1997	[1] 515,650	547,945	107.0	118.0
AGGR '89 - '97		0.8%	0.8%	0.8%	0.8%
Projected:	1998	527,420	560,120	109.2	124.3
	1999	539,255	572,150	111.6	127.0
	2000	550,537	583,845	113.8	129.6
	2001	561,063	595,008	116.0	132.1
	2002	570,696	605,223	118.0	134.4
	2003	579,055	613,798	119.7	136.3
	2004	586,727	621,931	121.3	138.1
	2005	593,351	628,952	122.6	139.6
	2006	599,221	635,174	123.9	141.0
	2007	604,640	640,918	125.0	142.3
AGGR '98 - '07		1.5%	1.5%	1.5%	1.5%
	2008	609,253	645,808	125.9	143.4
	2009	613,643	650,461	126.8	144.4
	2010	617,720	654,784	127.7	145.4
	2011	621,561	658,855	128.5	146.3
	2012	624,812	662,301	129.1	147.0
	2013	628,084	665,769	129.8	147.8
	2014	631,089	668,954	130.4	148.5
	2015	633,833	671,863	131.0	149.2
	2016	635,961	674,118	131.5	149.7
	2017	638,097	676,383	131.9	150.2
AGGR '08 - '17		0.5%	0.5%	0.5%	0.5%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	44,687.2	45,646.9	46,580.0	47,470.6	48,285.6
FEBRUARY	40,477.7	41,347.0	42,192.2	42,998.9	43,737.1
MARCH	42,863.5	43,784.1	44,679.1	45,533.3	46,315.1
APRIL	42,631.9	43,547.5	44,437.6	45,287.3	46,064.8
MAY	49,443.0	50,504.8	51,537.2	52,522.6	53,424.3
JUNE	49,092.5	50,146.8	51,171.8	52,150.2	53,045.6
JULY	53,683.0	54,835.9	55,956.8	57,026.7	58,005.7
AUGUST	54,980.5	56,161.3	57,309.3	58,405.0	59,407.8
SEPTEMBER	50,882.6	51,975.4	53,037.8	54,051.9	54,979.9
OCTOBER	47,369.9	48,387.2	49,376.3	50,320.4	51,184.3
NOVEMBER	39,735.7	40,589.1	41,418.8	42,210.7	42,935.4
DECEMBER	44,272.7	45,223.5	46,147.9	47,030.3	47,837.7
TOTAL	560,120.1	572,149.8	583,844.7	595,007.7	605,223.3
FY	551,991.8	569,328.2	581,101.6	592,389.4	602,827.2

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	124.3	127.0	129.6	132.1	134.4
FEBRUARY	97.1	99.2	101.3	103.2	105.0
MARCH	90.3	92.2	94.1	95.9	97.5
APRIL	92.3	94.3	96.2	98.0	99.7
MAY	103.1	105.3	107.5	109.6	111.4
JUNE	104.4	106.6	108.8	110.9	112.8
JULY	105.8	108.1	110.3	112.4	114.3
AUGUST	109.2	111.6	113.8	116.0	118.0
SEPTEMBER	103.3	105.6	107.7	109.8	111.7
OCTOBER	96.7	98.8	100.8	102.8	104.5
NOVEMBER	98.4	100.5	102.6	104.6	106.4
DECEMBER	104.6	106.9	109.1	111.1	113.1
TOTAL	1,229.7	1,256.1	1,281.8	1,306.3	1,328.7
FY	1,219.9	1,249.7	1,275.5	1,300.3	1,323.3

Florida
Municipal
Power
Agency

Energy and Demand Forecast

City of Green Cove Springs

March 10, 1998





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CELEBRATING 20 YEARS

March 10, 1998

Mr. Ted Biggs
Electric Utility Director
City of Green Cove Springs
229 Walnut St.
Green Cove Springs, FL 32043

Introduction	For your information, attached is a report for the City of Green Cove Springs Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

**City of Green Cove Springs, Florida
Electric System**

**Customers, Sales, Energy and Demand Forecast
1998 – 2017**

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Green Cove Springs for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 1.8% for the period of 1998-2007 and 1.2% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1989 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and nonseasonal; therefore an exponential smoothing model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service sales is general service demand customers. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

Large Demand Class Model

The explanatory variable used to determine large demand sales is large demand customers. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

City Accounts

City accounts are trended and seasonal. Box-Jenkins is use to project future sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989	1,922	20,312	10.57
	1990	1,962	21,534	10.98
	1991	2,004	22,534	11.24
	1992	2,036	23,370	11.48
	1993	2,068	24,403	11.80
	1994	2,103	24,922	11.85
	1995	2,156	27,380	12.70
	1996	2,190	28,738	13.12
	1997	[1]	25,798	11.57
AGGR '89 - '97		1.9%	3.0%	1.1%
Projected:				
	1998	2,268	26,443	11.66
	1999	2,305	27,086	11.75
	2000	2,340	27,700	11.84
	2001	2,373	28,310	11.93
	2002	2,407	28,933	12.02
	2003	2,439	29,540	12.11
	2004	2,470	30,131	12.20
	2005	2,498	30,703	12.29
	2006	2,525	31,256	12.38
	2007	2,549	31,787	12.47
AGGR '98 - '07		1.3%	2.1%	0.7%
	2008	2,571	32,296	12.56
	2009	2,591	32,781	12.65
	2010	2,609	33,239	12.74
	2011	2,627	33,705	12.83
	2012	2,643	34,143	12.92
	2013	2,656	34,553	13.01
	2014	2,667	34,933	13.10
	2015	2,675	35,282	13.19
	2016	2,681	35,600	13.28
	2017	2,684	35,884	13.37
AGGR '08 - '17		0.5%	1.2%	0.7%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989	361	7,359	20.39
	1990	401	7,912	19.73
	1991	426	7,944	18.65
	1992	439	8,345	19.01
	1993	439	8,368	19.06
	1994	435	8,061	18.53
	1995	441	8,433	19.12
	1996 [1]	457	8,818	19.30
	1997	453	9,494	20.96
AGGR '89 - '97		2.9%	3.2%	0.3%
Projected:	1998	460	9,731	21.15
	1999	466	9,965	21.38
	2000	472	10,194	21.61
	2001	477	10,418	21.86
	2002	482	10,637	22.09
	2003	486	10,850	22.32
	2004	490	11,056	22.55
	2005	494	11,255	22.78
	2006	497	11,446	23.01
	2007	500	11,630	23.24
AGGR '98 - '07		0.9%	2.0%	1.1%
	2008	503	11,804	23.47
	2009	505	11,981	23.73
	2010	506	12,149	23.99
	2011	508	12,319	24.25
	2012	509	12,479	24.53
	2013	510	12,641	24.79
	2014	511	12,793	25.05
	2015	512	12,946	25.31
	2016	513	13,102	25.55
	2017	514	13,246	25.79
AGGR '08 - '17		0.2%	1.3%	1.1%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989	76	23,677	311.54
	1990	84	25,398	302.35
	1991	86	25,021	290.94
	1992	85	27,382	322.14
	1993	90	28,540	317.11
	1994	91	29,481	323.96
	1995	88	31,255	355.17
	1996	89	32,324	363.19
	1997	[1] 91	34,268	376.57
AGGR '89 - '97		2.3%	4.7%	2.4%
Projected:	1998	93	35,296	380.00
	1999	93	36,320	390.53
	2000	94	37,337	397.20
	2001	95	38,345	403.63
	2002	96	39,342	409.81
	2003	97	40,325	415.72
	2004	98	41,333	421.77
	2005	99	42,325	427.53
	2006	100	43,299	432.99
	2007	101	44,251	438.13
AGGR '98 - '07		0.9%	2.5%	1.6%
	2008	102	45,225	443.38
	2009	103	46,175	448.30
	2010	104	47,098	452.87
	2011	105	47,993	457.08
	2012	106	48,857	460.91
	2013	107	49,687	464.37
	2014	108	50,482	467.43
	2015	109	51,240	470.09
	2016	110	51,957	472.34
	2017	111	52,632	474.17
AGGR '08 - '17		0.9%	1.7%	0.7%

[1] October, November, and December are estimated.

Large Demand				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989	4	25,143	6285.69
	1990	4	26,507	6626.64
	1991	6	30,978	5162.94
	1992	6	33,690	5615.00
	1993	6	36,007	6001.14
	1994	6	38,966	6494.27
	1995	5	37,008	7401.60
	1996	6	37,936	6322.73
	1997	[1]	39,763	6627.17
AGGR '89 - '97		5.2%	5.9%	0.7%
Projected:				
	1998	6	40,161	6693.44
	1999	6	40,562	6760.37
	2000	6	40,968	6827.98
	2001	6	41,378	6896.26
	2002	6	41,750	6958.32
	2003	6	42,126	7020.95
	2004	6	42,505	7084.14
	2005	6	42,887	7147.89
	2006	6	43,230	7205.08
	2007	6	43,576	7262.72
AGGR '98 - '07		0.0%	0.9%	0.9%
	2008	6	43,925	7320.82
	2009	6	44,232	7372.06
	2010	6	44,542	7423.67
	2011	6	44,854	7475.63
	2012	6	45,123	7520.49
	2013	6	45,394	7565.61
	2014	6	45,666	7611.00
	2015	6	45,894	7649.06
	2016	6	46,124	7687.31
	2017	6	46,308	7718.05
AGGR '08 - '17		0.0%	0.6%	0.6%

[1] October, November, and December are estimated.

	CY Year	City Accounts Sales MWh
Historical	1989	1,516
	1990	1,510
	1991	1,503
	1992	1,529
	1993	1,627
	1994	1,674
	1995	1,702
	1996	1,650
	1997 [1]	1,765
AGGR '89 - '97		1.9%
Projected:	1998	1,783
	1999	1,800
	2000	1,817
	2001	1,833
	2002	1,848
	2003	1,862
	2004	1,876
	2005	1,887
	2006	1,898
AGGR '98 - '07	2007	1,908
		0.8%
	2008	1,917
	2009	1,927
	2010	1,934
	2011	1,942
	2012	1,948
	2013	1,954
	2014	1,960
AGGR '08 - '17	2015	1,964
	2016	1,968
	2017	1,971
		0.3%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989	78,007	86,938	16.7	16.5
	1990	82,860	90,214	17.5	16.3
	1991	87,980	96,828	18.4	16.5
	1992	94,316	103,730	19.8	19.5
	1993	98,943	109,570	21.0	19.0
	1994	103,104	111,240	20.1	21.3
	1995	105,778	116,333	22.3	21.6
	1996	109,466	122,179	22.7	24.8
	1997	[1] 111,088	126,227	23.9	24.9
AGGR '89 - '97		4.5%	3.5%	3.0%	3.2%
Projected:					
	1998	113,414	128,838	24.4	24.2
	1999	115,733	131,472	24.8	24.7
	2000	118,016	134,066	25.3	25.2
	2001	120,283	136,642	25.8	25.7
	2002	122,509	139,170	26.3	26.2
	2003	124,703	141,663	26.8	26.6
	2004	126,901	144,159	27.2	27.1
	2005	129,058	146,610	27.7	27.6
	2006	131,130	148,963	28.2	28.0
	2007	133,152	151,261	28.6	28.4
AGGR '98 - '07		1.8%	1.8%	1.8%	1.8%
	2008	135,167	153,550	29.0	28.9
	2009	137,095	155,740	29.4	29.3
	2010	138,963	157,862	29.8	29.7
	2011	140,813	159,963	30.2	30.1
	2012	142,550	161,936	30.6	30.4
	2013	144,229	163,844	31.0	30.8
	2014	145,834	165,667	31.3	31.1
	2015	147,326	167,362	31.6	31.5
	2016	148,750	168,980	31.9	31.8
	2017	150,043	170,448	32.2	32.0
AGGR '08 - '17		1.2%	1.2%	1.2%	1.2%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	10,403.2	10,615.9	10,825.3	11,033.3	11,237.5
FEBRUARY	9,350.9	9,542.1	9,730.3	9,917.3	10,100.8
MARCH	9,769.5	9,969.3	10,165.9	10,361.3	10,553.0
APRIL	9,557.4	9,752.9	9,945.2	10,136.3	10,323.9
MAY	10,816.1	11,037.3	11,255.0	11,471.2	11,683.5
JUNE	11,182.4	11,411.0	11,636.1	11,859.7	12,079.1
JULY	12,597.2	12,854.8	13,108.4	13,360.3	13,607.5
AUGUST	12,832.8	13,095.3	13,353.6	13,610.2	13,862.0
SEPTEMBER	11,998.7	12,244.0	12,485.5	12,725.5	12,960.9
OCTOBER	10,537.5	10,753.0	10,965.1	11,175.8	11,382.6
NOVEMBER	9,246.0	9,435.0	9,621.1	9,806.0	9,987.5
DECEMBER	10,546.2	10,761.9	10,974.2	11,185.0	11,392.0
TOTAL	128,837.9	131,472.5	134,065.7	136,641.9	139,170.2
FY	125,090.9	130,852.3	133,455.2	136,035.4	138,575.0

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	24.2	24.7	25.2	25.7	26.2
FEBRUARY	21.2	21.6	22.1	22.5	22.9
MARCH	18.8	19.2	19.6	20.0	20.3
APRIL	18.8	19.2	19.5	19.9	20.3
MAY	21.9	22.4	22.8	23.3	23.7
JUNE	23.1	23.6	24.0	24.5	24.9
JULY	23.8	24.3	24.8	25.3	25.7
AUGUST	24.4	24.8	25.3	25.8	26.3
SEPTEMBER	23.0	23.5	23.9	24.4	24.9
OCTOBER	20.5	20.9	21.4	21.8	22.2
NOVEMBER	20.2	20.6	21.0	21.4	21.8
DECEMBER	23.5	23.9	24.4	24.9	25.4
TOTAL	263.4	268.8	274.1	279.4	284.6
FY	263.1	267.5	272.8	278.1	283.3

Florida
Municipal
Power
Agency

Energy and Demand Forecast

City of Jacksonville Beach

March 10, 1998





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March 10, 1998

Mr. Charles W. Smith, P.E.
Director of Electric Utilities
City of Jacksonville Beach
11 N. third St.
Jacksonville Beach, FL 32240-1389

Introduction	For your information, attached is a report for the City of Jacksonville Beach Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

**City of Jacksonville Beach, Florida
Electric System**

**Customers, Sales, Energy and Demand Forecast
1998 – 2017**

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Jacksonville Beach for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 3.0% for the period of 1998-2007 and 1.1% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1992 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service sales is general service demand customers. The series is trended and seasonal; therefore the model used is dynamic regression.

City Accounts

City accounts are trended and nonseasonal. Exponential smoothing is use to project future sales.

Lighting

Lighting is tied to customer growth and it is nonstational and seasonal. Exponential smoothing model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1992	19,923	258,951	13.00
	1993	21,404	293,495	13.71
	1994	21,944	324,915	14.81
	1995	22,393	351,161	15.68
	1996	23,209	378,002	16.29
	1997	[1] 23,928	363,877	15.21
	AGGR '92 - '97	3.7%	7.0%	3.2%
Projected:	1998	24,447	378,432	15.48
	1999	24,965	393,191	15.75
	2000	25,476	408,132	16.02
	2001	25,995	422,417	16.25
	2002	26,478	436,357	16.48
	2003	26,955	449,884	16.69
	2004	27,409	462,930	16.89
	2005	27,841	474,966	17.06
	2006	28,249	485,891	17.20
	2007	28,615	495,608	17.32
	AGGR '98 - '07	1.8%	3.0%	1.3%
	2008	28,958	505,025	17.44
	2009	29,249	513,610	17.56
	2010	29,503	521,315	17.67
	2011	29,731	528,613	17.78
	2012	29,932	535,485	17.89
	2013	30,106	541,911	18.00
	2014	30,223	547,330	18.11
	2015	30,310	552,256	18.22
	2016	30,370	556,674	18.33
	2017	30,400	560,571	18.44
	AGGR '08 - '17	0.5%	1.2%	0.6%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1992	3,301	42,748	12.95
	1993	3,353	51,850	15.46
	1994	4,155	61,147	14.72
	1995	3,446	62,545	18.15
	1996 [1]	3,633	69,968	19.26
	1997	3,700	70,918	19.17
AGGR '92 - '97		2.3%	10.7%	8.2%
Projected:				
	1998	3,766	73,400	19.49
	1999	3,829	75,896	19.82
	2000	3,891	78,400	20.15
	2001	3,951	80,752	20.44
	2002	4,005	83,013	20.73
	2003	4,056	85,172	21.00
	2004	4,104	87,216	21.25
	2005	4,150	89,135	21.48
	2006	4,191	90,828	21.67
	2007	4,229	92,281	21.82
AGGR '98 - '07		1.3%	2.6%	1.3%
	2008	4,263	93,481	21.93
	2009	4,292	94,416	22.00
	2010	4,317	95,266	22.07
	2011	4,337	96,028	22.14
	2012	4,358	96,700	22.19
	2013	4,374	97,280	22.24
	2014	4,390	97,767	22.27
	2015	4,402	98,158	22.30
	2016	4,409	98,452	22.33
	2017	4,412	98,649	22.36
AGGR '08 - '17		0.4%	0.6%	0.2%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1992	236	107,834	456.92
	1993	246	110,020	447.23
	1994	255	117,198	459.60
	1995	270	123,708	458.18
	1996	276	134,660	487.90
	1997	[1]	135,298	486.68
	AGGR '92 - '97	3.3%	4.6%	1.3%
Projected:	1998	284	140,710	495.38
	1999	290	146,198	504.08
	2000	296	151,753	512.98
	2001	302	157,368	521.88
	2002	308	162,876	529.58
	2003	314	168,251	536.58
	2004	320	173,467	542.58
	2005	325	178,497	548.58
	2006	330	183,316	555.08
	2007	335	187,899	561.08
	AGGR '98 - '07	1.9%	3.3%	1.4%
	2008	339	192,033	566.08
	2009	343	195,682	571.08
	2010	346	199,008	575.08
AGGR '08 - '17	2011	349	202,193	579.08
	2012	352	205,225	583.08
	2013	354	208,099	587.08
	2014	357	210,804	591.08
	2015	358	213,334	595.08
	2016	360	215,680	599.08
	2017	361	217,837	603.08
	AGGR '08 - '17	0.7%	1.4%	0.7%

[1] October, November, and December are estimated.

	CY Year	City Accounts Sales MWh	Lighting Sales MWh
Historical	1992		5,135
	1993		4,390
	1994	5,788	6,560
	1995	6,106	7,505
	1996	6,718	4,594
	1997	[1] 6,071	4,729
	AGGR '92 - '97	1.6%	-1.6%
Projected:	1998	6,132	4,800
	1999	6,193	4,867
	2000	6,249	4,930
	2001	6,305	4,990
	2002	6,350	5,039
	2003	6,394	5,090
	2004	6,432	5,136
	2005	6,465	5,182
	2006	6,497	5,223
	2007	6,529	5,265
	AGGR '98 - '07	0.7%	1.0%
	2008	6,555	5,302
	2009	6,582	5,339
	2010	6,601	5,371
	2011	6,621	5,403
	2012	6,634	5,430
	2013	6,647	5,458
	2014	6,661	5,485
	2015	6,667	5,507
	2016	6,674	5,523
	2017	6,681	5,534
	AGGR '08 -'17	0.2%	0.5%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1992	414,668	498,309	116.6	121.8
	1993	459,755	534,133	120.7	120.1
	1994	515,608	538,609	116.8	130.2
	1995	551,025	603,680	136.8	149.6
	1996	593,942	621,276	137.6	188.0
	1997	[1] 580,893	622,034	140.8	158.6
AGGR '92 - '97		7.0%	4.5%	3.8%	5.4%
Projected:	1998	603,474	646,019	145.4	180.2
	1999	626,345	670,502	150.9	187.1
	2000	649,465	695,252	156.4	194.0
	2001	671,832	719,196	161.8	200.7
	2002	693,635	742,536	167.1	207.2
	2003	714,790	765,183	172.2	213.5
	2004	735,181	787,011	177.1	219.6
	2005	754,245	807,419	181.7	225.3
	2006	771,755	826,164	185.9	230.5
	2007	787,584	843,108	189.7	235.2
AGGR '98 - '07		3.0%	3.0%	3.0%	3.0%
	2008	802,397	858,966	193.3	239.7
	2009	815,629	873,131	196.5	243.6
	2010	827,561	885,904	199.3	247.2
	2011	838,858	897,997	202.0	250.5
	2012	849,475	909,363	204.6	253.7
	2013	859,395	919,982	207.0	256.7
	2014	868,046	929,243	209.1	259.3
	2015	875,921	937,674	211.0	261.6
	2016	883,004	945,256	212.7	263.7
	2017	889,272	951,966	214.2	265.6
AGGR '08 - '17		1.1%	1.1%	1.1%	1.1%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	53,176.7	55,192.0	57,229.4	59,200.3	61,121.5
FEBRUARY	44,420.3	46,103.8	47,805.6	49,452.0	51,056.8
MARCH	43,530.0	45,179.7	46,847.4	48,460.8	50,033.5
APRIL	42,088.9	43,684.0	45,296.5	46,856.4	48,377.1
MAY	53,765.7	55,803.3	57,863.2	59,855.9	61,798.4
JUNE	60,246.6	62,529.8	64,838.0	67,071.0	69,247.6
JULY	68,478.0	71,073.2	73,696.8	76,234.8	78,708.8
AUGUST	69,729.1	72,371.7	75,043.2	77,627.6	80,146.8
SEPTEMBER	61,329.1	63,653.4	66,003.1	68,276.1	70,491.9
OCTOBER	51,064.1	52,999.4	54,955.7	56,848.3	58,693.2
NOVEMBER	43,543.3	45,193.6	46,861.8	48,475.7	50,048.8
DECEMBER	54,647.2	56,718.2	58,811.9	60,837.3	62,811.6
TOTAL	646,019.1	670,502.2	695,252.5	719,196.3	742,536.1

FY	630,879.1	664,845.7	689,534.2	713,664.3	737,143.7
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Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	180.2	187.1	194.0	200.7	207.2
FEBRUARY	146.2	151.7	157.3	162.7	168.0
MARCH	109.7	113.9	118.1	122.1	126.1
APRIL	99.1	102.9	106.7	110.3	113.9
MAY	120.7	125.3	129.9	134.4	138.7
JUNE	139.8	145.1	150.4	155.6	160.7
JULY	143.2	148.6	154.1	159.4	164.6
AUGUST	145.4	150.9	156.4	161.8	167.1
SEPTEMBER	133.3	138.3	143.4	148.4	153.2
OCTOBER	117.1	121.6	126.1	130.4	134.6
NOVEMBER	105.2	109.2	113.2	117.1	120.9
DECEMBER	153.2	159.0	164.9	170.5	176.1
TOTAL	1,593.1	1,653.4	1,714.5	1,773.5	1,831.1
FY	1,581.8	1,639.2	1,700.1	1,759.6	1,817.5

Florida
Municipal
Power
Agency

Energy and Demand Forecast

Utility Board, City of Key West

March 10, 1998



Poor Original



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(407) 859-7310 Fax (407) 856-6553
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CELEBRATING 20 YEARS

March 10, 1998

Mr. Larry J. Thompson
General Manager
Utility Board, City of Key West
1001 James St.
Key West, FL 33041-6100

Introduction	For your information, attached is a report for the City Electric System Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

**Utility Board, City of Key West, Florida
City Electric System**

**Customers, Sales, Energy and Demand Forecast
1998 – 2017**

The following is the summary of the analysis and development of the City Electric System customers and sales by rate class and the City Electric System energy and demand forecast for the Utility Board, City of Key West for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 1.6% for the period of 1998-2007 and 0.7% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the City Electric System customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1988 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service

The explanatory variable used to determine general service sales is general service customers. The series is nonstationary and seasonal; therefore dynamic regression is used to project future sales.

Lighting

Lighting is tied to customer growth and it is nonstationary and seasonal. The Box-Jenkins model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1988	18,071	161,800	8.95
	1989	18,520	177,800	9.60
	1990	19,067	188,500	9.89
	1991	19,598	197,400	10.07
	1992	19,999	196,800	9.84
	1993	20,432	213,900	10.47
	1994	20,744	216,900	10.46
	1995	21,170	251,202	11.87
	1996	21,548	256,236	11.89
	1997	[1]	271,205	12.53
AGGR '88 - '97		2.0%	5.9%	3.6%
Projected:	1998	21,898	277,443	12.67
	1999	22,135	283,546	12.81
	2000	22,373	289,501	12.94
	2001	22,593	295,291	13.07
	2002	22,830	300,901	13.18
	2003	23,049	306,318	13.29
	2004	23,248	311,525	13.40
	2005	23,463	316,510	13.49
	2006	23,657	321,257	13.58
	2007	23,847	325,755	13.66
AGGR '98 - '07		1.0%	1.8%	0.8%
	2008	24,017	329,990	13.74
	2009	24,182	333,949	13.81
	2010	24,342	337,623	13.88
	2011	24,462	340,999	13.94
	2012	24,576	344,068	14.00
	2013	25,702	346,821	14.04
	2014	24,805	349,248	14.08
	2015	24,900	351,344	14.11
	2016	24,972	353,101	14.14
	2017	25,019	354,513	14.17
AGGR '08 - '17		0.5%	0.8%	0.3%

[1] October, November, and December are estimated.

General Service				
	CY	Average	Sales	Sales
	Year	Number	MWh	Per
		Of		Customer
		Customers		MWh
Historical	1988	2,470	250,000	101.21
	1989	2,503	270,000	107.87
	1990	2,593	281,000	108.37
	1991	2,660	289,000	108.65
	1992	2,723	281,000	103.20
	1993	2,799	289,000	106.47
	1994	2,853	298,000	110.41
	1995	2,960	315,000	110.55
	1996	3,089	327,241	105.78
	1997	[1]	326,744	109.20
AGGR '88 - '97		2.8%	3.4%	0.6%
Projected:				
	1998	3,165	348,531	110.12
	1999	3,199	355,153	111.01
	2000	3,231	361,546	111.90
	2001	3,262	367,692	112.72
	2002	3,290	373,575	113.54
	2003	3,318	379,179	114.29
	2004	3,343	384,487	115.00
	2005	3,366	389,486	115.71
	2006	3,388	394,159	116.33
	2007	3,407	398,495	116.95
AGGR '98 - '07		0.8%	1.5%	0.7%
	2008	3,427	402,480	117.43
	2009	3,444	406,102	117.91
	2010	3,460	409,351	118.31
	2011	3,476	412,626	118.71
	2012	3,490	415,514	119.07
	2013	3,500	418,008	119.43
	2014	3,510	420,516	119.79
	2015	3,517	422,618	120.15
	2016	3,524	424,731	120.51
	2017	3,532	426,855	120.87
AGGR '08 - '17		0.3%	0.7%	0.3%

[1] October, November, and December are estimated.

	CY Year	Lighting Sales MWh
Historical	1988	7,000
	1989	6,700
	1990	7,100
	1991	6,600
	1992	6,600
	1993	6,900
	1994	8,200
	1995	5,596
	1996	5,430
	1997	[1] 4,020
AGGR '88 - '97		-3.1%
Projected:		
	1998	4,036
	1999	4,052
	2000	4,068
	2001	4,085
	2002	4,101
	2003	4,117
	2004	4,134
	2005	4,150
	2006	4,167
	2007	4,184
AGGR '98 - '07		0.4%
	2008	4,200
	2009	4,213
	2010	4,226
	2011	4,238
	2012	4,251
	2013	4,264
	2014	4,277
	2015	4,289
	2016	4,302
	2017	4,315
AGGR '08 - '17		0.3%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1988	418,800	452,100	79.5	72.8
	1989	454,500	490,700	82.6	68.2
	1990	476,600	514,500	87.5	82.9
	1991	493,000	532,200	90.0	83.1
	1992	484,400	523,000	93.4	78.9
	1993	518,800	560,100	101.0	81.3
	1994	540,100	605,700	104.9	87.0
	1995	584,039	628,765	110.7	89.2
	1996	588,410	631,391	109.9	93.5
	1997	[1] 616,922	670,616	119.7	95.4
AGGR '88 - '97		4.3%	4.5%	4.7%	3.0%
Projected:	1998	630,010	683,561	121.7	97.7
	1999	642,752	696,100	123.9	99.5
	2000	655,115	708,179	126.1	101.3
	2001	667,068	720,433	128.2	103.0
	2002	678,578	732,864	130.4	104.8
	2003	689,614	744,783	132.6	106.5
	2004	700,146	756,158	134.6	108.1
	2005	710,146	766,957	136.5	109.7
	2006	719,584	777,150	138.3	111.1
	2007	728,434	786,708	140.0	112.5
AGGR '98 - '07		1.6%	1.6%	1.6%	1.6%
	2008	736,670	795,604	141.6	113.8
	2009	744,265	803,806	143.1	114.9
	2010	751,200	811,296	144.4	116.0
	2011	757,864	818,493	145.7	117.0
	2012	763,834	824,940	146.8	118.0
	2013	769,092	830,619	147.9	118.8
	2014	774,041	835,964	148.8	119.5
	2015	778,252	840,512	149.6	120.2
	2016	782,134	844,705	150.4	120.8
	2017	785,683	848,538	151.0	121.3
AGGR '08 - '17		0.7%	0.7%	0.7%	0.7%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	46,918.2	47,778.9	48,608.0	49,449.0	50,302.2
FEBRUARY	46,391.0	47,242.0	48,061.8	48,893.4	49,737.0
MARCH	54,928.6	55,936.2	56,906.9	57,891.5	58,890.4
APRIL	53,665.9	54,650.3	55,598.7	56,560.7	57,536.6
MAY	62,103.6	63,242.8	64,340.3	65,453.6	66,582.9
JUNE	65,394.0	66,593.6	67,749.2	68,921.5	70,110.7
JULY	69,175.7	70,444.7	71,667.1	72,907.2	74,165.2
AUGUST	71,134.5	72,439.4	73,696.5	74,971.6	76,265.2
SEPTEMBER	63,562.6	64,728.6	65,851.8	66,991.3	68,147.2
OCTOBER	55,586.6	56,606.3	57,588.6	58,585.1	59,596.0
NOVEMBER	47,584.7	48,457.6	49,298.5	50,151.5	51,016.9
DECEMBER	47,115.2	47,979.5	48,812.1	49,656.7	50,513.5
TOTAL	683,560.6	696,100.1	708,179.5	720,433.1	732,863.9
FY	677,188.0	693,343.2	705,523.7	717,739.1	730,130.9

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	97.7	99.5	101.3	103.0	104.8
FEBRUARY	97.5	99.3	101.1	102.8	104.6
MARCH	101.4	103.2	105.0	106.8	108.7
APRIL	101.7	103.6	105.4	107.2	109.1
MAY	109.6	111.6	113.6	115.5	117.5
JUNE	118.8	121.0	123.1	125.2	127.4
JULY	119.8	122.0	124.1	126.3	128.4
AUGUST	121.7	123.9	126.1	128.2	130.4
SEPTEMBER	116.4	118.5	120.6	122.7	124.8
OCTOBER	102.3	104.2	106.0	107.9	109.7
NOVEMBER	102.9	104.8	106.6	108.5	110.3
DECEMBER	94.4	96.2	97.8	99.5	101.2
TOTAL	1,284.4	1,307.9	1,330.6	1,353.7	1,377.0
FY	1,273.5	1,302.4	1,325.3	1,348.3	1,371.6

Florida
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Energy and Demand Forecast

City of Leesburg

March 10, 1998



Poor Original



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March 10, 1998

Mr. Joseph M. Tardugno
Superintendent of Electric Utilities
City of Leesburg
P.O. Box 490630
Leesburg, FL 34749-0630

Introduction	For your information, attached is a report for the City of Leesburg Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

**City of Leesburg, Florida
City Electric System**

**Customers, Sales, Energy and Demand Forecast
1998 – 2017**

The following is the summary of the analysis and development of the City Electric System customers and sales by rate class and the City Electric System energy and demand forecast for the City of Leesburg for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 2.2% for the period of 1998-2007 and 1.6% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the City Electric System customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1989 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and nonseasonal; therefore the model used is exponential smoothing.

Commerical

The explanatory variable used to determine commercial sales is general service commercial customers. The series is trended and nonseasonal; therefore exponential smoothing is used to project future sales.

Municipal

Municipal sales are trended and nonseasonal. The exponential smoothing model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989	13,213	144,792	10.96
	1990	13,543	153,554	11.34
	1991	13,867	157,283	11.34
	1992	13,900	154,094	11.09
	1993	14,141	160,258	11.33
	1994	14,303	165,301	11.56
	1995	14,542	178,283	12.26
	1996	14,630	179,365	12.26
	1997	[1]	182,161	12.28
AGGR '89 - '97		1.5%	2.9%	1.4%
Projected:				
	1998	15,119	186,715	12.35
	1999	15,397	191,383	12.43
	2000	15,666	195,976	12.51
	2001	15,930	200,556	12.59
	2002	16,183	205,033	12.67
	2003	16,432	209,510	12.75
	2004	16,679	213,987	12.83
	2005	16,922	218,465	12.91
	2006	17,163	222,942	12.99
	2007	17,400	227,419	13.07
AGGR '98 - '07		1.6%	2.2%	0.6%
	2008	17,623	231,740	13.15
	2009	17,832	235,911	13.23
	2010	18,043	240,158	13.31
	2011	18,241	244,240	13.39
	2012	18,422	248,148	13.47
	2013	18,588	251,870	13.55
	2014	18,756	255,648	13.63
	2015	18,908	259,228	13.71
	2016	19,043	262,597	13.79
	2017	19,160	265,749	13.87
AGGR '08 - '17		0.9%	1.5%	0.6%

[1] October, November, and December are estimated.

Commerical				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1989	2,616	183,356	70.09
	1990	2,667	192,976	72.36
	1991	2,632	189,867	72.14
	1992	2,608	185,340	71.07
	1993	2,623	191,287	72.93
	1994	2,593	196,342	75.72
	1995	2,620	200,976	76.72
	1996	2,640	210,090	79.58
	1997	[1]	215,519	80.18
AGGR '89 - '97		0.3%	2.0%	1.7%
Projected:	1998	2,739	220,907	80.65
	1999	2,795	226,650	81.10
	2000	2,849	232,317	81.55
	2001	2,901	237,892	82.00
	2002	2,952	243,364	82.45
	2003	3,000	248,718	82.90
	2004	3,050	254,189	83.35
	2005	3,097	259,527	83.80
	2006	3,142	264,718	84.25
	2007	3,185	269,748	84.70
AGGR '98 - '07		1.7%	2.2%	0.5%
	2008	3,225	274,603	85.15
	2009	3,266	279,546	85.60
	2010	3,303	284,257	86.05
	2011	3,341	288,968	86.50
	2012	3,378	293,679	86.95
	2013	3,414	298,390	87.40
	2014	3,450	303,102	87.85
	2015	3,486	307,813	88.30
	2016	3,521	312,524	88.75
	2017	3,556	317,235	89.20
AGGR '08 - '17		1.1%	1.6%	0.5%

[1] October, November, and December are estimated.

	CY Year		Muni Sales MWh
Historical	1995		12,019
	1996		11,235
	1997	[1]	11,912
AGGR '95 - '97			-0.4%
Projected:			
	1998		12,031
	1999		12,151
	2000		12,272
	2001		12,395
	2002		12,519
	2003		12,644
	2004		12,758
	2005		12,873
	2006		12,989
	2007		13,106
AGGR '98 - '07			1.0%
	2008		13,224
	2009		13,329
	2010		13,436
	2011		13,544
	2012		13,652
	2013		13,761
	2014		13,871
	2015		13,968
	2016		14,066
	2017		14,165
AGGR '08 - '17			0.8%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1989	328,149	349,397	76.7	72.4
	1990	346,530	355,936	79.2	87.0
	1991	347,150	364,373	82.5	67.4
	1992	339,434	354,713	81.4	70.8
	1993	351,545	371,725	81.2	73.4
	1994	361,643	389,151	88.5	75.9
	1995	391,279	413,756	90.1	86.0
	1996	400,690	415,887	88.8	96.9
	1997	[1] 409,592	420,157	95.0	83.0
AGGR '89 - '97		2.8%	2.3%	2.7%	1.7%
Projected:					
	1998	419,653	430,983	96.5	91.4
	1999	430,184	441,799	99.0	93.7
	2000	440,565	452,461	101.4	95.9
	2001	450,843	463,016	103.7	98.2
	2002	460,916	473,361	106.0	100.4
	2003	470,872	483,586	108.3	102.5
	2004	480,935	493,920	110.6	104.7
	2005	490,865	504,118	112.9	106.9
	2006	500,649	514,166	115.2	109.0
	2007	510,272	524,050	117.4	111.1
AGGR '98 - '07		2.2%	2.2%	2.2%	2.2%
	2008	519,567	533,595	119.5	113.1
	2009	528,787	543,064	121.6	115.1
	2010	537,851	552,373	123.7	117.1
	2011	546,752	561,514	125.8	119.0
	2012	555,479	570,477	127.8	120.9
	2013	564,022	579,251	129.8	122.8
	2014	572,621	588,082	131.7	124.7
	2015	581,009	596,696	133.7	126.5
	2016	589,197	605,096	135.5	128.3
	2017	597,148	613,271	137.4	130.0
AGGR '08 - '17		1.6%	1.6%	1.6%	1.6%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	35,535.9	36,427.8	37,306.8	38,177.1	39,030.1
FEBRUARY	29,520.3	30,261.2	30,991.4	31,714.4	32,422.9
MARCH	31,649.3	32,443.6	33,226.5	34,001.6	34,761.3
APRIL	30,405.7	31,168.8	31,920.9	32,665.6	33,395.4
MAY	38,931.2	39,908.3	40,871.3	41,824.8	42,759.2
JUNE	39,109.6	40,091.1	41,058.6	42,016.4	42,955.2
JULY	44,391.3	45,505.3	46,603.4	47,690.6	48,756.1
AUGUST	45,721.4	46,868.8	47,999.8	49,119.6	50,217.0
SEPTEMBER	40,664.2	41,684.8	42,690.7	43,686.6	44,662.6
OCTOBER	33,828.9	34,677.9	35,514.7	36,343.2	37,155.2
NOVEMBER	29,107.8	29,838.3	30,558.3	31,271.2	31,969.8
DECEMBER	32,117.7	32,923.7	33,718.2	34,504.8	35,275.7
TOTAL	430,983.3	441,799.4	452,460.7	463,015.9	473,360.5
FY	427,437.3	439,413.9	450,109.3	460,687.9	471,079.0

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	91.4	93.7	95.9	98.2	100.4
FEBRUARY	76.3	78.2	80.1	82.0	83.8
MARCH	74.2	76.1	77.9	79.7	81.5
APRIL	72.4	74.2	76.0	77.7	79.5
MAY	87.5	89.7	91.9	94.0	96.1
JUNE	89.9	92.2	94.4	96.6	98.7
JULY	93.0	95.3	97.6	99.9	102.1
AUGUST	96.5	99.0	101.4	103.7	106.0
SEPTEMBER	88.1	90.3	92.5	94.7	96.8
OCTOBER	77.2	79.2	81.1	83.0	84.8
NOVEMBER	66.9	68.6	70.3	71.9	73.5
DECEMBER	79.2	81.2	83.1	85.1	87.0
TOTAL	992.7	1,017.6	1,042.1	1,066.4	1,090.3
FY	989.8	1,012.0	1,036.6	1,061.0	1,084.9

Coincident Peak with West Group
MW

	1998	1999	2000	2001	2002
JANUARY	91.3	93.6	95.8	98.1	100.3
FEBRUARY	76.2	78.2	80.0	81.9	83.7
MARCH	73.0	74.8	76.6	78.4	80.1
APRIL	72.3	74.1	75.9	77.7	79.4
MAY	86.9	89.1	91.3	93.4	95.5
JUNE	88.9	91.1	93.3	95.5	97.7
JULY	92.1	94.4	96.6	98.9	101.1
AUGUST	95.3	97.7	100.1	102.4	104.7
SEPTEMBER	86.5	88.7	90.8	93.0	95.0
OCTOBER	77.2	79.2	81.1	83.0	84.8
NOVEMBER	66.2	67.9	69.5	71.2	72.8
DECEMBER	79.2	81.2	83.1	85.1	87.0
TOTAL	985.2	1,009.9	1,034.3	1,058.4	1,082.0
FY	981.4	1,004.3	1,028.8	1,052.9	1,076.7

Florida
Municipal
Power
Agency

Energy and Demand Forecast

Ocala Electric Utility

March 10, 1998



Poor Original



7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
(407) 859-0744



March 10, 1998

Mr. Dean Shaw
Director of Electric Utility
Ocala Electric Utility
P.O. Box 1270
Ocala, FL 34478

Introduction	For your information, attached is a report for the Ocala Electric Utility Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

Poor Original

Ocala Electric Utility, Florida Electric System

Customers, Sales, Energy and Demand Forecast 1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the Ocala Electric Utility for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 2.0% for the period of 1998-2007 and 1.3% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1982 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The explanatory variable used to determine general service demand sales is general service demand customers. The series is trended and seasonal; therefore the model used is exponential smoothing.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. Exponential smoothing model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1987	28,465	338,282	11.88
	1988	29,324	340,390	11.61
	1989	30,205	361,505	11.97
	1990	30,735	365,160	11.88
	1991	31,081	367,773	11.83
	1992	31,490	372,420	11.83
	1993	32,067	389,346	12.14
	1994	32,576	393,804	12.09
	1995	33,056	429,200	12.98
	1996	33,438	429,112	12.83
	1997	[1] 33,760	430,861	12.76
AGGR '87 - '97		1.7%	2.4%	0.7%
Projected:				
	1998	34,059	437,324	12.84
	1999	34,356	443,883	12.92
	2000	34,623	450,098	13.00
	2001	34,885	455,949	13.07
	2002	35,116	461,420	13.14
	2003	35,349	466,958	13.21
	2004	35,576	472,094	13.27
	2005	35,770	476,815	13.33
	2006	35,930	481,106	13.39
	2007	36,092	485,436	13.45
AGGR '98 - '07		0.6%	1.2%	0.5%
	2008	36,219	489,320	13.51
	2009	36,347	493,234	13.57
	2010	36,477	497,180	13.63
	2011	36,571	500,660	13.69
	2012	36,683	503,664	13.73
	2013	36,760	506,183	13.77
	2014	36,837	508,714	13.81
	2015	36,877	510,749	13.85
	2016	36,864	512,040	13.89
	2017	36,865	513,525	13.93
AGGR '08 - '17		0.2%	0.5%	0.3%

[1] October, November, and December are estimated.

General Service Non-Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1987	4,741	86,738	18.30
	1988	4,925	90,589	18.39
	1989	5,072	96,822	19.09
	1990	5,181	100,283	19.36
	1991	5,134	96,338	18.76
	1992	5,105	94,967	18.60
	1993	5,164	99,018	19.17
	1994	5,291	104,774	19.80
	1995	5,431	111,069	20.45
	1996	[1]	116,645	20.97
	1997		120,512	21.31
AGGR '87 - '97		1.8%	3.3%	1.5%
Projected:				
	1998	5,735	123,525	21.54
	1999	5,816	126,489	21.75
	2000	5,898	129,525	21.96
	2001	5,977	132,504	22.17
	2002	6,051	135,419	22.38
	2003	6,121	138,263	22.59
	2004	6,185	141,028	22.80
	2005	6,252	143,849	23.01
	2006	6,313	146,582	23.22
	2007	6,369	149,220	23.43
AGGR '98 - '07		1.2%	2.1%	0.9%
	2008	6,420	151,757	23.64
	2009	6,465	154,185	23.85
	2010	6,504	156,498	24.06
	2011	6,545	158,846	24.27
	2012	6,580	161,069	24.48
	2013	6,608	163,163	24.69
	2014	6,631	165,121	24.90
	2015	6,655	167,103	25.11
	2016	6,675	169,018	25.32
	2017	6,696	170,949	25.53
AGGR '08 - '17		0.5%	1.3%	0.9%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1987	682	320,214	470
	1988	706	334,514	474
	1989	723	364,319	504
	1990	762	380,752	500
	1991	794	403,460	508
	1992	815	424,130	520
	1993	833	438,734	527
	1994	834	451,754	542
	1995	860	478,522	556
	1996	904	501,120	554
	1997	[1]	510,193	558
AGGR '87 - '97		3.0%	4.8%	1.7%
Projected:				
	1998	935	525,498	562
	1999	956	541,263	566
	2000	977	556,960	570
	2001	997	572,555	574
	2002	1,017	588,014	578
	2003	1,037	603,302	582
	2004	1,056	618,988	586
	2005	1,075	634,463	590
	2006	1,094	649,690	594
	2007	1,111	664,633	598
AGGR '98 - '07		1.9%	2.6%	0.7%
	2008	1,129	679,919	602
	2009	1,147	694,877	606
	2010	1,163	709,470	610
	2011	1,179	723,659	614
	2012	1,193	737,409	618
	2013	1,208	751,420	622
	2014	1,222	764,945	626
	2015	1,236	778,714	630
	2016	1,250	792,209	634
	2017	1,263	805,967	638
AGGR '08 - '17		1.3%	1.9%	0.6%

[1] October, November, and December are estimated.

	CY Year	Lighting Sales MWh
Historical	1987	20,796
	1988	22,448
	1989	22,755
	1990	24,049
	1991	24,144
	1992	25,006
	1993	25,141
	1994	25,126
	1995	26,366
	1996	29,001
	1997 [1]	29,509
AGGR '87 - '97		3.8%
Projected:		
	1998	29,882
	1999	30,249
	2000	30,591
	2001	30,912
	2002	31,204
	2003	31,490
	2004	31,773
	2005	32,032
	2006	32,289
	2007	32,525
AGGR '98 - '07		0.9%
	2008	32,730
	2009	32,932
	2010	33,107
	2011	33,255
	2012	33,399
	2013	33,515
	2014	33,626
	2015	33,704
	2016	33,781
	2017	33,859
AGGR '08 - '17		0.4%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1987	766,030	804,800	184.9	155.1
	1988	788,841	846,500	185.8	178.5
	1989	836,499	905,928	196.9	179.7
	1990	871,218	915,752	205.2	199.4
	1991	892,803	952,022	206.5	164.4
	1992	917,832	977,889	215.1	195.6
	1993	953,340	1016,103	227.7	184.2
	1994	975,459	1029,952	220.7	196.9
	1995	1,045,157	1104,562	240.2	222.6
	1996	1,075,878	1121,456	248.3	239.3
	1997	[1] 1,091,074	1132,202	244.6	212.6
AGGR '87 - '97		3.8%	3.5%	2.8%	3.2%
Projected:					
	1998	1,116,228	1158,645	249.1	236.4
	1999	1,141,885	1185,277	254.8	241.8
	2000	1,167,174	1211,527	260.5	247.2
	2001	1,191,920	1237,213	266.0	252.4
	2002	1,216,058	1262,268	271.4	257.5
	2003	1,240,013	1287,133	276.7	262.6
	2004	1,263,884	1311,911	282.1	267.6
	2005	1,287,159	1336,071	287.3	272.6
	2006	1,309,667	1359,434	292.3	277.3
	2007	1,331,814	1382,423	297.2	282.0
AGGR '98 - '07		2.0%	2.0%	2.0%	2.0%
	2008	1,353,726	1405,168	302.1	286.7
	2009	1,375,229	1427,487	306.9	291.2
	2010	1,396,255	1449,313	311.6	295.7
	2011	1,416,420	1470,244	316.1	299.9
	2012	1,435,541	1490,092	320.4	304.0
	2013	1,454,280	1509,543	324.6	307.9
	2014	1,472,406	1528,357	328.6	311.8
	2015	1,490,269	1546,900	332.6	315.6
	2016	1,507,048	1564,316	336.3	319.1
	2017	1,524,300	1582,223	340.2	322.8
AGGR '08 - '17		1.3%	1.3%	1.3%	1.3%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	90,861.4	92,949.9	95,008.4	97,022.7	98,987.6
FEBRUARY	81,530.4	83,404.4	85,251.5	87,058.9	88,822.0
MARCH	85,154.1	87,111.4	89,040.6	90,928.4	92,769.8
APRIL	82,495.2	84,391.4	86,260.3	88,089.2	89,873.1
MAY	100,559.7	102,871.1	105,149.3	107,378.6	109,553.2
JUNE	105,715.2	108,145.1	110,540.2	112,883.7	115,169.8
JULY	115,298.3	117,948.5	120,560.6	123,116.7	125,610.0
AUGUST	118,886.1	121,618.8	124,312.2	126,947.8	129,518.7
SEPTEMBER	109,171.8	111,681.1	114,154.5	116,574.7	118,935.5
OCTOBER	93,839.5	95,996.4	98,122.4	100,202.7	102,232.0
NOVEMBER	82,915.1	84,820.9	86,699.4	88,537.5	90,330.5
DECEMBER	92,218.3	94,338.0	96,427.3	98,471.6	100,465.8
TOTAL	1,158,645.0	1,185,277.0	1,211,526.8	1,237,212.5	1,262,268.0
FY	1,142,001.9	1,179,094.6	1,205,433.0	1,231,249.7	1,256,451.5

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	236.4	241.8	247.2	252.4	257.5
FEBRUARY	213.2	218.1	223.0	227.7	232.3
MARCH	188.7	193.0	197.3	201.5	205.5
APRIL	194.2	198.7	203.1	207.4	211.6
MAY	228.1	233.4	238.6	243.6	248.5
JUNE	243.5	249.1	254.6	260.0	265.2
JULY	245.2	250.8	256.4	261.8	267.1
AUGUST	249.1	254.8	260.5	266.0	271.4
SEPTEMBER	235.1	240.5	245.8	251.0	256.1
OCTOBER	218.2	223.2	228.1	233.0	237.7
NOVEMBER	179.7	183.9	187.9	191.9	195.8
DECEMBER	213.4	218.3	223.2	227.9	232.5
TOTAL	2,644.8	2,705.6	2,765.5	2,824.1	2,881.3
FY	2,618.5	2,691.5	2,751.6	2,810.6	2,868.1

Florida
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Energy and Demand Forecast

City of Starke

March 10, 1998



Poor Original



7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744



March 10, 1998

Mr. William M. Weldon.
Utility Director
City of Starke
P.O. Drawer "C"
Starke, FL 32091

Introduction	For your information, attached is a report for the City of Starke Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

L O R I D A M U N I C I P A L P O W E R A G E N C Y

City of Starke, Florida Electric System

Customers, Sales, Energy and Demand Forecast 1998 – 2017

The following are the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Starke for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 2.5% for the period of 1998-2007 and 1.2% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency (FMPA) uses ForecastPro as the application to project the electric system customers and sales by rate class. However, because FMPA only has two years of historical data, a time series / time trend analysis is used to project future electric sales. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. A description of the variables and considerations used in developing the forecast are described on the following pages.

Methodology

The period of 1996 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are taken into consideration. Future sales projections are calculated for each class. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly demand peaks are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer
Historical	1996	1,953	22,249	11.39
	1997	[1] 1,961	22,940	11.70
AGGR '96 - '97		0.4%	3.1%	2.7%
Projected:	1998	1,976	23,651	11.97
	1999	1,990	24,361	12.24
	2000	2,004	25,067	12.51
	2001	2,018	25,769	12.77
	2002	2,030	26,465	13.04
	2003	2,042	27,153	13.30
	2004	2,054	27,832	13.55
	2005	2,065	28,472	13.79
	2006	2,075	29,098	14.02
	2007	2,086	29,680	14.23
AGGR '98 - '07		0.6%	2.6%	1.9%
	2008	2,094	30,244	14.44
	2009	2,102	30,758	14.63
	2010	2,110	31,250	14.81
	2011	2,117	31,688	14.97
	2012	2,124	32,100	15.11
	2013	2,130	32,485	15.25
	2014	2,134	32,842	15.39
	2015	2,139	33,171	15.51
	2016	2,143	33,436	15.60
	2017	2,147	33,670	15.68
AGGR '08 - '17		0.3%	1.2%	0.9%

[1] October, November, and December are estimated.

General Service

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer
Historical	1996	589	40,185	68.23
	1997	[1] 593	41,333	69.70
AGGR '96 - '97		0.7%	2.9%	2.2%
Projected:				
	1998	598	42,573	71.21
	1999	603	43,808	72.69
	2000	607	45,034	74.17
	2001	611	46,250	75.65
	2002	615	47,453	77.13
	2003	619	48,639	78.61
	2004	623	49,758	79.93
	2005	627	50,852	81.13
	2006	631	51,920	82.33
	2007	634	52,907	83.48
AGGR '98 - '07		0.7%	2.4%	1.8%
	2008	637	53,859	84.56
	2009	640	54,775	85.64
	2010	642	55,596	86.62
	2011	644	56,375	87.50
	2012	646	57,107	88.38
	2013	648	57,793	89.16
	2014	649	58,371	89.94
	2015	650	58,896	90.62
	2016	651	59,367	91.20
	2017	652	59,783	91.68
AGGR '08 - '17		0.3%	1.2%	0.9%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1992	53,779	61,112	12.5	11.6
	1993	54,515	63,209	13.2	10.1
	1994	56,000	63,769	12.5	11.0
	1995	60,022	68,234	13.9	12.4
	1996	62,434	69,954	13.4	13.4
	1997	[1] 64,273	69,294	13.9	11.9
	AGGR '92- '97	3.8%	2.5%	2.1%	0.5%
Projected:					
	1998	66,224	71,390	14.1	12.6
	1999	68,168	73,485	14.6	13.0
	2000	70,101	75,569	15.0	13.4
	2001	72,019	77,637	15.4	13.7
	2002	73,917	79,683	15.8	14.1
	2003	75,792	81,704	16.2	14.5
	2004	77,589	83,641	16.6	14.8
	2005	79,324	85,511	16.9	15.1
	2006	81,018	87,338	17.3	15.5
	2007	82,587	89,029	17.6	15.8
	AGGR '98 - '07	2.5%	2.5%	2.5%	2.5%
	2008	84,103	90,663	18.0	16.0
	2009	85,533	92,204	18.3	16.3
	2010	86,847	93,621	18.5	16.6
	2011	88,062	94,931	18.8	16.8
	2012	89,207	96,165	19.0	17.0
	2013	90,278	97,319	19.3	17.2
	2014	91,213	98,328	19.5	17.4
	2015	92,067	99,248	19.7	17.6
	2016	92,803	100,042	19.8	17.7
	2017	93,453	100,742	19.9	17.8
	AGGR '08 - '17	1.2%	1.2%	1.2%	1.2%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	5,553.2	5,716.2	5,878.3	6,039.2	6,198.3
FEBRUARY	4,915.8	5,060.1	5,203.6	5,346.0	5,486.9
MARCH	5,225.1	5,378.5	5,531.0	5,682.3	5,832.1
APRIL	4,866.9	5,009.7	5,151.8	5,292.8	5,432.3
MAY	6,267.2	6,451.2	6,634.1	6,815.6	6,995.2
JUNE	6,485.8	6,676.2	6,865.5	7,053.3	7,239.2
JULY	7,340.8	7,556.3	7,770.6	7,983.2	8,193.6
AUGUST	7,555.8	7,777.6	7,998.1	8,217.0	8,433.5
SEPTEMBER	6,796.8	6,996.3	7,194.7	7,391.6	7,586.4
OCTOBER	5,719.3	5,887.2	6,054.2	6,219.8	6,383.7
NOVEMBER	5,344.3	5,501.2	5,657.2	5,812.0	5,965.2
DECEMBER	5,318.6	5,474.8	5,630.0	5,784.1	5,936.5
TOTAL	71,389.6	73,485.4	75,569.3	77,636.7	79,683.0

FY	71,132.3	73,004.5	75,091.1	77,162.2	79,213.4
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Peak Demands
MW

	1998	1999	2000	2001	2002
JANUARY	12.6	13.0	13.4	13.7	14.1
FEBRUARY	11.0	11.4	11.7	12.0	12.3
MARCH	10.1	10.4	10.7	10.9	11.2
APRIL	9.8	10.1	10.4	10.6	10.9
MAY	12.4	12.7	13.1	13.5	13.8
JUNE	12.9	13.2	13.6	14.0	14.3
JULY	13.2	13.6	14.0	14.4	14.8
AUGUST	14.1	14.6	15.0	15.4	15.8
SEPTEMBER	12.8	13.2	13.6	13.9	14.3
OCTOBER	11.1	11.4	11.8	12.1	12.4
NOVEMBER	10.4	10.7	11.0	11.3	11.6
DECEMBER	11.2	11.5	11.8	12.2	12.5
TOTAL	141.6	145.8	149.9	154.0	158.1
FY	142.1	144.8	149.0	153.1	157.2

Florida
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Energy and Demand Forecast

City of Vero Beach

March 10, 1998



Poor Original



7201 Lake Ellenor Drive
Orlando, Florida 32809-5769
(407) 859-7310 Fax (407) 856-6553
1 800 859-0744



March 10, 1998

Mr. Rex Taylor
City Manager/Utilities Director
City of Vero Beach
P.O. Box 3191
Vero Beach, FL 32961-1389

Introduction	For your information, attached is a report for the City of Vero Beach Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L Lee

Dianne L. Lee

DLL
Attachments

F L O R I D A M U N I C I P A L P O W E R A G E N C Y

City of Vero Beach, Florida Electric System

Customers, Sales, Energy and Demand Forecast 1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Vero Beach for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (NCP - MW) are projected to increase at compound annual growth rates of approximately 2.3% for the period of 1998-2007 and 0.9% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1986 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is nonstationary and seasonal; therefore the model used is exponential smoothing.

General Service Non-Demand Class Model

The explanatory variable used to determine general service non-demand sales is general service non-demand customers. The series is trended and seasonal; therefore a dynamic regression model is used to project future sales.

General Service Demand Class Model

The general service demand class has only one customer. Its sales are nonstationary and seasonal; therefore the model used is exponential smoothing.

Lighting

Lighting is tied to customer growth and it is trended and seasonal. A dynamic regression model is used to project the future lighting sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986	18,900	221,117	11.70
	1987	19,442	227,528	11.70
	1988	20,272	238,835	11.78
	1989	20,720	253,439	12.23
	1990	21,128	266,072	12.59
	1991	21,452	283,620	13.22
	1992	21,607	262,540	12.15
	1993	21,864	268,675	12.29
	1994	22,130	279,587	12.63
	1995	22,409	297,736	13.29
	1996	22,742	301,358	13.25
	1997	[1] 22,918	294,802	12.86
	AGGR '86 - '97	1.8%	2.6%	0.9%
Projected:	1998	23,322	303,646	13.02
	1999	23,743	312,452	13.16
	2000	24,150	321,200	13.30
	2001	24,562	329,873	13.43
	2002	24,959	338,450	13.56
	2003	25,353	346,572	13.67
	2004	25,722	354,197	13.77
	2005	26,085	361,281	13.85
	2006	26,421	367,784	13.92
	2007	26,729	373,668	13.98
	AGGR '98 - '07	1.5%	2.3%	0.8%
	2008	27,014	379,273	14.04
	2009	27,275	384,583	14.10
	2010	27,525	389,198	14.14
	2011	27,741	393,090	14.17
	2012	27,932	396,628	14.20
	2013	28,068	399,405	14.23
	2014	28,177	401,801	14.26
	2015	28,258	403,810	14.29
	2016	28,340	405,829	14.32
	2017	28,394	407,452	14.35
	AGGR '08 - '17	0.6%	0.8%	0.2%

[1] October, November, and December are estimated.

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986	3,395	182,356	53.71
	1987	3,619	193,300	53.41
	1988	3,769	198,124	52.57
	1989	3,873	206,599	53.34
	1990	3,971	211,996	53.39
	1991	3,909	212,588	54.38
	1992	3,941	210,596	53.44
	1993	3,981	220,670	55.43
	1994	4,102	231,793	56.51
	1995	4,163	241,605	58.04
	1996	4,253	252,917	59.47
	1997	[1]	4,324	286,758
AGGR '86 - '97		2.2%	4.2%	1.9%
Projected:				
	1998	4,412	295,361	66.95
	1999	4,501	303,926	67.52
	2000	4,589	312,436	68.09
	2001	4,673	320,872	68.66
	2002	4,755	329,215	69.23
	2003	4,835	337,116	69.72
	2004	4,912	344,532	70.14
	2005	4,985	351,423	70.50
	2006	5,049	357,749	70.86
	2007	5,109	363,830	71.22
AGGR '98 - '07		1.6%	2.3%	0.7%
	2008	5,164	369,652	71.58
	2009	5,215	375,196	71.94
	2010	5,262	380,449	72.30
	2011	5,304	385,395	72.66
	2012	5,341	390,020	73.02
	2013	5,372	393,920	73.33
	2014	5,397	397,465	73.64
	2015	5,418	400,645	73.95
	2016	5,433	403,449	74.26
	2017	5,443	405,870	74.57
AGGR '08 - '17		0.6%	1.0%	0.5%

[1] October, November, and December are estimated.

General Service Demand

	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1986	1	24,635	24,635
	1987	1	21,496	21,496
	1988	1	25,311	25,311
	1989	1	29,238	29,238
	1990	1	17,454	17,454
	1991	1	8,222	8,222
	1992	1	8,679	8,679
	1993	1	10,339	10,339
	1994	1	10,615	10,615
	1995	1	11,940	11,940
	1996	1	11,881	11,881
	1997	[1]	13,398	13,398
AGGR '86 - '97		0.0%	-5.4%	-5.4%
Projected:				
	1998	1	13,532	13,532
	1999	1	13,667	13,667
	2000	1	13,790	13,790
	2001	1	13,914	13,914
	2002	1	14,040	14,040
	2003	1	14,152	14,152
	2004	1	14,265	14,265
	2005	1	14,365	14,365
	2006	1	14,451	14,451
	2007	1	14,523	14,523
AGGR '98 - '07		0.0%	0.8%	0.8%
	2008	1	14,582	14,582
	2009	1	14,640	14,640
	2010	1	14,684	14,684
	2011	1	14,728	14,728
	2012	1	14,757	14,757
	2013	1	14,787	14,787
	2014	1	14,816	14,816
	2015	1	14,831	14,831
	2016	1	14,846	14,846
	2017	1	14,861	14,861
AGGR '08 - '17		0.0%	0.2%	0.2%

[1] October, November, and December are estimated.

	CY Year	Street Lights Sales MWh	City Accounts Sales MWh
Historical	1986	2,000	
	1987	2,056	
	1988	2,341	
	1989	2,535	
	1990	2,674	
	1991	2,789	
	1992	2,784	314
	1993	2,451	315
	1994	2,027	310
	1995	2,121	309
	1996	2,178	311
	1997 [1]	2,190	336
AGGR '86 - '97		0.8%	1.3%
Projected:	1998	2,208	338
	1999	2,225	340
	2000	2,241	342
	2001	2,254	344
	2002	2,265	346
	2003	2,277	348
	2004	2,286	349
	2005	2,295	351
	2006	2,302	353
	2007	2,309	354
AGGR '98 - '07		0.5%	0.5%
	2008	2,316	356
	2009	2,320	357
	2010	2,325	359
	2011	2,330	360
	2012	2,334	361
	2013	2,339	362
	2014	2,344	362
	2015	2,346	363
	2016	2,348	364
	2017	2,351	365
AGGR '08 - '17		0.2%	0.3%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1990	498,195	517,629	109.0	138.0
	1991	507,219	514,062	107.0	125.0
	1992	484,913	512,815	110.0	122.0
	1993	502,450	528,150	112.0	125.0
	1994	524,333	544,412	111.0	113.0
	1995	553,710	583,397	119.0	156.0
	1996	568,645	590,800	118.0	174.0
	1997	[1] 597,484	629,145	130.0	155.0
	AGGR '90 - '97	2.6%	2.2%	2.0%	1.3%
Projected:	1998	615,084	647,684	134.1	169.7
	1999	632,611	666,139	137.9	174.5
	2000	650,010	684,460	141.7	179.3
	2001	667,258	702,622	145.4	184.1
	2002	684,315	720,584	149.2	188.8
	2003	700,464	737,589	152.7	193.2
	2004	715,630	753,558	156.0	197.4
	2005	729,715	768,390	159.1	201.3
	2006	742,638	781,998	161.9	204.9
	2007	754,685	794,684	164.5	208.2
	AGGR '98 - '07	2.3%	2.3%	2.3%	2.3%
	2008	766,178	806,785	167.0	211.4
	2009	777,097	818,283	169.4	214.4
	2010	787,015	828,727	171.5	217.1
	2011	795,902	838,085	173.5	219.6
	2012	804,100	846,717	175.3	221.8
	2013	810,812	853,785	176.7	223.7
	2014	816,789	860,078	178.0	225.3
	2015	821,995	865,561	179.2	226.8
	2016	826,837	870,659	180.2	228.1
	2017	830,899	874,936	181.1	229.2
	AGGR '08 - '17	0.9%	0.9%	0.9%	0.9%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	52,163.8	53,650.2	55,125.8	56,588.5	58,035.1
FEBRUARY	47,456.9	48,809.1	50,151.6	51,482.3	52,798.4
MARCH	47,142.7	48,486.0	49,819.5	51,141.5	52,448.8
APRIL	47,489.8	48,843.0	50,186.4	51,518.0	52,835.0
MAY	55,364.9	56,942.5	58,508.6	60,061.1	61,596.5
JUNE	57,637.8	59,280.2	60,910.6	62,526.8	64,125.2
JULY	62,631.5	64,416.1	66,187.8	67,944.1	69,681.0
AUGUST	64,085.2	65,911.2	67,724.1	69,521.1	71,298.3
SEPTEMBER	60,403.6	62,124.7	63,833.4	65,527.2	67,202.3
OCTOBER	55,229.1	56,802.8	58,365.1	59,913.8	61,445.5
NOVEMBER	48,286.6	49,662.5	51,028.4	52,382.4	53,721.5
DECEMBER	49,791.8	51,210.5	52,619.0	54,015.3	55,396.1
TOTAL	647,683.8	666,138.9	684,460.2	702,622.2	720,583.8
FY	633,456.3	661,770.5	680,123.6	698,323.2	716,332.3

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	169.7	174.5	179.3	184.1	188.8
FEBRUARY	140.1	144.1	148.0	152.0	155.9
MARCH	119.9	123.3	126.7	130.0	133.4
APRIL	109.5	112.7	115.8	118.8	121.9
MAY	121.4	124.8	128.2	131.6	135.0
JUNE	131.8	135.6	139.3	143.0	146.7
JULY	130.5	134.2	137.9	141.5	145.1
AUGUST	134.1	137.9	141.7	145.4	149.2
SEPTEMBER	131.9	135.6	139.4	143.1	146.7
OCTOBER	117.8	121.2	124.5	127.8	131.1
NOVEMBER	107.8	110.9	113.9	117.0	120.0
DECEMBER	145.1	149.3	153.4	157.4	161.5
TOTAL	1,559.6	1,604.0	1,648.1	1,691.9	1,735.1
FY	1,537.8	1,593.4	1,637.6	1,681.5	1,724.8

Florida
Municipal
Power
Agency

Energy and Demand Forecast

City of Lake Worth Utilities

March 10, 1998



Poor Original



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1 800 859-0744



March 10, 1998

Mr. Harvey Wildschuetz
Utilities Director
City of Lake Worth Utilities
1900 2nd Ave. North
Lake Worth, FL 33461 - 4298

Introduction	For your information, attached is a report for the City of Lake Worth Utilities Customers, Sales, Energy and Demand Forecast for the period 1998 - 2017.
Purpose of Forecast	Florida Municipal Power Agency forecasts the Energy and Demand needs for each All-Requirements Project member in order to determine additional capacity commitments for the project.
Method	Each All-Requirements Project participant is evaluated individually. Economics and demographics for each city are used as determinants for the projection of electric sales. The projection for the total electric sales and peak demands for the All-Requirements Project is the aggregate of the electric sales and peak demands of each participant.
Requested Action	• If you require graphs or additional data, please contact me.

Sincerely,

Dianne L. Lee

Dianne L. Lee

DLL
Attachments

City of Lake Worth Utilities, Florida Electric System

Customers, Sales, Energy and Demand Forecast 1998 – 2017

The following is the summary of the analysis and development of the electric system customers and sales by rate class and the electric system energy and demand forecast for the City of Lake Worth Utilities for 1998 through 2017. Based on our analysis, the expected Total Sales to Customers (MWh), Net Energy for Load (MWh) and Non-Coincident Peak Demands (MW) are projected to increase at compound annual growth rates of approximately 0.9% for the period of 1998-2007 and 0.5% for the period of 2008-2017.

Summary of Methodology and Assumptions

Florida Municipal Power Agency uses ForecastPro as the application to project the electric system customers and sales by rate class. The forecast attempts to correlate historical electric sales and customer growth with historical economic, demographic, and weather activity. The results are examined for reasonableness and compared to time series / time trend analysis. Finally, adjustments are made accordingly. A description of the variables and methodologies used in developing the models are described on the following pages.

Methodology

The period of 1991 – 1997 is used to forecast future electric energy requirements and customer growth. Historical energy costs, migration, and cooling and heating degree days are found to exhibit significant explanatory tendencies and are used as variables in the models. For each class, models are created and applied. The aggregate sales of all classes are compared to the average annual historical system loss factor, and then applied to the forecast of the Total Sales to Customers in order to project the Net Energy for Load.

The monthly Net Energy for Load projections are developed by determining from historical data an average monthly factor for each month and applying the factor with the projected Net Energy for Load for the year. By determining an average peak factor from historical data and applying the factor to the Net Energy for Load, monthly NCP's are projected.

Assumptions

The following section describes the key general assumptions used in developing the sales for customers.

Price of Electricity

The wholesale price of electricity is used as a variable in the projection of residential sales. The price of electricity is projected to remain constant over the forecast period because the total per-unit power costs are projected to increase slightly.

Weather

Heating Degree Days (HDD) and Cooling Degree Days (CDD) are used as explanatory variables in the residential sales class model. Data is obtained from the Climatological Data Summaries from the National Climatic Data Center.

Other Considerations

Gross Domestic Product

The Gross Domestic Product (GDP) is the primary measure of overall U.S. economic growth. In the past few years, the U.S. economy has remained strong. The GDP has been increasing between 2.5% - 4.0% each year. (2.5% for 1993, 3.9% for 1994, 2.6% for 1995, and for 3.8% 1996). In 1997, the GDP increased 4.6%. It is predicted to remain strong for the next few years and then after 2000 to slow to 2.2%.

Inflation

The 1990's produced relatively low inflation rates, averaging 2.2%. This trend is expected to continue through 2000. Then the inflation rates may increase slightly.

Descriptions of Results

Residential Class Model

The explanatory variables used to determine the residential sales are residential customers, HDD, CDD, migration and energy costs. The series is trended and seasonal; therefore the model used is dynamic regression.

General Service Class Model

The explanatory variable used to determine general service sales is general service customers. The series is trended and seasonal; therefore dynamic regression model is used to project future sales.

Lighting

Lighting is tied to customer growth. The series is nonstationary and nonseasonal; therefore, Box-Jenkins is use to project future sales.

Below are charts showing the historical and projected customers, sales (MWh), and sales per customer for each class.

Residential				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1991	20,206	181,181	8.97
	1992	20,092	176,559	8.79
	1993	20,219	177,671	8.79
	1994	20,516	192,700	9.39
	1995	20,758	202,872	9.77
	1996	20,877	205,954	9.87
	1997	[1]	206,979	9.86
AGGR '91 - '97		0.6%	2.2%	1.6%
Projected:	1998	21,120	209,877	9.94
	1999	21,247	212,605	10.01
	2000	21,353	215,156	10.08
	2001	21,460	217,523	10.14
	2002	21,567	219,698	10.19
	2003	21,675	221,676	10.23
	2004	21,783	223,671	10.27
	2005	21,870	225,460	10.31
	2006	21,958	227,264	10.35
	2007	22,046	228,855	10.38
AGGR '98 - '07		0.5%	1.0%	0.5%
	2008	22,134	230,457	10.41
	2009	22,222	232,070	10.44
	2010	22,289	233,462	10.47
	2011	22,356	234,863	10.51
	2012	22,423	236,037	10.53
	2013	22,468	237,217	10.56
	2014	22,513	238,166	10.58
	2015	22,558	239,119	10.60
	2016	22,603	239,836	10.61
	2017	22,648	240,556	10.62
AGGR '08 - '17		0.3%	0.5%	0.2%

[1] October, November, and December are estimated.

General Service				
	CY Year	Average Number Of Customers	Sales MWh	Sales Per Customer MWh
Historical	1991	2,971	154,597	52.04
	1992	2,962	148,596	50.17
	1993	2,958	146,777	49.62
	1994	2,985	153,770	51.51
	1995	3,010	148,310	49.27
	1996	3,052	143,248	46.94
	1997	[1] 3,071	146,422	47.68
AGGR '91 - '97		0.6%	-0.9%	-1.4%
Projected:				
	1998	3,102	148,196	47.77
	1999	3,131	149,847	47.86
	2000	3,159	151,437	47.94
	2001	3,185	152,963	48.03
	2002	3,211	154,420	48.09
	2003	3,233	155,739	48.17
	2004	3,256	156,983	48.21
	2005	3,276	158,149	48.28
	2006	3,296	159,235	48.31
	2007	3,316	160,329	48.35
AGGR '98 - '07		0.7%	0.9%	0.1%
	2008	3,336	161,339	48.36
	2009	3,353	162,357	48.42
	2010	3,370	163,218	48.43
	2011	3,387	164,086	48.45
	2012	3,404	164,958	48.46
	2013	3,418	165,740	48.49
	2014	3,432	166,526	48.52
	2015	3,446	167,316	48.55
	2016	3,459	168,111	48.60
	2017	3,473	168,909	48.63
AGGR '08 - '17		0.4%	0.5%	0.1%

[1] October, November, and December are estimated.

	CY Year	Lighting Sales MWh
Historical	1991	4,200
	1992	4,181
	1993	4,261
	1994	4,353
	1995	2,430
	1996	4,505
	1997 [1]	4,576
AGGR '91 - '97		1.4%
Projected:	1998	4,651
	1999	4,723
	2000	4,793
	2001	4,860
	2002	4,925
	2003	4,987
	2004	5,046
	2005	5,101
	2006	5,154
	2007	5,205
AGGR '98 - '07		1.3%
	2008	5,253
	2009	5,297
	2010	5,339
	2011	5,378
	2012	5,414
	2013	5,448
	2014	5,477
	2015	5,503
	2016	5,523
	2017	5,544
AGGR '08 - '17		0.6%

[1] October, November, and December are estimated.

	CY Year	Total Sales To Customers MWh	Net Energy For Load MWh	FY Summer NCP MW	FY Winter NCP MW
Historical	1991	323,978	344,865	65.8	60.8
	1992	318,569	337,396	66.4	61.6
	1993	321,202	347,318	69.5	61.8
	1994	345,911	364,509	69.1	59.8
	1995	353,612	377,104	73.7	76.3
	1996	353,715	375,805	73.7	82.0
	1997	[1] 357,985	377,288	74.0	74.0
AGGR '91 - '97 Projected:		1.7%	2.0%	3.0%	3.3%
	1998	362,724	382,311	74.9	76.5
	1999	367,175	387,003	75.9	77.4
	2000	371,387	391,442	76.7	78.3
	2001	375,346	395,615	77.5	79.1
	2002	379,044	399,512	78.3	79.9
	2003	382,401	403,051	79.0	80.6
	2004	385,700	406,527	79.7	81.3
	2005	388,710	409,701	80.3	81.9
	2006	391,652	412,801	80.9	82.6
	2007	394,388	415,685	81.5	83.1
AGGR '98 - '07		0.9%	0.9%	0.9%	0.9%
	2008	397,049	418,490	82.0	83.7
	2009	399,724	421,309	82.6	84.3
	2010	402,020	423,729	83.1	84.7
	2011	404,326	426,160	83.5	85.2
	2012	406,410	428,356	84.0	85.7
	2013	408,406	430,460	84.4	86.1
	2014	410,169	432,319	84.7	86.5
	2015	411,938	434,183	85.1	86.8
	2016	413,470	435,797	85.4	87.2
	2017	415,009	437,419	85.7	87.5
AGGR '08 - '17		0.5%	0.5%	0.5%	0.5%

[1] October, November, and December are estimated.

Net Energy For Load
MWh

	1998	1999	2000	2001	2002
JANUARY	29,107.5	29,464.8	29,802.8	30,120.5	30,417.2
FEBRUARY	25,399.6	25,711.3	26,006.3	26,283.5	26,542.4
MARCH	28,313.1	28,660.6	28,989.3	29,298.4	29,587.0
APRIL	27,902.1	28,244.6	28,568.6	28,873.1	29,157.5
MAY	33,763.2	34,177.5	34,569.6	34,938.1	35,282.3
JUNE	35,209.5	35,641.6	36,050.5	36,434.7	36,793.7
JULY	39,560.9	40,046.4	40,505.8	40,937.5	41,340.8
AUGUST	39,869.6	40,358.9	40,821.8	41,257.0	41,663.4
SEPTEMBER	36,884.8	37,337.5	37,765.8	38,168.4	38,544.4
OCTOBER	32,574.7	32,974.4	33,352.7	33,708.2	34,040.3
NOVEMBER	26,431.9	26,756.2	27,063.2	27,351.7	27,621.1
DECEMBER	27,293.9	27,628.9	27,945.8	28,243.7	28,522.0
TOTAL	382,310.7	387,002.7	391,442.1	395,614.8	399,512.1
FY	379,939.3	385,943.6	390,440.0	394,672.9	398,632.3

Peak Demands (NCP)
MW

	1998	1999	2000	2001	2002
JANUARY	76.5	77.4	78.3	79.1	79.9
FEBRUARY	66.2	67.0	67.8	68.5	69.2
MARCH	61.9	62.6	63.4	64.0	64.7
APRIL	59.3	60.0	60.7	61.4	62.0
MAY	66.9	67.8	68.5	69.3	69.9
JUNE	70.2	71.0	71.9	72.6	73.3
JULY	73.3	74.2	75.1	75.9	76.6
AUGUST	74.9	75.9	76.7	77.5	78.3
SEPTEMBER	72.7	73.6	74.5	75.3	76.0
OCTOBER	60.5	61.2	61.9	62.6	63.2
NOVEMBER	51.7	52.3	53.0	53.5	54.0
DECEMBER	65.1	65.9	66.6	67.3	68.0
TOTAL	799.3	809.1	818.4	827.1	835.2
FY	782.0	806.9	816.3	825.1	833.4

**SITE CERTIFICATION
APPLICATION**

Volume 2

Kissimmee Utility Authority
Florida Municipal Power Agency
Cane Island – Units 1 - 3



BLACK & VEATCH^{LLP}

SITE CERTIFICATION APPLICATION

Volume 2

Kissimmee Utility Authority
Florida Municipal Power Agency



Cane Island
Units 1 - 3



BLACK & VEATCH_{LLP}

Cane Island Power Park

Site Certification Application

VOLUME 2

Manual Number KUA/FMPA- 64

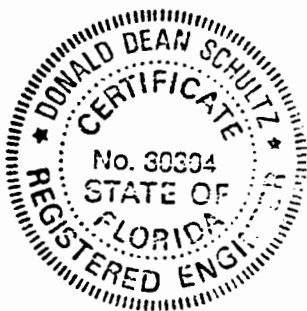
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SITE CERTIFICATION APPLICATION

CANE ISLAND POWER PARK UNITS 1-3

VOLUME 2



D D Schultz 8/6/98
Donald D. Schultz Date
Florida No. 30304
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11401 Lamar
Overland Park, Kansas 66211

Poor Original

Submitted by:

Kissimmee Utility Authority
and the
Florida Municipal Power Agency

August 1998





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Preface

This Site Certification Application (SCA) is being submitted by the Kissimmee Utility Authority (KUA) and the Florida Municipal Power Agency (FMPA) for certification of Cane Island Power Park Units 1-3 and a new 230 kV transmission line. Units 1 and 2 are existing units at the site; Unit 3 is proposed. Units 1 and 2 are operating under permits issued by the individual governing agencies.

This document is intended to serve as the Site Certification Application for Units 1-3 at the Cane Island Power Park, and the Cane Island-Intercession City Transmission Line, an associated facility, including all state and local permits for the construction and operation of the facilities.

Summary of the major section headings:

1. Need for Power.
2. Site and Vicinity Characterization.
3. Plant and Directly Associated Facilities.
4. Effects of Site Preparation, and Plant and Associated Facility Construction.
5. Effects of Plant Operation.
6. Transmission Lines and Other Linear Facilities.
7. Economic and Social Effects of Plant Construction and Operation.
8. Site and Design Alternatives.
9. Coordination.
10. Appendices.

The pertinent applicant information follows the Preface.

Section 1.0 which contains the Need For Power consists of three volumes labeled Volumes 1A through 1C. Volume 1A includes information common to both applicants such as the characterization of Unit 3. Volume 1B includes information specific to KUA's need for Unit 3, and Volume 1C includes information specific to FMPA's need for Unit 3.

Project Information

The Cane Island Power Park is located at 6075 Old Tampa Highway near Intercession City, in Osceola County, Florida, and includes two operating units at present. Unit 1 is a nominal 40 MW simple cycle combustion turbine generating unit that began commercial



operation in January 1995. Unit 2 is a nominal 120 MW combined cycle combustion turbine generating unit that began commercial operation in May 1995. Cane Island 3 will be a combined cycle combustion turbine generating unit proposed for installation adjacent to Unit 2, scheduled for commercial operation in June 2001. Unit 3 will produce 250 MW (nominal) of electricity for distribution by KUA and FMFA.

Units 1 and 2 fire natural gas as the primary fuel, as will Unit 3. No. 2 fuel oil is stored onsite as backup fuel. All existing equipment was, and all new equipment will be, installed with modern pollution control devices. All three units will be jointly owned by KUA and FMFA, and operated by KUA.

Project Impacts

Air

Units 1 and 2 are currently operating under Florida Department of Environmental Protection Permit AC49-205703. Unit 3, as proposed, classifies the addition as a major modification to an existing major stationary source under the New Source Review - Prevention of Significant Deterioration (NSR-PSD) program, as it will emit more than 100 tons per year (tpy) of at least one regulated pollutant and is located in an attainment area for all criteria pollutants.

A comprehensive analysis of the Unit 3 potential to emit demonstrates that it will emit significant amounts of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM/PM_{10}) with respect to the PSD program. Sulfur dioxide (SO_2) emissions will be less than the PSD significant emission rate because natural gas will be fired as the primary fuel. A full PSD analysis was performed for those pollutants emitted above the PSD thresholds, including:

- Best Available Control Technology (BACT) Analysis,
- Ambient Air Quality Impact Analysis, and
- Additional Impact Analysis.

The technology proposed to control emissions from Unit 3 include dry low NO_x burners for the control of NO_x , the use of clean fuel and advanced combustion control technology to reduce CO, PM/PM_{10} , SO_2 , and VOC emissions.

An air dispersion modeling analysis was performed to determine the Unit 3 maximum NO_x , CO, and PM/PM_{10} air quality impacts. The maximum air quality impacts at all modeled



receptors were less than the applicable PSD significant impact levels, and consequently below the less stringent de minimis ambient background monitoring levels. As such, a multi-source modeling of nearby existing sources for PSD increment consumption and ambient air quality standards (AAQS) comparison was not required.

The Unit 3 predicted pollutant impact concentrations are well below the threshold levels above which the air quality may be significantly affected. Moreover, an additional impact assessment determined that the Unit 3 visual impacts, PSD Class I regional haze impacts, air quality impacts on vegetation and soils, and air quality impacts due to growth, are inconsequential as the predicted levels are well below threshold levels.

Water Use

The Unit 2 cooling tower requires a maximum of approximately 1 million gallons of treated sewage effluent per day from the City of Kissimmee (Kissimmee) municipal effluent pipeline. The Unit 3 cooling tower will require a maximum of approximately 2 million gallons per day. A new pumping station will be required on the property near the entrance to provide sufficient pressure for effluent delivery to both cooling towers. At full load operation, approximately 680,000 gallons of cooling tower blowdown from Units 2 and 3 will be returned to the effluent pipeline per day.

Under natural gas operation, the units will require 221,000 gallons of ground water per day from the deep Floridan Aquifer for service water supply. Under fuel oil operation, the units will require 776,000 gallons per day. The majority of this amount is required for power cycle demineralized makeup water and evaporative cooler makeup water. The additional water required during oil firing is used for NO_x injection water to the combustion turbines. Modeling results indicate that ground water quality and quantity will be unaffected by this withdrawal.

In addition to the normal service water demand, KUA and FMPA also request the use of 3 million gallons of ground water per day for emergency use as cooling tower makeup in the event of pipeline catastrophe or supply disruptions regarding the Kissimmee effluent pipeline. KUA and FMPA request this ground water allocation on a temporary use (3 day event) basis to continue operations until effluent supply is restored.

**Land**

The Cane Island Power Park property was approved for industrial use in January 1993 by the Osceola County Board of Commissioners prior to construction of Units 1 and 2. KUA was issued a 30 year Conditional Use Permit (CU/SDP 92-86) authorizing power plant construction and operation on the property. Use of the property in an industrial capacity is consistent with the current and future elements of the Osceola County Comprehensive Plan.

A biophysical assessment of the property concluded that the property is not inhabited by any federally listed protected species. However, gopher tortoises inhabit the geographic feature known as Cane Island and other upland areas onsite. The gopher tortoise is categorized as a species of Special Concern by the Florida Committee of Rare and Endangered Plants and Animals. KUA applied for and was issued a Gopher Tortoise Incidental Take Permit (Permit OSC-6) by the Florida Game and Fresh Water Fish Commission in December 1994 for Cane Island Power Park development. The permit is still valid, and authorizes incidental takings of tortoises or their burrows in association with power-related development.

There are no archaeological, historic, or cultural sites present on the property or in the immediate vicinity considered eligible for listing on the *National Register of Historic Places*. In July 1992, the Florida Division of Historical Resources (FDHR) stated that the onsite survey findings were insignificant, and that the project was unlikely to affect any properties currently listed or eligible for the *National Register*; the FDHR approved the property for development.

Natural gas is delivered to the site by an underground 20 inch pipeline. No new natural gas delivery or metering facilities will be required for the addition of Unit 3.

Potential impacts from fuel oil deliveries have been minimized through the use of regulatory based standards. The unloading area is curbed and has a common drain to an oil/water separator. The fuel oil storage tanks have automatic shutoffs when full, and lined secondary containment.

***Wastewater and Solid Waste***

Process wastewaters will be treated and discharged at three locations. Drainage from oil containment areas and other potential oil contaminated areas are and will be routed through oil/water separators and an onsite percolation pond prior to groundwater discharge. Expansion of the percolation pond will be required with the addition of Unit 3. Cooling tower blowdown, neutralization basin effluent, and boiler blowdown are currently and will continue to be collected and returned to the Kissimmee treated effluent pipeline for additional reuse or ultimate disposal at the Imperial percolation pond site. Sanitary wastewaters are currently and will continue to be directed to the existing onsite septic tank/tile field system for treatment and disposal. Uncontaminated storm waters are currently and will continue to be directed to onsite storm water detention ponds. All wastewaters will be treated to meet all applicable water quality standards. No significant impacts will result from the disposal of these wastewaters based on regulatory standards. A licensed contractor will be responsible for treatment and disposal of boiler and combustion turbine cleaning wastewaters.

Trash and other solid waste will be disposed of at an approved facility by a licensed contractor.

Socioeconomic

Operation of Units 1 and 2 have had only positive socioeconomic impacts in Osceola County, through tax revenues and employment. Construction and operation of Unit 3 will incrementally increase these benefits. During the peak period of Cane Island 3 construction, approximately 240 jobs will be created by the project. The net direct employment effect will be the creation of 2 additional full-time operations positions, in addition to the existing 28 positions, for the operating life of the units. The addition of Unit 3 at the Cane Island Power Park will not significantly impact the local or regional services or infrastructure based on the Units 1 and 2 experience.

Need for Power

KUA and FMPPA have jointly filed a Need for Power petition for the addition of Unit 3 to the Cane Island Power Park, in accordance with the Florida Electrical Power Plant Siting Act. Unit 3 is a proposed combined cycle unit with a nominal rating of approximately 250 MW. The determination of need for the proposed Unit 3 is being sought under



FS 403.519. In accordance with FS 403.5175(1), a determination of need is not required for Units 1 and 2.

The basic power generation cycle for Unit 3 will consist of an F-class combustion turbine, a heat recovery steam generator (HRSG), a condensing steam turbine, and a mechanical draft cooling tower. Duct burners will be installed in the HRSG inlet to allow the steam turbine to be fully loaded at higher ambient temperatures. The HRSG will be provided with a bypass stack and diverter damper to accommodate operation in simple cycle mode.

Natural gas will be the primary fuel for the combustion turbine and the only fuel for the HRSG duct burners. Low sulfur (0.05 percent), No. 2 fuel oil is currently planned to be the emergency backup fuel for the combustion turbine. The existing onsite fuel oil storage capacity of 1 million gallons will be increased by 1 million gallons when a third storage tank is installed to provide backup fuel oil for Unit 3.

KUA was the project manager for licensing and construction of Units 1 and 2. KUA is also the operator for Units 1 and 2. Likewise, KUA will be the project manager for licensing and construction of Unit 3 and will be the operator.

Schedule

The Cane Island Power Park certification and major milestone schedule follows.

Need for Power Submittal	July 1998
Need for Power Approval	November 1998
Site Certification Application Submittal	August 1998
Site Certification Issued	September 1999
Start of Construction	September 1999
Construction Complete	April 2001
Commercial Operation	June 2001

Applicant Information

Applicants' Official Names

Kissimmee Utility Authority (KUA)

Florida Municipal Power Agency (FMPA)



Address

KUA: Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, FL 34741

FMPA: Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, FL 32809

Address of Official Headquarters

KUA: Same as address

FMPA: Same as address

Business Entity

KUA: Municipality

FMPA: Joint Action Agency

Names, Owners, etc.

Not applicable

Name and Title of Chief Executive Officers

KUA: James C. Welsh, President and General Manager

FMPA: Claude L'Engle, General Manager



***Name, Address, and Telephone Number of Official Representative
Responsible for Obtaining Certification***

Mr. A. K. Sharma
Director of Power Supply, KUA
1701 West Carroll Street
Kissimmee, FL 34741
(407) 933-7777

Site Location

Osceola County

Nearest Incorporated City

Kissimmee

Latitude and Longitude

Lat: 28 degrees, 16 minutes, 50 seconds
Long: 81 degrees, 32 minutes, 00 seconds

UTM Coordinates

3128000 North
447500 East

Section, Township, and Range

Sections 29 and 32, Township 25S, Range 28E

Location of Any Directly Associated Transmission Facilities

Osceola County



Nameplate Generating Capacity

Unit 1: 42 MW Simple Cycle Combustion Turbine Unit

Unit 2: 120 MW Combined Cycle Combustion Turbine Unit (80 MW CT, 40 MW ST)

Capacity of Proposed Additions

Unit 3: Nominal 250 MW Combined Cycle Combustion Turbine Unit (150 MW CT, 100 MW ST)

Remarks:

Site Certification Request: 412 MW Generating Capacity
Cane Island--Intercession City Transmission Line



Acronyms and Abbreviations

AAQS	Ambient Air Quality Standards
AQCS	Air Quality Control System
BACT	Best Available Control Technology
bgs	Below ground surface
BOD	Biochemical oxygen demand
BTU	British thermal unit
Btu/h	British thermal units per hour
cfs	Cubic feet per second
CO	Carbon monoxide
COD	Chemical oxygen demand
dBA	Decibels (A-weighted)
dBC	Decibels (C-weighted)
EPA	US Environmental Protection Agency
EPRI	Electric Power Research Institute
F	Degrees Fahrenheit
FAC	Florida Administrative Code
FCREPA	Florida Committee on Rare and Endangered Plants & Animals
FDA	Florida Department of Agriculture
FDEP	Florida Department of Environmental Protection
FGFWFC	Florida Game and Fresh Water Fish Commission
FMPA	Florida Municipal Power Agency
FNAI	Florida Natural Areas Inventory
FPC	Florida Power Corporation
FS	Florida Statutes
GEP	Good Engineering Practice
gpd	Gallons per day
gpm	Gallons per minute
gr/dscf	Grains per dry standard cubic foot
GWH	Gigawatt hours
HgA	Mercury, absolute



HRSG	Heat recovery steam generator
ISCST	Industrial Source Complex Short-Term
kg	Kilogram(s)
km	Kilometer(s)
KUA	Kissimmee Utility Authority
LAER	Lowest achievable emission rate
lb/h	Pounds per hour
lb/MBtu	Pounds per million British thermal units
m	Meters
MBtu	Million British thermal units
mgd	Million gallons per day
mg/l	Milligrams per liter
mg/m ³	Milligrams per cubic meter
mm	Millimeters
msl	Mean sea level
MW	Megawatt(s)
MWh	Megawatt hour
NEMA	National Electrical Manufacturers Association
NGVD	National Geodetic Vertical Datum
NRCS	Natural Resources Conservation Service
NML	Noise Monitoring Location
NO _x	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NWS	National Weather Service
ORD	Open Rural District
pCi/l	Picocuries per liter
PM ₁₀	Particulate matter less than 10 microns
ppm	Parts per million
ppmvd	Parts per million by volume dry
PSC	Florida Public Service Commission
PSD	Prevention of Significant Deterioration



psig	Pounds per square inch, gauge
PTPLU-2	Screening level point source dispersion model
SACTI	Seasonal/annual cooling tower impact
SCA	Site Certification Application
scfm	Standard cubic feet per minute
SCR	Selective catalytic reduction
SFWMD	South Florida Water Management District
SIP	State Implementation Plan
SO ₂	Sulfur dioxide
STP	Sewage treatment plant
TDS	Total dissolved solids
TOC	Total organic carbon
tpy	Tons per year
TRS	Total reduced sulfur
TSP	Total suspended particulate
TSS	Total suspended solids
ug/m ³	Micrograms per cubic meter
UNAMAP	User's Network for the Applied Modeling of Air Pollution
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile organic compounds



1.0 Need For Power and the Proposed Facilities

A Joint Petition to Determine Need for Electrical Power Plant was submitted to the Florida Public Service Commission (PSC) by the Kissimmee Utility Authority and the Florida Municipal Power Agency on July 1, 1998.

The Need for Power application includes three volumes (Volumes 1A, 1B, and 1C) attached as exhibits to the Joint Petition for Need. Volume 1A includes information common to both applicants such as the characterization of Unit 3. Volume 1B includes information specific to KUA's need for Unit 3, and Volume 1C includes information specific to FMPA's need for Unit 3.

The Cane Island Power Park currently includes two existing units (Units 1 and 2) and related support facilities. Unit 1 is a nominal 40 MW simple cycle combustion turbine unit. Unit 2 is a nominal 120 MW combined cycle combustion turbine unit. Unit 3 is proposed as a nominal 250 MW combined cycle combustion turbine unit. All units will fire natural gas as the primary fuel. The electricity generated is stepped up in voltage for distribution to the power grid. Units 1 and 2 began commercial operation in January and May of 1995, respectively. Unit 3 is scheduled for commercial operation in June 2001.

2.0 Site & Vicinity Characterization



2.0 Site and Vicinity Characterization

2.1 Site and Associated Facilities Delineation

This section provides information concerning the physical, biological, and sociological characteristics of the existing site and project area that might be affected by construction and operation of Cane Island Power Park Unit 3 (Unit 3).

2.1.1 Site Location

The Cane Island Power Park (Power Park) is located in rural northwest Osceola County. Figure 2.1-1 shows the general location of the Power Park which is 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The Power Park address is 6075 Old Tampa Highway, Intercession City.

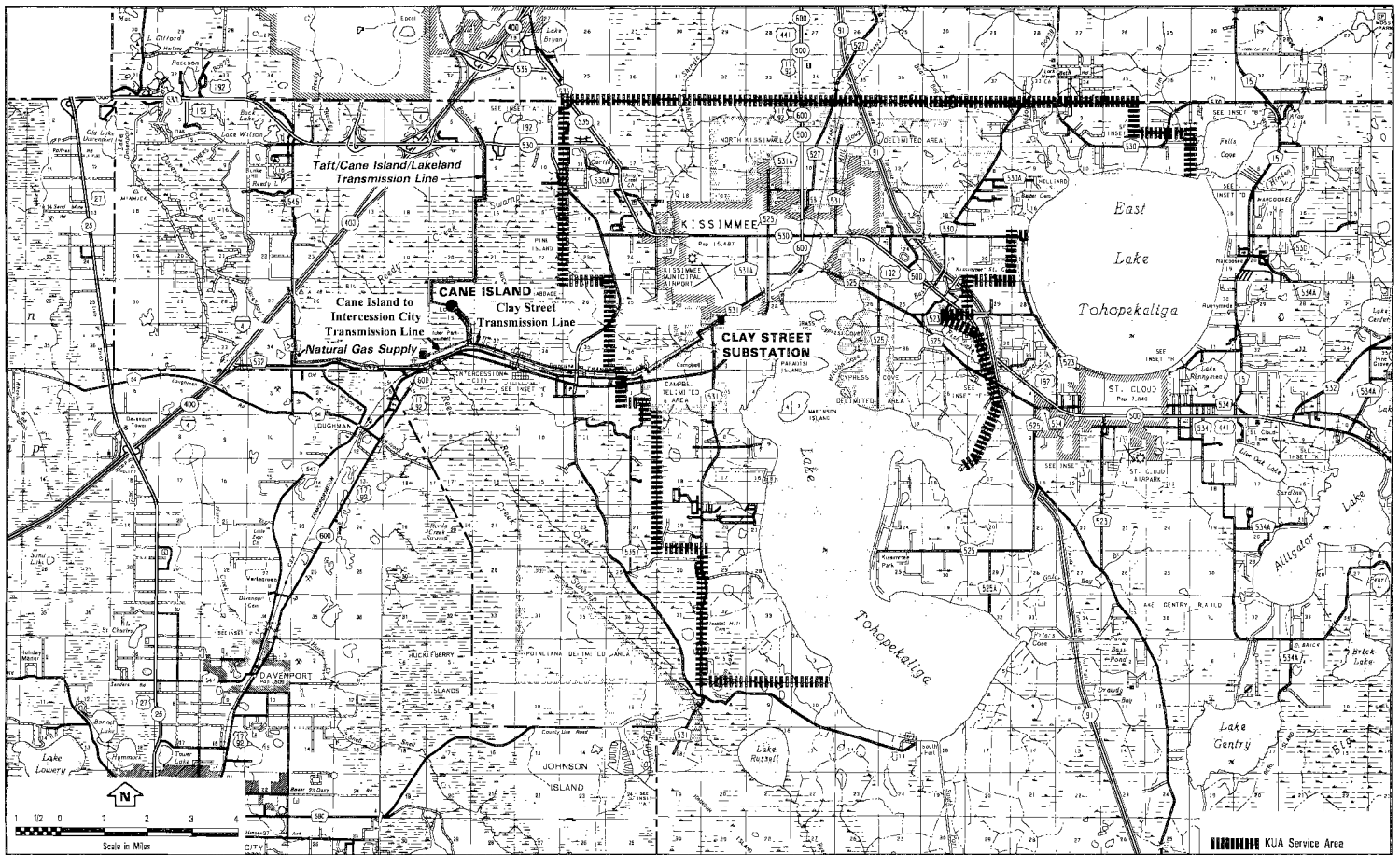
The Power Park occupies 1,027 acres in Section 29 and a portion of Section 32, Township 25 South, Range 28 East, in Osceola County. Figure 2.1-2 shows the Power Park boundaries and identifies adjacent property owners. Table 2.1-1 provides information on the adjacent property owners. Unit 3 will be a new unit located adjacent to and north of Unit 2 as shown on Figure 2.1-3 Site Arrangement. Approximately 164 acres have been permitted for power development and support facilities at the Power Park.

2.1.2 Site Modification

Proposed site modifications will consist of construction and operation of Unit 3, a 250 MW (nominal) combined cycle combustion turbine generating unit. The Unit 3 power block area will occupy approximately 5 acres north of the existing Units 1 and 2. New major equipment associated with Unit 3 will include a combustion turbine generator, heat recovery steam generator, a steam generator, cooling tower, water and wastewater treatment facilities, fuel oil and water storage tanks, and a storm water detention pond. Similar facilities exist onsite associated with the operation of Units 1 and 2. A new 230 kV transmission line will be an associated facility. Section 6 presents information concerning this transmission line and proposed corridor.

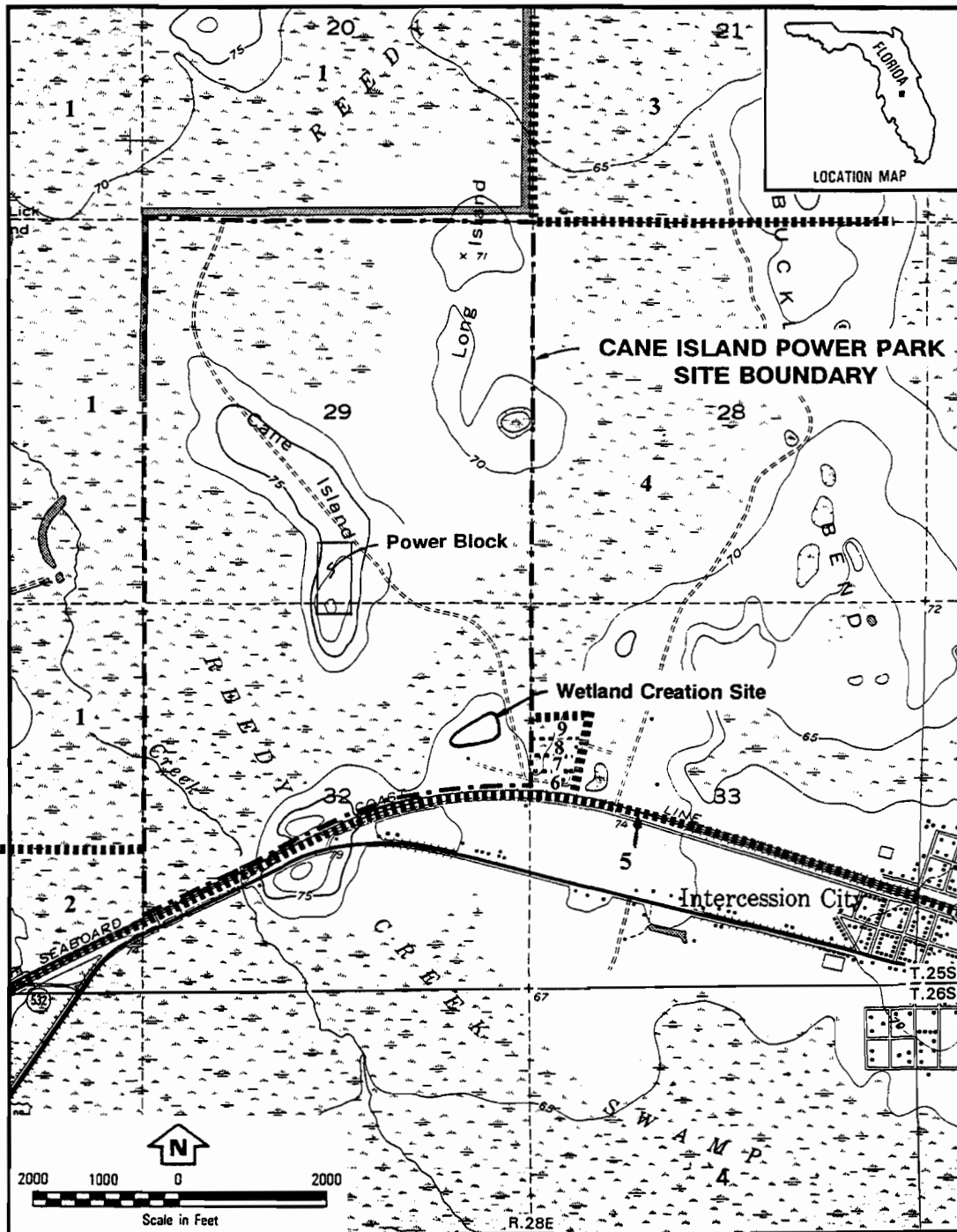
IMAGE QUALITY

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PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



REGIONAL SITE LOCATION

Figure 2.1-1



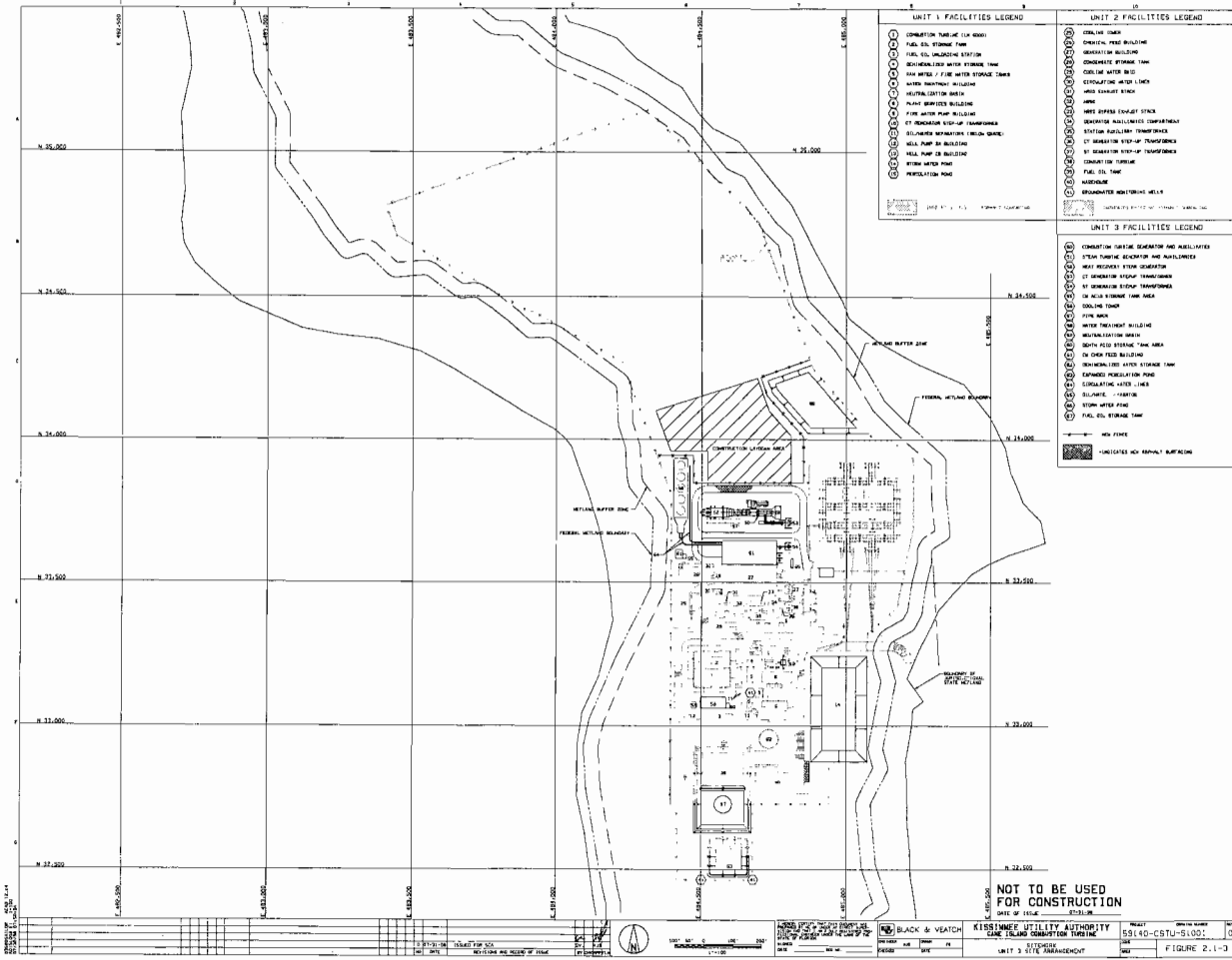
Base Map Source: USGS, Note: Table 2.1-1 lists the property owners adjacent to Cane Island Power Park.
Intercession City, FL quad.

PROJECT LOCATION

Figure 2.1-2



Table 2.1-1 Adjacent Property Owners Cane Island Power Park	
Parcel No.	Property Owner
1	Disney's Wide World of Sports Inc./Reedy Creek Improvement District Attn: Tax Department P.O. Box 691177 Orlando, FL 32869-1177
2	Florida Power Corp Attn: Prop Tax Dept BT8A Saint Petersburg, FL 33733-4042
3	Ecosystems Mitigation Bank 1031 W. Morse Blvd. Ste. 375 Winter Park, FL 32789
4	SMC Properties, Inc. 6610 W. Linebaugh Ave. Tampa, FL 33625
5	CSX Transportation 5656 Adamo Dr. Tampa, FL 33619-3240
6	Myrtle Lee Rowe P.O. Box 36 Intercession City, FL 33848-0036
7	David M. and Janice J. Haley 1386 Montzen Rd. Davenport, FL 33837-9327
8	Karen L. Potocnak 231 Old Bay Ln. Kissimmee, FL 34743
9	Kimberly Ann McClellan Reed 1356 Montzen Rd. Davenport, FL 33837-9327
Note: Figure 2.1-2 illustrates the adjacent property ownership.	



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2.1.3 Existing and Proposed Uses

The Power Park includes 1,024 acres of Reedy Creek Swamp uplands and wetlands. KUA was issued Conditional Use/Site Development Plan Permit 92-86 by the Osceola County Board of Commissioners in January 1993 for use of the site in an industrial capacity as an electrical power plant facility.

Through negotiations with the South Florida Water Management District (SFWMD) and the Florida Game and Fresh Water Fish Commission (FGFWFC), 860 acres of Power Park uplands and wetlands were dedicated as a conservation area during the permitting of Units 1 and 2. The remaining 164 acres are designated for power generation and support uses. Approximately 47 of these acres are on the central portion of the geographic feature known as Cane Island where Units 1 and 2 are located and where Unit 3 will be located. Utility corridors comprise the remaining development acreage.

2.1.4 Flood Zones

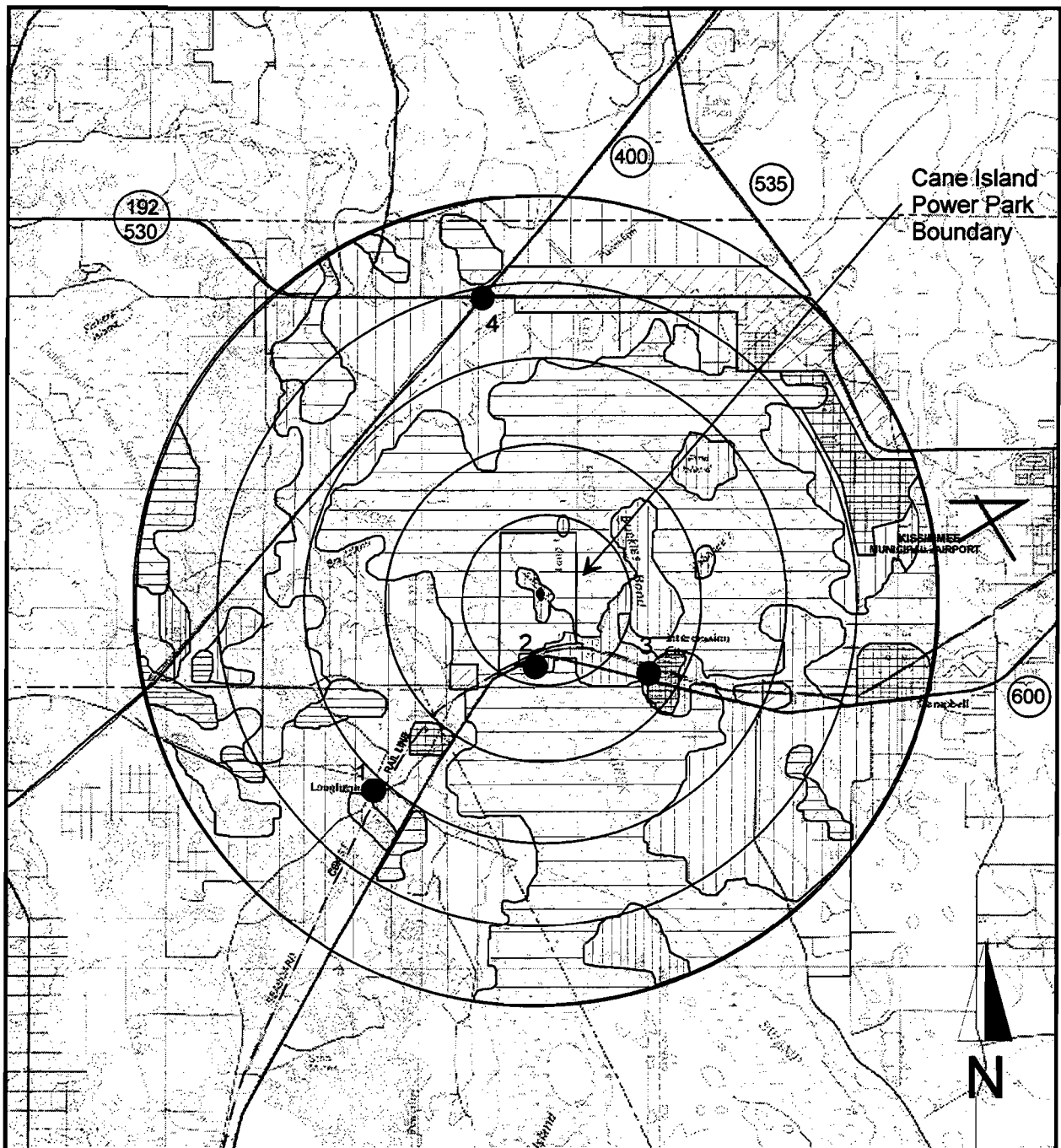
The SFWMD required during the permitting of Units 1 and 2 that the site access road be located 2 feet above the 10 year 24 hour storm elevation, which is 69 feet NGVD. The access road center line is at 71 feet NGVD. Roads in the power block area on Cane Island were required to be located 4.5 feet above the 10 year, 24 hour storm elevation, which is 76.25 feet NGVD. Road crown elevations on Cane Island are and will continue to be at 80.75 feet NGVD.

The SFWMD also required during the permitting of Units 1 and 2 that the finished floor elevations in the power block area be located at least 3.8 feet above the 100 year, 72 hour storm elevation. The finished floor elevations are and will be at 81.75 feet NGVD.

2.2 Socio-Political Environment

2.2.1 Governmental Jurisdictions

The Power Park is located within an unincorporated area of Osceola County. The southern boundary of Orange County is 4.5 miles north of the power block (site). The northeast boundary of Polk County is 2 miles southwest of the site. The western city limit of Kissimmee is 5 miles east of the site. The incorporated town of Campbell is 4.5 miles southeast of the site. The unincorporated town of Intercession City is 2 miles southeast of the site. The unincorporated town of Loughman is 3.5 miles southwest of the site. Figure 2.2-1 indicates jurisdictional boundaries and designated areas within a 5 mile radius of the site. Figure 2.2-2 shows the area within a 1 mile radius of the site.



Cane Island Power Park Vegetation and Land Use Use Within a 5 Mile Radius

Points of Interest Legend

- 1 - Rodgers House,
Old Wilson Lake, Loughman
- 2 - Fletcher Park Monument / South OBT Bridge
- 3 - Intercession City Playground
- 4 - Homely Cow Dip Area

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Figure 2.2-1



2.2.2 Zoning and Land Use Plans

The Power Park was zoned agricultural prior to purchase by KUA. Upon purchase, KUA applied for a Conditional Use/Site Development Plan Permit from Osceola County for development of the site in an industrial capacity as a power plant. Power generation is a conditional use within an agricultural zone. KUA was granted Conditional Use/Site Development Plan Permit 92-86 by the Osceola County Board of Commissioners in January 1993 for development of the site as an electrical power plant facility. The permit expires on January 11, 2023. KUA has contacted the Osceola County Planning and Zoning Department Pre-Development Committee for the procedures and approvals required for construction of Unit 3. Essentially, a Building Permit must be secured. This is a 3-step process. First, a Conditional Use/Site Development Plan (CU/SDP) application is submitted to the Zoning Department for review. Upon approval, construction plans are submitted to the County Engineer for review. Upon approval of the construction plans, a Building Permit is issued and construction may commence. The CU/SDP application for Unit 3 is included in Section 10.6 of this document.

The Osceola County Comprehensive Plan indicates that the Power Park is in compliance with the current and future elements of the Comprehensive Plan.

2.2.3 Demography and Ongoing Land Use

The population of Osceola County has grown rapidly since 1970, due in large part to the construction and operation of Disney World. The county population in 1970 was approximately 25,000. The population nearly doubled by 1980 to approximately 49,000. By 1990, the population had increased 66 percent from 1980 to approximately 82,000. The 1997 estimated population is 107,700, a 31 percent increase since 1990. These population increases can be attributed largely to the jobs created by the expansion of Disney World, other new tourist attractions, and development of related support services.

The latest population counts for cities and towns within 5 miles of the Power Park are as follows:

Kissimmee	30,050
Campbell	3,884
Intercession City	750
Loughman	1,214



Development of the proposed World Expo Center (Expo Center), to be located near the intersection of US-192 and ST-535 in Kissimmee, would have a significant influence on the socioeconomics of the Osceola/Orange County area. The Expo Center is anticipated to provide approximately 30,000 related jobs and have a significant electrical demand. Section 5.0, Volume 1B of the Need For Power application provides further details concerning the Expo Center.

2.2.4 Easements, Title, Agency Works

There are no easements or titles to be obtained for the Power Park or Unit 3. The entire site is owned by KUA.

Potential requirements associated with the new offsite overhead transmission line from the Power Park to FPC's Intercession City Plant are addressed in Section 6.

2.2.5 Regional Scenic, Cultural, and Natural Landmarks

There are more than thirty recorded scenic, cultural, or natural landmarks within 5 miles of the Power Park. Figure 2.2-2 shows the significant cultural landmarks with 1 mile of the Power Park. The *National Registry of Natural Landmarks* does not list any sites for Osceola County.

The cultural resources within 5 miles of the Power Park include the FDEP/Disney Conservation Easement north and west of the site and the playground/park in Intercession City. Another cultural resource is the Fletcher Park Monument on the US-17/92 bridge over Reedy Creek. Two historical bridges, the South OBT Bridge and the Disney 5000 13 Bridge, are present in the Intercession City area.

Homely Cow Dip, a historical structure, is located near the junction of US-192 and I-4 highways. Other historic structures that occur within the 5 mile radius include the following: (1) Lake Wilson Boy Scout Camp, Oak Island Road, Kissimmee; (2) Homestead Cemetery, Kinney Harmon Road, Davenport; and (3) Rodgers House, Old Wilson Lake, Loughman. Several of these resources are identified on Figure 2.2-1.

Two historic residences occur in Campbell and twenty historic structures, mainly residences, are present near Intercession City. These structures are as follows:

4480 Old Tampa Highway, Campbell.

4489 Old Tampa Highway, Campbell.



5552 Old Tampa Highway, Intercession City.
5618 Old Tampa Highway, Intercession City.
531 Tallahassee Blvd, Intercession City.
5958 Tomoka Road, Intercession City.
4936 South Orange Blossom Trail, Intercession City.
4955 South Orange Blossom Trail, Intercession City.
5508 South Orange Blossom Trail, Intercession City.
5505 South Orange Blossom Trail, Intercession City.
5510 South Orange Blossom Trail, Intercession City.
4955 South Orange Blossom Trail, Intercession City.
5515 South Orange Blossom Trail (Rainbow Trailer Park Office), Intercession City.
5540 South Orange Blossom Trail, Intercession City.
5544 South Orange Blossom Trail, Intercession City.
5548 South Orange Blossom Trail, Intercession City.
5535 South Orange Blossom Trail, Intercession City.
5551 South Orange Blossom Trail, Intercession City.
5581 South Orange Blossom Trail, Intercession City.
5599 South Orange Blossom Trail, Intercession City.
5605 South Orange Blossom Trail, Intercession City.
5637 South Orange Blossom Trail, Intercession City.

The Power Park conservation easement is not a Save Our Rivers (SOR) property. However, approximately 500 to 600 acres south of Highway 92, and approximately 1,000 acres north of the Power Park are SOR properties.

2.2.6 Archeological and Historic Sites

In January 1992, in association with construction and operation of Units 1 and 2, the Florida Division of Historical Resources (FDHR) was requested to conduct an assessment of known or potential cultural resources onsite and in the project area. The FDHR indicated in February 1992 that there were no known archeological or historical resources onsite or within the project area, listed on the NRHP, but recommended that a systematic survey of the site and project area be conducted prior to any project land disturbing activities.



A Phase I cultural resources investigation of the Power Park and associated corridors was conducted by Janus Research/Piper Archaeology of St. Petersburg, FL, in May 1992. The investigation discovered thirteen previously unrecorded sites: seven prehistoric; six historic. It was the consultant's opinion that none of the sites were eligible for listing on the *National Register of Historic Places*. All of the historic sites were outside of direct impact areas. The Phase I report was submitted to the FDHR for review in June 1992.

On July 23, 1992, the FDHR issued a clearance letter concurring with the consultant's opinion and approving the project for construction.

2.2.7 Socioeconomics and Public Services

This section describes the current socioeconomic situation in the area that would be affected by Unit 3 development.

2.2.7.1 Social and Economic Characteristics. The Power Park is located in extreme northwestern Osceola County, only a few miles from the borders of Polk, Lake, and Orange counties. The proximity of these political boundaries and the multitude of highways in the project area means that the effects of the project may be felt in each of these political jurisdictions. Therefore, these three counties and Osceola County have been designated as the project impact area.

Despite the large geographic area covered by this impact area, (Polk and Osceola counties alone cover approximately 3,173 square miles), the impact area is not considered to be excessive due to the labor force and economic conditions described below.

Labor Force

The construction, installation, and operation of a combined cycle combustion turbine electric power plant requires the combined efforts of many individuals from an extremely wide range of professional and skilled disciplines. A large geographic area is necessary to gather such a large number of employees with such a wide array of skills. Statistics indicate that a large number of construction workers already reside in these counties. Since the highway system is well-developed, skilled workers will be able to commute to the Power Park from relatively long distances. However, it is conceded that the effects of the construction project may be diminished by distance, depending on the type of impact being analyzed.



It is anticipated that certain areas will be especially impacted by the construction. Included in this category are the municipalities of Kissimmee, St. Cloud, Davenport, and Haines City, the unincorporated communities of Intercession City, Campbell, and Loughman, and the southwestern quadrant of metropolitan Orlando.

Employment by Occupation

The latest breakdown in employment by occupation is found in the 1990 U.S. Census data. This data was organized by zip code and therefore indicates the relative distribution of population in the project impact area.

The heavily populated Orlando Division contained a workforce of almost 220,000 workers--more than five times the workforce of the second-largest workforce area, the Kissimmee Division. In fact, the Orlando Division contained more than two times the workforce of all the other three divisions combined. The predominant employment category varied by division. In the Kissimmee and Haines City Divisions, nonprotective services were by far the most common job category. In the Orlando Division, most positions were described as administrative support. For the Winter Garden-Ocoee Division, which includes the Disney World complex, sales is the dominant position. Table 2.2-1 provides details on the employment in the primary impact areas.

Employment by Industrial Sector (SIC Code)

According to 1995 data, employment in the impact area is dominated by service workers. Almost 40 percent of the workforce is employed in the services industry. Retail trade is the next most populated category followed in general by manufacturing. The data indicates that over 33,000 construction jobs were in existence in 1995 (Table 2.2-2).

Baseline Employment Projections

The economic activity in and around the Orlando-Kissimmee area has been growing rapidly for over 10 years and is expected to continue to grow at a similar pace. For example, employment in Orlando grew by 45.8 percent between 1986 and 1996. This was the second largest percentage expansion for major metropolitan areas in the United States for this time frame, ranking only behind Las Vegas. The number of jobs is expected to grow in the Orlando market by 29.7 percent between 1996 and 2006. This is anticipated to be the fastest



Table 2.2-1
Employment by Occupation
Primary Impact Areas, 1990

	Kissimmee Division ¹	Orlando Division ²	Haines City Division ³	Winter Garden- Ocoee Div. ⁴
Total Employed Persons	38,558	219,708	17,295	29,735
Executive, Administrative, Managerial	3,659	27,465	1,361	3,141
Professional Specialty	3,441	27,660	1,268	2,758
Technicians and Support	896	7,240	301	758
Sales	4,828	28,736	2,403	7,450
Administrative Support	5,870	37,538	2,014	4,212
Private Household	89	962	88	78
Protective Service	893	4,099	337	534
Service, Except Protective	8,460	33,476	3,422	4,214
Farming, Forestry, Fishing	834	3,435	816	672
Precision Production, Craft, Repair	4,750	23,138	2,312	2,913
Transportation, Material Moving	1,844	8,149	859	924
Machine Operators, Assemblers, Inspectors	1,469	9,588	1,274	1,111
Handlers, Cleaners, Laborers, Helpers	1,525	8,222	840	970

¹A subdivision of Osceola County which includes zip codes 34741, 34744, 34746, 34758, 34759, and 34772 combined with zip codes 34743 (Buena Ventura Lakes) and 34769 (St. Cloud).

²A subdivision of Orange County which includes zip codes 32703, 32751, 32789, 32792, 32801, 32803, 32804, 32805, 32806, 32807, 32808, 32809, 32810, 32811, 32812, 32813, 32818, 32822, 32824, 32827, 32835, and 32839, combined with zip code 32819 (Orlando - Sand Lake).

³A subdivision of Polk County which includes zip codes 33823, 33837, 33838, 33844, 33850, 33853, 33868, 33884, and 34759.

⁴A subdivision of Lake County which includes zip codes 32818, 32835, 34761, 34786, and 34787 combined with zip codes 32830 and 32836 (both for Lake Buena Vista).

Source: 1990 US Census of Population; US Department of Commerce, Bureau of Economic Analysis webpage at venus.census.gov/cdrom/lookup/893180141.



Table 2.2-2
Employment by Industry
By County, with Percentage of Workforce
(1995)

	Osceola		Polk		Orange		Lake	
Total Employment	38,414		151,270		436,522		44,500	
Agricultural Services, Forestry and Fishing	267	1 %	1,924	1 %	4,351	1 %	622	1 %
Mining	0	0 %	2,540	2 %	106	0 %	152	0 %
Construction	2,020	5 %	8,396	6 %	19,018	4 %	4,172	9 %
Manufacturing	1,626	4 %	21,046	14 %	37,354	9 %	3,877	9 %
Transportation and Public Utilities	484	1 %	8,454	6 %	31,150	7 %	2,501	6 %
Wholesale Trade	1,273	3 %	10,959	7 %	27,371	6 %	2,260	5 %
Retail Trade	14,140	37 %	37,188	25 %	86,051	20 %	11,812	27 %
Finance, Insurance and Real Estate	3,388	9 %	8,974	6 %	30,790	7 %	2,378	5 %
Services	15,184	40 %	51,669	34 %	199,944	46 %	16,635	37 %
Unclassified Establishments	32	0 %	120	0 %	387	0 %	91	0 %

Source: U.S. Census Bureau at www.census.gov/datamap/www/12.html.



growing market in the country. Specifically, construction job growth was expected to be 32.1 percent between 1992 and 2002. Service jobs were projected to grow in the same time frame by 46.7 percent.

Statewide, projections reflect the expectation that Florida's economy will continue to rapidly expand well into the 21st century. Table 2.2-3 provides the statewide employment growth projections for the top 12 occupations.

Despite large population growth in the area, unemployment rates remain low. In Osceola County, the unemployment rate was 4.8 percent in 1997. For Orange County, it was 5 percent in 1994 and dropped to 4.6 percent in 1996. The Polk County unemployment rate was 6.9 percent in 1996.

General Income Characteristics

A Bureau of Labor Statistics survey for the Orlando area from March 1997, provides information on wages for several economic sectors. White collar occupations, excluding sales, command an average of \$15.84 per hour. Professional specialty and technical occupations average \$18.60 per hour with engineers, architects and surveyors, a subset, averaging an hourly wage of \$26.64. Executive, administrative and managerial occupations average an hourly wage of \$22.93. Sales occupations average \$10.96 per hour. Blue collar workers average \$10.07 per hour.

In Polk County, the average annual wage is \$23,147. Employees in the mining industry have the highest incomes while workers in agriculture, forestry and fishing receive the lowest incomes. Table 2.2-4 shows gross employment figures for Polk County as well as annual wage figures.

Baseline Income Projections

Incomes are expected to grow sharply in the project impact area for the next few years. The median effective buying income (EBI) household in the Orlando Metropolitan Statistical Area was \$32,933 in 1996. This is expected to grow by 28 percent between 1996 and 2001. In Osceola County, the median household EBI of \$28,483 was expected to grow by 19 percent over this same time frame. Orange and Lake counties, with median household EBIs of \$33,433 and \$23,820, were expected to grow by 27 percent and 22 percent respectively. For the same time frame, Polk County residents had a median EBI of \$25,802.



Table 2.2-3
1996 Occupational Forecasts
Aggregate Ranking by Openings, Wage, and Growth

Rank Order	Occupational Title	Percent Growth 1994-2005	Average Annual Openings	Average Hourly Wage
1	Systems Analyst	79.97	1,497	20.29
2	Teacher, Special Ed.	47.14	1,179	21.70
3	Computer Engineer	71.21	634	21.04
4	Teacher, Secondary	33.05	3,749	21.99
5	Management Analyst	39.78	806	20.04
6	Physical Therapist	62.01	426	22.73
7	Medicine and Health Service Manager	39.43	543	23.09
8	Teacher, Preschool and Kindergarten	37.40	1,307	17.07
9	Engineering, Mathematics, Natural Scientist Manager	33.84	654	27.55
10	Financial Manager	29.25	1,752	24.89
11	Marketing, Advertising, Public Relations Manager	32.21	881	22.03
12	Registered Nurse	32.86	5,115	16.55
13	Police Patrol Officer	41.14	1,226	14.81

Source: Florida Bureau of Labor Statistics



Table 2.2-4
Employment by Industry - Polk County

Industry	Establishments	Employment	Annual Payroll, \$	Annual Wage, \$
Total All Industries	8,942	165,255	3,825,212,382	23,147.33
Agricultural Forestry and Fishing	609	10,076	47,147,442	14,603.76
Mining	16	3,506	138,102,514	39,390.33
Construction	838	7,793	197,353,113	25,324.41
Manufacturing	473	20,310	589,755,831	29,037.71
Transport, Comm, and Public Util.	406	8,123	225,900,642	27,810.00
Wholesale Trade	752	7,455	207,793,928	27,873.10
Retail Trade	1,953	36,930	618,107,895	16,737.28
Finance, Insurance, and Real Estate	730	7,497	205,011,738	27,345.84
Services	2,867	38,455	877,681,415	22,823.60
Federal Government	35	1,396	49,824,401	35,690.83
State Government	63	4,416	110,460,847	25,013.78
Local Government	35	18,914	450,162,938	23,800.51

Source: The Central Florida Development Council webpage at www.cfdc.org/business/demographic/labor.html.



Existing Housing Stock

Existing housing stock features both renter and owner-occupier situations. In September 1996, over 95,000 rental apartment units existed in the Orlando MSA. Of those, 5,617 units were vacant. Kissimmee had over 7,600 similar units with 329 vacancies. In March 1998, over 130,000 residential units existed in Polk County, with 44,861 in Lake County, and 42,526 and 237,561 in Osceola and Orange counties respectively.

Temporary housing is abundant due to the vacation destination status of the project impact area. A recent count indicated that over 86,500 hotel rooms existed in the Orlando MSA. Also, at least 43 camping and recreational vehicle sites are located in the project impact area.

Building Activity

The housing stock in the project area continues to expand rapidly. In 1995, 16,100 new residential units were started in the Orlando MSA. Also in 1995, 7,376 production and custom single family homes were started in the Orlando residential market.

Housing Costs

Compared to other major metropolitan areas in the United States, the Power Park area is one of the most affordable places to buy a home. In 1995, the average price of a purchased home in Orlando was \$111,000. This equaled the average for Memphis (\$111,000) and was slightly below Cleveland (\$112,400). However, Orlando was significantly lower than such areas as Dallas/Ft. Worth (\$130,600), Atlanta (\$151,500), Los Angeles (\$226,700), Seattle-Tacoma (\$181,100) and Phoenix (\$127,800). In fact, the average home price in the Orlando area was only 61.6 percent of the nationwide average, which stood at \$180,200.

Of course, housing values vary by location. In Polk County, the values range from \$30,000 to \$339,000. Osceola County has the smallest range--\$47,000 to \$291,000. Lake County's range, \$44,000 to \$302,000, is roughly the same as Osceola County. Orange County has the largest differences between high and low end with a range from \$47,000 to \$889,000.

Rental units remain affordable. In Polk County, monthly rates run from between \$250 and \$400 for an unfurnished, one bedroom apartment to between \$550 and \$1,500 per month for an unfurnished, four bedroom house. In the Orlando MSA, the average monthly rent for



an efficiency apartment in 1996 was \$398. For a four bedroom, two bath house, the average was \$846 per month.

2.2.7.2 Area Public Service and Utilities. This section of the application serves two purposes. First, it provides the base information that will be used in Chapter 7 to gauge the physical impacts caused by the construction of the Power Park expansion. Second, it provides the information needed to gauge the extended impact of any influx of workers associated with the construction or operation of the project.

Education

Very few educational facilities exist within a 5 mile radius of the Power Park. The Florida Bible College is located approximately 2 miles east at the intersection of Poinciana Boulevard and the Orange Blossom Trail (Highway 600/17/92). In Kissimmee, Poinciana High and Reedy Creek Elementary lie on Poinciana Boulevard approximately 5 miles southeast of the Power Park. To the southwest, there are elementary schools in Loughman and Davenport.

Despite the low need for schools in the immediate Power Park area, there are dozens of public and private schools in the Orlando MSA and Polk County. In Kissimmee, the Osceola Public School District (OPSD) operates ten elementary schools, five middle schools (6-8) and three high schools. The Community High School Adult Learning Center, two technical schools, and five alternative schools also operate in Kissimmee. In Celebration, a community approximately 6 miles north of the Power Park, the OPSD operates one combined K-12 school. In Haines City, there are three elementary schools, two middle schools and Haines City High School. Orange County's public school system has 129,137 students in 138 schools, 91 elementary, 23 middle and 13 high schools, and four alternative/exceptional and 19 technical education and adult and community education centers.

The project impact area is also home to institutions of higher learning. Kissimmee hosts Valencia Community College and Florida College. Orange County hosts several Valencia Community College campuses, as well as Rollins College, Orlando College, the University of Central Florida and Seminole Community College. Lakeland and Winter Haven each have campuses for the Polk Community College.

**Transportation**

Since the project impact area is such a popular vacation destination, the area transportation system is highly developed. Three airports serve the area-- Kissimmee Municipal, Orlando International, (which features more than 30 scheduled airlines and 50 charters serving more than 25 million passengers each year) and Orlando Executive. Several major highways traverse the area including Interstate 4, the Florida Turnpike, the Central Florida Greenway, the Osceola Parkway, and U.S. Highways 17, 27, 92, and 98.

In and around Orlando, the Central Florida Regional Transportation Authority (also known as LYNX) runs 54 regular public passenger bus routes and serves communities from Sanford to Kissimmee. There is no public mass transit serving all of Polk County although Greyhound-Trailways connects Lakeland, Kissimmee and Orlando to many U.S. destinations. Local public bus service (the "Citrus Connection") and a lift-equipped/senior citizen bus service (the "Handy Bus") are provided in Lakeland by the Lakeland Area Mass Transit District (LAMTD). Outside of Lakeland, the Polk County Transportation System (PCTS) provides transportation for those requiring a lift-equipped vehicle or who are over 60 years old to keep medical appointments or to travel to multipurpose senior centers in rural and small urban areas.

Area rail freight service is provided by CSX. Passenger rail service is provided by Amtrak which has daily arrivals and departures in Lakeland, Winter Haven, Kissimmee and Orlando.

Because of the vacation destination status of the impact area, rental cars are plentiful and relatively inexpensive, compared to the rest of the United States. Taxi service is likewise widely available.

Medical Facilities

The Florida Hospital System (run by the Seventh-day Adventist Church) provides 1,432 beds in six locations throughout metropolitan Orlando including Florida Hospital - Kissimmee (formerly Kissimmee Memorial) which has 100 in-patient beds and an emergency room. In July 1998, the Adventist facility in Celebration is expected to begin offering in-patient bed services as well as an emergency room.



Osceola Regional Medical Center, (ORMC), owned by Columbia Health Care Systems and located in Kissimmee, is a 165-bed facility which features an 18-bed emergency room. ORMC will be opening a walk-in facility in Poinciana in the summer of 1998.

The Orlando Regional Healthcare System (ORHS) includes many separate facilities in the project impact area. The largest facility is the Orlando Regional Medical Center, (ORMC), a major teaching hospital in downtown Orlando which features central Florida's only Level I trauma center and the area's only burn unit. Other ORHS facilities include the Arnold Palmer Hospital for Children & Women, featuring a 78-bed neonatal intensive care unit, the M.D. Anderson Cancer Center Orlando, Sand Lake Hospital (a complete medical and surgical facility serving southwest Orange County), St. Cloud Hospital, and South Lake Hospital (a 68-bed hospital serving South Lake County).

The Heart of Florida Hospital, a 51-bed acute care facility in Haines City, is only fourteen miles from the Power Park.

Farther to the south and west of the Power Park are Lakeland Regional Medical Center, the Lake Wales Medical Centers and Winter Haven Hospital.

Besides full service hospitals, several "walk-in" medical facilities operate in the impact area. For example, the Florida Hospital System operates thirteen walk-in "Centra Care" facilities, one in Kissimmee and two in Lake Buena Vista.

Finally, paramedic/ambulance services are provided by various entities. For example, each City of Kissimmee fire station contains an ambulance unit and all city firefighters are also trained Emergency Medical Technicians (EMT) or Paramedics.

Firefighting Facilities

As with all unincorporated areas in Osceola County, fire protection for the Power Park is provided by the Osceola County Department of Public Safety. Osceola County employs 104 firefighters. A station staffed with 9 firefighters is located in Intercession City, approximately one and a half miles from the Power Park.

Several political jurisdictions maintain staffs of professional firefighter personnel as well as a cadre of volunteers. The City of Kissimmee has sixty firefighters on staff, with twenty available to respond to calls at all times. Orange County has a Fire and Rescue Division with 690 full-time staff and 100 volunteers at 31 stations across unincorporated Orange County. The City of Orlando Fire Department employs 324 firefighters and officers



and maintains 12 fire stations. The Lake County Fire/Rescue Department has 32 paid professionals and 200 volunteer professionals. In Polk County, there are 373 firefighters with 966 volunteers available.

Police Protection

Since the Power Park is unincorporated, police protection is provided by the Osceola County Sheriff's Department, whose headquarters lies between Kissimmee and St. Cloud. The Sheriff's Department has 160 uniformed patrol deputies on staff. Elsewhere in the impact area, police protection responsibilities are shared by local municipal police forces, the Florida Highway Patrol and county sheriff's departments. For example, the Orlando Police Department serves the residents of Orlando with 600 sworn officers and 200 civilian employees.

The City of Kissimmee Police Department currently has a force of 104 officers and 52 civilian employees. In Polk County, incorporated municipalities are protected by 480 full-time police officers. In unincorporated areas, the Florida Highway Patrol and the Polk County Sheriff's Office provide protection with 48 full-time officers and 214 full-time deputies, respectively.

Recreation Facilities

Although the Power Park is at the heart of one of the most popular recreation destinations in the world, the closest public recreation facilities are two golf courses, one to the north and the other to the east. Each of these courses lies approximately 7 miles from the Power Park. As mentioned previously, the impact area contains several of the most popular tourist attractions in the world. Walt Disney World, which covers forty-six square miles is approximately 6 miles to the north of the Power Park. SeaWorld and Universal Studios lie around 10 and 15 miles to the north-northeast respectively. In 1995, it was estimated that more than 35 million people visited Walt Disney World, with 8 million going to Universal Studios and almost 5 million enjoying SeaWorld. Many other smaller scale amusement parks, such as Splendid China and Wet n' Wild, a 25 acre water park in southwest Orange County, attract thousands of visitors annually.

The area offers dozens of recreational opportunities other than the major theme parks. Well over thirty golf courses operate in and around metropolitan Orlando. Eight golf courses



operate in Haines City. Lake Tohopekaliga, approximately 15 miles east of the Power Park, is renowned as a fishing and water sports attraction. Lake Apopka, the largest of the areas many lakes, lies approximately 25 miles north of the Power Park. Over a dozen other smaller lakes dot the impact area. Haines City alone boasts of sixteen freshwater fishing lakes.

Furthermore, there are many municipal parks and recreation sites within the project impact area. For example, the City of Kissimmee has over 237 acres of active and passive parks including tennis courts, soccer, softball and little league baseball fields, picnic areas and walking/biking trails. Other sites of interest include the Southern Ballet Theatre, the Orlando Opera Company, the Orlando Science Center and the Orlando Museum of Art.

Electricity and Gas

Electricity is provided by several entities. In Osceola County, electricity is delivered by the City of St. Cloud, KUA, and FPC. Polk County receives power from several different electric utilities including the Tampa Electric Company (TECO), Lakeland Department of Electric and Water Utilities, and FPC. TECO serves the communities of Auburndale, Eagle Lake, Lake Alfred, Mulberry, Fort Meade and Winter Haven. FPC provides power to several communities including Bartow, Davenport, Dundee, Haines City and Frostproof.

Gas service is available in the project impact area. Distribution service is provided by Central Florida Gas and Peoples Gas Company; bulk service is provided by Florida Gas Transmission.

Water Supply Facilities

Throughout the impact area, many small scale, independent water treatment systems operate, serving small networks of customers. For example, Florida Water Services operates a water treatment plant in Intercession City which consists of a groundwater pump, water storage equipment, a chlorine treatment system and a distribution system. It provides potable water to approximately 750 local residents in Intercession City.

The potable water needs of the Power Park are served by the facility's own independent well system. This system is supplemented by regular deliveries of bottled drinking water.

If a customer is not a part of a similar small network, potable water service is generally provided by either a local municipality (e.g. Orlando, Kissimmee, St. Cloud), or



Florida Water Services, Inc. The City of Kissimmee Department of Water Resources currently operates eight potable water plants which have an aggregate capacity of 26,424 million gpd. These facilities provide water service to Kissimmee and certain unincorporated areas of northwest Osceola County. The Water Division of Orange County's Utilities Department operates eighteen water treatment facilities which have an annual aggregate production capacity in excess of 10 billion gallons.

According to 1989 census data, 498,728 households in Polk, Osceola, Orange and Lake counties used a public system or private company; 92,744 used private wells and 1,134 used other sources to obtain potable water.

Sewage Treatment Facilities

In the immediate Power Park area, as well as in Intercession City, all residences are on self-contained septic sewage treatment systems. The Power Park is likewise served by an independent septic sewer system.

As with potable water service, sewage service is provided either by small, individual septic systems, local governmental agencies or private companies, depending on the physical location of the customer. The Wastewater Division of the Orange County Utilities Department provides sewer service in unincorporated Orange County. Eight wastewater reclamation facilities are in operation which treat more than 10 billion gallons each year. All of this wastewater is used to irrigate citrus groves, water golf courses, recharge the aquifer, create wetlands, or satisfy the cooling water needs of the Orlando Utilities' Stanton Energy Center. In Kissimmee, the City Department of Water Resources provides sewer services to the City and certain unincorporated areas of northwest Osceola County. The City operates five wastewater treatment plants which have the capacity to handle 16,862 million gpd.

According to 1990 census data, 387,412 households in Osceola, Polk, Orange and Lake counties were hooked up to public sewers, 200,221 used septic tanks or cesspools; 4,944 used other means of sewage disposal.

Solid Waste Disposal

Solid waste collection and disposal is handled by a private contractor in the immediate Power Park vicinity. Within the project impact area, solid waste collection and disposal is often handled by local governments. For example, the Sanitation Division of the City of



Kissimmee's Department of Public Works and Engineering collects garbage curbside from residents and commercial entities twice a week.

Solid waste disposal is often accomplished through the use of sanitary landfills. The Solid Waste Division of the Orange County Utilities Department operates a 5,000 acre landfill which receives around 1 million tpy of garbage and more than 25,000 tpy of recyclable material. Other area landfills include the Bass Road facility, the St. Cloud landfill, the Seminole Landfill in Sanford, and the Southport Landfill. The latter is scheduled to close in 2002.

2.3 Biophysical Environment

2.3.1 Geohydrology

Three types of geologic data were used to identify the subsurface conditions at the Power Park: (1) published literature providing regional geologic information for Florida's Osceola County geologic setting performed by and for the Florida Geologic Survey and the SFWMD, (2) onsite subsurface investigations performed under the supervision of Black & Veatch, and (3) installation of two production wells to the deep Floridan Aquifer. These data sources provided information on the Power Park stratigraphy, aquifers, and soil engineering properties. Information from these sources was used to evaluate regional geologic features affecting development at the Power Park and determine the site-specific geology.

2.3.1.1 Geologic Description of the Power Park Area. The following discussion of regional geology has been condensed from the references cited in this report, but principally from SFWMD Technical Publication 84-1.

The Power Park lies within the transitional physiographic boundary between the Lake Wales Ridge and the Osceola Plain. Regional geology for this area consists of Pleistocene Age undifferentiated surficial deposits underlain by the Miocene Age Hawthorne Formation underlain by Eocene Age limestone deposits. A stratigraphic section is presented as Figure 2.3-1.

The surficial deposits consist of sand, clay, and shell. The upper horizon is composed of fine to medium grained quartz sand with organic material and iron staining. Below this are shell beds intermixed with clay layers.

WATER-BEARING CHARACTERISTICS AND DESCRIPTION OF THE GEOLOGIC UNITS
IN ORANGE AND SEMINOLE COUNTIES
(Modified from Lichter and others, 1968)

Series	Formation Name	Thickness (feet)	Description	Water-bearing Characteristics	Aquifer
Pleistocene to Recent	Undifferentiated deposits (0.0-1.6 million years ago)	0-75	Clay to frosted, fine to coarse, quartz sand, with occasional shells and thin clay layers.	Varies widely in quantity and quality of water produced.	Surficial (unconfined)*
Miocene	Hawthorn Group (11.2-23.7 million years ago)	0-200	Gray-green, clayey, quartz sand and silt; phosphatic sand; and buff, impure, phosphatic limestone, mostly in lower part.	Generally impermeable except for limestone, shell, or gravel beds.	Generally an aquitard. Confines underlying aquifers. Some beds serve as intermediate (shallow artesian)* aquifer. Lower limestone beds may be part of Floridan Aquifer.
	Ocala Group (36.6-40.0 million years ago)	0-200	Cream to tan, fine, soft to medium hard, granular, porous, some dolomitic limestone.	Moderately high transmissivity. Most wells also penetrate underlying formations.	Floridan.
Eocene	Avon Park Limestone (40.0-43.6 million years ago)	400-600	Upper section mostly cream to tan, granular porous limestone. Lower section mostly dense, hard, brown, crystalline dolomites.	Overall transmissivity very high. Contains many interconnected solution cavities. Many large capacity wells draw water from this formation.	Floridan.
	Lake City Limestone (43.6-52.0 million years ago)	More than 700. Total unknown	Dark brown crystalline layers of dolomite alternating with chalky fossiliferous layers of limestone.	Similar to Avon Park Limestone. Closes Olando and Winter Park obtain water supply from this formation.	Floridan.

*terminology of Lichter and others, 1968.

Figure 2.3-1



The Hawthorne Formation includes sandy phosphatic limestones and sandy calcareous clays. The calcareous clays are light greenish-gray to dark green with black to brown phosphoric sand. The limestone is white to yellow and becomes harder and more phosphatic towards the base. The top of the Hawthorne Formation in the region is generally about elevation 50 feet NGVD, approximately 30 feet bgs. Thickness varies considerably but is about 50 feet in the northwest corner of the county.

Limestone found below the Hawthorne Formation consists of the Ocala Group and Avon Park Limestone. The Ocala Group is composed of a white to cream, chalky, soft coquina of foraminifera. The top of the Ocala Group is an eroded surface which underlies the Hawthorne Formation. The deposition of the Ocala Group is believed to have occurred in an open, shallow, marine environment. The Ocala Group is easily recognizable by the abundance of flat and saddle shaped foraminifera.

Underlying the Ocala Group is the Avon Park Limestone. The limestone is dark brown to cream, very hard to soft, finely crystalline to chalky, fossiliferous dolomite and limestone. It is believed that the Avon Park Limestone was a shallow marine deposit which received little clastic material. The formation is distinguished from overlying formations by the abundance of sand-sized, cone-shaped forams.

The Power Park is located in Seismic Risk Zone 0, one of the most seismically stable areas of the United States. The potential for damage from a seismic event is minimal. All of the earthquakes that have occurred in Florida have had a Modified Mercalli Intensity of VI or less, and have caused very minor damage.

2.3.1.2 Detailed Lithologic Description.

Summary of Field Investigations. Detailed lithologic descriptions have been determined from the results of subsurface investigations completed for the Power Park. These investigations included soil borings, test pits, cone penetrometer soundings, installation of shallow piezometers, soil resistivity tests, infiltrometer tests, laboratory tests on selected samples, and a ground penetrating radar survey.

The soil borings were advanced to depths ranging from 50 feet to 122 feet bgs for a total of 868.5 lineal feet. Total footage included 31 feet of rock coring performed in three separate borings. Sampling while drilling consisted of continuous Standard Penetration Test (SPT) samples from 0 feet to 10 feet, with subsequent SPT samples obtained at 5 feet intervals. Cohesive soil, where encountered, was sampled using a combination of SPT's and shelly tubes. Borehole logging and field classification of samples were performed in the field by Black & Veatch.



A total of five test pits were excavated by backhoe during the subsurface investigation. Two test pits were excavated on Cane Island, two pits were excavated adjacent to the entrance corridor from the Old Tampa Highway, and one pit was excavated in the borrow area. The test pits ranged in depth from approximately 5 feet to 8 feet bgs. The pits were logged by Black & Veatch and samples were obtained for laboratory testing.

Four piezometers were installed on Cane Island using a 6 inch diameter hollow stem auger. A series of laboratory tests were performed on samples obtained during the subsurface investigation. The tests included natural moisture content, density, Atterberg limits, organic content, specific gravity, sieve and hydrometer analysis, triaxial and unconfined compression strength, consolidation, CBR bearing ratio, and modified proctor compaction.

Cone penetrometer soundings were performed at twelve locations on Cane Island at proposed structure locations. A truck-mounted electric cone penetrometer rig was used to advance the soundings. Total depths ranged from 60 feet to 114 feet. Soil resistivity tests were completed at ten locations on Cane Island. The tests were performed using the Wenner Four-Pin Method. A total of three infiltrometer tests were completed during the subsurface investigation. A double-ring infiltrometer was used to perform the tests, one on Cane Island at the location of the Units 1 and 2 surface water detention pond, and two tests along the entrance corridor.

Subsurface conditions encountered during the subsurface investigation drilling indicated the presence of anomalies in the subsurface profile. These anomalies consisted of highly variable depths to bedrock and the presence of very loose soils within these areas. As a result of these findings, a ground penetrating radar study was performed to evaluate these conditions. The survey was conducted on Cane Island using a 120 MHz antenna towed in the east-west direction across the site using 50 feet spacings. The entire southern portion of Cane Island was surveyed.

Data collected from these investigations is summarized in the following reports:

Subsurface Investigation Data Report for Units 1 and 2, Kissimmee Utility Authority, Cane Island Combustion Turbine Project, March 9, 1993 by Black & Veatch.

Karstic Foundation Hazards at the Cane Island Site, Osceola County, Florida, February 1993, by P.E. Lamoreaux and Associates.

These reports are presented in Section 10.8.



Results of the Investigations. The power block area on Cane Island consists of a locally elevated ridge of dry sands surrounded by the wetlands of the Reedy Creek Swamp. The surface stratum consists of a topsoil layer generally less than 1 foot thick consisting of sand with numerous roots and organic material. Underlying the topsoil is a 30 to 50 foot zone of loose to medium dense sand with intermittent layers of clayey and silty sands. Color was predominately orange to tan with varying lighter shades. Ground water recorded while drilling was generally 8 to 14 feet bgs.

The test pits excavated in the surface stratum away from Cane Island, TP-3, TP-4, and TP-5, encountered a "hardpan" layer approximately 3 feet bgs that was not found on Cane Island. This layer consisted of a hard, slightly cemented dark brown to black fine sand with a strong sulfur odor. This layer would perch water during periods of heavy rainfall.

Underlying the surficial deposits is the Hawthorne Formation consisting of olive green clayey silt, silty clay, and clayey sand. The formation was identified by color and the presence of phosphate particles. The zone varied from firm to very stiff and contained varying amounts of shell. Thickness varied from 30 to 50 feet. A dense to very dense layer of highly weathered limestone, logged as calcareous sand, was encountered from 68 to 102 feet bgs in seven of the borings. This layer was located immediately above the limestone in Boring B-10.

Limestone was encountered in four borings at depths ranging from 62 to 109 feet bgs. The limestone was white to cream, moderately weathered with some solutioning and some fossils.

Subsurface soil density and layer continuity encountered in borings B-8, B-9, and B-10 varied considerably from conditions found in the other borings. SPT samples in these borings revealed a very loose, highly variable zone of sands and silts. The olive green material designated as the Hawthorne Formation was not found at expected depths. These three borings revealed a random collection of highly variable, loose sands and silts located from approximately 50 feet bgs down to the limestone. Depth to limestone in these three borings was significantly greater than the other borings. Limestone cored below this layer in Boring B-10 revealed the presence of voids and evidence of clay and silt-filled cavities.

The ground penetrating radar survey provided excellent correlation with the anomalies encountered during the soil drilling phase of the investigation. The radar indicated that the anomalies were the result of buried karstic activity. Buried karstic activity indicates that at



some point in past geologic time, the Power Park was subject to karstic activity and a portion of the underlying limestone had been solutioned away with the resultant ravelling of the overlying sediments. This ancient activity has been buried by more recent deposits and is not evident by inspection of the ground surface.

2.3.1.3 Bearing Strength. The subsurface investigation programs performed by Black & Veatch determined the power block area stratigraphy and material properties. The subsurface soils were sampled by split barrel tests recording standard penetration blow-counts. In addition to the soil classification tests, consolidation and triaxial strength tests were performed on selected samples to determine engineering properties of the clayey materials.

The performance of the foundation systems for the project must have an acceptable factor of safety against failure of the foundation element or bearing soils, and limit total and differential settlements to an acceptable level that will not result in damage to, or loss of service of, the supported facility.

The results of the subsurface investigations indicate that several foundation types will be used to support different portions of the project. The main criterion will be settlement limitations as bearing capacity will not control. This is based on the thickness of the upper sands. For heavily loaded, settlement sensitive structures such as the main power block structures, deep foundations consisting of friction piling or thick mat foundations supported onsite soils densified by ground modification techniques such as vibro replacement or compaction grouting will be used to meet design constraints. Shallow mat or individual spread footings will be used for lightly loaded facilities.

The existing units were constructed using shallow foundations consisting of mats, and spread and strip footings. However, ground improvement methods consisting of stone columns, deep dynamic compaction, and compaction grouting were utilized to prepare the subsurface materials for the constructed facilities. Facilities constructed in areas outside of the mapped buried karstic features employed the use of stone columns and deep dynamic compaction. Facilities constructed within areas of the mapped buried karstic features employed the use of compaction grouting and deep dynamic compaction. The compaction grouting was successful in mitigating the karstic hazards at the site. The Units 1 and 2 foundations have been performing very satisfactorily since installation in 1994; it is anticipated that similar methods will be used for Unit 3.



2.3.2 Subsurface Hydrology

The regional hydrogeologic system beneath the Power Park consists of a surficial aquifer and the Floridan Aquifer system. The surficial aquifer is separated from the Floridan Aquifer by the relatively low permeable deposits of the Hawthorn Formation.

2.3.2.1 Subsurface Investigation Program. The subsurface hydrology of the power block area was determined by review of existing reference documents, installation of shallow piezometers, and from the installation of two production water wells for Units 1 and 2.

Four temporary piezometers were installed into the surficial aquifer during the subsurface investigation to monitor ground water levels for use in design and construction of Units 1 and 2. These piezometers were installed in the general plant area located on Cane Island. Surface water infiltration was determined using double ring infiltrometer tests. Infiltrimeter test I-1 was performed on Cane Island at the location of the Units 1 and 2 surface water detention pond; I-2 and I-3 were performed along the entrance corridor.

Maximum high ground water levels were investigated during the test pit excavations. Coloration, iron staining, and visual observation were used to estimate the historic high ground water levels for Cane Island, the entrance corridor, and the borrow pit area. Test pits TP-1 and TP-2 were excavated on Cane Island. Test pit depths in this area were limited by caving and sloughing of pit walls; free ground water was not encountered. TP-3, TP-4, and TP-5 were excavated along the entrance corridor and at the borrow area.

In addition to the temporary piezometers installed during the investigation, three monitoring wells were installed for the purpose of long-term monitoring of the surficial aquifer. A description of the monitoring program is provided in Subsection 5.3.5.2.

Two production water wells were installed into the Floridan Aquifer for use in Unit 1 and 2 operations. The wells were cased to a depth of 150 feet bgs. Total well depths ranged from 300 to 360 feet below ground surface. Details of the well installation including drillers logs, pump test results, and geophysical logs are included in the well completion report presented in Section 10.8.

Results of Investigation Program

The Surficial Aquifer. The surficial aquifer at Cane Island consists of the upper unconfined sands of the Pleistocene and Recent age. The fine grained sand layer extends to



approximately 35 feet bgs. Underlying the sand layer is the Hawthorne Formation, a silty clay/clayey sand layer that acts as a separation or confining unit for the Floridan Aquifer.

The surficial aquifer is recharged by precipitation, and discharges into lakes, streams, and occasionally to the Floridan Aquifer by downward percolation. The surficial aquifer will have a tendency to mirror ground surface elevation. This is readily seen at the Power Park as the installed piezometers indicate a higher water table at the raised elevation of Cane Island compared to the surrounding wetlands. The surrounding wetlands are very flat. Overall local gradient would seem to be slightly influenced by the Bonnet Creek Canal located to the north and northwest of Cane Island causing a very slight gradient to the north. Localized surficial aquifer gradient below Cane Island consists of radial outward flow caused by recharge during precipitation events. Ground water levels measured from piezometers installed at the Power Park are as follows:

Piezometer Number	Ground Surface Elevation	Ground Water Elevation (08/12/92)	Ground Water Elevation (09/23/92)	Ground Water Elevation (10/14/92)
PZ-1	78.0 ft	69.8 ft	69.6 ft	71.3
PZ-2	78.0 ft	69.7 ft	70.9 ft	71.3
PZ-3	83.0 ft	69.4 ft	70.7 ft	71.7
PZ-4	78.5 ft	69.5 ft	70.4 ft	71.4

Maximum high ground water levels were investigated during the test pit excavations. Coloration, iron staining, and visual observation were used to estimate the historic high ground water levels for Cane Island, the entrance corridor, and the borrow pit area. Test pits TP-1 and TP-2 were excavated on Cane Island.

TP-3, TP-4, and TP-5 were excavated along the entrance corridor and at the borrow area. These test pits indicated similar profiles regardless of surface elevation. A hardpan layer was encountered at approximately 3 feet bgs. Perched ground water was encountered above the hardpan layer. The true ground water level was estimated to be approximately 6 feet bgs. The pits were backfilled before the ground water was able to stabilize in the open pit. Maximum high ground water in these areas is estimated to be 0 to 12 inches bgs and is directly related to the hardpan layer. Maximum groundwater levels encountered during this



investigation are consistent with the *Osceola County Soil Survey* published by the United States Department of Agriculture Soil Conservation Service in 1979.

Ground water levels have been recorded from the monitoring wells described in Subsection 5.3.5.2. The data collected from the quarterly intervals are presented on Figure 2.3-2.

Surface water infiltration was determined using double ring infiltrometer tests. Infiltrometer test I-1 was performed on Cane Island at the location of the Units 1 and 2 surface water detention pond. I-2 and I-3 were performed along the entrance corridor. Test results are as follows:

Test No.	Steady State Infiltration Rate (in/h)
I-1	21.5
I-2	10.2
I-3	7.3

Results of the infiltrometer tests confirm the very high permeability of the surficial sands encountered on Cane Island. Permeabilities conducted at locations along the entrance corridor were much lower in the silty materials associated with the near surface soils of the wetlands.

As a result of these investigations, the following characteristics were established for the surficial aquifer in the immediate power block vicinity. Maximum high ground water was estimated to be at approximately elevation 74 feet. Low groundwater elevation was estimated to be elevation 69.5 feet. It could be expected during the course of seasons for the surficial aquifer water levels to vary by 3 to 4 feet. Vertical permeability of the surficial sands is estimated to be 30 feet/day.

The Floridan Aquifer. The Floridan Aquifer is the principle aquifer of the Florida Peninsula. The aquifer is typically confined by the Hawthorne Formation with variable potentiometric head across the state. Within the Orange and Osceola county areas, the potentiometric surface of the aquifer ranges from elevation 70 to 80 feet MSL which correlates closely with

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

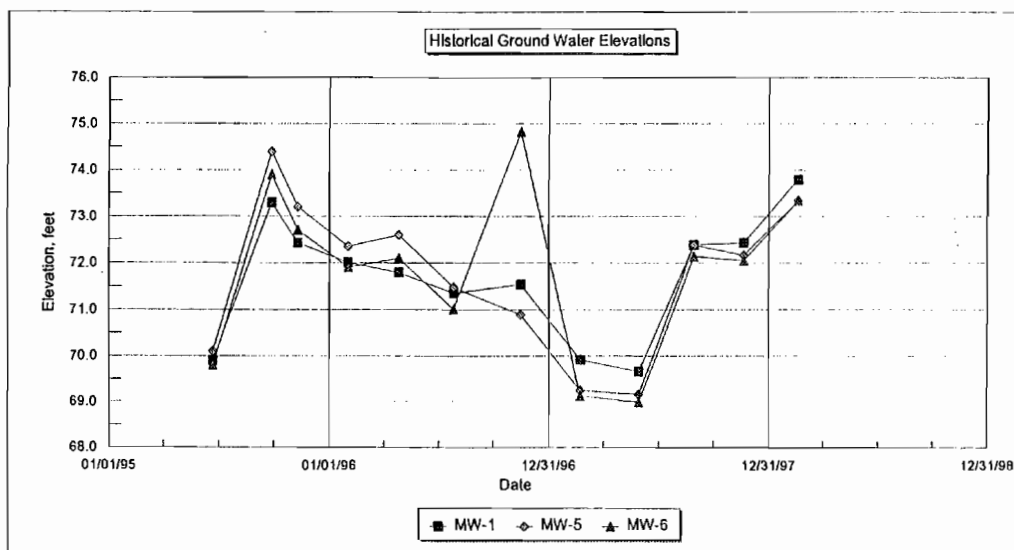


Figure 2.3-2



measured data within the installed wells. This very productive aquifer can have yields from the upper zone as high as 4,000 gpm. Yields vary with location.

From a regional consideration, surficial deposits for the area consist of unconsolidated clastic deposits to a depth of approximately 150 feet. These undifferentiated deposits consist of sands, clays, clayey sands and sandy phosphatic clays. The age of these materials ranges from middle Miocene to Recent. Some small irrigation and domestic water supplies are obtained from this zone. Underlying the clastic deposits is the Inglis Formation, from the Ocala Group. This is the uppermost limestone member of the Floridan Aquifer, all other members having been eroded in this area. This formation consists of partially to highly dolomitized, highly fossiliferous limestone with some local soft chalky zones. Thickness of the Inglis Formation in this area is approximately 75 feet.

The principle water bearing unit for the Floridan Aquifer in this region is the Avon Park Limestone. The Avon Park stratum is described as dark brown to cream, very hard to soft, granular to chalky to finely crystalline, highly fossiliferous limestone. This aquifer is the source of all major public, industrial, and irrigation water supplies for this region. The Power Park is located on the northernmost fringe of flowing artesian conditions for the Floridan Aquifer. This study assumed that the aquifer was confined by the clay present in the clastic deposits above the Inglis Formation.

On Cane Island, the Hawthorne Formation thickness varies, but is approximately 35 feet. The Floridan Aquifer was encountered below the Hawthorne formation at approximately 70 feet bgs. Piezometric head for the Floridan Aquifer is approximately 14 feet bgs, but is confined by the Hawthorne Formation. Measured piezometric head within the surficial aquifer was approximately 10 feet bgs.

Water required for Unit 1 and 2 operations is obtained from the Floridan Aquifer by two wells constructed into the aquifer. Water is pumped from one well, with the second well acting as a backup well. The ground water wells were designed to each pump 200 gpm. The wells consist of 8 inch diameter black steel casing grouted to 150 feet below ground surface with a 6 inch diameter open hole to 300 feet in PW-1, and 360 feet in PW-2. The wells were permitted and constructed to standards as specified by the SFWMD. Well and aquifer characteristics determined from pump tests conducted on the wells at the time of installation resulted in a predicted yield of 90 gpm per foot of drawdown with a maximum recommended pumping rate of 450 gpm per well. Well completion reports are present in Section 10.8.



Additional aquifer characteristics determined for wellfield studies indicate a confined aquifer with a transmissivity of 26,740 ft³/day/ft.

2.3.2.2 Karst Hydrology. A description of the karst conditions encountered at the site is presented in Section 2.3.1.

2.3.3 Site Water Budget and Area Users

Additional climatological information and the tables identified in this section are provided in Section 2.3.7 of this application. A summary of the requested information is included in this subsection.

2.3.3.1 Orlando Climatological Conditions. The following meteorological information was collected from the Orlando International Airport. This is the closest National Weather Service office to the Power Park, approximately 20 miles northeast of the Power Park, at elevation 96 feet msl. The Orlando airport data are considered to be representative of long-term, Power Park conditions due to the proximity to the Power Park.

2.3.3.2 Temperature and Precipitation. Normal monthly and annual temperatures are presented in Table 2.3-2. The annual average temperature for the period of record is 72.3° F. The warmest month is typically August; the coldest month is typically January. Additional temperature information is included in Tables 2.3-3 through 2.3-5.

Normal monthly and annual rainfall totals are presented in Table 2.3-6. The annual average for the period of record is approximately 48 inches. Rainfall is greatest in the summer months, May through September. April has the lowest average rainfall. Additional rainfall information is included in Tables 2.3-7 through 2.3-9.

2.3.3.3 Evapotranspiration and Runoff. Rainfall averages 48.11 inches per year in the Orlando area. A portion of this rainfall is intercepted by vegetation or stored in small depressions on the surface, a portion infiltrates into the soil, and the remainder directly runs off during storm events. Base flow in streams is sustained by ground water inflow from the shallow aquifer system which is recharged from storm water infiltration. The Natural Resource Conservation Service (NRCS) estimates evaporation of 50 inches per year in this area from shallow lakes and reservoirs. Evaporation also occurs to a lesser degree from soil surfaces and as transpiration from vegetation. The total evaporation and transpiration is known as evapotranspiration which varies with surface conditions.



2.3.3.4 Water Use. There are two existing well users located approximately 4 miles from the Power Park. These users are Hidden Glen, located to the southwest, and the Good Samaritan Retirement Home located to the southeast. Both of these facilities are considered small users.

2.3.4 Surficial Hydrology

Cane Island is crowned in the central portion and drains to the east or to the west into Reedy Creek Swamp. The elevation at the site is 5 to 15 feet higher than that of the surrounding swamp.

Reedy Creek Swamp has very little gradient. The eastern portion of the swamp is drained by Shingle Creek, which discharges into Lake Tohopekaliga. The western portion of the swamp, which includes the plant site, drains to Reedy Creek.

Reedy Creek flows from northwest to southeast. It is located approximately 3,000 feet southwest of the power block. The gradient of Reedy Creek in the vicinity of the plant site is approximately 0.023 percent. Reedy Creek discharges into Lake Russell, approximately 13 miles downstream from the Power Park.

The native soil in the power block area is predominantly classified as Candler sand by the NRCS. This material is excessively drained, with very rapid permeability. The water table in this soil is typically in excess of 72 inches.

The native soil in the swamp surrounding the site is predominately classified as Pompano fine sand by the NRCS. This material is nearly level, and typically covered with standing water. Permeability of this soil is very rapid.

The water surface elevation in Reedy Creek Swamp is subject to seasonal variation, with rising water during the summer rainy season. The swamp is considered a Class III body of water, as defined in FAC 62-302.400.

Since May 1970, the flow in Reedy Creek has been regulated by Reedy Creek Improvement District Structure 40 (S-40), which is located 3,500 feet west of the power block. The peak flow rate in Reedy Creek at the USGS gauging station 1.0 mile downstream from S-40 is 790 cubic feet per second (cfs). The minimum flow rate at this gauging station is 0.0 cfs. The highest annual mean and lowest annual mean flows at this station are 182 cfs and 15.2 cfs, respectively.



Limited water quality data are available at S-40 for portions of the period from January 1985 to the current year. For this period of record, the maximum daily mean specific conductance was 308 microsiemens. The minimum daily mean specific conductance was 93 microsiemens/cm. The maximum daily mean dissolved oxygen content was 9.1 mg/l. The minimum daily mean dissolved oxygen content was 0.0 mg/l. The maximum and minimum daily mean water temperatures were 28.9 and 6.8 degrees Celsius, respectively.

Additional water quality data are presented in the Water Resources Atlas of Florida for Lake Tohopekaliga, which is approximately 7.5 miles east of the Power Park. The mean pH of the water is 8. The mean conductivity is 300 micromhos. The mean color is 80 PTC. Mean turbidity is 7.5 JTU. The mean total phosphorus is 0.3 mg/l, and the mean total nitrogen is 2.0 mg/l. These values are typical for surface waters in central Florida.

The Power Park is not required to monitor any surface waters in the project area.

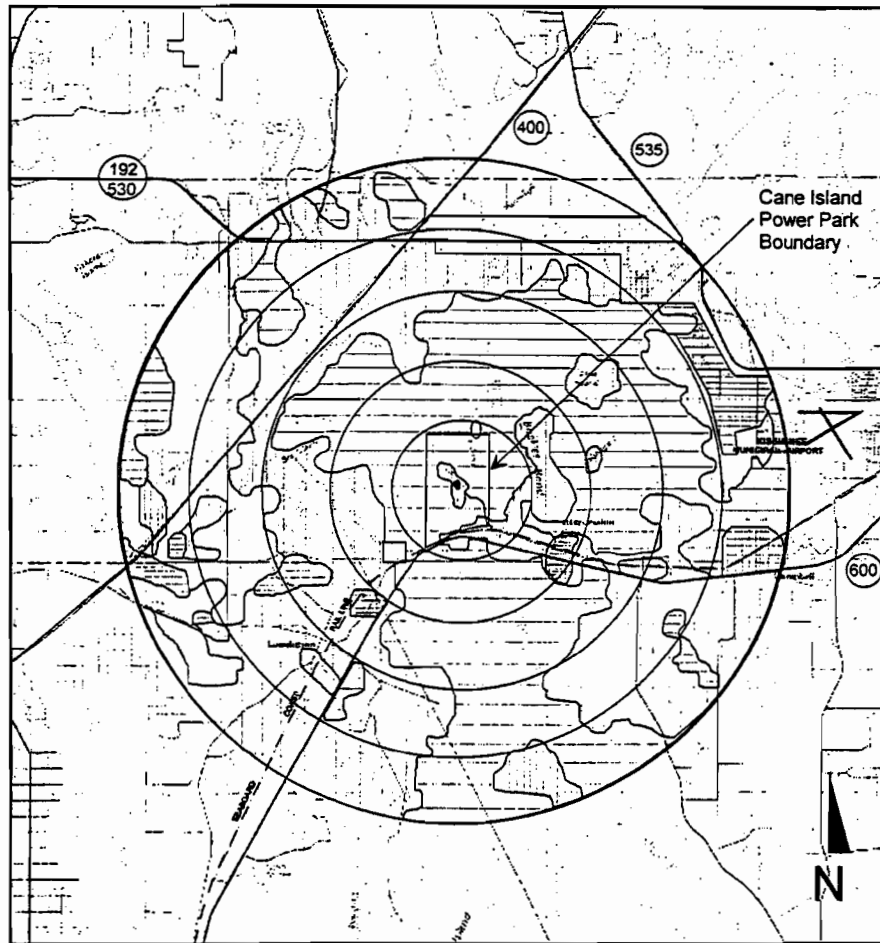
2.3.5 Vegetation/Land Use

Cane Island lies within the Osceola Plain physiographic section of central Florida. The local relief of the area ranges from 65 to 75 feet NGVD. Bonnet Creek Canal borders project property on the north and west boundaries; Reedy Creek crosses the southwest corner of the property.

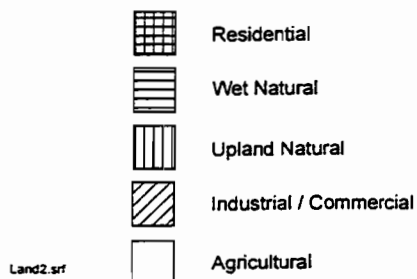
A botanical survey was conducted on Power Park property in January 1991. Plants identified during the 1991 survey and subsequent surveys are listed in Appendix 10.10. Figure 2.3-3 shows vegetation and land use within a 5 mile radius of the Power Park.

Units 1 and 2 were constructed primarily in the improved grassland plant community. Unit 3 site development is proposed to occur within two plant communities: improved grassland and sand pine scrub. Figure 2.3-4 is a map of the plant communities that occur onsite. The plant communities adjacent to the improved grassland and the sand pine scrub include flatwoods, pine flatwoods, pine mesic oak, and hydric hammock.

Improved grassland is an artificial plant community that occurs on the southern half of Cane Island. The original vegetation, sand pine scrub, was removed and exotic grasses were planted by the previous owner. The soils are well-drained and the topography is flat. The vegetation consists of sparse overstory and understory with dense ground cover. The overstory and understory species include sand live oak (*Quercus geminata*), Florida hickory (*Carya floridana*), cabbage palm (*Sabal palmetto*), beauty bush (*Callicarpa americana*),

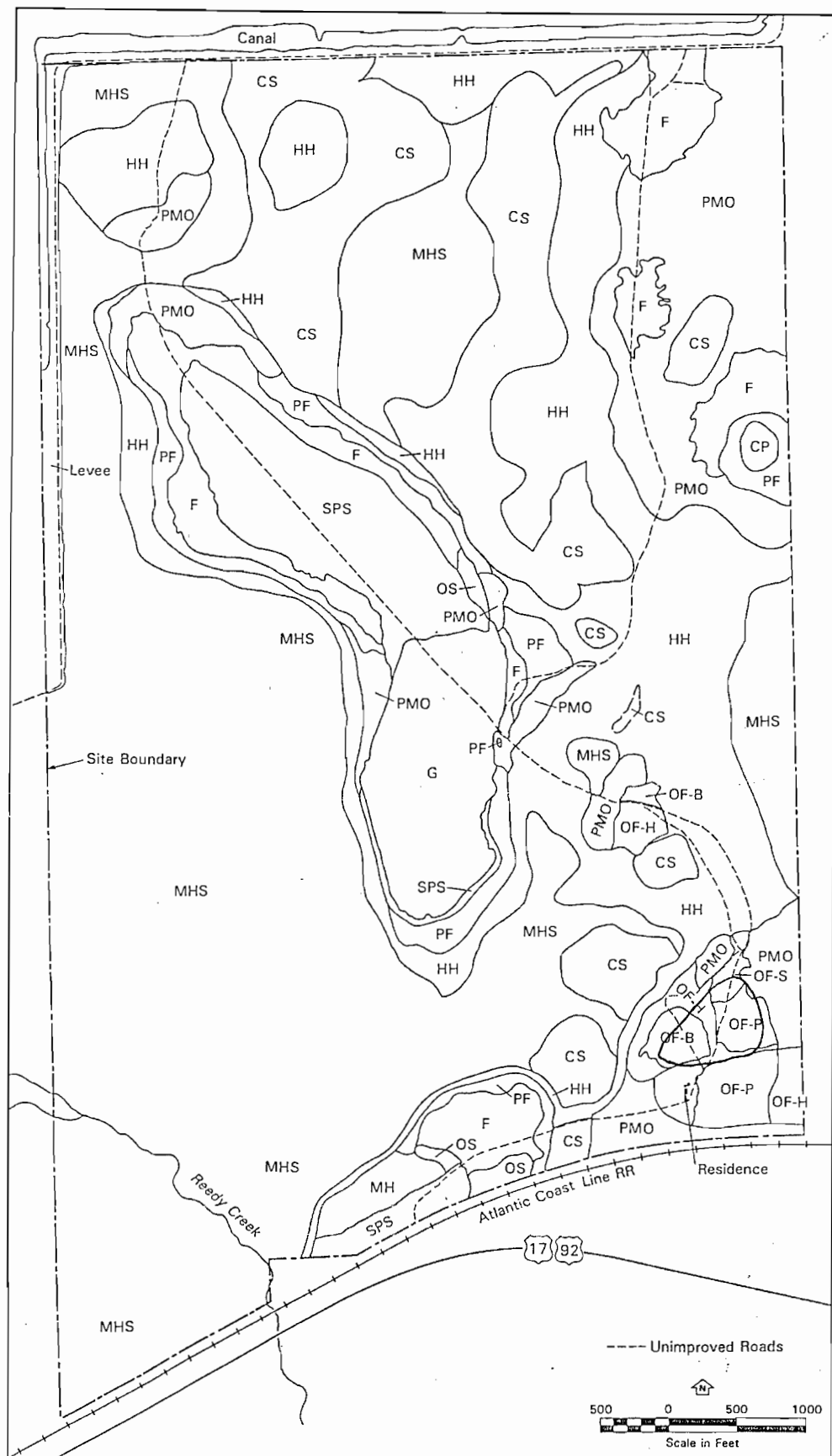


Vegetation and Land Use within
5 miles of the Site Location



Poor Original

Figure 2.3-3



Plant Communities					
MH	Mesic Hammock	PF	Pine Flatwoods	G	Improved Grassland
HH	Hydric Hammock	PMO	Pine Mesic Oak	OF-B	Old Field — Broomsedge
CS	Cypress Strand	MHS	Mixed Hardwood Swamp	OF-H	Old Field — Mixed Hardwood
CP	Cypress Pond	OS	Oak Scrub	OF-P	Old Field — Saw Palmetto
F	Flatwoods	SPS	Sand Pine Scrub	OF-S	Old Field — Slash Pine

August 1992

PLANT COMMUNITIES ON KISSIMMEE UTILITY AUTHORITY'S
CANE ISLAND PROJECT SITE (OSCEOLA COUNTY, FLORIDA)



and coralbeans (*Erythrina herbacea*). The ground cover is dominated by grasses: *Eustachys glauca* (no common name), bahiagrass (*Paspalum notatum*), thin paspalum (*Paspalum setaceum*), natal grass (*Rhynchyletrum repens*), and broomsedge (*Andropogon virginicus*). Other species observed in the ground cover are prickly-pear cactus (*Opuntia humifusa*), sedge (*Cyperus retrorsus*), hairy indigo (*Indigoifera hirsuta*) and cottonweed (*Froelichia floridana*).

Sand pine scrub is a natural upland community that occurs on the northern half of Cane Island on flat terrain with well-drained soils. The overstory is dominated by sand pine (*Pinus clausa*), sand live oak (*Quercus geminata*), Chapman's oak (*Quercus chapmanii*), and scrub oak (*Quercus inopina*). The shrubby understory includes rusty lyonia (*Lyonia ferruginea*), fetterbush (*Lyonia lucida*), palmetto (*Serenoa repens*), and rosemary (*Ceratiola ericoides*). Ground cover is typically sparse with few species, including: wire-grass (*Aristida stricta*), golden aster (*Heterotheca graminifolia*), yellow buttons (*Balduina angustifolia*), several *Cladonia* spp., beak rush (*Rhynchospora megalocarpa*), white-head bogbuttons (*Lachnocaulon anceps*), yellow-eyed grass (*Xyris brevifolia*), and broomsedge.

Pine-mesic oak is an upland community on flat to sloping terrain with well-drained soils. It is associated with most of the plant communities at the study area. This community is dominated by slash pine (*Pinus elliottii*), laurel oak (*Quercus laurifolia*), and Virginia live oak (*Quercus virginiana*), which form a dense canopy often reaching 60 to 80 feet in height. The midstory is usually open, but may approach closure. It includes cabbage palm, loblolly bay (*Gordonia lasianthus*), wax myrtle (*Myrica cerifera*), dahoon holly (*Ilex cassine*), sweet gum (*Liquidambar styraciflua*), and swamp honeysuckle (*Rhododendron viscosum*). The understory and ground cover tend to be sparse, but may be somewhat thick in transitional zones with other communities.

Hydric hammock is a wetland community with a flat to slightly sloping topography, which may be inundated for up to 6 months per year. It is often situated between xeric upland communities and wetlands that are flooded for longer periods. The vegetation is characterized by a canopy of cabbage palm, Virginia live oak, laurel oak, slash pine, water oak, red maple. The sparse understory and ground cover include wax myrtle, loblolly bay, greenbrier (*Smilax bona-nox*), grapevines (*Vitis* sp.), golden polypodium (*Polypodium aureum*), marsh fern (*Thelypteris palustris*), cinnamon fern (*Osmunda cinnamomca*), Florida shield fern (*Dryopteris indoviciiana*), longleaf chasmanthium (*Chasmanthium sessilifolium*), and cypress witchgrass (*Dicantheleum dichotomum*).



Flatwoods is a natural upland community found on flat topography and well-drained soils. Under the right conditions, this community should mature into pine flatwoods. Characteristically, it is associated with sand pine scrub, sandhills (not at the project site), oak scrub, pine flatwoods, and hydric hammock. Onsite, flatwoods are found on Long Island and to the south near the site entrance. This community encircles the northern half of Cane Island. At Cane Island, flatwoods canopy cover is sparse to nonexistent with an occasional slash pine encroaching from the pine flatwoods. The understory is dense and includes inkberry (*Ilex glabra*), fetterbush, rusty lyonia, sand live oak, and palmetto. Ground cover ranges from sparse to somewhat dense and includes seedlings of the understory, as well as wire-grass, prickly-pear cactus, white-head bogbuttons, British soldier moss (*Cladonia leporina*), shiny blueberry (*Vaccinium myrsinites*), needle-leaf witchgrass (*Dichanthelium aciculare*), and Atlantic St. John's wort (*Hypericum reductum*).

Pine flatwoods is an upland community with flat to slightly sloping topography and well to moderately drained soils. Canopy cover consists of primarily slash pine and may be dense or open. Mid-canopy, which often approaches closure includes loblolly bay, wax myrtle, water oak, and cabbage palm. Typical understory species include inkberry, palmetto, fetterbush, and dahoon holly. Ground cover is sparser than the understory and includes shiny blueberry, cinnamon fern, grapevines (*Vitis* sp.), and greenbrier.

Previous to KUA's purchase of the Power Park, a single unimproved road segmented the 43 acres of sand pine scrub. KUA constructed a transmission line in association with Units 1 and 2 that required a corridor through the sand pine scrub.

2.3.6 Ecology

This section identifies endangered, threatened, and other sensitive species that have the potential to occur within 5 miles of the Power Park which might reasonably be expected to be affected by the construction and operation of Unit 3. Sensitive species include plants and animals listed as endangered or threatened by the USFWS; species listed by the FGFWFC in FAC 39-27 as endangered, threatened, or of special concern; species listed as game, fur-bearers, or freshwater game fish in FAC 39-1; and, species which are indicators of, endemic to, or are unique to specific plant communities and habitat types.



The USFWS and FGFWFC were contacted for information concerning threatened, endangered, and species of concern during the permitting efforts for Units 1 and 2. These agencies were contacted again in June 1998 to advise them of the proposed Unit 3 activities and to get up-to-date information about endangered, threatened, special concern, game, fur-bearers, freshwater game fish, and indicator species.

Field surveys for endangered, threatened, and other sensitive species were conducted in 1991 and 1992 before construction of the generation facilities began. Additionally, vegetation and wildlife surveys were conducted in 1993 and 1997, and will be performed once every 5 years until 2023, as mitigation required by the FGFWFC and SFWMD for construction of the Power Park

No federally listed plant or animal species have been recorded onsite, none have been observed during surveys, and no critical habitat for federally listed species occurs within the Power Park boundaries (see following USFWS letter dated 7/20/98). Marginal habitat for the Florida scrub jay (federally threatened) was discovered on the northern half of Cane Island, but no scrub jays have been observed during surveys.

Several state listed species occur either on Cane Island or in habitats adjacent to Cane Island on Power Park property (Table 2.3-1). However, only two state listed animals have been found onsite. The gopher tortoise (*Gopherus polyphemus*), a state species of special concern and the Florida mouse (*Peromyscus floridanus*), a state species of special concern.

The gopher tortoise occurs in high concentrations in the improved grassland on the southern end of Cane Island. It is also found in the sand pine scrub community on the northern half of Cane Island, but in much lower concentrations (Black & Veatch, 1998). The diet of the gopher tortoise typically consists of broad-leaved grasses, wiregrass and legumes but may include other plant materials, animals, and organic matter (Cox et. al., 1987). The improved grassland provides an abundant supply of grasses, including wiregrass and the open canopy of the improved grassland provides sunlight necessary for proper egg incubation.

The Florida mouse is commonly associated with the gopher tortoise. It often excavates its den along the burrow shaft and will center much of its foraging activities around the burrow of the gopher tortoise. Food of the Florida mouse consists principally of seeds, but includes leaves and an occasional insect.

Six state protected plants listed below were located onsite, primarily in the hydric hammocks.



United States Department of the Interior

FISH AND WILDLIFE SERVICE

South Florida Ecosystem Office

P.O. Box 2676

Vero Beach, Florida 32961-2676

July 20, 1998

RECEIVED

JUL 26 1998

EAS

J. Michael Soltys, Licensing Manager
Black and Veatch
P.O. Box 8405
Kansas City, Missouri 64114

Dear Mr. Soltys:

Thank you for your letter to the U.S. Fish and Wildlife Service (FWS) requesting information on the presence of federally listed species in the vicinity of the site described in your letter. The project site is located in Intercession City, Osceola County, Florida.

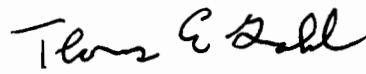
The FWS has reviewed the information in your letter as well as information available to us on the presence of threatened or endangered species in the vicinity of the project site. From this review, we find no evidence of federally listed species on the project site. Additionally, Wesley Shockley (FWS biologist) conducted a preliminary site inspection on July 10, 1998. No threatened or endangered species were observed during that visit, though inclement weather reduced the probability of encountering wildlife during the inspection. Therefore, we would appreciate the opportunity to revisit the site by attending the upcoming interagency site inspection. No critical habitat has been designated on the project site.

We have provided for your consideration a list of species that are protected as either threatened or endangered under the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), as well as candidates for listing which may be present in Osceola County. Since this list does not include State-listed species, the Florida Game and Fresh Water Fish Commission should be contacted to identify those species potentially present in the vicinity.

In addition, we are providing you with a list of species that we would consider during our review of any proposal associated with this project. This list represents species that the FWS is required to protect and conserve under other authorities, such as the Fish and Wildlife Coordination Act (16 U.S.C. 661 *et seq.*) and the Migratory Bird Treaty Act (16 U.S.C. 701 *et seq.*). We are providing this list as technical assistance only. If you would like to discuss means and methods to conserve these species, please contact this office.

Thank you for the opportunity to provide this information. If you have any questions, please contact Mr. Shockley at (561) 562-3909.

Sincerely,

A handwritten signature in black ink, appearing to read "James J. Slack".

James J. Slack
Project Leader
South Florida Field Office

Enclosures

cc: COE, Tampa, FL (w/o enclosures)
GFC, Punta Gorda, FL (w/o enclosures)

FEDERALLY LISTED THREATENED AND ENDANGERED SPECIES
AND CANDIDATES FOR FEDERAL LISTING
IN OSCEOLA COUNTY

Scientific Name	Common Name	Status
Amphibians and Reptiles		
<i>Alligator mississippiensis</i>	American alligator	T(S/A)
<i>Drymarchon corais couperi</i>	Eastern indigo snake	T
Birds		
<i>Ammodramus savannarum floridanus</i>	Florida grasshopper sparrow	E
<i>Aphelocoma coerulescens</i>	Florida scrub jay	T
<i>Campephilus principalis principalis</i>	Ivory-billed woodpecker (probably extinct in south Florida)	E
<i>Haliaeetus leucocephalus</i>	Bald eagle	T
<i>Mycteria americana</i>	Wood stork	E
<i>Picoides (=Dendrocopos) borealis</i>	Red-cockaded woodpecker	E
<i>Polyborus (=Caracara) plancus audubonii</i>	Audubon's crested caracara	T
<i>Vermivora bachmanii</i>	Bachman's warbler	E
Mammals		
<i>Ursus americanus floridanus</i>	Florida black bear	C
Plants		
Family Agavaceae		
<i>Nolina brittoniana</i>	Scrub beargrass	E
Family Caryophyllaceae		
<i>Paronychia chartacea (=Nychia pulvinata)</i>	Papery whitlow-wort	T
Family Convolvulaceae		
<i>Bonamia grandiflora</i>	Florida bonamia	T
Family Fabaceae		
<i>Clitoria fragrans</i>	Pigeon wing	T
Family Oleaceae		
<i>Chionanthus pygmaeus</i>	Pygmy fringetree	E
Family Polygalaceae		

Scientific Name	Common Name	Status
<i>Polygala lewtonii</i>	Lewton's polygala	E
Family Polygonaceae		
<i>Eriogonum longifolium</i> var. <i>gnaphalifolium</i>	Scrub buckwheat	T
<i>Polygonella myriophylla</i>	Sandlace	E
Family Rosaceae		
<i>Prunus geniculata</i>	Scrub plum	E

MIGRATORY BIRDS OCCURRING IN SOUTH FLORIDA

ORDER GAVIIFORMES

FAMILY GAVIIDAE

- Gavia stellata*, Red-throated Loon
- Gavia immer*, Common Loon
- Gavia pacifica*, Pacific Loon

ORDER PODICIPEDIFORMES

FAMILY PODICIPEDIDAE

- Tachybaptus dominicus*, Least Grebe
- Podilymbus podiceps*, Pied-billed Grebe
- Podiceps auritus*, Horned Grebe
- Podiceps nigricollis*, Eared Grebe

ORDER PROCELLARIIFORMES

FAMILY PROCELLARIIDAE

- Calonectris diomedea*, Cory's Shearwater
- Puffinus gravis*, Greater Shearwater
- Puffinus griseus*, Sooty Shearwater
- Puffinus puffinus*, Manx Shearwater
- Puffinus lherminieri*, Audubon's Shearwater

FAMILY HYDROBATIDAE

- Oceanites oceanicus*, Wilson's Storm-Petrel
- Oceanodroma leucorhoa*, Leach's Storm-Petrel
- Oceanodroma castro*, Band-rumped Storm-Petrel

ORDER PELECANIFORMES

FAMILY PHAETHONTIDAE

- Phaethon lepturus*, White-tailed Tropicbird
- Phaethon aethereus*, Red-billed Tropicbird

FAMILY SULIDAE

- Sula dactylatra*, Masked Booby
- Sula leucogaster*, Brown Booby
- Sula sula*, Red-footed Booby
- Sula bassanus*, Northern Gannet

FAMILY PELECANIDAE

- Pelecanus erythrorhynchos*, American White Pelican
- Pelecanus occidentalis*, Brown Pelican

FAMILY PHALACROCORACIDAE

- Phalacrocorax carbo*, Great Cormorant
- Phalacrocorax auritus*, Double-crested Cormorant

FAMILY ANHINGIDAE

- Anhinga anhinga*, Anhinga

FAMILY FREGATIDAE

- Fregata magnificens*, Magnificent Frigatebird

ORDER CICONIIFORMES

FAMILY ARDEIDAE

- Botaurus lentiginosus*, American Bittern
- Ixobrychus exilis*, Least Bittern
- Ardea herodias*, Great Blue Heron
- Casmerodius albus*, Great Egret
- Egretta thula*, Snowy Egret

Egretta caerulea, Little Blue Heron

Egretta tricolor, Tricolored Heron

Egretta rufescens, Reddish Egret

Bubulcus ibis, Cattle Egret

Butorides striatus, Green-backed Heron

Nycticorax nycticorax, Black-crowned Night Heron

Nycticorax violaceus, Yellow-crowned Night Heron

FAMILY THRESKIORNITHIDAE

Eudocimus albus, White Ibis

Eudocimus ruber, Scarlet Ibis

Plegadis falcinellus, Glossy Ibis

Plegadis chihi, White-faced Ibis

Ajaia ajaja, Roseate Spoonbill

FAMILY CICONIIDAE

Mycteria americana, Wood Stork

ORDER PHOENICOPTERIFORMES

FAMILY PHOENICOPTERIDAE

Phoenicopterus ruber, Greater Flamingo

ORDER ANSERIFORMES

FAMILY ANATIDAE

Dendrocygna bicolor, Fulvous Whistling-Duck

Dendrocygna autumnalis, Black-bellied Whistling-Duck

Anser albifrons, Greater White-fronted Goose

Chen caerulescens, Snow Goose

Branta bernicla, Brant

Branta canadensis, Canada Goose

Aix sponsa, Wood Duck

Anas crecca, Green-winged Teal

Anas rubripes, American Black Duck

Anas fulvigula, Mottled Duck

Anas platyrhynchos, Mallard

Anas bahamensis, White-cheeked Pintail

Anas acuta, Northern Pintail

Anas discors, Blue-winged Teal

Anas cyanoptera, Cinnamon Teal

Anas chrypeata, Northern Shoveler

Anas strepera, Gadwall

Anas penelope, Eurasian Wigeon

Anas americana, American Wigeon

Aythya valisineria, Canvasback

Aythya americana, Redhead

Aythya collaris, Ring-necked Duck

Aythya marila, Greater Scaup

Aythya affinis, Lesser Scaup

Somateria mollissima, Common Eider

Somateria spectabilis, King Eider

Histrionicus histrionicus, Harlequin Duck

Clangula hyemalis, Oldsquaw

Melanitta nigra, Black Scoter

Melanitta perspicillata, Surf Scoter

Melanitta fusca, White-winged Scoter

Bucephala clangula, Common Goldeneye

Bucephala albeola, Bufflehead
Lophodytes cucullatus, Hooded Merganser
Mergus merganser, Common Merganser
Mergus serrator, Red-breasted Merganser
Oxyura jamaicensis, Ruddy Duck
Oxyura dominica, Masked Duck

ORDER FALCONIFORMES

FAMILY CATHARTIDAE

Coragyps atratus, Black Vulture
Cathartes aura, Turkey Vulture

FAMILY ACCIPITRIDAE

Pandion haliaetus, Osprey
Elanoides forficatus, American Swallow-tailed Kite
Elanus caeruleus, Black-shouldered Kite
Rhostrhamus sociabilis, Snail Kite
Ictinia mississippiensis, Mississippi Kite
Haliaeetus leucocephalus, Bald Eagle
Circus cyaneus, Northern Harrier
Accipiter striatus, Sharp-shinned Hawk
Accipiter cooperii, Cooper's Hawk
Buteo lineatus, Red-shouldered Hawk
Buteo platypterus, Broad-winged Hawk
Buteo brachyurus, Short-tailed Hawk
Buteo swainsoni, Swainson's Hawk
Buteo jamaicensis, Red-tailed Hawk

FAMILY FALCONIDAE

Polyborus plancus, Crested Caracara
Falco sparverius, American Kestrel
Falco columbarius, Merlin
Falco peregrinus, Peregrine Falcon

ORDER GRUIFORMES

FAMILY RALLIDAE

Coturnicops noveboracensis, Yellow Rail
Laterallus jamaicensis, Black Rail
Rallus longirostris, Clapper Rail
Rallus elegans, King Rail
Rallus limicola, Virginia Rail
Porzana carolina, Sora
Porphyrio martinica, Purple Gallinule
Gallinula chloropus, Common Moorhen
Fulica americana, American Coot

FAMILY ARAMIDAE

Aramus guarauna, Limpkin

FAMILY GRUIDAE

Grus canadensis, Sandhill Crane

ORDER CHARADRIIFORMES

FAMILY CHARADRIIDAE

Pluvialis squatarola, Black-bellied Plover
Pluvialis dominica, Lesser Golden-Plover
Charadrius alexandrinus, Snowy Plover
Charadrius wilsonia, Wilson's Plover

Charadrius semipalmatus, Semipalmated Plover
Charadrius melodus, Piping Plover
Charadrius vociferus, Killdeer
Charadrius montanus, Mountain Plover

FAMILY HAEMATOPODIDAE

Haematopus palliatus, American Oystercatcher

FAMILY RECURVROSTRIDAE

Himantopus mexicanus, Black-necked Stilt
Recurvirostra americana, American Avocet

FAMILY SCOLOPACIIDAE

Tringa melanoleuca, Greater Yellowlegs
Tringa flavipes, Lesser Yellowlegs
Tringa solitaria, Solitary Sandpiper
Catoptrophorus semipalmatus, Willet
Actitis macularia, Spotted Sandpiper
Bartramia longicauda, Upland Sandpiper
Numenius phaeopus, Whimbrel
Numenius americanus, Long-billed Curlew
Limosa limosa, Black-tailed Godwit
Limosa haemastica, Hudsonian Godwit
Limosa fedoa, Marbled Godwit
Arenaria interpres, Ruddy Turnstone
Aphriza virgata, Surfbird
Calidris canutus, Red Knot
Calidris alba, Sanderling
Calidris pusilla, Semipalmated Sandpiper
Calidris mauri, Western Sandpiper
Calidris minutilla, Least Sandpiper
Calidris fuscicollis, White-rumped Sandpiper
Calidris bairdii, Baird's Sandpiper
Calidris melanotos, Pectoral Sandpiper
Calidris acuminata, Sharp-tailed Sandpiper
Calidris maritima, Purple Sandpiper
Calidris alpina, Dunlin
Calidris ferruginea, Curlew Sandpiper
Calidris himantopus, Stilt Sandpiper
Tryngites subruficollis, Buff-breasted Sandpiper
Philomachus pugnax, Ruff
Limnodromus griseus, Short-billed Dowitcher
Limnodromus scolopaceus, Long-billed Dowitcher
Gallinago gallinago, Common Snipe
Scolopax minor, American Woodcock
Phalaropus tricolor, Wilson's Phalarope
Phalaropus lobatus, Red-necked Phalarope
Phalaropus fulicaria, Red Phalarope

FAMILY LARIDAE

Stercorarius pomarinus, Pomarine Jaeger
Stercorarius parasiticus, Parasitic Jaeger
Stercorarius longicaudus, Long-tailed Jaeger
Larus atricilla, Laughing Gull
Larus pipixcan, Franklin's Gull
Larus minutus, Little Gull
Larus ridibundus, Common Black-headed Gull
Larus philadelphia, Bonaparte's Gull

Larus delawarensis, Ring-billed Gull
Larus argentatus, Herring Gull
Larus thayeri, Thayer's Gull
Larus fuscus, Lesser Black-backed Gull
Larus hyperboreus, Glaucous Gull
Larus marinus, Great Black-backed Gull
Rissa tridactyla, Black-legged Kittiwake
Xema sabini, Sabine's Gull
Sterna nilotica, Gull-billed Tern
Sterna caspia, Caspian Tern
Sterna maxima, Royal Tern
Sterna sandvicensis, Sandwich Tern
Sterna dougallii, Roseate Tern
Sterna hirundo, Common Tern
Sterna paradisaea, Arctic Tern
Sterna forsteri, Forster's Tern
Sterna antillarum, Least Tern
Sterna anaethetus, Bridled Tern
Sterna fuscata, Sooty Tern
Chlidonias niger, Black Tern
Anous stolidus, Brown Noddy
Anous minutus, Black Noddy
Rynchops niger, Black Skimmer

FAMILY ALCIDAE

Alle alle, Dovekie
Alca torda, Razorbill

ORDER COLUMBIFORMES

FAMILY COLUMBIDAE

Columba squamosa, Scaly-naped Pigeon
Columba leucocephala, White-crowned Pigeon
Columba fasciata, Band-tailed Pigeon
Zenaida asiatica, White-winged Dove
Zenaida aurita, Zenaida Dove
Zenaida macroura, Mourning Dove
Columbina passerina, Common Ground-Dove
Geotrygon chrysis, Key West Quail-Dove
Geotrygon montana, Ruddy Quail-Dove

ORDER CUCULIFORMES

FAMILY CUCULIDAE

Coccyzus erythrophthalmus, Black-billed Cuckoo
Coccyzus americanus, Yellow-billed Cuckoo
Coccyzus minor, Mangrove Cuckoo
Crotophaga ani, Smooth-billed Ani
Crotophaga sulcirostris, Groove-billed Ani

ORDER STRIGIFORMES

FAMILY TYTONIDAE

Tyto alba, Common Barn-Owl

FAMILY STRIGIDAE

Otus asio, Eastern Screech-Owl
Bubo virginianus, Great Horned Owl
Athene cunicularia, Burrowing Owl
Strix varia, Barred Owl

Asio otus, Long-eared Owl
Asio flammeus, Short-eared Owl
Aegolius acadicus, Northern Saw-whet Owl

ORDER CAPRIMULGIFORMES

FAMILY CAPRIMULGIDAE

Chordeiles acutipennis, Lesser Nighthawk
Chordeiles minor, Common Nighthawk
Chordeiles gundlachii, Antillean Nighthawk
Caprimulgus carolinensis, Chuck-will's-widow
Caprimulgus vociferus, Whip-poor-will

ORDER APODIFORMES

FAMILY APODIDAE

Chaetura pelagica, Chimney Swift
Tachornis phoenicobia, Antillean Palm Swift

FAMILY TROCHILIDAE

Amazilia yucatanensis, Buff-bellied Hummingbird
Calliphlox evelynae, Bahama Woodstar
Archilochus colubris, Ruby-throated Hummingbird
Archilochus alexandri, Black-chinned Hummingbird
Selasphorus rufus, Rufous Hummingbird

ORDER CORACIIFORMES

FAMILY ALCEDINIDAE

Ceryle alcyon, Belted Kingfisher

ORDER PICIFORMES

FAMILY PICIDAE

Melanerpes erythrocephalus, Red-headed Woodpecker
Melanerpes carolinus, Red-bellied Woodpecker
Sphyrapicus varius, Yellow-bellied Sapsucker
Picoides pubescens, Downy woodpecker
Picoides villosus, Hairy woodpecker
Picoides borealis, Red-cockaded woodpecker
Colaptes auratus, Northern Flicker
Dryocopus pileatus, Pileated Woodpecker
Campephilus principalis, Ivory-billed Woodpecker

ORDER PASSERIFORMES

FAMILY TYRANNIDAE

Contopus borealis, Olive-sided flycatcher
Contopus virens, Eastern Wood-Pewee
Empidonax flaviventris, Yellow-bellied Flycatcher
Empidonax virescens, Acadian Flycatcher
Empidonax alnorum, Alder Flycatcher
Empidonax traillii, Willow Flycatcher
Empidonax minimus, Least Flycatcher
Sayornis nigricans, Black Phoebe
Sayornis phoebe, Eastern Phoebe
Sayornis saya, Say's Phoebe
Pyrocephalus rubinus, Vermilion Flycatcher
Myiarchus cinerascens, Ash-throated Flycatcher
Myiarchus crinitus, Great Crested Flycatcher
Myiarchus tyrannulus, Brown-crested Flycatcher
Tyrannus vociferans, Cassin's Kingbird

Tyrannus verticalis, Western Kingbird
Tyrannus tyrannus, Eastern Kingbird
Tyrannus dominicensis, Gray Kingbird
Tyrannus caudifasciatus, Loggerhead Kingbird
Tyrannus forficatus, Scissor-tailed Flycatcher
Tyrannus savana, Fork-tailed Flycatcher

FAMILY ALAUDIDAE

Eremophila alpestris, Horned Lark

FAMILY HIRUNDINIDAE

Progne subis, Purple Martin
Tachycineta bicolor, Tree Swallow
Tachycineta cyaneoviridis, Bahama Swallow
Stelgidopteryx serripennis, Northern Rough-winged Swallow
Riparia riparia, Bank Swallow
Hirundo pyrrhonota, Cliff Swallow
Hirundo fulva, Cave Swallow
Hirundo rustica, Barn Swallow

FAMILY CORVIDAE

Cyanocitta cristata, Blue Jay
Aphelocoma coerulescens, Scrub Jay
Corvus brachyrhynchos, American Crow
Corvus ossifragus, Fish Crow

FAMILY PARIDAE

Parus carolinensis, Carolina Chickadee
Parus bicolor, Tufted Titmouse

FAMILY SITTIDAE

Sitta canadensis, Red-breasted Nuthatch
Sitta pusilla, Brown-headed Nuthatch

FAMILY CETHIIDAE

Certhia americana, Brown Creeper

FAMILY TROGLODYTIDAE

Thryothorus ludovicianus, Carolina Wren
Troglodytes aedon, House Wren
Troglodytes troglodytes, Winter Wren
Cistothorus platensis, Sedge Wren
Cistothorus palustris, Marsh Wren

FAMILY MUSCICAPIDAE

SUBFAMILY SYLVIINAE

Regulus satrapa, Golden-crowned Kinglet
Regulus calendula, Ruby-crowned Kinglet
Poliophtila caerulea, Blue-gray Gnatcatcher

SUBFAMILY TURDINAE

Oenanthe oenanthe, Northern Wheatear
Sialis sialis, Eastern Bluebird
Catharus fuscescens, Veery
Catharus minimus, Gray-cheeked Thrush
Catharus ustulatus, Swainson's Thrush
Catharus guttatus, Hermit Thrush
Hylocichla mustelina, Wood Thrush
Turdus migratorius, American Robin
Ixoreus naevius, Varied Thrush

FAMILY MIMIDAE

Dumetella carolinensis, Gray Catbird
Mimus polyglottos, Northern Mockingbird
Toxostoma rufum, Brown Thrasher

FAMILY MOTACILLIDAE

Anthus spragueii, Sprague's Pipit

FAMILY BOMBYCILLIDAE

Bombycilla cedrorum, Cedar Waxwing

FAMILY LANIIDAE

Lanius ludovicianus, Loggerhead Shrike

FAMILY VIREONIDAE

Vireo griseus, White-eyed Vireo
Vireo bellii, Bells' Vireo
Vireo solitarius, Solitary Vireo
Vireo flavifrons, Yellow-throated Vireo
Vireo gilvus, Warbling Vireo
Vireo philadelphicus, Philadelphia Vireo
Vireo olivaceus, Red-eyed Vireo
Vireo altiloquus, Black-whiskered Vireo

FAMILY EMBERIZIDAE

SUBFAMILY PARULINAE

Vermivora bachmanii, Bachman's Warbler
Vermivora pinus, Blue-winged Warbler
Vermivora chrysoptera, Golden-winged Warbler
Vermivora peregrina, Tennessee Warbler
Vermivora celata, Orange-crowned Warbler
Vermivora ruficapilla, Nashville Warbler
Parula americana, Northern Parula
Dendroica petechia, Yellow Warbler
Dendroica pensylvanica, Chestnut-sided Warbler
Dendroica magnolia, Magnolia Warbler
Dendroica tigrina, Cape May Warbler
Dendroica caerulescens, Black-throated Blue Warbler
Dendroica coronata, Yellow-rumped Warbler
Dendroica nigrescens, Black-throated Gray Warbler
Dendroica townsendi, Townsend's Warbler
Dendroica virens, Black-throated Green Warbler
Dendroica fusca, Blackburnian Warbler
Dendroica dominica, Yellow-throated Warbler
Dendroica pinus, Pine Warbler
Dendroica kirtlandii, Kirtland's Warbler
Dendroica discolor, Prairie Warbler
Dendroica palmarum, Palm Warbler
Dendroica castanea, Bay-breasted Warbler
Dendroica striata, Blackpoll Warbler
Dendroica cerulea, Cerulean Warbler
Mniotilta varia, Black-and-White Warbler
Setophaga ruticilla, American Redstart
Protonotaria citrea, Prothonotary Warbler
Helmitheros vermivorus, Worm-eating Warbler
Limnithlypis swainsonii, Swainson's Warbler
Seiurus aurocapillus, Ovenbird
Seiurus noveboracensis, Northern Waterthrush
Seiurus motacilla, Louisiana Waterthrush

Oporornis formosus, Kentucky Warbler
Oporornis agilis, Connecticut Warbler
Oporornis philadelphia, Mourning Warbler
Geothlypis trichas, Common Yellowthroat
Wilsonia citrina, Hooded Warbler
Wilsonia pusilla, Wilson's Warbler
Wilsonia canadensis, Canada Warbler
Icteria virens, Yellow-breasted Chat

SUBFAMILY THRAUPINAE

Spindalis zena, Stripe-headed Tanager
Piranga rubra, Summer Tanager
Piranga olivacea, Scarlet Tanager
Piranga ludoviciana, Western Tanager

SUBFAMILY CARDINALINAE

Cardinalis cardinalis, Northern Cardinal
Pheucticus ludovicianus, Rose-breasted Grosbeak
Pheucticus melanocephalus, Black-headed Grosbeak
Guiraca caerulea, Blue Grosbeak
Passerina amoena, Lazuli Bunting
Passerina cyanea, Indigo Bunting
Passerina ciris, Painted Bunting
Spiza americana, Dickcissel

SUBFAMILY EMBERIZINAE

Pipilo erythrophthalmus, Rufous-sided Towhee
Tiaris bicolor, Black-faced Grassquit
Aimophila aestivalis, Bachman's Sparrow
Spizella passerina, Chipping Sparrow
Spizella pallida, Clay-colored Sparrow
Spizella pusilla, Field Sparrow
Pooecetes gramineus, Vesper Sparrow
Chondestes grammacus, Lark Sparrow
Calamospiza melanocorys, Lark Bunting
Passerculus sandwichensis, Savannah Sparrow
Ammodramus savannarum, Grasshopper Sparrow
Ammodramus henslowii, Henslow's Sparrow
Ammodramus leconteii, Le Conte's Sparrow
Ammodramus caudacutus, Sharp-tailed Sparrow
Ammodramus maritimus, Seaside Sparrow
Melospiza melodia, Song Sparrow
Melospiza lincolni, Lincoln's Sparrow
Melospiza georgiana, Swamp Sparrow
Zonotrichia albicollis, White-throated Sparrow
Zonotrichia leucophrys, White-crowned Sparrow
Zonotrichia querula, Harris' Sparrow
Junco hyemalis, Dark-eyed Junco
Calcarius lapponicus, Lapland Longspur

SUBFAMILY ICTERINAE

Dolichonyx oryzivorus, Bobolink
Agelaius phoeniceus, Red-winged Blackbird
Sturnella magna, Eastern Meadowlark
Sturnella neglecta, Western Meadowlark
Xanthocephalus xanthocephalus, Yellow-headed Blackbird
Euphagus carolinus, Rusty Blackbird
Euphagus cyanocephalus, Brewer's Blackbird
Quiscalus major, Boat-tailed Grackle

Quiscalus quiscula, Common Grackle
Molothrus bonariensis, Shiny Cowbird
Molothrus aeneus, Bronzed Cowbird
Molothrus ater, Brown-headed Cowbird
Icterus spurius, Orchard Oriole
Icterus galbula, Northern Oriole

FAMILY FRINGILLIDAE

SUBFAMILY CARDUELINAE

Carpodacus purpureus, Purple Finch
Carduelis pinus, Pine Siskin
Carduelis tristis, American Goldfinch



Table 2.3-1
State Listed Species On or Near the Power Park

Protected Plants

Lechea cernua (nodding pinweed, State Threatened)

Osmunda cinnamomea (cinnamon fern, Commercially Exploited)

Osmunda regalis (royal fern, commercially Exploited)

Encyclia tampensis (butterfly orchid, Commercially Exploited)

Epidendrum conopseum (greenfly orchid, Commercially Exploited)

Garberia heterophylla (garberia, State Threatened)



Table 2.3-1 (Continued)
State Listed Species On or Near the Power Park

Protected Animals

Florida scrub jay (*Aphelocoma coerulescens*, State Threatened, Federally Threatened)

Gopher frog (*Rana capito*, State Species of Special Concern)

American alligator (*Alligator mississippiensis*, State Species of Special Concern, Federally Threatened)

Eastern Indigo snake (*Drymarchon corais couperi*, State Threatened, Federally Threatened)

Gopher Tortoise (*Gopherus polyphemus*, State Species of Special Concern)

Bald eagle (*Haliaeetus leucocephalus*, State Threatened)

Red-cockaded woodpecker (*Picoides borealis*, State Threatened, Federally Endangered)

Florida panther (*Felis concolor coryi*, State Endangered, Federally Endangered)

Florida mouse (*Peromyscus floridanus*, State Species of Special Concern)

Florida black bear (*Ursus americanus floridanus*, State Threatened)



Several common animals classified as fur bearers and game animals occur or could potentially occur in the power block area. However, the potential for the game and furbearer species to occur in the power block area is low because of the disturbances and human presence during operation and maintenance of the facilities. Prior to any construction at the Power Park, and on a regular basis since operation, wildlife monitoring efforts have recorded over 100 species. A list of the species observed at the Power Park is included in Appendix 10.11.

2.3.6.1 Species-environmental relationships. It is possible that all of the animals mentioned above use the power block area as habitat for feeding. This habitat is likely used by eastern cottontails and is utilized by gopher tortoises as habitat for breeding. Eastern cottontails usually occur in forested areas and are known to nest very close to human activity. Gopher tortoises occur in areas that have well-drained, sandy soils, which allow easy burrowing, support an abundance of herbaceous ground cover, and generally have an open canopy with sparse shrub cover (Cox et. al., 1987). Gopher tortoise nesting sites are typically located just outside the burrow.

2.3.6.2 Pre-existing stresses. Prior to KUA acquiring the property and prior to construction of any power generation facilities on Cane Island, pre-existing stresses were caused by the alteration and removal of habitat on the southern end of Cane Island. The alteration and removal of habitat was done in an attempt to attract game animals for hunters.

Environmental stresses existing prior to construction of Unit 3 include removal of habitat for construction, noise from operation, and activity of pedestrian and vehicular traffic for maintenance of Units 1 and 2 facilities. The remaining vegetation on the southern end of Cane Island will be granted to the SFWMD in a conservation easement. This area is monitored and managed according to the *Cane Island Project Mitigation Plan*. The remaining vegetation on the north end of Cane Island is also in conservation easement and is monitored and managed. The conservation and exclusion areas are shown on Figure 2.3-5.

2.3.6.3 Measurement Programs. Initial vegetation and wildlife investigations of the 1,027 acre Power Park site began in 1991 as part of an Environmental Assessment for the proposed simple cycle combustion turbine facility (Unit 1). Environmental studies were conducted by Black & Veatch and its consultant, Alvarez, Lehman & Associates, Inc. (Gainesville, FL). Studies consisted of protected species surveys, general wildlife surveys, plant species identification, plant community assessments, and wetland delineations.

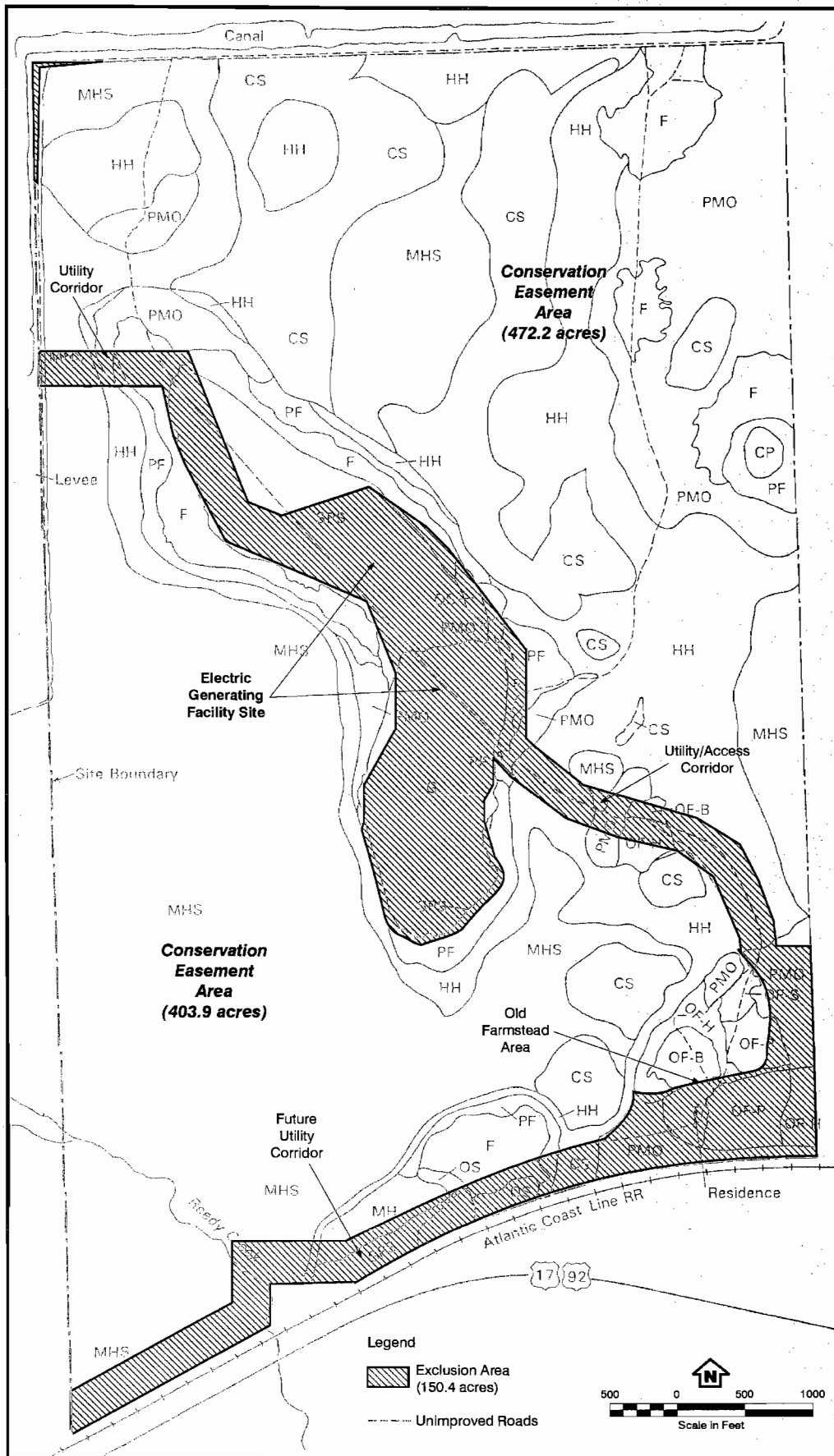


Figure 2.3-5



Measurement programs were established to assess floral and faunal characteristics of the Power Park resulting from development of the power generation facilities. The *Cane Island Project Mitigation Plan* describes the measurement and monitoring programs in detail. Line transects, nested quadrats, and meter square quadrats are used to assess the composition of the upland and wetland vegetation. Vegetation monitoring was conducted in the spring and summer of 1993 and in the summer of 1997 and will continue to be conducted once every five years until 2023. Growth and abundance of the trees planted in the wetland created as mitigation was assessed in the fall of 1993, 1994, 1995, and 1996. During botanical surveys, plants were identified by a botanist and verified by using the collections of the University of Kansas Herbarium, Lawrence, Kansas. Through an extended program of exchange and collection, this herbarium includes a large number of specimens from the southeast United States. Voucher specimens were collected for some plants and deposited in the University of Kansas Herbarium.

The flora used to aid plant identification was the following:

Godfrey, R. K., and J. W. Wooten. Aquatic and Wetland Plants of Southeastern United States, 1979. The University of Georgia Press, Athens.
Wunderlin, R. P., Guide to the Vascular Plants of Central Florida, University of North Florida, Jacksonville, 1982.

Wildlife is surveyed by using opportunistic observations, pedestrian surveys, and live-trapping. Special efforts are used to assess the occurrence of gopher tortoises, Florida mice (*Peromyscus floridanus*), gopher frogs (*Rana areolata*), and scrub jays in the Power Park.

Gopher tortoise densities are determined by conducting burrow surveys following FGFWFC guidelines (Allen 1988). Mammal traplines are established in areas with potential for the occurrence of the Florida mouse. Funnel traps are placed in the entrances of gopher tortoise burrows to determine the status of gopher frogs. Scrub jay recordings are played along avian transects in all scrub habitats to enhance the probability of detecting scrub jays. Wildlife monitoring efforts were conducted in 1993 and 1997 and will continue to be performed once every 5 years until 2023.

Annual habitat monitoring reports are submitted to the SFWMD and other interested agencies.



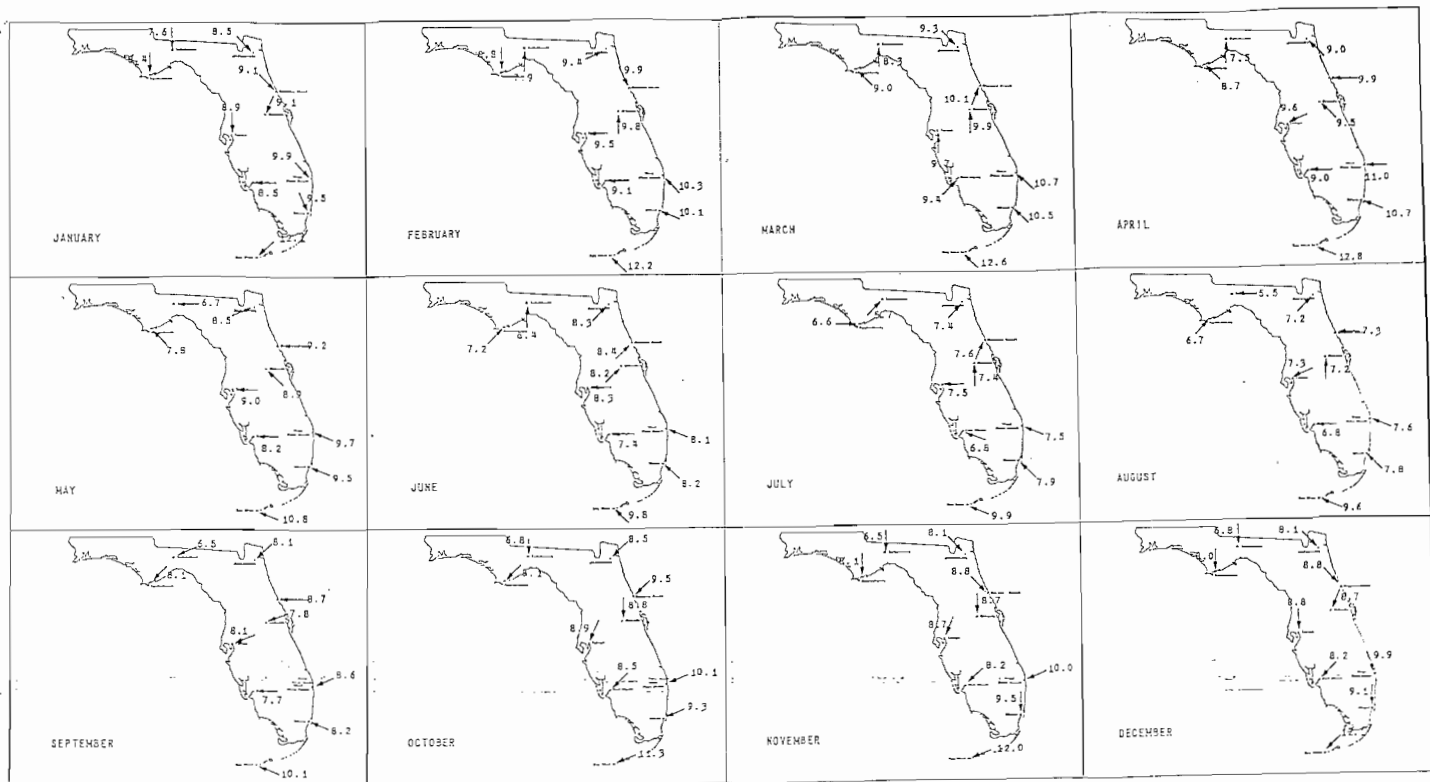
2.3.7 Meteorology and Ambient Air Quality

2.3.7.1 Regional Climatology/Meteorology. The prevailing subtropical marine climate of the central Florida region results from the influence of the Atlantic Ocean and the Bermuda high-pressure system. Long, warm, humid summers and short, mild winters prevail. Because of the southerly location and marine influences, this area has a climate characterized by small annual and diurnal temperature variations. Rainfall is moderate to heavy during the summer (rainy season) and light during the winter (dry season). Well developed extratropical migratory high- and low-pressure centers usually travel north of the region.

Winds are of moderate speed and blow predominantly from the south to southeast during the spring and summer (February through August). During the fall and winter months (September through January), the predominant direction is from the north to northeast. Along the coastal areas of central Florida, local land-sea breeze circulations modify regional wind patterns by superimposing an easterly wind component during the daytime hours and a westerly component at night. Monthly and annual wind speed and prevailing direction for selected Florida locations are given on Figures 2.3-6 and 2.3-7, respectively. Hurricane force winds have a 1 in 7 chance of occurrence for any given year in Palm Beach and a 1 in 100 chance of occurring in Jacksonville (Bradley, 1972).

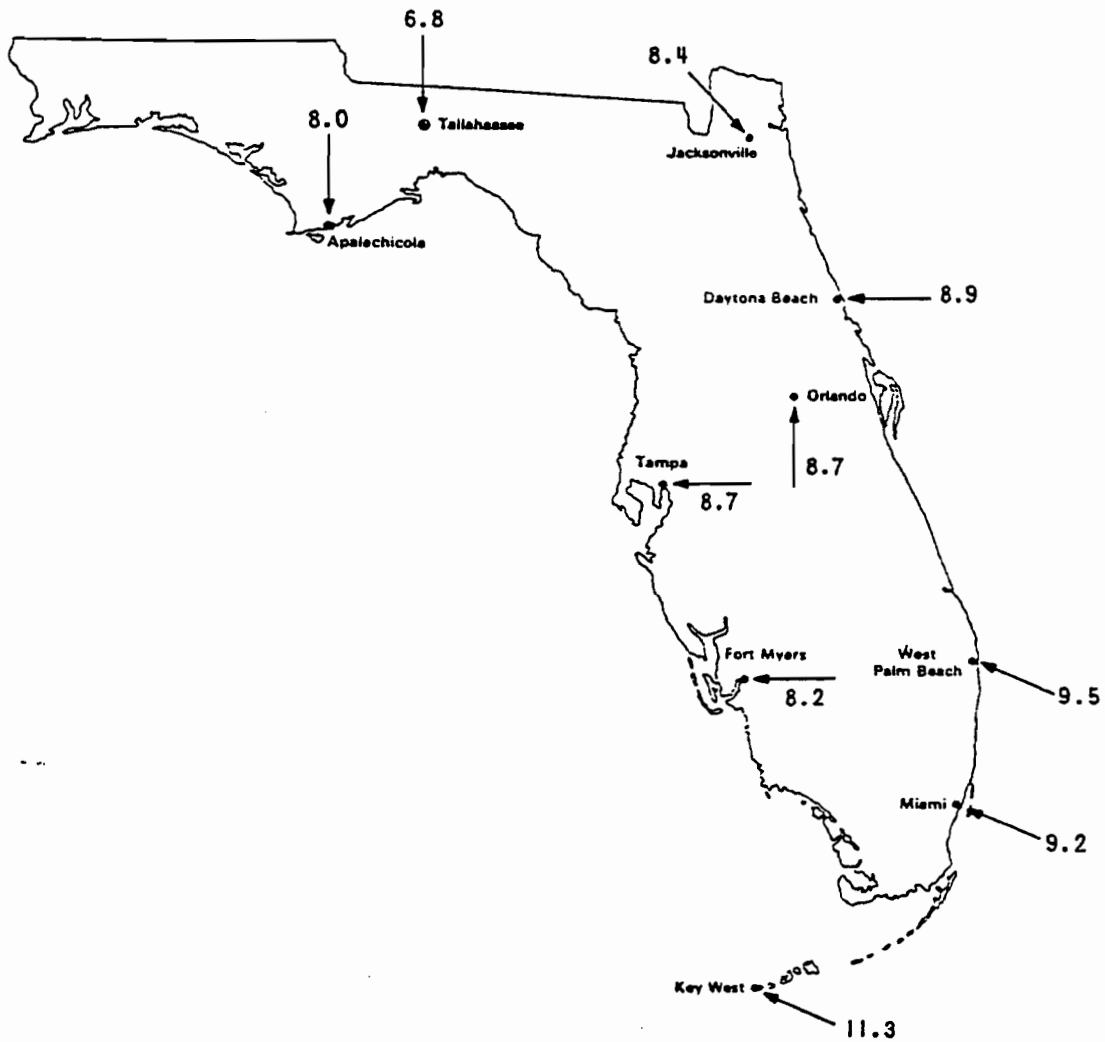
The average annual rainfall in this region is approximately 50 inches. Summer precipitation due to frequent afternoon thundershowers exceeds winter precipitation due to frontal systems, pre-frontal squall lines, and wave disturbances along fronts stalled over the Florida peninsula. Summer precipitation is mostly of the convective type, resulting in frequent summertime afternoon thundershowers in this region. Tropical disturbances periodically cause significant precipitation during the summer and fall seasons.

Extremely hot weather is rare because of the ocean influence; maximum temperatures over a summer average near 90° F along the coast and low-90s in the Power Park region. Winter temperatures are mild, interrupted only a few times each season by northerly or northwesterly advection of polar air. In these cases, minimum temperatures may reach 32° F. Only rarely do temperatures fall below 32° F. Inland locations generally display a greater range of temperatures because of the rapid heating and cooling of ground surfaces as compared with water bodies. With the abundance of lakes in this region, average annual humidities are high, ranging in percent from the mid-50s during the afternoon to the upper-80s at night.



NOTE: NUMBERS GIVEN ARE SCALAR AVERAGE
WIND SPEED IN MILES PER HOUR.
ARROWS FLY WITH WIND.

Monthly Average Wind Speed and Prevailing
Direction for Selected Florida Cities
Figure 2.3-6



NOTE: NUMBERS GIVEN ARE SCALAR AVERAGE
WIND SPEED IN MILES PER HOUR.
ARROWS FLY WITH WIND.

Annual Average Wind Speed and Prevailing
Direction for Selected Florida Cities
Figure 2.3-7



The dispersion characteristics of the region are generally good because of land-sea and lake breeze circulations, good ventilation, mixing due to convective instability, and flat terrain.

2.3.7.2 Site Climatology. The Power Park is located in central Florida about 45 miles inland from the Atlantic Ocean. This region of the United States is subject to a subtropical climate which is partly influenced by the Atlantic Ocean. This results in small to moderate variations in temperature and relative humidity throughout the year. Monthly precipitation is fairly consistent, with a peak in the summer months. The occurrence of severe weather is usually associated with midsummer thunderstorms. The summers are long and rather warm, with periods of hot and humid weather. The winters are mild with occasional cool mornings due to invasion of cool northern air.

There are no existing local meteorological data with long periods of record for the Power Park. However, there is a location with meteorological data covering long periods of record which are considered representative of the Power Park area. This location is the National Weather Service (NWS) office in Orlando, Florida. The NWS office is approximately 20 miles northeast of the Power Park at an elevation of 96 feet above mean sea level.

Temperatures and Humidity

The temperature variation from season to season is slight, with warm, humid summers and mild winters. Table 2.3-2 presents a summary of the means and extremes of monthly and daily dry-bulb temperatures. Temperatures above 90° F occur during the summer months. The hottest month is August, with a mean monthly temperature of 82.5° F. The daily minimum and maximum temperature averages are 73.4° F and 91.5° F, respectively, for this month. Subfreezing temperatures rarely occur (i.e., about 3 days per year) and subzero temperatures have never been recorded. In some years, no freezing temperatures occur.

January is the coldest month with a mean monthly temperature of 59.7° F. Average January daily minimum and maximum temperatures are 48.6° F and 70.8° F, respectively. The absolute temperature range is from 102° F (May) to 19° F (January).

Table 2.3-3 presents a summary of the wet-bulb and dry-bulb design temperatures. The 1 and 5 percent wet-bulb temperatures for June through September are 79° F and 78° F, respectively. The 1 and 5 percent dry-bulb temperatures, based on historical data from June through September, are 93° F and 90° F, respectively (Department of Army, Navy, and Air



Table 2.3-2
Dry-Bulb Temperature Data for Orlando, Florida

Month	Normal Temperature*			Extreme Temperature**	
	Monthly (F)	Daily Minimum (F)	Daily Maximum (F)	Lowest (F)	Highest (F)
January	59.7	48.6	70.8	19	87
February	61.2	49.7	72.7	26	90
March	66.7	55.2	78.0	25	92
April	71.2	59.4	83.0	38	96
May	76.9	65.9	87.8	48	102
June	81.1	71.8	90.5	53	100
July	82.3	73.1	91.5	64	100
August	82.5	73.4	91.5	64	100
September	81.0	72.4	89.7	56	98
October	75.2	65.8	84.6	43	95
November	68.0	57.5	78.5	29	89
December	62.1	51.3	72.9	20	90
Annual	72.3	62.0	82.6	19	102
<u>Season</u>					
Summer	82.0	72.8	91.2	53	100
Fall	74.7	65.2	84.3	29	98



Table 2.3-2 (Continued)
Dry-Bulb Temperature Data for Orlando, Florida

Month	Normal Temperature*			Extreme Temperature**	
	Monthly (F)	Daily Minimum (F)	Daily Maximum (F)	Lowest (F)	Highest (F)
Winter	61.0	49.9	72.1	19	90
Spring	71.6	60.2	82.9	25	102

*Period of record: 1961-1990.

**Period of record: 1943-1996.

Source: United States Department of Commerce, Local Climatological Data--Annual Summary with Comparative Data--1996, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1997.



Table 2.3-3
Wet-Bulb and Dry-Bulb Design Temperatures
for Orlando, Florida

Percent of Time	Temperatures (°F)	
	Wet-Bulb	Dry-Bulb
1*	79	93
2.5*	78	92
5*	78	90
10*	77	88
97.5**	--	39
99**	--	35

*Percentage of the time the temperature is exceeded during the months of June through September.

**Percentage of the time the temperature is exceeded during the months of December, January, and February.

Source: Departments of the Army, the Navy, and the Air Force, Army, Navy, and Air Force Manual-Engineering Weather Data, April, 1963.



Force, April 1963). The 1 percent temperatures are exceeded only 1 percent of the time, and the 5 percent temperatures are exceeded 5 percent of the time. Table 2.3-3 also includes other design temperatures for percentages of 2.5, 5, 97.5, and 99.

Average relative humidities are presented in Table 2.3-4 (US Department of Commerce, 1997). The table shows that the average annual relative humidity is approximately 74 percent. Hourly average minimum and maximum values are 46 percent and 92 percent and occur at 1300 in April and 0700 in August, respectively. The relative humidity does not vary significantly from season to season, with winter days being slightly drier. Heavy fog visibility (1/4 mile or less) averages only 26 days per year at Orlando (US Department of Commerce, 1997).

Heating and Cooling Degree-Days

Units of degree-days can be used as an indicator of heating or cooling requirements. One heating degree-day is accumulated for each degree that the daily mean temperature drops below the base temperature of 65° F. Cooling degree-days are accumulated when the daily mean temperature is above 65° F. Table 2.3-5 gives mean monthly and annual degree-day totals considered representative of the Power Park area.

Precipitation

Normal monthly and annual precipitation (rain) totals are shown in Table 2.3-6. As shown in the table, precipitation is highest during the summer months. Annually, thunderstorms occur about 83 days, mainly during the summer.

During the period 1967-1996, the annual precipitation has ranged from 38.12 inches to 67.85 inches. Measurable snows under 1/2 inch have been recorded only a few times in the last century. Only a trace of snowfall was recorded during the period 1970 through 1996. Extreme monthly precipitation totals are listed in Table 2.3-7. The highest recorded 24-hour rainfall and snowfall totals are 9.67 inches (September 1943) and a trace, respectively. Maximum recorded rainfall totals for various time periods are presented in Table 2.3-8. Precipitation maximums and intensities for various return periods and durations are shown in Table 2.3-9.



Table 2.3-4
Normal Relative Humidity Data for Orlando, Florida*

Month	Hour (Local Standard Time)				
	0100 (percent)	0700 (percent)	1300 (percent)	1900 (percent)	Normal (percent)
January	84	87	56	68	73
February	84	87	53	63	71
March	84	88	51	62	70
April	83	87	46	58	67
May	86	88	49	63	70
June	89	90	57	73	76
July	89	91	59	75	78
August	91	92	60	78	79
September	90	91	60	78	79
October	87	88	55	74	75
November	87	89	55	73	75
December	86	87	56	72	74
Annual	87	89	55	70	74
<u>Season</u>					
Summer	90	91	59	76	78
Fall	88	89	57	75	76
Winter	85	87	55	68	73
Spring	84	88	49	61	69

*Period of record: 1961-1990.

Source: United States Department of Commerce, Local Climatological Data-- Annual Summary with Comparative Data--1996, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1997.



Table 2.3-5
Heating and Cooling Degree-Day Data
for Orlando, Florida*

Month	Normal Degree-Day	
	Heating**	Cooling**
January	234	70
February	164	86
March	65	117
April	5	191
May	0	369
June	0	483
July	0	536
August	0	543
September	0	480
October	0	316
November	54	144
December	164	74
Annual	686	3,381

*Period of record: 1961-1990.

**Base 65° F.

Source: United States Department of Commerce, Local Climatological Data--Annual Summary with Comparative Data--1996, Orlando, Florida, National Climatic Data Center, Asheville, North Carolina, 1997.



Table 2.3-6
Total Precipitation Data for Orlando, Florida

Month	Normal Precipitation* (inches)
January	2.30
February	3.02
March	3.21
April	1.80
May	3.55
June	7.32
July	7.25
August	6.78
September	6.01
October	2.42
November	2.30
December	2.15
Annual	48.11

*Period of record: 1961-1990.

**Base 65° F.

Source: United States Department of Commerce, Local Climatological Data--Annual Summary with Comparative Data--1996, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1997.



Table 2.3-7
Extreme Precipitation Data for Orlando, Florida*

Month	Extreme Precipitation			Extreme Snowfall	
	Maximum 24-Hour (inches)	Maximum Monthly (inches)	Minimum Monthly (inches)	Maximum 24-Hour (inches)	Maximum Monthly (inches)
January	4.19	7.23	0.15	Trace	Trace
February	4.38	8.32	0.10	--	--
March	5.03	11.38	0.16	Trace	Trace
April	5.65	9.10	0.14	Trace	Trace
May	3.18	10.36	0.43	--	--
June	8.40	18.28	1.97	--	--
July	8.19	19.57	2.60	Trace	Trace
August	5.29	16.11	2.92	Trace	Trace
September	9.67	15.87	0.43	--	--
October	7.74	14.51	0.35	--	--
November	5.87	10.29	0.03	--	--
December	3.61	5.33	Trace	--	--
Annual	9.67	19.57	Trace	Trace	Trace

*Period of record: 1943-1996.

Source: United States Department of Commerce, Local Climatological Data--Annual Summary with Comparative Data--1996, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1997.



Table 2.3-8
Maximum Recorded Rainfall Data for Orlando, Florida

Duration	Rainfall (inches)	Date
5 minutes*	0.82	April 13, 1952
10 minutes*	1.25	July 25, 1960
15 minutes*	1.80	July 23, 1958
30 minutes*	3.42	July 25, 1960
60 minutes**	5.75	July 25, 1960
2 hours**	7.95	July 25, 1960
3 hours**	8.16	July 25, 1960
6 hours**	8.19	July 25, 1960
12 hours**	8.19	July 25, 1960
24 hours**	9.67	September 15, 1943
*Period of record: 1952-1961. **Period of record: 1941-1961. Source: United States Weather Bureau, <u>Maximum Recorded United States Point Rainfall for 5 Minutes to 24 Hours at 296 First-Order Stations</u>, Technical Paper No. 2, Washington, D.C., 1963.		



Table 2.3-9
Precipitation Amounts and Intensities for
Selected Durations and Return Periods
Expected in the Power Park Area

PRECIPITATION AMOUNTS							
Duration (hours)	Return Period						
	1-Year (inches)	2-Year (inches)	5-Year (inches)	10-Year (inches)	25-Year (inches)	50-Year (inches)	100-Year (inches)
½	1.56	1.80	2.15	2.42	2.83	3.04	3.30
1	2.02	2.25	2.78	3.08	3.48	3.83	4.14
2	2.33	2.72	3.40	3.75	4.30	4.76	5.30
3	2.52	2.80	3.75	4.29	4.75	5.39	5.90
6	2.90	3.49	4.40	5.15	5.90	6.35	7.35
12	3.40	4.15	5.25	6.25	7.40	8.10	8.94
24	3.90	4.75	6.25	7.10	9.00	9.50	10.50
PRECIPITATION INTENSITIES							
Duration (hours)	Return Period						
	1-Year (inches/h)	2-Year (inches/h)	5-Year (inches/h)	10-Year (inches/h)	25-Year (inches/h)	50-Year (inches/h)	100-Year (inches/h)
½	3.12	3.60	4.30	4.84	5.66	6.08	6.60
1	2.02	2.25	2.78	3.08	3.48	3.83	4.14
2	1.17	1.36	1.70	1.88	2.15	2.38	2.65
3	0.84	0.93	1.25	1.43	1.58	1.80	1.97
6	0.48	0.58	0.73	0.86	0.98	1.06	1.23
12	0.28	0.35	0.44	0.52	0.62	0.68	0.75
24	0.16	0.20	0.26	0.30	0.38	0.40	0.44
Source: United States Weather Bureau, <u>Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24 Hours and Return Periods from 1 to 100 Years</u> , Technical Paper No. 40, Washington, D.C., May 1961.							



Wind Characteristics

Five years of wind data (1988-1992) were used to generate the annual and monthly wind roses from Orlando, as shown on Figures 2.3-8 through 2.3-20. These wind roses are considered appropriate in describing the general wind flow at the Power Park. Table 2.3-10 includes the annual percent frequency of occurrence of the wind speed categories for each of the 16 wind directions. The annual wind rose shows a predominance of south to northeasterly flow with a secondary preference for northerly flow. The winter months show a predominance of winds from the north at a maximum speed of 11-16 knots. The spring and summer months show abundance of southerly and easterly winds, which could be a result of the easterly trade winds. Fall months show a predominance of winds from the northeast quadrant.

The design wind speed for wind loadings is 105 miles per hour for the Power Park area (ANSI, 1982). The Orlando fastest observed 2 minute wind speed and peak gust on record are 64 and 74 miles per hour, respectively. The periods of record for the fastest 2 minute wind speed and peak gust are 47 and 13 years, respectively.

2.3.7.3 Atmospheric Dispersion. Atmospheric dispersion depends primarily on four meteorological parameters:

- Height of the mixing layer (mixing height).
- Wind speed within the mixing layer.
- Frequency of low level temperature inversions.
- Atmospheric stability.

Holzworth (1972) has estimated mean mixing depths and average wind speed within the mixing layer for 62 National Weather Service radiosonde stations within the 48 contiguous states. The morning and afternoon mixing depths are calculated from the twice daily vertical temperature profiles and the morning and afternoon surface temperatures. Within the mixing depth, relatively vigorous mixing occurs. Diffusion within layers above this height is inhibited because of thermal buoyancy considerations (that is, neutral or slightly stable conditions). The worst dispersion conditions occur when both the mixing depth and wind speed are low. In general, Holzworth's data show that Florida has the best combinations of greater mixing depths and higher wind speeds than other areas. Table 2.3-11 presents values of seasonal and annual morning and afternoon mixing depths and wind speed representative of the Power Park area.

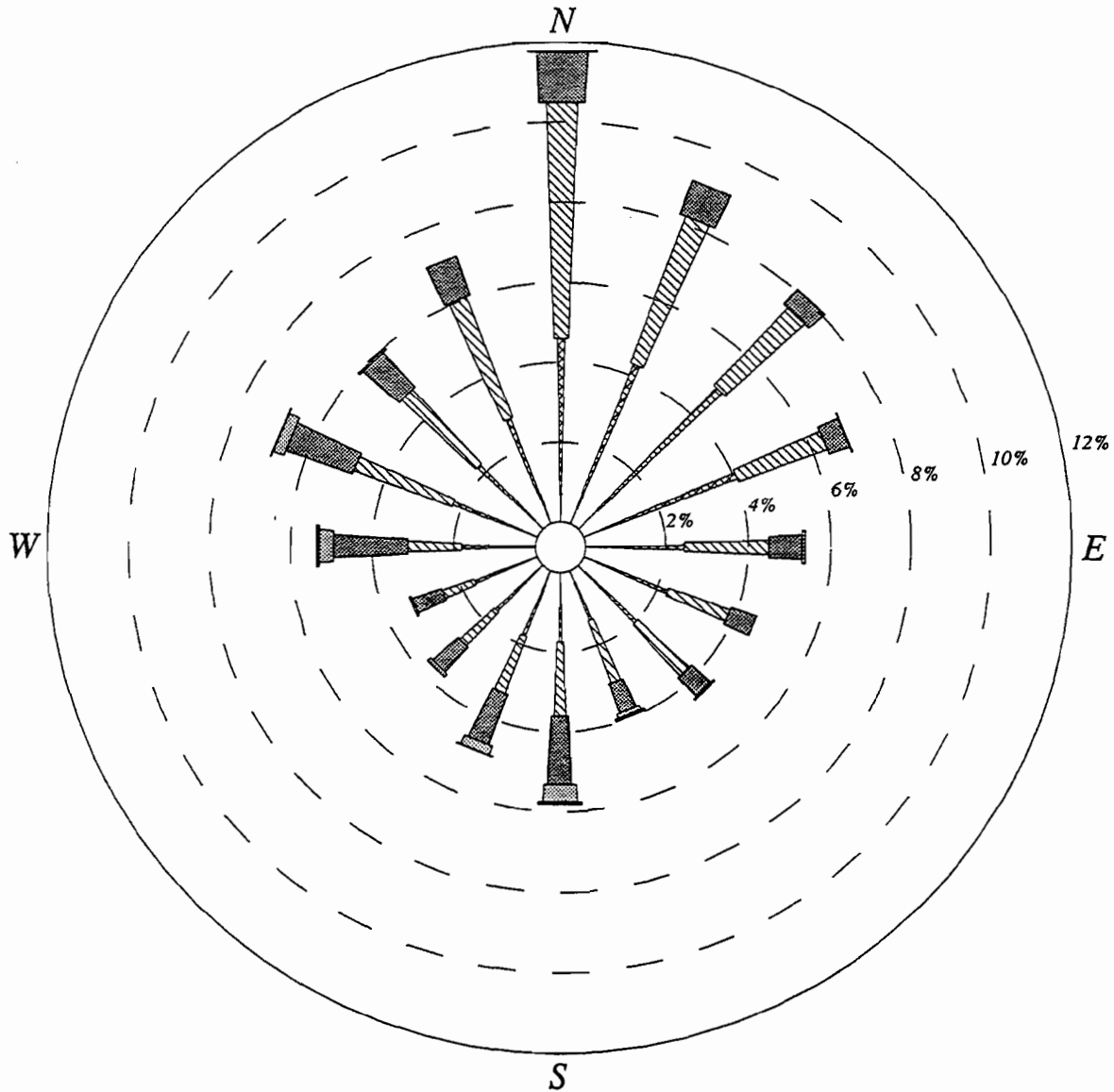
IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Orlando, FL

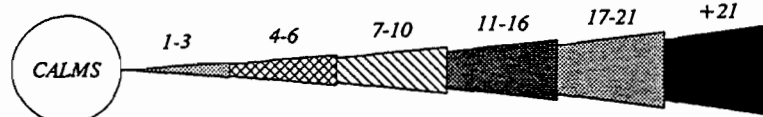
January 1-January 31; Midnight-11 PM



CALM WINDS 2.72%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.

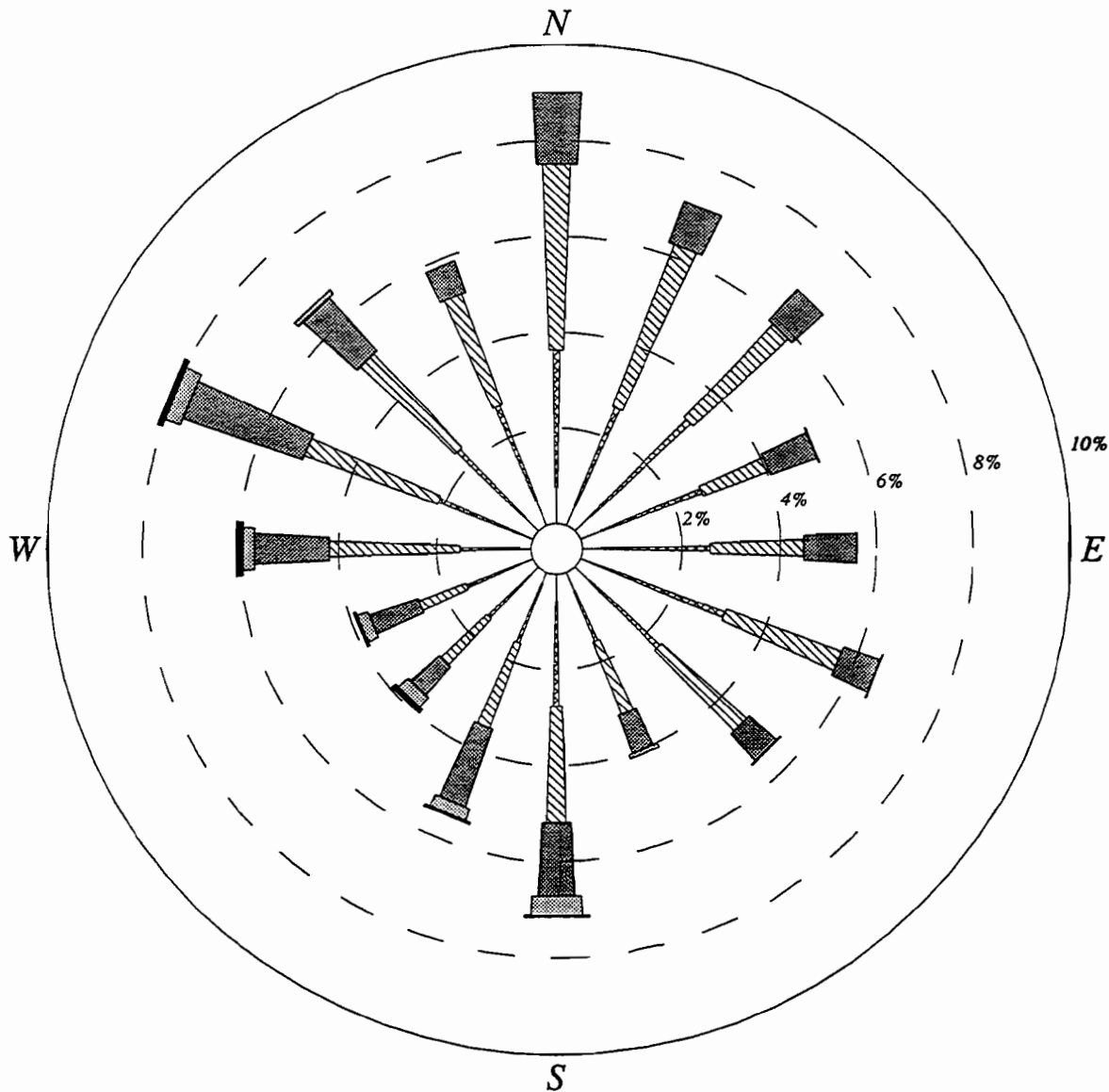


January Wind Rose for Orlando, Florida
Period of Record: 1988-1992
Figure 2.3-8



Orlando, FL

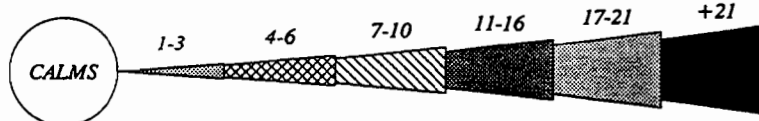
February 1-February 28; Midnight-11 PM



CALM WINDS 2.99%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



February Wind Rose for Orlando, Florida

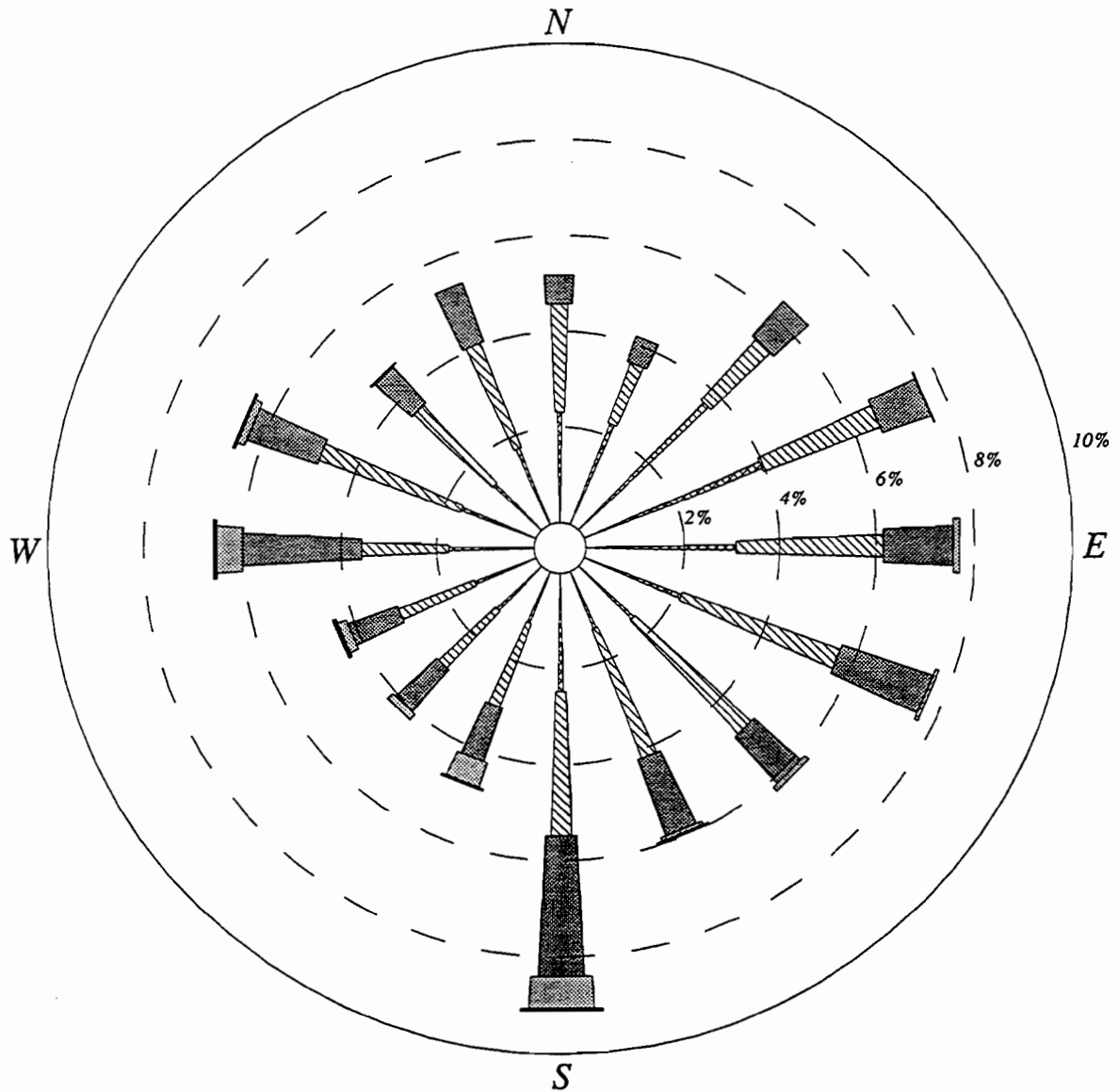
Period of Record: 1988-1992

Figure 2.3-9



Orlando, FL

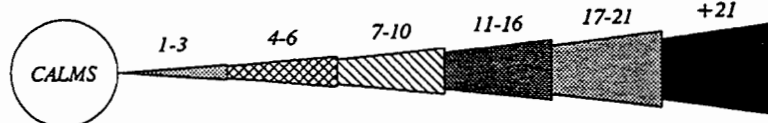
March 1-March 31; Midnight-11 PM



CALM WINDS 3.28%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



March Wind Rose for Orlando, Florida

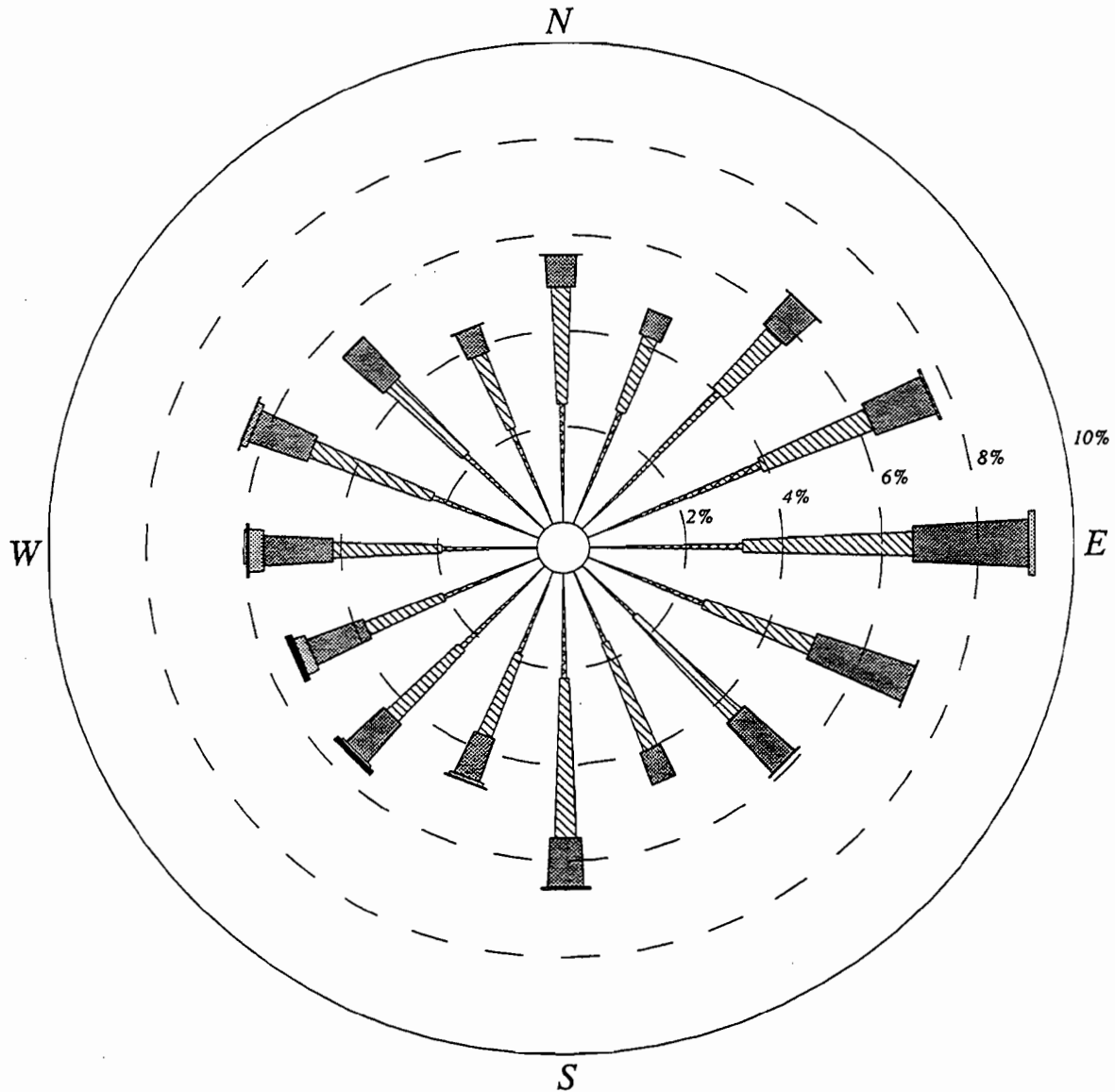
Period of Record: 1988-1992

Figure 2.3-10



Orlando, FL

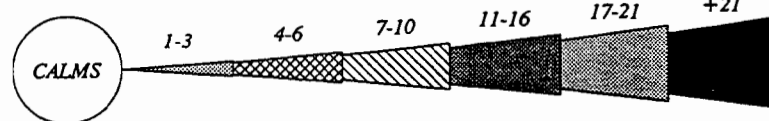
April 1-April 30; Midnight-11 PM



CALM WINDS 3.69%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



April Wind Rose for Orlando, Florida

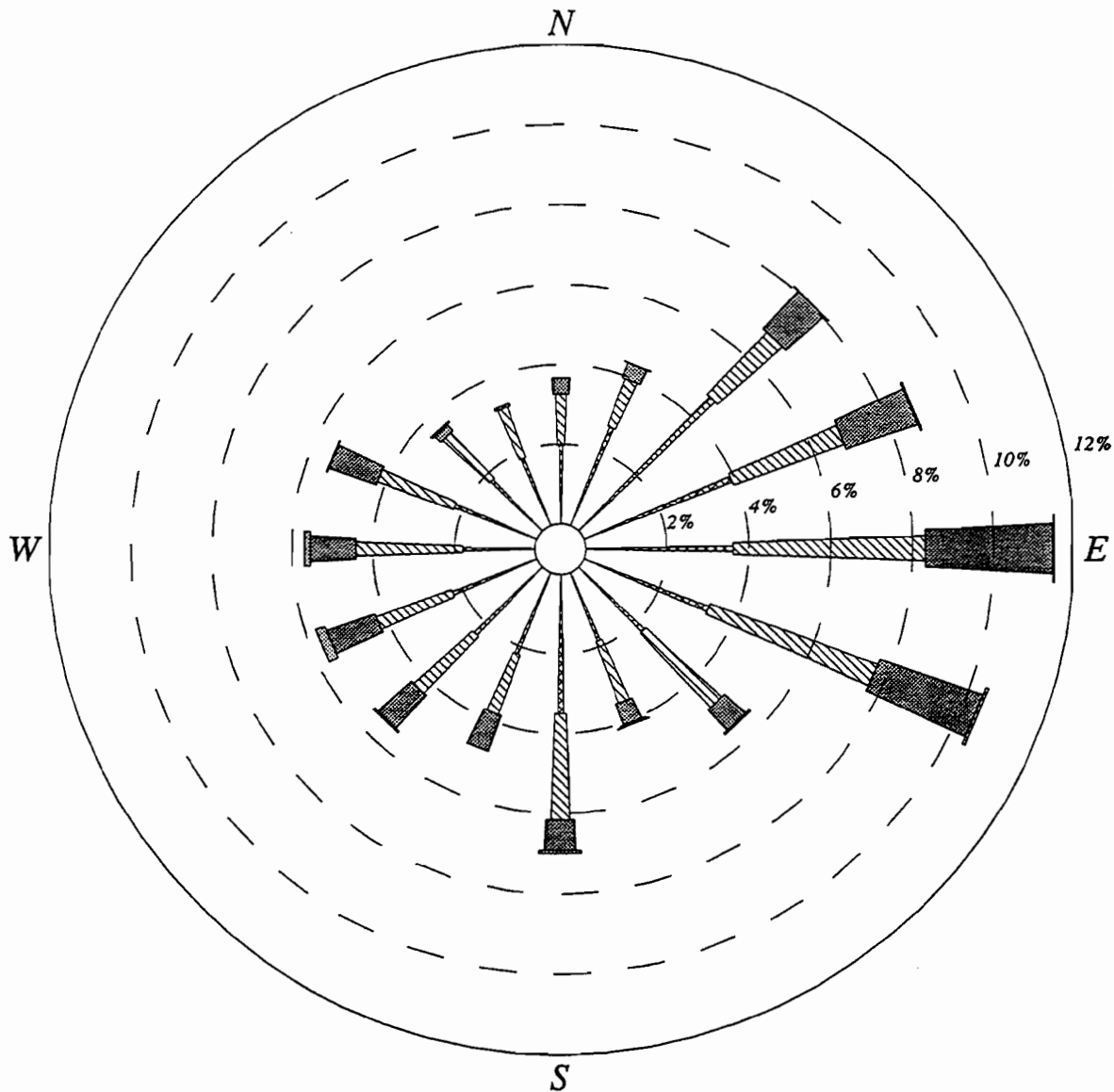
Period of Record: 1988-1992

Figure 2.3-11



Orlando, FL

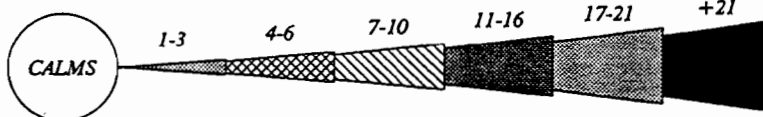
May 1-May 31; Midnight-11 PM



CALM WINDS 2.47%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



May Wind Rose for Orlando, Florida

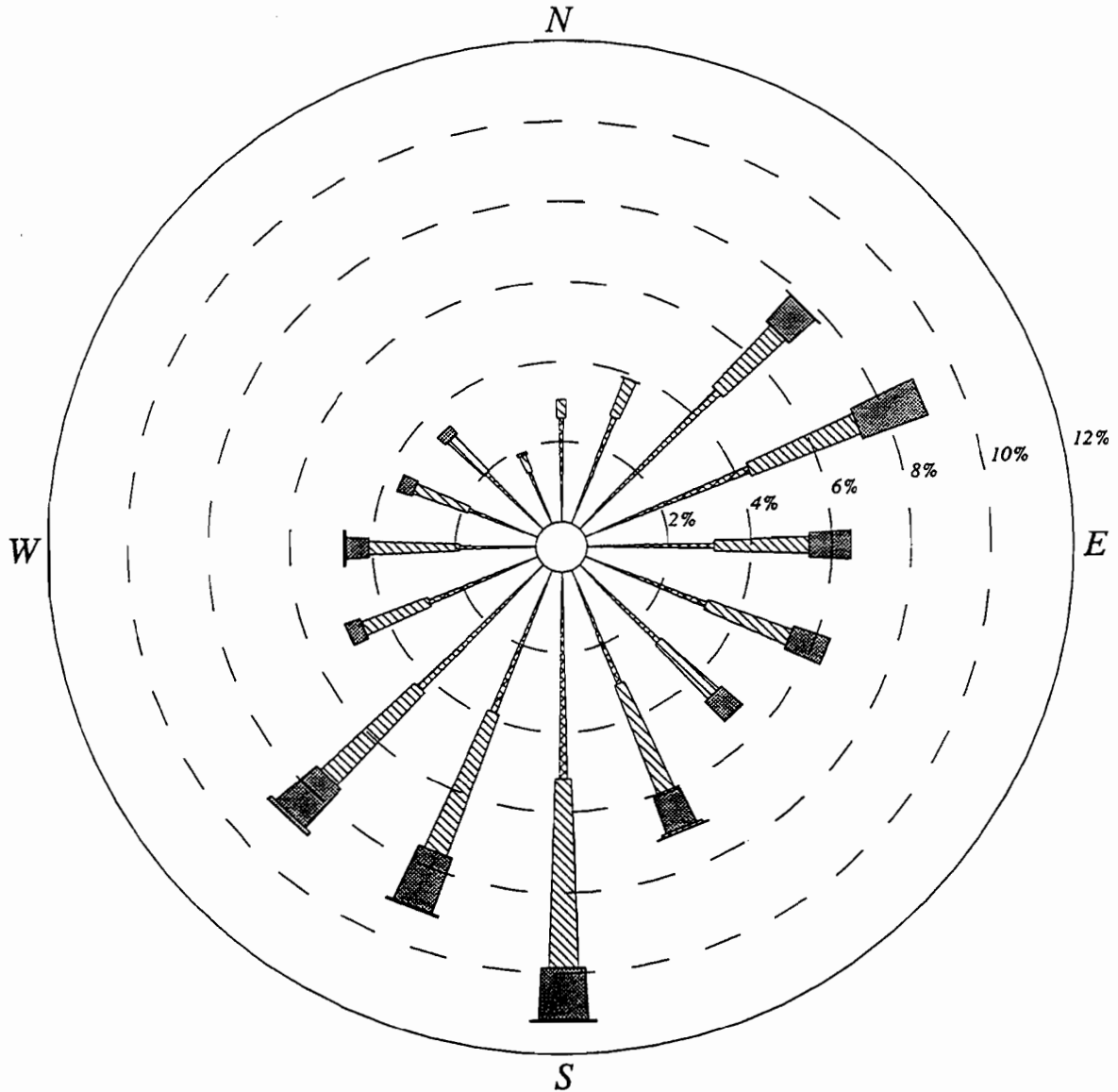
Period: 1988-1992

Figure 2.3-12



Orlando, FL

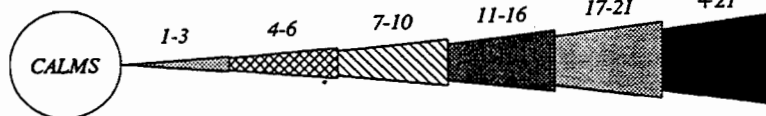
June 1-June 30; Midnight-11 PM



CALM WINDS 3.00%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



June Wind Rose for Orlando, Florida

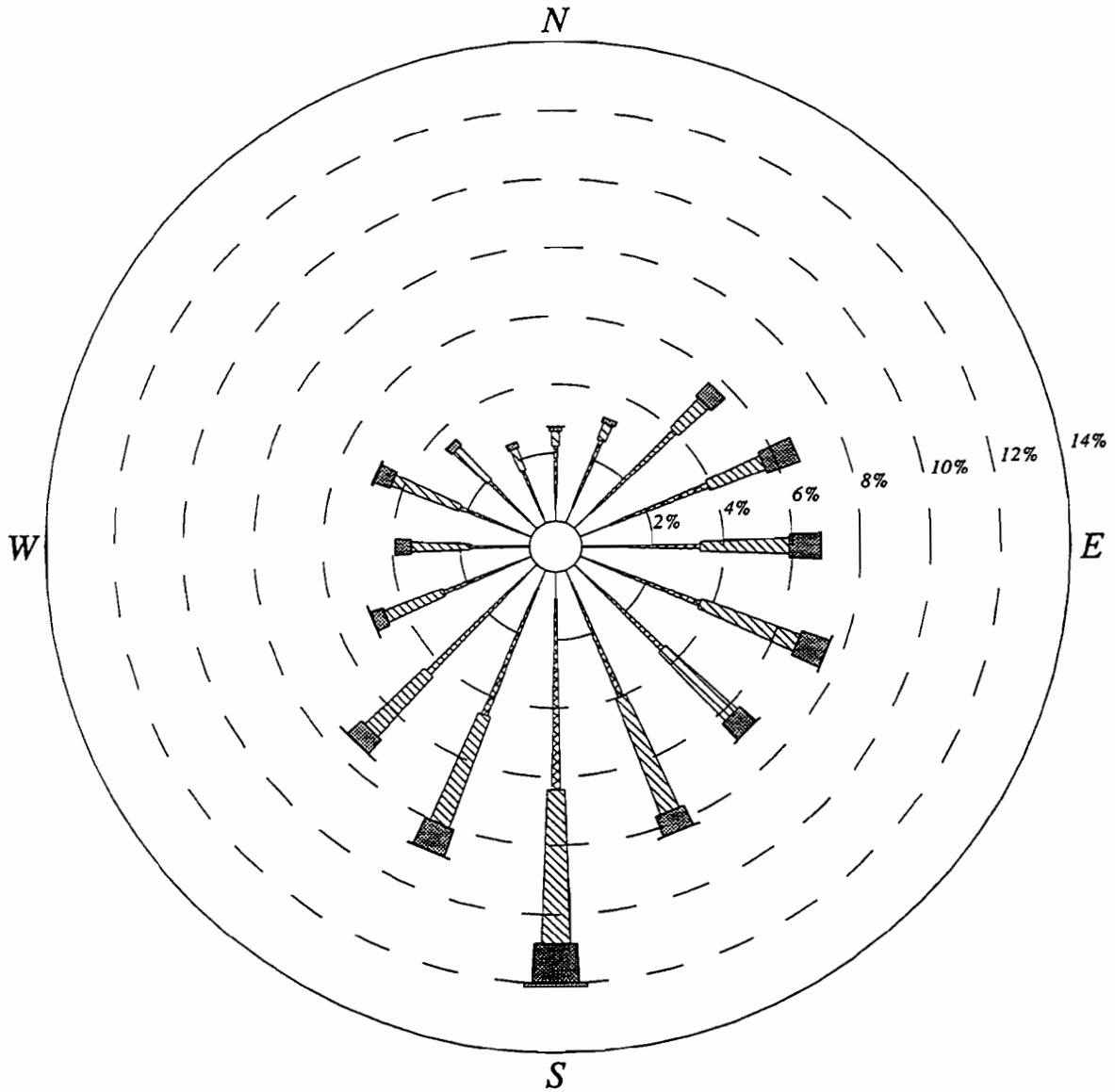
Period: 1988-1992

Figure 2.3-13



Orlando, FL

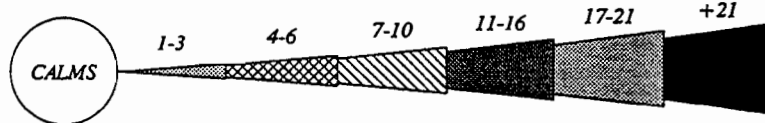
July 1-July 31; Midnight-11 PM



CALM WINDS 3.55%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



July Wind Rose for Orlando, Florida

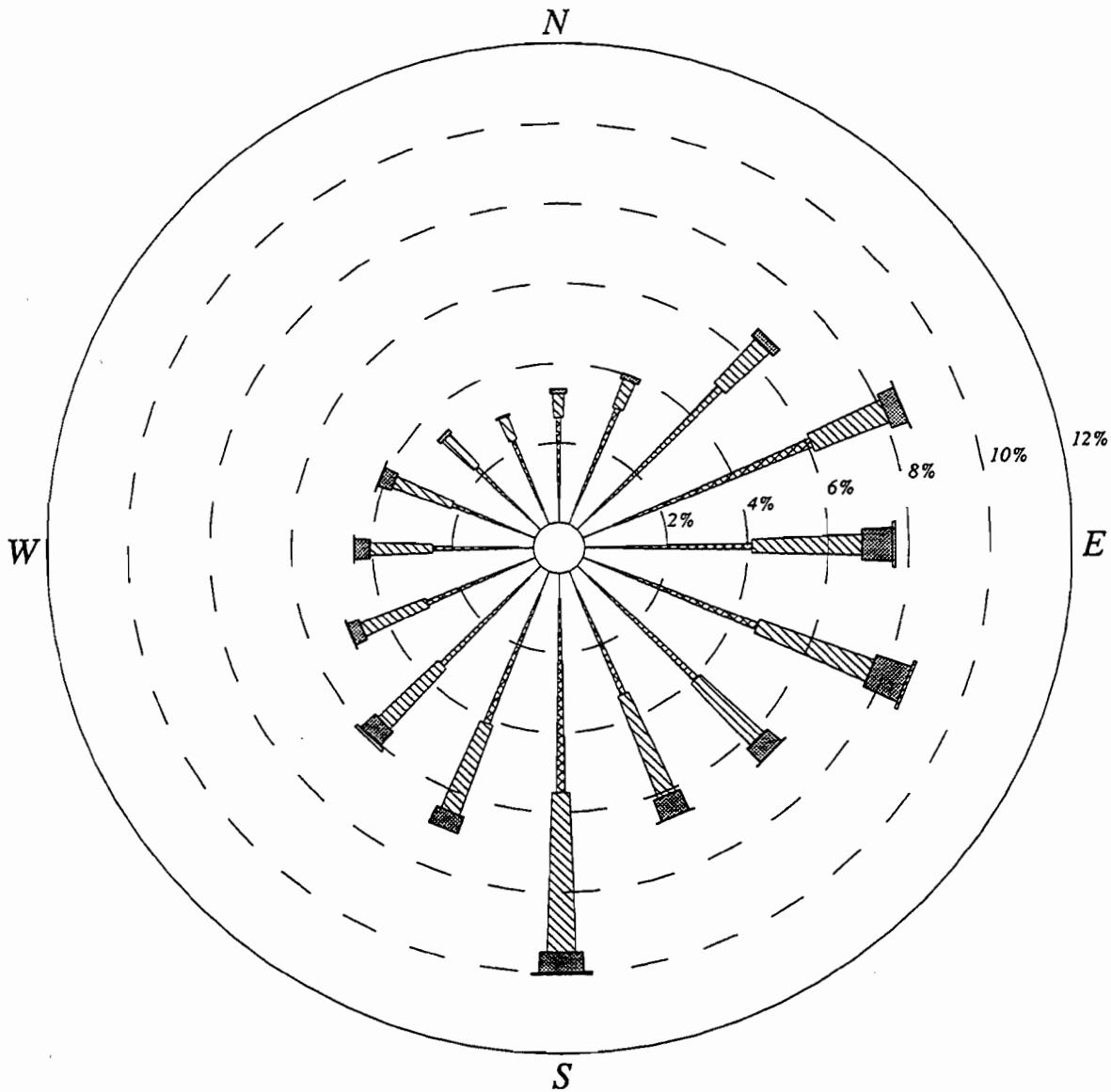
Period: 1988-1992

Figure 2.3-14



Orlando, FL

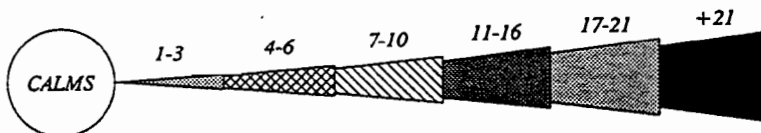
August 1-August 31; Midnight-11 PM



CALM WINDS 4.38%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



August Wind Rose for Orlando, Florida

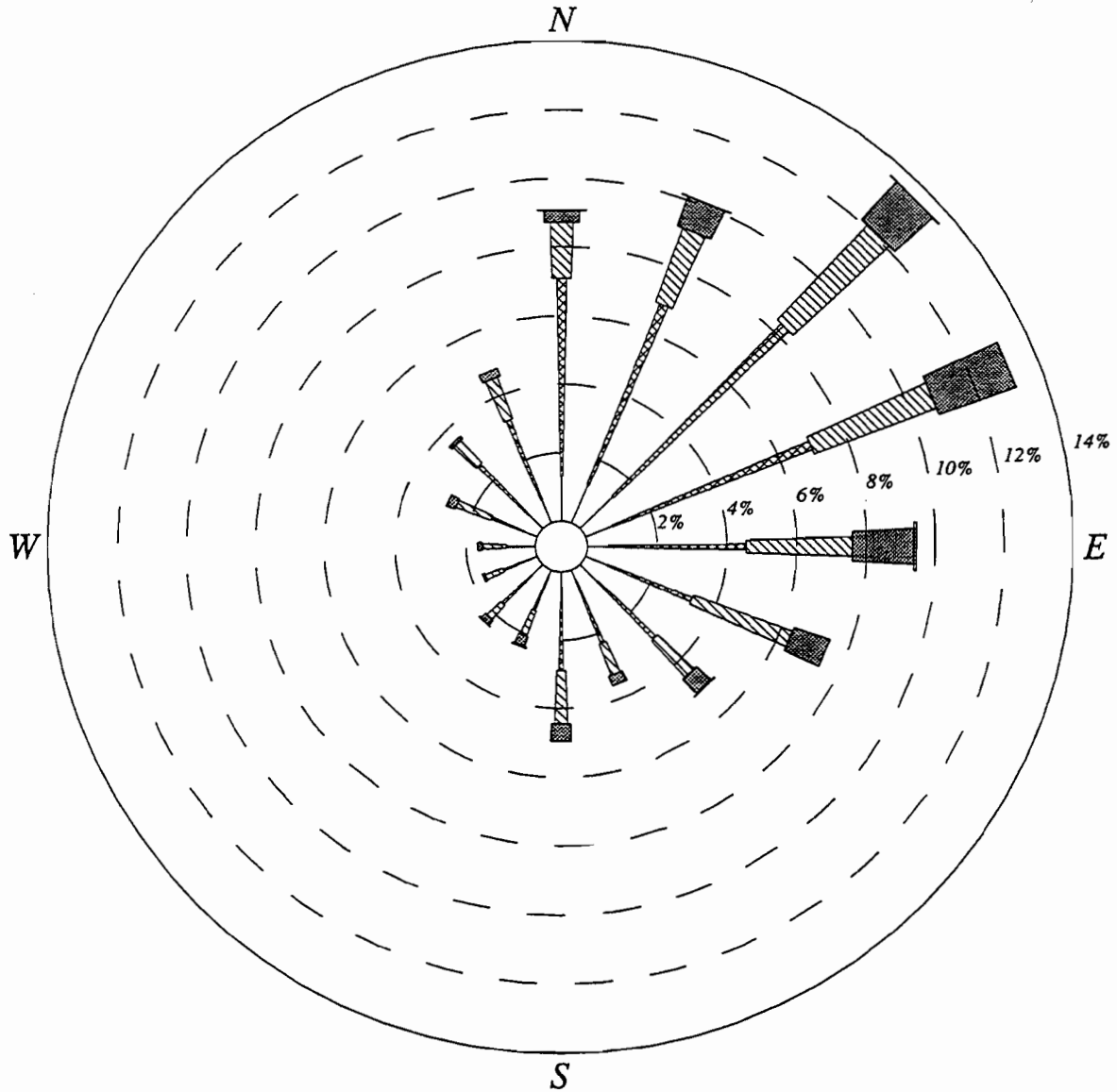
Period: 1988-1992

Figure 2.3-15



Orlando, FL

September 1-September 30; Midnight-11 PM



CALM WINDS 4.17%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



September Wind Rose for Orlando, Florida

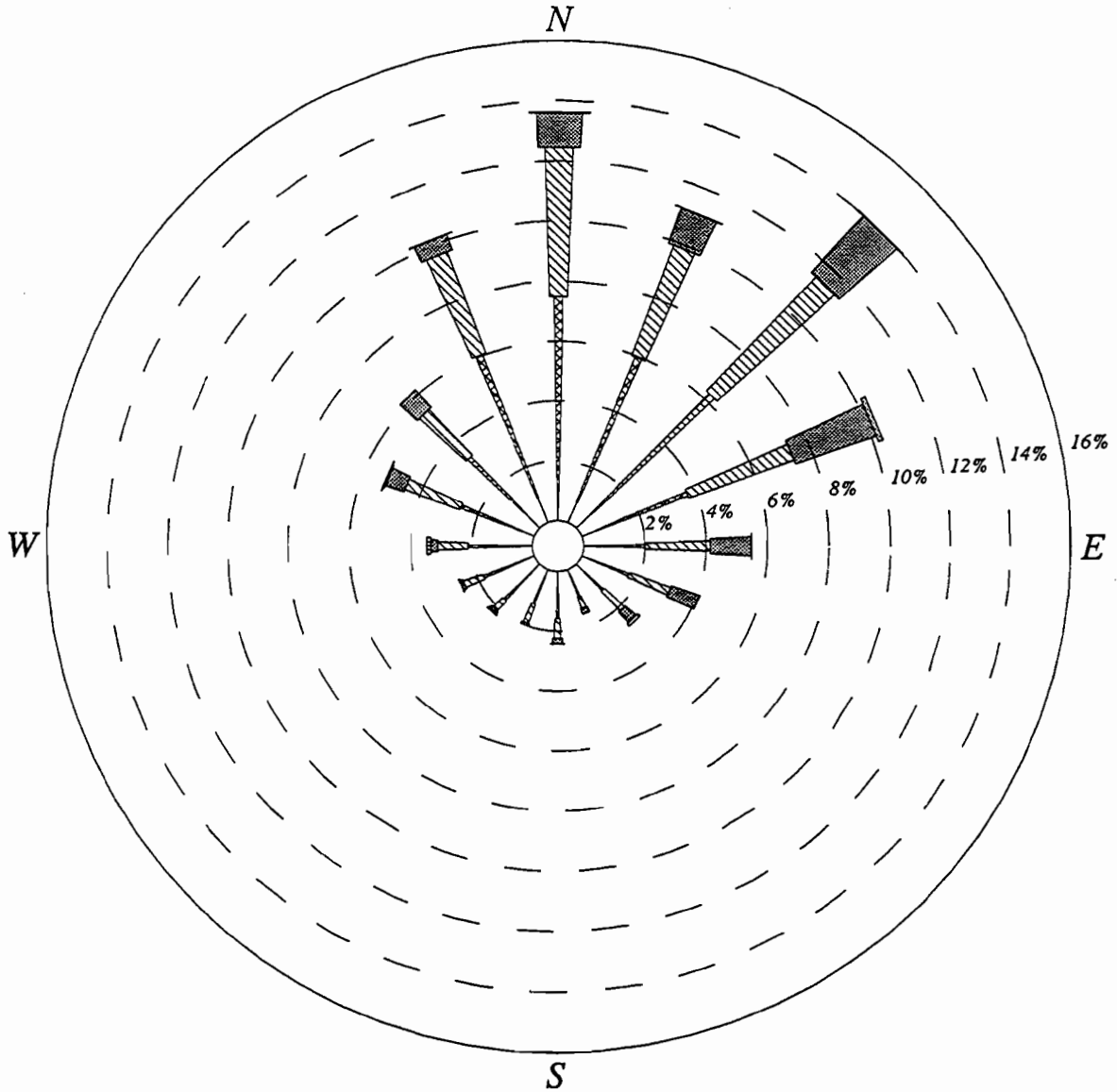
Period: 1988-1992

Figure 2.3-16



Orlando, FL

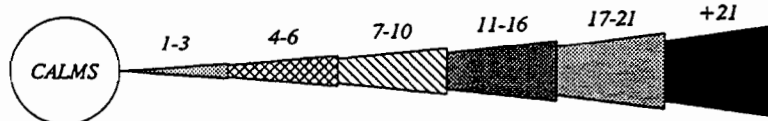
October 1-October 31; Midnight-11 PM



CALM WINDS 2.47%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



October Wind Rose for Orlando, Florida

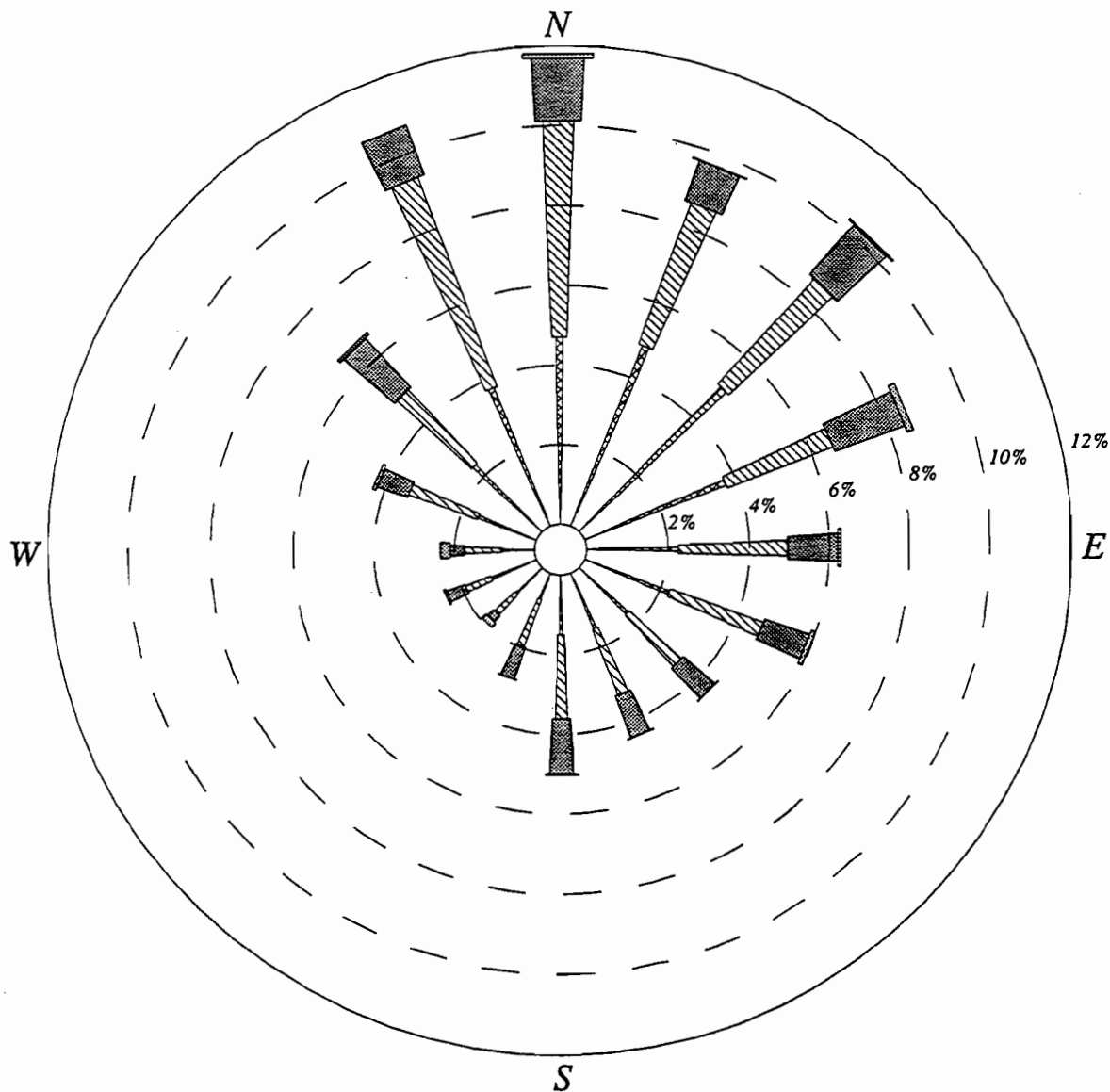
Period: 1988-1992

Figure 2.3-17



Orlando, FL

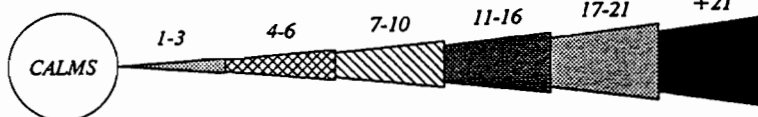
November 1-November 30; Midnight-11 PM



CALM WINDS 2.19%

WIND SPEED (KNOTS)

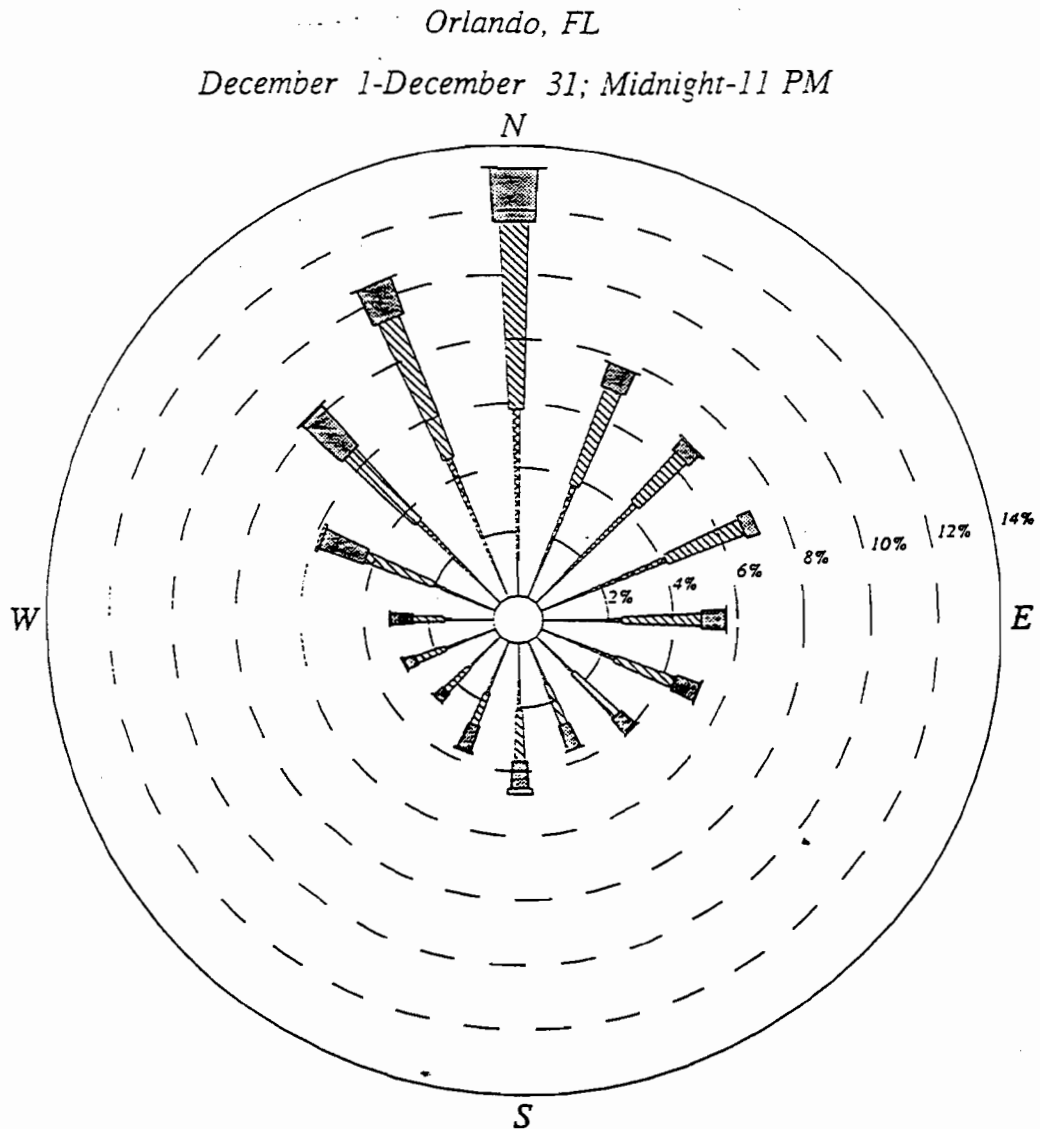
NOTE: Frequencies
indicate direction
from which the
wind is blowing.



November Wind Rose for Orlando, Florida

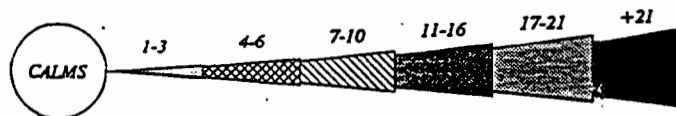
Period: 1988-1992

Figure 2.3-18



CALM WINDS 3.92%

NOTE: Frequencies
indicate direction
from which the
wind is blowing.

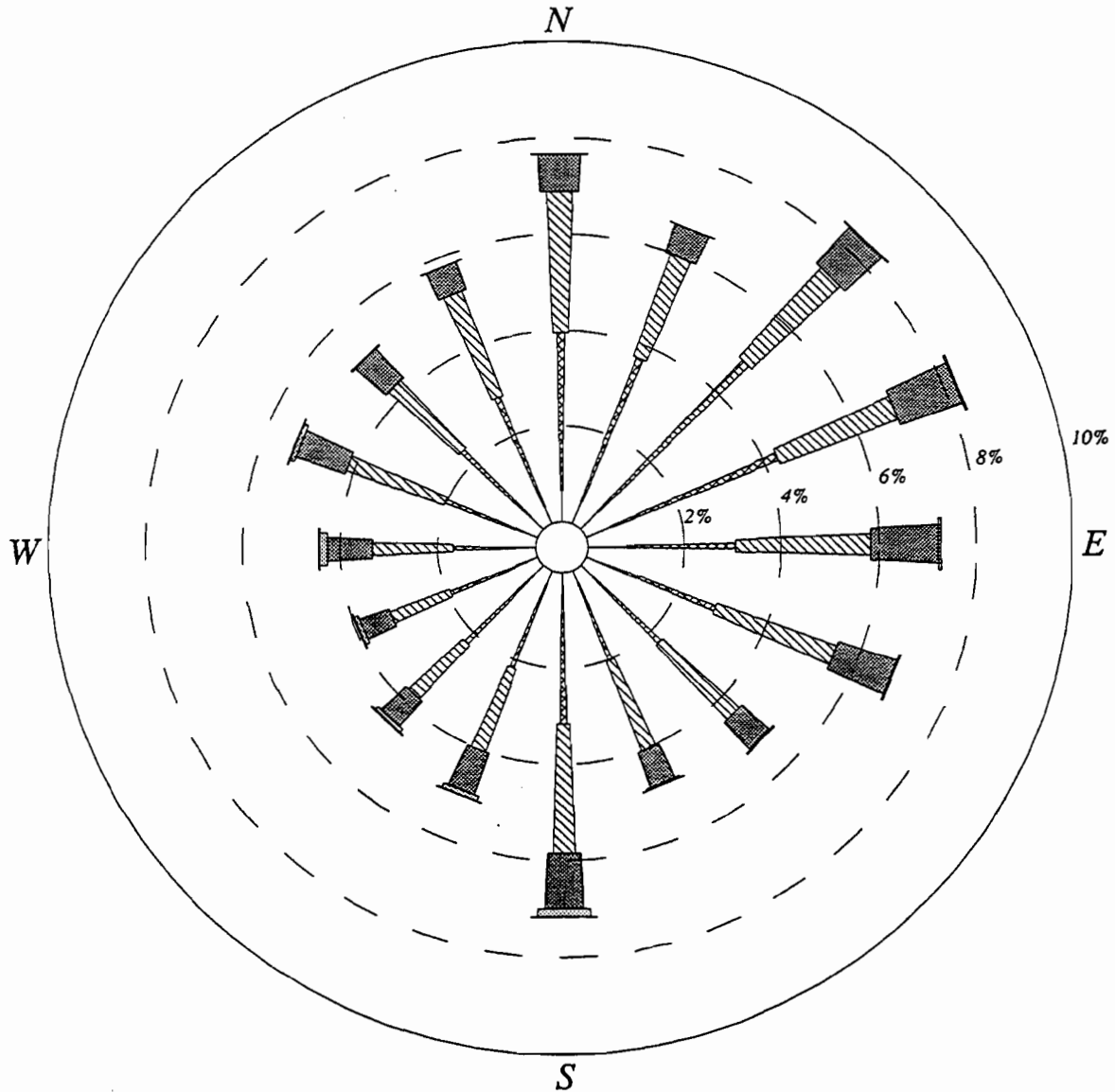


December Wind Rose for Orlando, Florida
Period: 1988-1992
Figure 2.3-19



Orlando, FL Annual

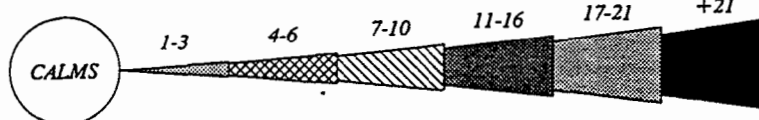
January 1-December 31; Midnight-11 PM



CALM WINDS 3.24%

WIND SPEED (KNOTS)

NOTE: Frequencies
indicate direction
from which the
wind is blowing.



Annual Wind Rose for Orlando, Florida
Period: 1988-1992
Figure 2.3-20



Table 2.3-10
Annual Wind Rose
Percent Frequency Distribution

Direction Sector	Wind Speed Categories, knots*						Total (percent)
	0-3	4-6	7-10	11-16	17-21	>21	
N	0.650	3.305	2.924	0.791	0.025	0.000	7.695
NNE	0.497	3.209	2.262	0.641	0.011	0.000	6.621
NE	0.500	4.356	2.504	1.022	0.025	0.000	8.406
ENE	0.547	3.738	2.589	1.371	0.046	0.000	8.290
E	0.306	2.750	2.776	1.403	0.059	0.000	7.293
ESE	0.354	2.516	2.636	1.259	0.041	0.000	6.805
SE	0.312	1.975	2.132	0.782	0.043	0.000	5.245
SSE	0.262	1.765	2.007	0.769	0.043	0.016	4.862
S	0.399	2.755	2.696	1.161	0.178	0.016	7.204
SSW	0.276	1.902	1.834	0.915	0.114	0.014	5.054
SW	0.294	1.959	1.517	0.693	0.089	0.021	4.573
WSW	0.242	1.685	1.286	0.636	0.094	0.025	3.968
W	0.230	1.448	1.642	0.937	0.171	0.034	4.463
WNW	0.299	1.738	2.121	1.067	0.105	0.023	5.353
NW	0.347	1.980	1.927	0.832	0.032	0.000	5.118
NNW	0.370	2.490	2.326	0.618	0.007	0.000	5.811
Calm	3.239	--	--	--	--	--	3.239
Total	9.123	39.571	35.178	14.897	1.083	0.148	100.000

*1 knot = 1.15 mph.

Source: Derived from hourly Orlando, Florida, National Climatic Center meteorological data tapes (1988-1992).



Table 2.3-11
Estimated Average Mixing Heights and Average Wind Speeds
Through the Mixed Layer Representative
of the Power Park Area

Season	Morning		Afternoon	
	Mixing Height (m)	Wind Speed (m/s)	Mixing Height (m)	Wind Speed (m/s)
Winter	550	5.8	1,150	6.8
Spring	700	5.7	1,600	7.0
Summer	800	4.8	1,550	5.7
Fall	600	5.7	1,400	6.5
Annual	600	5.8	1,400	6.7

Source: Holzworth, 1972.



Atmospheric stability, in conjunction with general wind patterns, indicates the potential of the atmosphere to disperse airborne pollutants. Atmospheric conditions are typically categorized as unstable, neutral, or stable. An unstable atmosphere is one in which relatively rapid dispersion takes place in both the horizontal and vertical direction. Viewed in terms of changes in temperature with height, an unstable atmosphere is characterized by a sharp decrease in temperature with height. Neutral conditions are common in the atmosphere and are associated with moderate diffusion rates. Temperatures also decrease with height in a neutral atmosphere but not as rapidly as under unstable conditions (neutral conditions are associated with the adiabatic lapse rate). A stable atmosphere is characterized by slight decreases, or even increases of temperature with height, and greatly reduced dispersion rates in comparison with unstable or neutral atmospheres.

The stability classifications presented in this section are based on the well-known Pasquill, Gifford, Turner method, which assigns a stability on the basis of surface wind speed, cloud cover, and solar altitude (Turner, 1969). Stability classes range from Class A (most unstable) to Class F (most stable). Class D represents a neutral stability condition. The joint frequency distribution wind speed, wind direction, and stability at Orlando is summarized in Tables 2.3-12 through 2.3-17.

2.3.7.4 Ambient Air Quality. One requirement in obtaining site certification and applicable air quality permits is to demonstrate that the operation of the proposed facility will not cause or contribute to a violation of any federal or state ambient air quality standard or allowable air quality increment. This demonstration is included in Section 5.6, which also addresses many of the requirements of the Prevention of Significant Deterioration (PSD) permit application. One necessary part of the application is to establish representative values for background air quality for applicable pollutants. The existing air quality in the vicinity of the Power Park is described in this section including applicable standards and allowable incremental effects. The impact predictions resulting from the consideration of the proposed source emissions are also described in Appendix 10.7 attached under separate cover.

Air Quality Standards--Ambient air quality standards (AAQS) have been set to protect public health (primary standards) and public welfare (secondary standards). In addition, the State of Florida has adopted ambient air quality standards. The federal and state AAQS are given in Table 2.3-18.



Table 2.3-12
Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--A Stability
(Orlando, Florida, 1997)

Direction	Speed Categories (mph)						Total (hours)
	1-3	4-7	8-12	13-18	19-24	Greater Than 24	
N	1	5	0	0	0	0	6
NNE	1	0	0	0	0	0	1
NE	0	3	0	0	0	0	3
ENE	0	4	0	0	0	0	4
E	1	3	0	0	0	0	4
ESE	0	3	0	0	0	0	3
SE	0	9	0	0	0	0	9
SSE	0	1	0	0	0	0	1
S	3	6	0	0	0	0	9
SSW	1	4	0	0	0	0	5
SW	0	4	0	0	0	0	4
WSW	1	0	0	0	0	0	1
W	1	6	0	0	0	0	7
WNW	2	4	0	0	0	0	6
NW	1	4	0	0	0	0	5
NNW	0	3	0	0	0	0	3
Totals	12	59	0	0	0	0	71
Number of Occurrences of A Stability = 155 hours							
Number of Calms with A Stability = 84 hours							



Table 2.3-13
Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--B Stability
(Orlando, Florida, 1997)

Direction	Speed Categories (mph)						Total (hours)
	1-3	4-7	8-12	13-18	19-24	Greater Than 24	
N	4	26	22	0	0	0	52
NNE	3	7	14	0	0	0	24
NE	4	15	16	0	0	0	35
ENE	5	9	15	0	0	0	29
E	4	18	23	0	0	0	45
ESE	3	10	2	0	0	0	15
SE	4	12	15	0	0	0	31
SSE	1	13	5	0	0	0	19
S	7	27	20	0	0	0	54
SSW	8	23	22	0	0	0	53
SW	3	19	17	0	0	0	39
WSW	8	14	8	0	0	0	30
W	5	19	36	0	0	0	60
WNW	6	19	26	0	0	0	51
NW	3	8	24	0	0	0	35
NNW	5	11	10	0	0	0	26
Totals	73	250	275	0	0	0	598
Number of Occurrences of B Stability = 696 hours Number of Calms with B Stability = 98 hours							



Table 2.3-14
Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--C Stability
(Orlando, Florida, 1997)

Direction	Speed Categories (mph)						Total (hours)
	1-3	4-7	8-12	13-18	19-24	Greater Than 24	
N	1	37	60	3	0	0	101
NNE	0	14	36	5	0	0	55
NE	0	14	40	7	0	0	61
ENE	1	10	57	21	1	0	90
E	3	25	67	13	0	0	108
ESE	2	11	35	3	0	0	51
SE	2	12	18	6	0	0	38
SSE	5	12	28	4	0	0	49
S	4	21	48	7	1	0	81
SSW	2	12	26	3	0	0	43
SW	1	17	24	12	0	0	54
WSW	0	18	33	8	0	0	59
W	4	19	51	10	0	0	84
WNW	0	11	50	11	0	0	72
NW	0	10	33	6	0	0	49
NNW	0	19	29	4	0	0	52
Totals	25	262	635	123	2	0	1,047
Number of Occurrences of C Stability = 1,089 hours							
Number of Calms with C Stability = 42 hours							



Table 2.3-15
Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--D Stability
(Orlando, Florida, 1997)

Direction	Speed Categories (mph)						Total (hours)
	1-3	4-7	8-12	13-18	19-24	Greater Than 24	
N	7	39	118	57	1	2	224
NNE	3	17	81	72	3	0	176
NE	5	20	82	73	2	0	182
ENE	4	27	83	89	3	0	206
E	6	36	103	65	0	0	210
ESE	4	23	57	45	0	0	129
SE	4	28	57	13	0	0	102
SSE	7	22	60	35	0	0	124
S	6	49	124	78	4	1	262
SSW	6	42	76	41	2	2	169
SW	3	27	48	26	2	0	106
WSW	2	18	37	36	2	0	95
W	4	24	45	69	6	0	148
WNW	1	14	49	59	9	1	133
NW	3	18	41	53	7	1	123
NNW	2	19	42	58	4	0	125
Totals	67	423	1,103	869	45	7	2,514
Number of Occurrences of D Stability = 2,593 hours							
Number of Calms with D Stability = 79 hours							



Table 2.3-16
Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--E Stability
(Orlando, Florida, 1997)

Direction	Speed Categories (mph)						Total (hours)
	1-3	4-7	8-12	13-18	19-24	Greater Than 24	
N	0	106	75	0	0	0	181
NNE	0	55	43	0	0	0	98
NE	0	33	39	0	0	0	72
ENE	0	58	45	0	0	0	103
E	0	99	29	0	0	0	128
ESE	0	42	19	0	0	0	61
SE	0	49	22	0	0	0	71
SSE	0	52	14	0	0	0	66
S	0	110	29	0	0	0	139
SSW	0	71	3	0	0	0	74
SW	0	49	7	0	0	0	56
WSW	0	39	10	0	0	0	49
W	0	56	51	0	0	0	107
WNW	0	35	33	0	0	0	68
NW	0	20	29	0	0	0	49
NNW	0	21	14	0	0	0	35
Totals	0	895	462	0	0	0	1,357
Number of Occurrences of E Stability = 1,357 hours							
Number of Calms with E Stability = 0 hours							



Table 2.3-17
Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--F Stability
(Orlando, Florida, 1997)

Direction	Speed Categories (mph)						Total (hours)
	1-3	4-7	8-12	13-18	19-24	Greater Than 24	
N	56	141	0	0	0	0	197
NNE	22	61	0	0	0	0	83
NE	12	18	0	0	0	0	30
ENE	25	58	0	0	0	0	83
E	76	101	0	0	0	0	177
ESE	29	22	0	0	0	0	51
SE	42	39	0	0	0	0	81
SSE	52	27	0	0	0	0	79
S	80	63	0	0	0	0	143
SSW	45	35	0	0	0	0	80
SW	38	34	0	0	0	0	72
WSW	28	36	0	0	0	0	64
W	39	81	0	0	0	0	120
WNW	22	43	0	0	0	0	65
NW	13	32	0	0	0	0	45
NNW	11	25	0	0	0	0	36
Totals	590	816	0	0	0	0	1,406

Number of Occurrences of F Stability = 2,343 hours
Number of Calms with F Stability = 937 hours

Table 2.3-18
Ambient Air Quality Standards

Standard	Less Than 24-Hour Average	24-Hour Average	Annual Average
Sulfur Dioxide ($\mu\text{g}/\text{m}^3$)			
Federal primary	--	365*	80
Federal secondary	1,300 (3-hour)*	--	--
Florida	1,300 (3-hour)*	260*	60
Nitrogen Dioxide ($\mu\text{g}/\text{m}^3$)			
Federal primary and secondary	--	--	100
Florida	--	--	100
Carbon Monoxide ($\mu\text{g}/\text{m}^3$)			
Federal primary and secondary	40,000 (1-hour)*	--	--
Federal primary and secondary	10,000 (8-hour)*	--	--
Florida	Same as Federal**	--	--
Particulate Matter (PM_{10}) ($\mu\text{g}/\text{m}^3$)			
Federal primary and secondary	--	150*	50
Florida	--	150**	50
Lead (Pb) ($\mu\text{g}/\text{m}^3$)			
Federal primary and secondary	--	--	1.5 (3 mo)
Florida	--	--	1.5 (3 mo)
Ozone ($\mu\text{g}/\text{m}^3$)			
Federal primary and secondary	235 (1-hour)*	--	--
Florida	235 (1-hour)*	--	--

*Not to be exceeded more than once per year; averaging times given in parenthesis.

**Not to be exceeded an average of more than 1 day per year over a 3 year period.

NOTE: $\mu\text{g}/\text{m}^3$ --micrograms per cubic meter at 25° C and 760 mm Hg.



In addition to ambient standards, the operation of the units must not cause air quality incremental impacts beyond those specified by Prevention of Significant Deterioration (PSD) criteria. The Power Park area is classified as PSD Class II. Class II PSD increments will be applicable for this analysis in all areas surrounding the Power Park.

Existing Air Quality--The State of Florida has been conducting air quality monitoring for criteria pollutants at locations throughout the state for many years. The FDEP document, *ALLSUM 1997*, accessed on the Internet provides the most recent monitoring data for use in establishing background concentrations for applicable criteria pollutants (FDEP, 1998).

FDEP and EPA guidance would generally require the use of the highest or second-highest monitored concentrations to establish conservative background concentrations for the project area. For this analysis, 1997 data from all central Florida monitoring sites were reviewed for each pollutant. The monitoring location nearest the Power Park was used to establish the background air quality levels. In all cases, the highest measured concentrations at the location considered were conservatively used as background values. Table 2.3-19 summarizes the monitoring data used as background pollutant concentrations for the Power Park area.

2.3.8 Noise

Four separate ambient noise surveys have been conducted in the community surrounding the Power Park. The first noise survey was conducted from February 11-13, 1991, prior to any construction at the Power Park. The second noise survey was conducted from January 12-14, 1995. The Unit 1 turbine operated at various load conditions throughout this survey. Unit 2 was not operating during this survey period. The third survey was conducted from June 6-7, 1995. Both Units 1 and 2 were operating at or near full load throughout the third noise survey. The fourth survey was conducted from July 9-11, 1998. The Unit 2 turbine was operating at base load during the survey; Unit 1 was operating at various times and loads during this survey. The purpose of the fourth survey was to quantify the existing C-weighted noise levels within the site vicinity.



Table 2.3-19
Background Ambient Air Quality

	Background Concentration ^a	Location	SAROAD Site No.	Year
Sulfur Dioxide ($\mu\text{g}/\text{m}^3$) ^b				
Annual	4	Winter Park	4900-002-G01	1997
24-hour	18	Winter Park	4900-002-G01	1997
3-hour	75	Winter Park	4900-002-G01	1997
Nitrogen Dioxide ($\mu\text{g}/\text{m}^3$) ^b				
Annual	23	Winter Park	4900-002-G01	1997
PM ₁₀ ($\mu\text{g}/\text{m}^3$) ^b				
Annual	20	Winter Park	4900-002-G01	1997
24-hour	40	Winter Park	4900-002-G01	1997
Carbon Monoxide (PPM) ^b				
8-hour	3	Winter Park	4900-002-G01	1997
1-hour	4	Winter Park	4900-002-G01	1997
Ozone ($\mu\text{g}/\text{m}^3$)				
1-hour	0.100	Kissimmee	2060-002-F01	1997
Lead ($\mu\text{g}/\text{m}^3$) ^b				
Calendar quarter	0.0		c	1997

^aRepresents maximum reported values for 1997(FDEP sites).

^bFrom 1997 ALLSUM, Florida Department of Environmental Protection, dated 1/6/98.

^cAll Florida locations had quarterly averages of 0.0 $\mu\text{g}/\text{m}^3$ for lead during 1997, except for several locations in the Tampa area.



During the initial preconstruction survey, periodic measurements were conducted during various time periods. During the three operational surveys, continuous noise measurements were taken along the south and southeast Power Park boundary to characterize noise emissions within the residential areas. The following sections summarize the procedures followed in performing the ambient noise surveys and the existing ambient noise environment.

2.3.8.1 Characterization of Site Vicinity. The Power Park is located in a predominantly rural area along South Orange Blossom and Old Tampa highways. Noise sensitive areas within the vicinity include residences located along Old Tampa Highway (approximately 3,500 feet south of the power block) and Wooten Road (east of the site), and several residences along various side streets intersecting Wooten Road (approximately 4,000 feet east of the site).

The dominant nonnatural noise sources include frequent traffic along South Orange Blossom Highway, less frequent traffic along Old Tampa Highway, occasional aircraft noise and the existing Power Park combustion turbine facility.

The existing Power Park noise is faintly audible at the east residences in the early morning hours during periods of very low background noise. The Power Park facilities were not audible at any other periods and was never audible at the southern residences.

Noise Measurement Locations (NMLs)

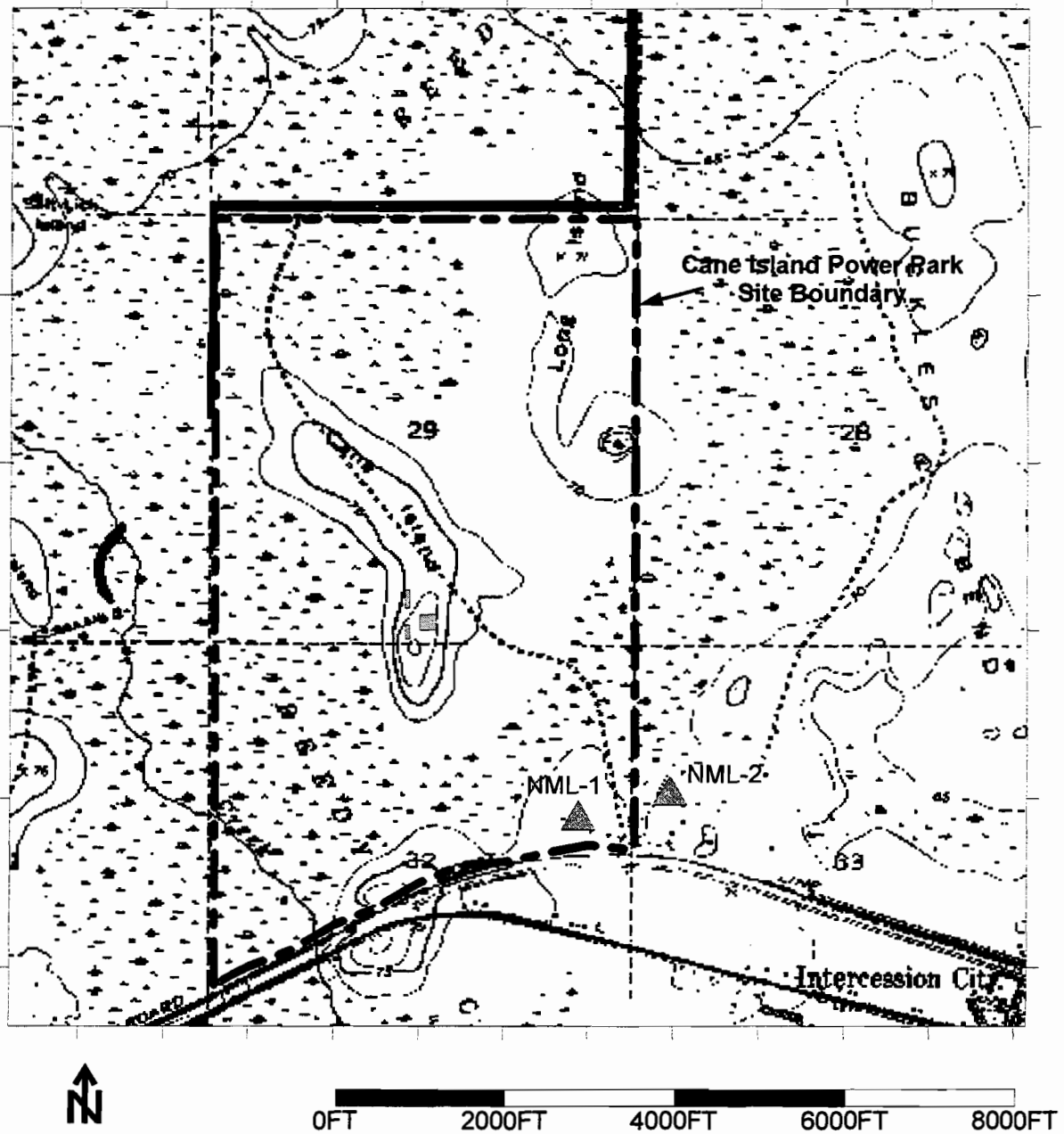
Measurements were recorded at two locations during the surveys. The locations are shown on Figure 2.3-21. The measurement locations were chosen to represent the acoustic environment at the nearest residences to the power block.

Noise Measurement Location 1

NML-1 is located along the south fence line, approximately 50 feet west of the Power Park entrance, approximately 3,200 feet south of the power block. The nearest residence in this direction is located across the railroad corridor and Old Tampa Highway.

Noise Measurement Location 2

NML-2 is located in the backyard of a resident located approximately 4,000 feet southeast of the power block.



Noise Measurement Locations
Figure 2.3-21



Measurement Types

Ambient sound levels were measured in decibels using the A-weighted scale (dBA). The A-weighted scale is preferred for applications such as this because it simulates the frequency response of the human ear. The human ear does not hear low frequency noise as well as mid and upper range noise. As such, the A-weighted adjustments include relatively high discount in the low frequency bands and very little adjustment to mid and high frequency bands. Four types of A-weighted sound levels were recorded to define the noise environment; the equivalent sound level (Leq), and four statistical exceedance levels: L90, L50, L33, and L10.

The equivalent sound level, denoted as Leq, is the energy averaged sound level integrated over the measurement period. The statistical sound levels are useful in describing the time-varying nature of the sound. L90 is the sound level exceeded 90 percent of the measurement period or the quietest 10 percent sound level. L90 is commonly considered to represent the residual background sound level because it effectively "filters out" transient loud noise events such as traffic passes and dogs barking. Combustion turbine noise emissions are steady in nature. Steady noise sources are best measured using the L90 descriptor. The L90 value measures steady sounds while being minimally influenced by transient noises and therefore indicates the steady combustion turbine noise levels measured during periods when background noise is at a minimum.

The L50 is defined as the sound level exceeded 50 percent of the measurement period or the median sound level. L33 is the sound level exceeded 33 percent of the time. Similarly, L10 is the sound level exceeded 10 percent of the measurement period and is sometimes called the intrusive sound level because it represents occasional loud noises, such as traffic passes. Highly variable noise environments will result in a large difference between the measured L90 and L10 noise levels. A completely steady noise source will result in all noise descriptors being the same.

The Osceola County Code was revised since these surveys were conducted to include C-weighted noise limits. C-weighted values were recorded during the fourth survey. Octave band levels were also recorded during the preconstruction noise survey and the fourth survey. The A-weighted and C-weighted sound levels were calculated from these octave band values.



Measurement Periods

The periodic measurements during survey one, were recorded at different time periods throughout the day. The intent of the measurement times were to quantify the ambient level during morning, afternoon, evening and early morning time periods. Each measurement value was averaged over a 15 minute period.

Continuous measurements were conducted at each measurement location. The sound meters were programmed to average the noise values over 30 minute sampling periods on a continuous basis.

Measurement Equipment

The noise surveys were conducted using a CEL Instruments type 1, precision sound level meter. This instrument is capable of measuring octave band values. The equipment used to conduct the continuous measurements were Larson Davis (LD) model 700 ANSI Type 2, hand-held integrating noise meters. The LD700s are capable of continuous acoustic monitoring and providing Leq, and three statistical sound levels for specified time intervals. The equipment was programmed to provide 1 hour Leq, L10, L50, and L90 levels. The meters and field calibrator were laboratory calibrated within a 12 month period preceding the surveys. The meters were field calibrated during the surveys using the corresponding pistophone calibrator.

2.3.8.2 Facility Operation. During the January 1995 survey, the Unit 1 operating load varied throughout the survey depending upon energy demand. The Unit 1 operating load and recorded sound levels are summarized in Table 2.3-20. During two periods, Unit 1 was brought to full load to ensure the noise measurements were conducted at full load conditions. During the June 6, 1995 survey, both units operated at or near full load throughout the survey. The Unit 1 turbine load varied with energy demand; however, Unit 2 remained near full load throughout the survey (Table 2.3-21). During the 1998 survey, Unit 2 operated near full load throughout the survey; Unit 1 operated at various loads.

Table 2.3-20. A-Weighted Sound Levels and Identifiable Noise Sources Observed at Each Noise Measurement Location (NML)

NML	Date	Measurement Period Start Time	A-Weighted Sound Level, dBA					Identifiable Noise Sources
			L ₉₀	L ₅₀	L ₁₀	L _{eq}	L _{max}	
1	02-11-91	10:28 a.m.	37.5	43.0	50.0	59.3	85.3	Local traffic on S. Orange Blossom and Old Tampa Highways was the controlling source. The maximum occurred when a car with its muffler dragging on the ground passed the noise meter. Other sources included a distant airplane, birds, and insects.
	02-11-91	2:20 p.m.	46.0	49.5	53.5	59.8	88.5	Old Tampa Highway and S. Orange Blossom traffic was the dominant source. Other sources included an airplane flyover, two skywriters, a train whistle, insects, birds, and leaf rustle.
	02-11-91	8:18 p.m.	38.0	42.0	50.5	62.9	83.8	Insects, birds, and a train passing were the background and intermittent sources. Local traffic was again the dominant noise source.
	02-12-91	2:35 a.m.	28.0	31.0	39.5	35.9	53.9	Infrequent local traffic dominated. Insects and leaf rustle (faint) were also audible.
	02-12-91	8:19 a.m.	38.5	43.5	52.5	63.1	91.6	Once again the local traffic, birds, and insects were the only sources.
	02-12-91	12:16 p.m.	37.0	42.0	50.5	59.3	83.4	During the time period, a rail maintenance truck went by on the train tracks, birds chirped, leaves rustled, and cars drove by.
	02-12-91	4:28 p.m.	42.5	46.0	57.0	60.3	83.9	The local traffic was the controlling noise source; however, birds, insects, a dog barking, an airplane flyover, a slow truck on the railroad tracks, and two vehicle backup alarms were contributing factors.
	02-13-91	3:08 a.m.	28.5	31.0	36.0	33.3	50.9	Infrequent local traffic and occasional distant dog barks were the only noise sources.
	02-11-91	10:50 a.m.	31.5	36.5	48.0	46.7	70.6	Distant traffic on S. Orange Blossom and Old Tampa Highways was the controlling source. Three cars passed by on Wooten Road, dogs barked in the distance, two planes flew over, and birds and insects were audible.
2	02-11-91	2:02 p.m.	33.5	37.0	42.0	44.4	66.4	Old Tampa Highway and S. Orange Blossom traffic was the dominant source. Other sources included three airplane flyovers, a dog barking and whining, insects, birds, and one car driving by on Wooten Road.
	02-11-91	8:34 p.m.	34.0	38.0	43.5	40.8	59.1	A distant airplane, dogs barking, and a stereo in the neighboring house (faint) were the background and intermittent sources. Distant traffic was the dominant noise source.
	02-12-91	2:58 a.m.	28.5	31.0	35.0	34.0	56.1	Local traffic dominated. Buzzing insects and barking dogs were also audible.
	02-12-91	8:40 a.m.	36.0	38.0	44.0	41.5	53.5	The local traffic, birds, and a distant airplane were audible. In addition, a policeman drove by very slowly.
	02-12-91	12:37 p.m.	32.5	35.5	42.5	42.3	64.3	Local traffic dominated, birds, insects, an airplane, and leaf rustle contributed.
	02-12-91	4:46 p.m.	32.0	37.5	48.0	46.6	67.3	The local traffic is the controlling noise source. Birds, insects, two airplane flyovers, and two bicycle riders were audible.
	02-13-91	3:27 a.m.	29.5	32.0	38.5	34.9	48.1	Infrequent local traffic and a dog barking were the only noise sources.

TABLE 2.3-21
KUA - CANE ISLAND FACILITY
Noise Measurement Location 1 (NML-1)
Main Gate to Cane Island Facility
Unit 1 Operation

DATE	TIME	FACILITY LOAD	Leq (dBA)	L10 (dBA)	L50 (dBA)	L90 (dBA)
January 12, 1995	13:30	29.7	52.0	57.0	44.5	42.0
January 12, 1995	14:00	34.1	59.5	56.0	45.5	41.5
January 12, 1995	14:30		55.5	56.0	45.5	41.5
January 12, 1995	15:00	34.8	47.0	49.0	43.0	40.5
January 12, 1995	15:30		50.5	51.5	45.0	42.0
January 12, 1995	16:00	34.6	48.5	52.5	43.0	40.0
January 12, 1995	16:30		50.5	49.5	43.0	40.5
January 12, 1995	17:00	34.8	55.0	59.0	46.5	42.5
January 12, 1995	17:30		53.0	56.5	46.0	44.0
January 12, 1995	18:00	35.5	52.0	50.0	44.5	42.0
January 12, 1995	18:30		46.0	48.5	44.0	42.0
January 12, 1995	19:00	32.2	40.5	46.5	43.0	41.5
January 12, 1995	19:30		42.0	47.0	42.5	41.0
January 12, 1995	20:00	28.9	41.5	46.0	42.5	41.0
January 12, 1995	20:30		*	44.0	42.0	40.5
January 12, 1995	21:00	32.0	44.0	51.0	44.0	41.0
January 12, 1995	21:30		46.5	52.0	49.0	46.5
January 12, 1995	22:00	28.6	48.0	51.0	48.0	45.0
January 12, 1995	22:30		57.0	56.5	51.0	47.5
January 12, 1995	23:00	30.0	50.5	54.5	50.0	46.5
January 12, 1995	23:30		40.0	47.5	42.5	40.5
January 13, 1995	00:00	22.1	*	43.0	41.0	39.5
January 13, 1995	00:30		*	41.0	39.5	38.5
January 13, 1995	01:00	20.9	*	40.5	38.5	38.5
January 13, 1995	01:30		*	41.5	39.0	38.5
January 13, 1995	02:00	21.1	*	43.0	39.5	38.5
January 13, 1995	02:30		*	42.0	39.0	38.5
January 13, 1995	03:00	21.0	*	44.5	40.0	38.5
January 13, 1995	03:30		*	48.5	41.5	39.0
January 13, 1995	04:00	21.5	*	47.0	42.0	40.0
January 13, 1995	04:30		*	44.0	42.0	41.0
January 13, 1995	05:00	27.9	*	44.0	41.0	40.0
January 13, 1995	05:30		*	44.5	42.0	40.5
January 13, 1995	06:00	34.8	49.5	51.5	45.0	42.5
January 13, 1995	06:30		55.5	60.0	47.5	44.5
January 13, 1995	07:00	20.1	53.5	53.0	47.0	44.0
January 13, 1995	07:30		47.5	50.0	46.5	44.5
January 13, 1995	08:00	33.7	48.0	51.5	45.5	43.0
January 13, 1995	08:30		45.5	49.0	44.0	41.5
January 13, 1995	09:00	33.9	45.5	49.5	43.5	41.0
January 13, 1995	09:30		50.0	52.5	44.0	41.5
January 13, 1995	10:00	27.1	49.5	53.0	45.5	42.0
January 13, 1995	10:30		52.5	56.0	46.5	43.5
January 13, 1995	11:00	28.2	56.5	57.5	48.0	44.0
January 13, 1995	11:30		54.0	57.5	48.5	44.0
January 13, 1995	12:00	29.8	59.5	60.0	48.0	43.5
January 13, 1995	12:30		54.5	57.5	47.5	43.0
January 13, 1995	13:00	29.9	54.0	57.0	47.0	43.0
January 13, 1995	13:30		53.0	54.5	46.5	43.0
January 13, 1995	14:00	29.3	52.5	54.0	46.5	43.0

* Data lost due to equipment malfunction.

TABLE 2.3-21 (contd.)
KUA - CANE ISLAND FACILITY
Noise Measurement Location 1 (NML-1)
Main Gate to Cane Island Facility
Unit 1 Operation

DATE	TIME	FACILITY LOAD	Leq (dBA)	L10 (dBA)	L50 (dBA)	L90 (dBA)
January 13, 1995	15:30	29.8	50.5	49.0	44.0	41.5
January 13, 1995	16:00	29.4	48.0	51.0	45.5	43.0
January 13, 1995	16:30		41.0	49.0	44.0	42.0
January 13, 1995	17:00	31.7	55.0	58.0	45.0	41.5
January 13, 1995	17:30		53.5	57.5	47.0	43.5
January 13, 1995	18:00	30.8	49.0	53.0	46.0	43.5
January 13, 1995	18:30		48.5	52.0	45.5	44.0
January 13, 1995	19:00	27.4	47.5	51.5	45.5	43.5
January 13, 1995	19:30		48.5	52.5	48.5	43.5
January 13, 1995	20:00	27.2	49.5	51.0	45.0	43.0
January 13, 1995	20:30		47.0	50.0	44.5	42.5
January 13, 1995	21:00	28.5	52.0	49.0	43.5	42.0
January 13, 1995	21:30		41.0	48.0	43.5	41.5
January 13, 1995	22:00	30.7	45.0	47.0	42.5	41.5
January 13, 1995	22:30		49.0	48.0	43.0	41.0
January 13, 1995	23:00	29.5	43.5	46.5	42.0	40.5
January 13, 1995	23:30		47.0	51.0	43.0	41.0
January 14, 1995	00:00	25.5	47.5	51.0	43.0	41.0
January 14, 1995	00:30		46.0	51.0	43.0	41.5
January 14, 1995	01:00	24.9	45.5	46.0	42.5	41.0
January 14, 1995	01:30		45.5	49.0	42.5	41.0
January 14, 1995	02:00	34.9	41.5	47.5	42.5	41.0
January 14, 1995	02:30		38.0	46.5	42.5	41.5
January 14, 1995	03:00	35.0	45.0	49.5	44.0	42.5
January 14, 1995	03:30		44.5	48.0	44.0	43.0
January 14, 1995	04:00	35.0	47.5	50.5	44.0	43.0
January 14, 1995	04:30		50.0	53.5	45.0	43.5



Survey Weather Conditions

Accurate environmental noise measurements require that there is no precipitation or wet road conditions during the measurement period and winds must be below 12 mph. Weather conditions were favorable throughout all survey periods. Wind speeds were generally below 12 mph.

Measured Ambient Sound Levels

The 1991 noise survey results are summarized in Table 2.3-20. The preconstruction L90 sound levels ranged from a high of 46.0 dBA to a low of 28.0 dBA. The preconstruction Leq values ranged from a high of 63.1 dBA to a low of 33.3 dBA.

Sound level measurements were recorded at NML-1 and NML-2 from 1:30 p.m. Thursday, January 12 through 5:00 a.m. Saturday, January 14, 1995. The sound levels measured at NML-1 and NML-2 are summarized in Tables 2.3-21 and 2.3-22, respectively. The table also includes the Unit 1 operating load. Full load operation for Unit 1 is approximately 35 megawatts (MW).

The measured L90 sound level at NML-1 ranged from a high of 47.5 dBA to a low of 40.5 dBA. The measured L90 sound level at NML-2 ranged from a high of 42.5 dBA to a low of 33.5 dBA.

Sound level measurements during full Units 1 and 2 operation were recorded at NML-1 from 8:30 a.m. Tuesday, June 6 through 11:30 a.m. Wednesday, June 7, 1995. The sound levels measured at NML-1 are summarized in Table 2.3-23.

Sound level measurements were recorded at NML-1 and NML-2 from 2:30 p.m. Thursday, July 9, 1998 to 8:30 a.m. Friday, July 10, 1998 as shown in Tables 2.3-24 and 2.3-25. Both units were operating at near full load capacity (100 MW to 103 MW) for a majority of the survey period. At NML-1 the A-weighted Leq sound level ranged from a high of 62.5 to a low of 48.0 dBA. The A-weighted L90 sound level ranged from a high of 50.0 dBA to a low of 42.0 dBA. At NML-2 the A-weighted Leq sound level ranged from a high of 61.5 dBA to a low of 44.5 dBA. The A-weighted L90 sound level ranged from a high of 48.0 dBA to a low of 40.0 dBA. The sound level at both locations was largely controlled by insect noise with contributions from local traffic noise. The plant was not audible at this location.

TABLE 2.3-22
KUA - CANE ISLAND FACILITY
Noise Measurement Location 2 (NML-2)
Haley's Residence
Unit 1 Operation

DATE	TIME	FACILITY LOAD	Leq (dBA)	L10 (dBA)	L50 (dBA)	L90 (dBA)
January 12, 1995	13:30	29.7	53.0	64.0	53.5	42.5
January 12, 1995	14:00	34.1	53.0	47.5	41.0	37.5
January 12, 1995	14:30		43.5	46.5	41.0	37.5
January 12, 1995	15:00	34.8	42.5	45.0	40.5	37.5
January 12, 1995	15:30		44.5	47.5	42.5	39.5
January 12, 1995	16:00	34.6	46.5	50.5	40.5	37.0
January 12, 1995	16:30		45.5	46.5	40.0	37.0
January 12, 1995	17:00	34.8	45.5	48.0	43.5	40.0
January 12, 1995	17:30		49.0	48.0	44.0	42.0
January 12, 1995	18:00	35.5	50.5	46.5	43.0	41.5
January 12, 1995	18:30		46.5	47.0	42.5	41.0
January 12, 1995	19:00	32.2	43.5	45.5	42.5	41.0
January 12, 1995	19:30		44.0	45.0	41.5	40.0
January 12, 1995	20:00	28.9	42.0	44.5	40.5	38.5
January 12, 1995	20:30		41.0	42.5	39.0	37.5
January 12, 1995	21:00	32.0	42.0	43.0	38.0	35.5
January 12, 1995	21:30		38.5	41.0	37.5	35.5
January 12, 1995	22:00	28.6	40.0	43.0	38.0	35.5
January 12, 1995	22:30		49.0	41.5	37.5	36.0
January 12, 1995	23:00	30.0	37.5	39.0	37.0	35.5
January 12, 1995	23:30		38.0	39.5	36.5	34.5
January 13, 1995	00:00	22.1	38.5	40.0	37.0	35.0
January 13, 1995	00:30		37.0	38.5	36.5	35.5
January 13, 1995	01:00	20.9	38.0	40.0	38.0	35.5
January 13, 1995	01:30		36.0	38.0	34.5	33.0
January 13, 1995	02:00	21.1	37.0	40.0	34.5	33.5
January 13, 1995	02:30		35.5	38.5	34.0	33.5
January 13, 1995	03:00	21.0	38.0	41.0	35.5	33.5
January 13, 1995	03:30		43.0	43.5	38.5	36.0
January 13, 1995	04:00	21.5	40.0	41.5	38.0	36.0
January 13, 1995	04:30		38.5	41.0	37.5	36.0
January 13, 1995	05:00	27.9	41.5	44.5	40.5	35.0
January 13, 1995	05:30		39.0	41.0	38.0	35.5
January 13, 1995	06:00	34.8	42.5	44.5	41.5	39.0
January 13, 1995	06:30		44.5	47.0	43.0	40.5
January 13, 1995	07:00	20.1	49.0	47.0	43.5	41.0
January 13, 1995	07:30		44.5	46.5	43.5	41.0
January 13, 1995	08:00	33.7	45.0	48.0	42.5	39.0
January 13, 1995	08:30		43.0	45.5	41.0	38.5
January 13, 1995	09:00	33.9	43.5	44.5	40.5	38.0
January 13, 1995	09:30		43.5	46.0	41.5	38.5
January 13, 1995	10:00	27.1	43.0	46.0	41.5	38.5
January 13, 1995	10:30		46.0	48.0	43.0	40.0
January 13, 1995	11:00	28.2	52.5	48.0	44.0	40.5
January 13, 1995	11:30		48.5	49.5	44.0	39.5
January 13, 1995	12:00	29.8	53.0	48.5	44.0	41.0
January 13, 1995	12:30		47.5	48.5	43.5	40.5
January 13, 1995	13:00	29.9	47.0	48.0	42.0	39.5
January 13, 1995	13:30		49.5	48.0	43.5	39.5
January 13, 1995	14:00	29.3	45.5	47.5	42.5	39.5
January 13, 1995	14:30		43.5	45.5	41.0	38.5

TABLE 2.3-22 (contd.)
KUA - CANE ISLAND FACILITY
Noise Measurement Location 2 (NML-2)
Haley's Residence
Unit 1 Operation

DATE	TIME	FACILITY LOAD	Leq (dBA)	L10 (dBA)	L50 (dBA)	L90 (dBA)
January 13, 1995	16:00	29.8	45.5	48.5	42.5	39.5
January 13, 1995	16:30	29.4	43.5	45.5	41.5	39.5
January 13, 1995	17:00		51.0	49.0	42.0	38.5
January 13, 1995	17:30	31.7	46.5	47.5	43.5	40.5
January 13, 1995	18:00		44.5	45.5	42.5	41.0
January 13, 1995	18:30	30.8	43.5	44.5	42.5	41.5
January 13, 1995	19:00		43.0	44.5	42.0	41.0
January 13, 1995	19:30	27.4	44.0	44.5	42.5	41.5
January 13, 1995	20:00		43.0	44.0	42.0	41.0
January 13, 1995	20:30	27.2	43.5	45.0	42.0	41.0
January 13, 1995	21:00		50.5	45.5	42.0	41.0
January 13, 1995	21:30	28.5	43.0	44.0	42.0	41.0
January 13, 1995	22:00		42.0	43.0	41.5	40.5
January 13, 1995	22:30	30.7	46.5	43.5	41.5	40.5
January 13, 1995	23:00		41.5	42.5	41.0	40.5
January 13, 1995	23:30	29.5	42.0	42.5	41.0	40.0
January 14, 1995	00:00		42.0	43.0	41.0	40.0
January 14, 1995	00:30	25.5	41.5	42.5	41.0	40.0
January 14, 1995	01:00		41.0	42.0	40.5	40.0
January 14, 1995	01:30	24.9	41.0	41.5	40.5	40.0
January 14, 1995	02:00		41.0	42.0	40.5	40.0
January 14, 1995	02:30	34.9	40.5	42.0	40.5	39.5
January 14, 1995	03:00		40.5	41.5	40.5	39.5
January 14, 1995	03:30	35.0	40.5	41.5	40.5	39.5
January 14, 1995	04:00		40.5	41.5	40.0	39.0
January 14, 1995	04:30	35.0	39.5	41.0	39.0	38.0

Table 2.3-23
KUA - CANE ISLAND FACILITY
Noise Measurement Location 1 (NML-1)
Main Gate to Cane Island Facility
Full Facility Operation

DATE	TIME	Leq (dBA)	L10 (dBA)	L50 (dBA)	L90 (dBA)
June 6, 1995	08:30	51.5	55.0	46.0	40.0
June 6, 1995	09:00	47.0	49.5	45.5	42.5
June 6, 1995	09:30	56.0	48.0	44.0	42.0
June 6, 1995	10:00	48.0	50.5	46.0	44.0
June 6, 1995	10:30	47.5	49.5	45.5	43.5
June 6, 1995	11:00	48.5	51.0	45.0	42.0
June 6, 1995	11:30	53.0	56.0	46.5	43.0
June 6, 1995	12:00	54.5	55.0	46.0	42.0
June 6, 1995	12:30	49.5	50.5	45.5	42.5
June 6, 1995	13:00	46.0	48.0	44.5	42.0
June 6, 1995	13:30	50.0	51.5	45.5	42.5
June 6, 1995	14:00	47.5	49.5	45.5	43.0
June 6, 1995	14:30	48.0	50.0	45.5	43.0
June 6, 1995	15:00	47.5	49.5	45.0	42.5
June 6, 1995	15:30	48.0	51.0	45.5	43.0
June 6, 1995	16:00	56.5	50.0	45.0	43.0
June 6, 1995	16:30	61.0	50.5	45.5	43.0
June 6, 1995	17:00	46.5	48.5	45.0	43.0
June 6, 1995	17:30	46.0	48.5	44.5	42.0
June 6, 1995	18:00	47.5	49.5	45.0	42.5
June 6, 1995	18:30	45.0	47.5	44.0	42.0
June 6, 1995	19:00	45.5	47.5	44.0	42.0
June 6, 1995	19:30	47.5	48.5	44.0	42.0
June 6, 1995	20:00	56.5	49.5	46.5	44.0
June 6, 1995	20:30	47.0	49.5	46.5	44.5
June 6, 1995	21:00	49.5	48.5	46.5	45.5
June 6, 1995	21:30	47.5	48.5	47.0	46.0
June 6, 1995	22:00	50.0	49.5	47.5	46.5
June 6, 1995	22:30	49.0	50.0	48.0	47.5
June 6, 1995	23:00	46.5	48.0	46.0	45.0
June 6, 1995	23:30	52.0	48.0	46.0	45.0
June 7, 1995	00:00	45.5	46.5	45.0	44.0
June 7, 1995	00:30	44.0	43.5	43.5	43.0
June 7, 1995	01:00	43.0	43.0	43.0	42.5
June 7, 1995	01:30	43.0	43.0	43.0	42.0
June 7, 1995	02:00	43.0	42.5	42.5	41.5
June 7, 1995	02:30	60.5	42.5	42.5	41.0
June 7, 1995	03:00	43.0	42.5	42.5	41.5
June 7, 1995	03:30	62.5	43.5	43.5	42.5
June 7, 1995	04:00	41.5	41.0	41.0	40.0
June 7, 1995	04:30	41.5	41.5	41.5	40.0
June 7, 1995	05:00	44.0	41.0	41.0	40.0
June 7, 1995	05:30	42.5	42.0	42.0	40.5
June 7, 1995	06:00	46.0	44.0	44.0	42.0
June 7, 1995	06:30	47.5	43.5	43.5	41.5
June 7, 1995	07:00	59.0	43.0	43.0	41.0
June 7, 1995	07:30	44.0	43.0	43.0	41.5
June 7, 1995	08:00	44.5	42.5	42.5	40.5
June 7, 1995	08:30	45.0	41.5	41.5	40.0
June 7, 1995	09:00	47.0	43.5	43.5	41.5
June 7, 1995	09:30	44.5	43.5	43.5	41.5
June 7, 1995	10:00	52.5	44.0	44.0	42.0
June 7, 1995	10:30	50.0	45.0	45.0	43.0
June 7, 1995	11:00	46.5	45.0	45.0	42.5
June 7, 1995	11:30	48.0	43.5	43.5	41.5

Table 2.3-24
KUA - Cane Island
Noise Measurement Location 1 (NML-1)
A-Weighted and C-Weighted Sound Levels

DATE	TIME	Facility Load (MW)	Leq		L90	
			(dBA)	(dBC)	(dBA)	(dBC)
July 9, 1998	14:30	102.2	55.5	69.0	45.0	59.0
July 9, 1998	15:30	97.5	62.5	71.0	46.0	60.0
July 9, 1998	16:30	97.5	48.5	66.0	44.0	61.0
July 9, 1998	17:30	97.9	48.0	63.5	43.0	59.5
July 9, 1998	18:30	98.3	48.5	61.0	42.0	58.5
July 9, 1998	19:30	100.2	56.5	70.5	49.5	59.5
July 9, 1998	20:30	100.6	58.0	69.5	50.0	60.0
July 9, 1998	21:30	101.9	50.5	63.0	49.0	60.0
July 9, 1998	22:30	102.3	50.5	58.0	48.5	54.5
July 9, 1998	23:30	102.3	50.0	56.0	48.0	54.0
July 10, 1998	00:30	103.7	49.0	56.5	47.0	53.0
July 10, 1998	01:30	103.4	48.0	54.5	47.0	51.0
July 10, 1998	02:30	103.4	47.5	54.5	46.0	51.5
July 10, 1998	03:30	68.4	46.0	56.0	43.5	52.5
July 10, 1998	04:30	68.4	52.0	67.0	44.0	55.0
July 10, 1998	05:30	50.3	50.0	61.5	43.0	57.0
July 10, 1998	06:30	51.3	48.5	62.0	42.5	56.0
July 10, 1998	07:30	69.3	47.5	61.5	42.5	55.5
July 10, 1998	08:30	69.3	62.5	75.0	42.5	55.5

Table 2.3-25
KUA - Cane Island
Noise Measurement Location 2 (NML-2)
A-Weighted and C-Weighted Sound Levels

DATE	TIME	Facility Load (MW)	Leq		L90	
			(dBA)	(dBC)	(dBA)	(dBC)
July 9, 1998	14:30	102.2	54.5	75.5	43.0	58.5
July 9, 1998	15:30	97.5	61.5	69.5	44.5	59.5
July 9, 1998	16:30	97.5	47.0	64.0	42.5	60.0
July 9, 1998	17:30	97.9	47.0	63.0	41.0	58.5
July 9, 1998	18:30	98.3	47.0	60.5	40.0	58.0
July 9, 1998	19:30	100.2	55.5	70.0	48.0	59.0
July 9, 1998	20:30	100.6	57.0	69.5	48.0	59.5
July 9, 1998	21:30	101.9	49.0	62.5	47.5	59.5
July 9, 1998	22:30	102.3	49.0	58.0	47.0	54.5
July 9, 1998	23:30	102.3	48.0	56.5	46.0	54.5
July 10, 1998	00:30	103.7	47.5	56.5	45.0	53.5
July 10, 1998	01:30	103.4	46.0	55.0	45.0	52.5
July 10, 1998	02:30	103.4	46.0	55.0	44.5	52.0
July 10, 1998	03:30	68.4	44.5	56.0	41.5	52.5
July 10, 1998	04:30	68.4	51.0	67.0	42.5	55.0
July 10, 1998	05:30	50.3	48.5	66.5	41.5	57.0
July 10, 1998	06:30	51.3	47.0	63.0	41.5	57.0
July 10, 1998	07:30	69.3		61.0		55.5
July 10, 1998	08:30	69.3		75.5		55.5



The C-weighted sound levels were also recorded at each location. Measured C-weighted sound levels are very sensitive to low frequency noise such as noise produced by industrial facilities or local traffic. At both locations NML-1 and NML-2, traffic noise was the controlling C-weighted noise source. The facility was not audible at either location. At NML-1 the C-weighted Leq sound level ranged from a high of 75.0 dBC to a low of 54.5 dBC. The C-weighted L90 sound level ranged from a high of 61.0 dBC to a low of 51.0 dBC. At NML-2, the C-weighted Leq sound level ranged from a high of 75.5 dBC to a low of 55.0 dBC. The C-weighted L90 sound level ranged from a high of 60.0 dBC to a low of 52.0 dBC. As the data indicates, the minimum C-weighted sound levels occurred during the early morning hours (approximately 1:30 a.m.) when traffic noise is minimum, even though the facility was operating near full load during these time periods.

Octave band values were recorded during both the 1991 preconstruction noise survey and during the 1998 operational noise survey. The measured sound levels are summarized in Table 2.3-26. Both A-weighted and C-weighted sound levels have been calculated from the octave band data. Both the A-weighted and C-weighted values have remained quite consistent from 1991 to 1998. The introduction of the existing plant has not resulted in a significant increase in either the existing A-weighted or C-weighted sound levels.

Description of Acoustic Environment

Sound levels at NML-1 near the Power Park main gate are controlled by traffic noise along the roadways to the south, natural noise such as frogs and crickets, occasional traffic along the Power Park entrance road, and occasional aircraft noise. The Leq values were highly variable due to the traffic along the entrance road. The Power Park was faintly audible throughout the survey. At many periods the natural noise masked the plant noise. During the early morning hours the L90 sound level reached a minimum of 40 dBA during full load operation. The current Power Park noise emission level is assumed to be 40 dBA at this location.

Sound levels at the neighboring residential locations are controlled by faint traffic noise and natural noise sources. The Power Park was very faintly audible at certain times during the survey. During the early morning hours the L90 sound level reached a minimum of 33 dBA. The Power Park noise emission level is assumed to be 33 to 35 dBA at this residence.



Table 2.3-26
KUA Cane Island
Octave Band Noise Data

Measurement Location	DATE	TIME	Overall		Octave Band Center Frequency (Hz)								
			dBA	dBC	31.5	63	125	250	500	1000	2000	4000	8000
1	February 11, 1991	14:38	45.9	57.1	53.8	53.8	49.3	49.3	42.1	40.1	36.1	29.9	26.9
			50.9	65.0	55.4	58.6	63.5	53.8	45.9	40.6	33.8	27.8	20.9
1	February 12, 1991	00:32	44.0	56.6	56.3	53.4	44.9	37.4	37.5	41.6	36.4	22.8	18.1
			47.7	60.1	50.1	57.3	56.8	44.4	45.3	41.4	39.3	29.3	20.6
1	July 9, 1998	15:30	48.7	52.5	51.1	47.0	42.8	36.1	33.4	34.2	39.8	44.3	44.8
			48.4	53.8	52.1	49.6	45.0	34.9	33.8	36.6	40.3	43.6	43.9
1	July 9, 1998	01:35	48.7	53.2	51.8	47.8	44.8	34.8	30.8	33.9	39.9	44.1	45.1
			48.4	53.8	52.1	49.6	45.0	34.9	33.8	36.6	40.3	43.6	43.9
1	July 10, 1998	01:35	48.7	53.2	51.8	47.8	44.8	34.8	30.8	33.9	39.9	44.1	45.1
			48.4	53.8	52.1	49.6	45.0	34.9	33.8	36.6	40.3	43.6	43.9
1	July 10, 1998	02:25	45.8	52.9	52.9	47.8	42.4	33.9	31.9	32.7	38.6	40.6	41.3
			45.7	52.6	50.9	49.5	42.9	35.4	31.7	33.2	38.6	40.7	40.5
2	February 11, 1991	14:17	38.4	53.2	50.8	50.6	46.1	38.4	35.3	32.8	27.5	22.4	22.1
			40.8	52.4	44.6	49.6	45.3	46.6	35.1	33.1	30.1	21.1	17.1
2	February 12, 1991	00:55	37.4	52.8	52.8	48.5	42.7	42.5	32.1	28.2	25.8	25.5	23.3
			36.4	53.2	52.1	51.1	41.9	33.1	30.9	30.9	29.4	24.5	18.1
2	July 10, 1998	01:50	48.5	53.4	51.2	47.9	46.9	40.3	34.2	32.1	39.4	42.3	46.2
			49.2	56.4	53.4	53.9	46.3	42.9	39.4	36.9	38.8	42.6	46.8

Site and Vicinity Characterization



2.3.9 Other Environmental Features

Ultimate Power Park development was delineated during the permitting of Units 1 and 2; mitigation was provided for access road corridor, ultimate power block area, and the Bonnet Creek Canal and Clay Street transmission lines impacts. As a result, development areas have been restricted to approximately 164 acres of the total 1,027 Power Park acres. The remaining 860 acres have been granted to the SFWMD and FGFWFC as conservation easements which are actively managed by KUA for the benefit of wildlife. In addition, the Power Park habitats were identified as a "regionally significant resource" by the SFWMD. KUA is committed to preserving these habitats and developing an environmentally safe and responsible project.

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3.0 The Plant and Directly Associated Facilities

3.1 Background

The Cane Island Power Park (Power Park) currently includes two existing units (Units 1 and 2) and support facilities as shown on the Site Arrangement (Figure 2.1-3). The location and layout of Unit 3 is also shown.

The three unit Power Park will include three combustion turbine generators, two heat recovery steam generators, two steam turbine generators, natural gas delivery system, water supply, treatment, and disposal systems, and storm water management facilities. The electricity generated by the combustion of the natural gas is stepped up in voltage by generator step-up transformers for distribution to the power grid.

Flue gas is the only byproduct of the combustion process whether burning natural gas or No. 2 fuel oil. Both are low sulfur, low ash fuels. Other than combustion control measures, such as dry low NO_x combustors and temperature control by water injection, no other air pollution control techniques are required to meet current regulations.

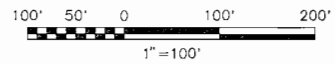
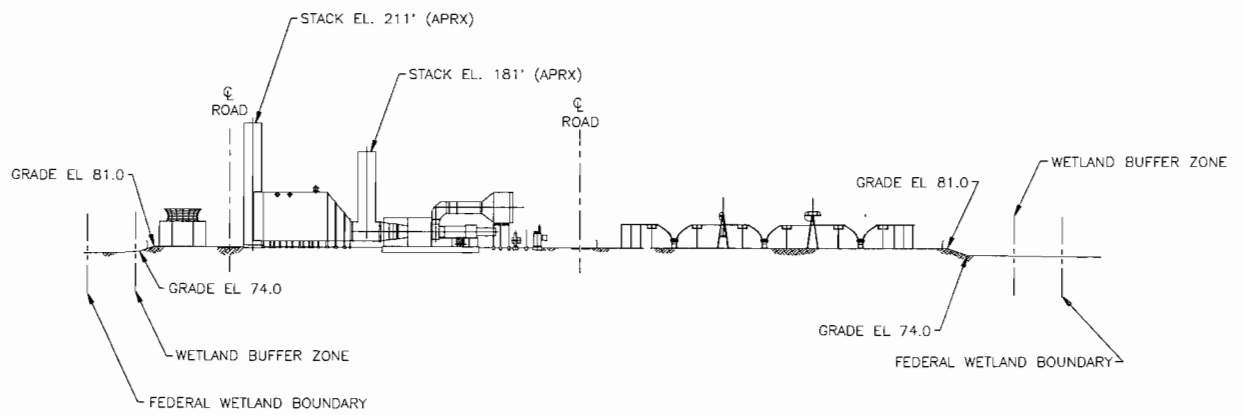
Cycle heat rejection is and will continue to be accomplished using rectangular, multicell, mechanical draft cooling towers. Treated sewage effluent supplied by the City of Kissimmee (Kissimmee) effluent pipeline adjacent to the Power Park is and will continue to be used as cooling tower makeup water. Service and potable water is supplied from onsite wells to the Floridan Aquifer.

3.2 Site Layout

The Site Arrangement depicts the proposed layout for the Unit 3 expansion of the Power Park, the existing Units 1 (GE LM-6000) and 2 (GE Frame 7EA in combined cycle), and associated facilities. The general profile associated with Unit 3 combustion turbine is depicted on Figure 3.2-1. This profile is based on preliminary elevations and dimensions and may change during detailed design and equipment selection. Figure 3.2-2 depicts the proposed locations and elevations for the release points of gaseous and liquid release points associated with Unit 3.

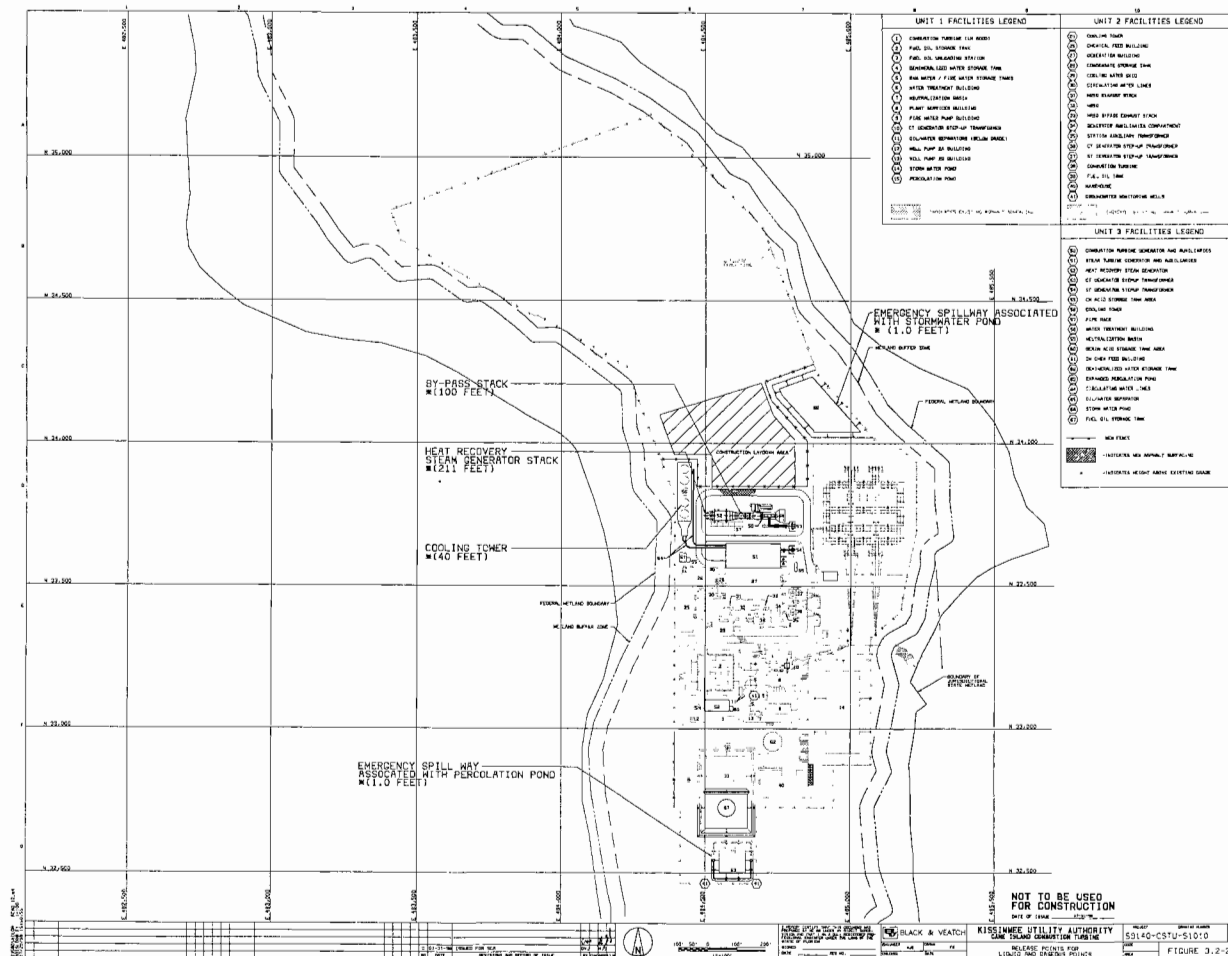
IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



GENERAL PROFILE OF
KUA UNIT-3 LOOKING NORTH
FIGURE 3.2-1
07-31-98

Poor Original





3.3 Fuel

3.3.1 Fuel Types and Qualities

The primary fuel for the Power Park is and will continue to be natural gas. Firm delivery contracts are in-place for Units 1 and 2 with the Florida Gas Transmission Company (FGT). Table 3.3-1 presents typical property values for the primary fuel.

The backup fuel is and will continue to be low sulfur (0.05 percent) No. 2 fuel oil. Approximately 2 million gallons will be stored onsite with the addition of the Unit 3 storage tank. Operation on oil is limited to a specific number of hours (720) per year per unit. Table 3.3-2 presents typical property values for the backup fuel.

3.3.2 Fuel Quantities

The natural gas consumption rate, at a 100 percent capacity factor for all three units, would be approximately 3.1 million cubic feet per hour.

The fuel oil consumption rate of all units, operating at a 100 percent capacity factor, would be approximately 0.56 million gallons per day.

3.3.3 Fuel Transportation

Natural gas is the primary fuel at the Power Park and is supplied via an underground 20 inch diameter natural gas line owned by KUA and operated by FGT. The natural gas line was installed in 1993 to support the Power Park. The line ties into an existing FGT natural gas line near the intersection of Interstate I-4 and State Road 545, and is designed as a Class 3 location as specified in Part 192 of the Department of Transportation (DOT) Pipeline Safety Regulations. The line was sized based on a total build out of approximately 1,000 MW at the Power Park.

No. 2 fuel oil is the secondary (backup) fuel for the Power Park. Fuel oil is delivered to the Power Park by tanker trucks. Once onsite, the fuel is transferred from the tankers to the onsite storage tanks.

3.3.3.1 Natural Gas Delivery and Metering. Natural gas is delivered to Power Park as described in Subsection 3.3.3. A metering station was installed (1993) in conjunction with the 20 inch natural gas line to support the Power Park. The metering station is located at the

Table 3.3-1
Natural Gas Properties

Parameter	Mole, %	Gal/Mcf **	Btu *	Rel Den *
C 6 +	0.067	0.0299	3.54	0.0022
Propane	0.961	0.2649	24.24	0.0146
I-Butane	0.249	0.0814	8.12	0.0050
N-Butane	0.193	0.0609	6.31	0.0039
NEO-C5	3,000.00-6	0.0011	0.12	0.0001
I-Pentane	0.061	0.0223	2.45	0.0015
N-Pentane	0.030	0.0109	1.21	0.0007
Nitrogen	0.246	0.0000	0.00	0.0024
Methane	93.753	0.0000	949.06	0.5193
CO ₂	1.172	0.0000	0.00	0.0178
Ethane	3.265	0.8734	57.91	0.0339
Totals	100.0	1.3448	1,052.95	0.6014

Notes:

* @ 14.730 psia and uncorrected for compressibility

** @ 14.730 and 60° F

Total sulfur = 74.1% of 16 ppm = 11.8 ppm/V



Table 3.3-2
No. 2 Fuel Oil Properties

Parameter	Value
Ash Content, % wt	0.001
Sulfur Content by XRF, % wt	0.03
Water Content KF, ppm	77
Density, kg/l @ 15° C	0.8450
Gross Heat Value, Btu/gal	138,064
Net Heat Value, Btu/gal	129,550
Gross Heat Value, Btu/lb	19,615
Net Heat Value, Btu/lb	18,405
Arsenic, ppm	<0.05
Beryllium, ppm	<0.05
Mercury, ppm	<0.05
Lead, ppm	0.07



tie-in location (intersection of I-4 and State Road 545) with the FGT pipeline. This metering station will also be utilized to meter and supply the amount of natural gas required by Unit 3. No modifications to the delivery or metering facilities are required.

3.3.3.2 Fuel Oil Storage and Handling. A new 1 million gallon fuel oil (No. 2) storage tank will be added at the Power Park for Unit 3. This tank will tie into and use the existing backup fuel system associated with Units 1 and 2.

The existing fuel oil storage consists of two aboveground tanks (one 300,000 gallon tank for Unit 1, and one 700,000 gallon tank for Unit 2). The construction, materials, installation, and use of the bulk storage tanks conform to API Standard 650, AISC, ASTM, NEC, and OSHA standards. The locations of these storage tanks are indicated on the Site Arrangement, Figure 2.1-3.

Fuel will be delivered to one of the three vertical oil storage tanks by tanker truck as described in Section 3.3.3 above. The containment area for each fuel oil tank is provided by an earthen berm. Each berm is designed to meet Florida Department of Environmental Protection (FDEP) requirements to provide containment for both 110 percent of the storage capacity of the largest tank within the impoundment and a sufficient allowance for the design (10 year 24 hour) rainfall storm event (approximately 7 inches). In addition, each containment area is provided with a synthetic liner which is protected with approximately 6 inches of sand. The liner is sufficiently impermeable to ensure that no oil can escape by infiltrating through the liner and soil, and into surface or ground waters as required by FDEP regulation.

The fuel oil truck unloading station is located south of the Unit 1 storage tank as indicated on the Site Arrangement. The station consists of aboveground and double-walled below grade piping running to the storage tanks outside and inside each of the earthen berm areas. The station includes a manually operated isolation valve and a check valve immediately adjacent to the station. This allows immediate isolation of the piping system from a spill at the delivery truck and prevents backflow spillage of oil from the system.

Semi-trailer tanker trucks enter the site at the main gate, park adjacent to the unloading station, and are connected to the unloading station. Unloading operations are coordinated between the Plant Operator(s) and the truck driver and are constantly monitored by both parties. The Plant Operator(s) are responsible for operating valves and the truck



driver is responsible for pumping the fuel. A warning sign alerting drivers to disconnect lines and check valves has been provided at the unloading station.

The existing Spill Prevention, Control, and Countermeasures Plan, and Facility Response Plan will be modified as required to include Unit 3 facilities.

3.3.4 Alternate Fuel Types

KUA investigated various alternative technologies and fuels for phased development at the Power Park. Economics, environmental acceptability, and the tourist/entertainment culture of the project region were important considerations in the analysis. The portion of the Power Park suitable for development is relatively small (about 100 acres), compared to several thousand acre coal fired plant sites, which restricted technology alternatives.

KUA determined that combustion turbines, in either simple or combined cycle mode, firing primarily natural gas, would be the most efficient technology for power generation at the Power Park. Natural gas does not require delivery vehicles, storage facilities, secondary containment structures, or large dedicated acreages. Natural gas is also the cleanest burning fossil fuel, causing minimal air quality impacts. Incremental additions of natural gas fired combustion turbine capacity are also more flexible than additions of oil or coal fired capacity.

3.4 Air Emissions and Control

The anticipated air emissions and proposed control technologies are presented in Appendix 10.7 - PSD Application which is attached to this Site Certification Application under separate cover.

3.5 Plant Water Use

Deep wells to the Floridan Aquifer will supply all process, service, and potable water uses, except for cooling tower makeup. There are two existing wells at the site, each with a 200 gpm pump used to supply Units 1 and 2. Additional process water demand for Unit 3, excluding cooling tower makeup, will be approximately 126,000 gpd. Total process water demand for Units 1-3 will be approximately 221,000 gpd.



Well water withdrawal is increased with the addition of Unit 3 because of the need for additional potable water, steam cycle makeup, and general plant service water. The water use for Unit 3 fired on natural gas is shown on Figure 3.5-1. The water use for all three units fired on natural gas is shown on Figure 3.5-2.

Well water is also requested for use as an emergency source of cooling tower makeup for Units 2 and 3. This demand is estimated to be approximately 3 million gpd. It is estimated that four new wells will be required to accommodate the emergency well water demands.

Normal fuel is natural gas; however, Power Park design allows all units to be fired on oil. The Power Park water usage will increase when firing on fuel oil due to the additional demineralized water required for NO_x injection. The water use for Unit 3 fired on oil is shown on Figure 3.5-3. The water use for all three units fired on oil is shown on Figure 3.5-4.

The water mass balances represent operation at 100 percent load conditions. Actual average annual flows will be less, dependent upon the electrical loading of the generators.

3.5.1 Heat Dissipation System (Cooling Tower)

Waste heat from Units 2 and 3 will be rejected to the atmosphere by a cooling cycle using mechanical draft cooling towers. The source of cooling water makeup will be treated sewage effluent from the Kissimmee effluent pipeline. Provisions will be included to utilize well water as an emergency source of cooling water makeup.

The estimated cooling water makeup rate from the Kissimmee effluent pipeline for Units 2 and 3 is approximately 3 million gpd. When the Unit 3 combustion turbine inlet air evaporative cooler is in service, 43,000 gpd of the Unit 3 evaporative cooler blowdown will be routed to the cooling tower to provide a portion of the Unit 3 cooling water makeup requirement.

Cooling water requirements for Unit 3 and all three units are included on the water balances on Figures 3.5-1 through 3.5-4. Unit 2 requires approximately 1 million gpd; Unit 3 will require approximately 2 million gpd.

Cooling tower blowdown will be directed back to the Kissimmee effluent pipeline as described in Section 3.6.1 below.

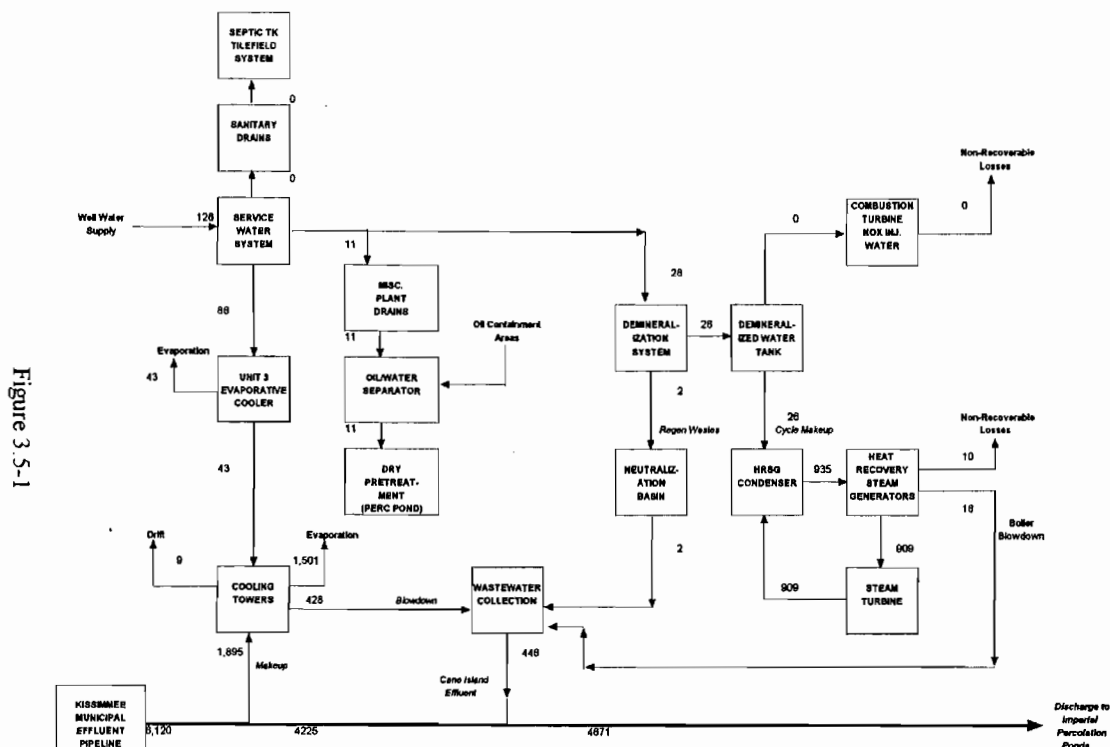


Figure 3.5-1

ALL FLOWS ARE GIVEN IN 1000 GALLONS PER DAY

28-Jul-88

KISSIMMEE UTILITY AUTHORITY
CANE ISLAND 3
WATER MASS BALANCE

FIGURE 3.5-1
100% LOAD CONDITION
UNIT 3
NATURAL GAS FIRED

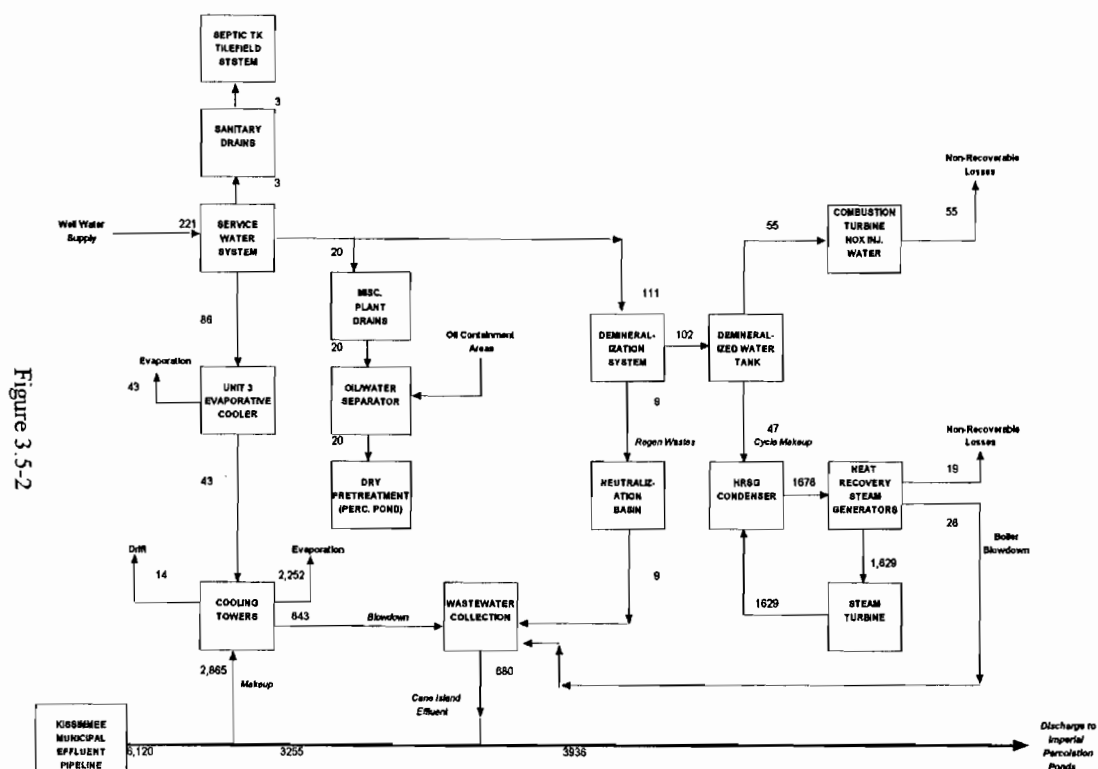


Figure 3.5-2

KISSIMMEE UTILITY AUTHORITY CANE ISLAND 3 WATER MASS BALANCE

FIGURE 3.5-2
100% LOAD CONDITION
UNITS 1 THRU 3 COMBINED
NATURAL GAS FIRED

ALL FLOWS ARE GIVEN IN 1000 GALLONS PER DAY
28-JUL-98

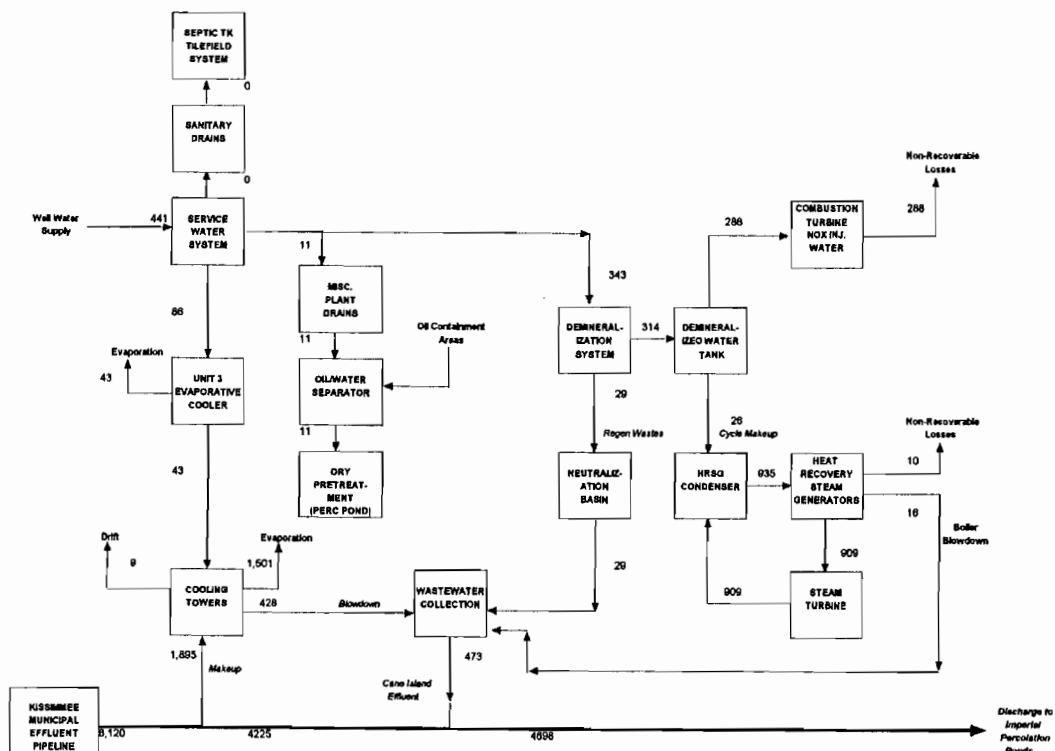


Figure 3.5-3

KISSIMMEE UTILITY AUTHORITY
CANE ISLAND 3
WATER MASS BALANCE

FIGURE 3.5-3
100% LOAD CONDITION
UNIT 3
OIL FIRED

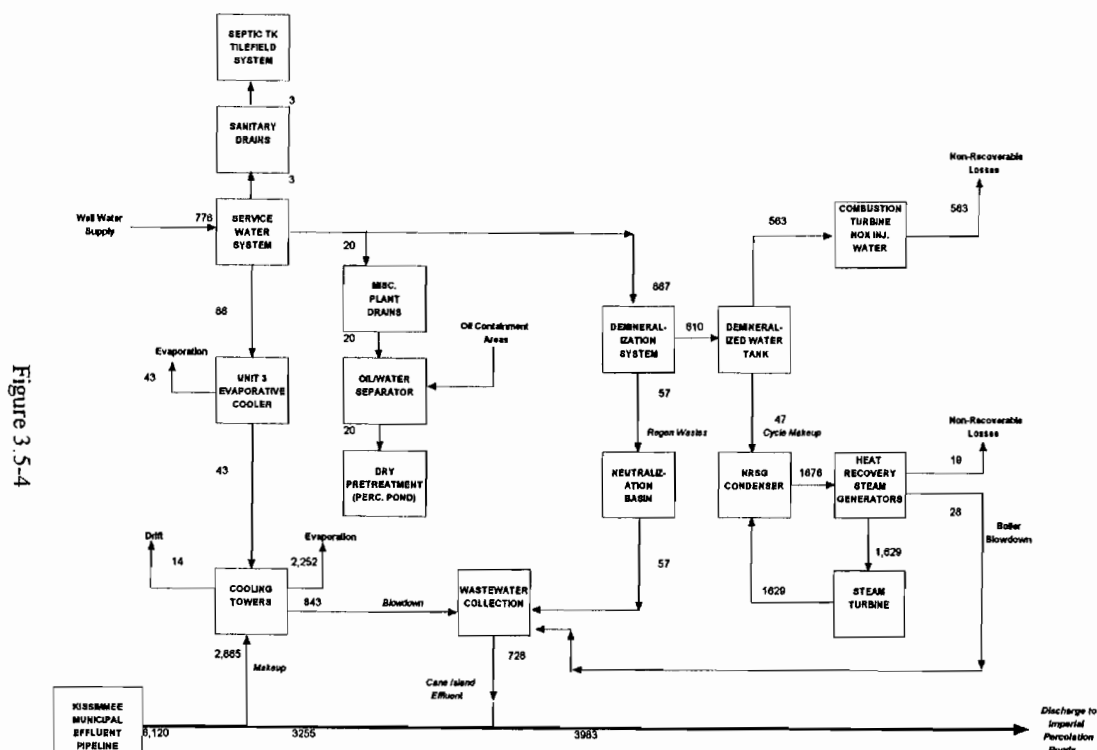


Figure 3.5-4

ALL FLOWS ARE GIVEN IN 1000 GALLONS PER DAY
28-Jul-98

KISSIMMEE UTILITY AUTHORITY CANE ISLAND 3 WATER MASS BALANCE

FIGURE 3.5-4
100% LOAD CONDITION
UNITS 1 THRU 3 COMBINED
OIL FIRED



3.5.2 Domestic/Sanitary Wastewater

Domestic and sanitary wastewater are generated by showers, lavatories, sinks, toilets, urinals, and drinking fountains.

Based on present staffing, sanitary wastewater is estimated at 3,000 gpd. It is estimated that there will be two new employees in association with Unit 3. At a flow of 40 gpd per person, approximately 80 additional gpd of sanitary waste will require treatment.

Unit 3 sanitary wastes will be routed to the existing septic tank/tile field system for treatment.

3.5.3 Potable Water System

Potable water uses at the plant will include water for drinking, washing, showers, urinals, and toilets. Potable water for Unit 3 will be provided from an extension of the existing site service/potable water system, which is a permitted noncommunity public water system supplied by well water. The estimated potable water analysis prior to treatment is shown in Table 3.5-1.

3.5.4 Process Water Systems

Service/process water will be provided for washdown purposes, and for pump and equipment seal water and flushing as necessary. Hose stations will be located for washdown use as required.

Fire water is obtained from a dedicated supply of treated well water available from the existing service/fire water storage tank. Existing fire water pumps provide water by means of an underground piping loop which serves fire hydrants, hose racks and reels, and automatic suppression systems.

Demineralized water will be required for use as makeup to the steam-condensate-feedwater cycle associated with the HRSGs. The makeup is required to replace cycle losses and boiler blowdown. In addition, demineralized water will be used when firing fuel oil on all units, and Unit 1 on natural gas, to control combustion turbine NO_x emissions, as well as for demineralizer regeneration.



Table 3.5-1
Potable Water Analysis

Constituent	Concentration
Calcium, mg/l as CaCO_3	110
Magnesium, mg/l as CaCO_3	58
Sodium, mg/l as CaCO_3	35
Potassium, mg/l as CaCO_3	1
M-Alkalinity, mg/l as CaCO_3	145
Sulfate, mg/l as CaCO_3	20
Chloride, mg/l as CaCO_3	10
Silica, mg/l as SiO_2	12
Total Dissolved Solids, mg/l	290



Demineralized water treatment will consist of an ion exchange demineralizer system. Service water will be transferred to the demineralizer inlet. As the water passes through the system, it will be progressively demineralized until the effluent contains essentially no dissolved solids. Exhausted ion exchange resin will be regenerated using sulfuric acid and sodium hydroxide. The resulting chemical wastewater flows will be treated as described in Section 3.6 below.

The demineralized water storage system for Unit 3 will be interconnected with the existing demineralized water storage system.

3.5.5 Water Use Variations

All water requirements described in the preceding sections are based on full load operation of the Power Park. When the units operate at less than full load, the evaporation rate from the cooling towers, and consequently the cooling tower makeup and blowdown rates, decrease proportionately. Cooling tower makeup (treated effluent) is the major water use at the Power Park, and a decrease in operating capacity would mean a substantial decrease in overall water use. Demineralized water makeup (ground water) requirements will also decrease proportionately at lower capacity loads. The balance of water uses will be basically independent of the operating load.

In the event of combined cycle mode shutdown, the cooling system (cooling towers) will be shut down and no makeup will be required, but other systems may continue to operate.

3.6 Chemical and Biocide Waste

The Power Park has five major sources of wastewater. These are sanitary wastewaters, oil/water separator effluent, cooling tower blowdown, chemical wastes, and boiler blowdown. Process wastewaters will be treated and discharged at three locations. Oil/water separator effluent is and will continue to be routed to an onsite percolation pond for additional treatment prior to ground water discharge. Cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be combined and returned to the Kissimmee effluent pipeline for additional reuse or disposal at the Imperial percolation pond site. Sanitary wastes will be routed to the existing onsite septic tank/tile field system. There is no source of leachate associated with the Power Park or Unit 3 and, therefore, no basis for this process to occur.



It is estimated that 680,000 gpd of combined wastewater from cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be returned to the Kissimmee effluent pipeline during natural gas operation of all three units at 100 percent load.

The heat recovery steam generator and preboiler cycle piping will be chemically cleaned during commissioning and also periodically during the life of the plant. The chemical boiler cleaning wastes resulting from this process will be immediately neutralized onsite, thereby avoiding the classification as hazardous wastes. The treated cleaning wastes will be disposed of offsite by a licensed contractor.

3.6.1 Cooling Tower Blowdown

Cooling tower blowdown will be collected and transferred to the Kissimmee effluent pipeline. The water is then available for additional reuse or ultimate disposal at the Imperial percolation pond site.

3.6.2 Sanitary Waste Treatment

Sanitary wastes are routed to the existing onsite septic tank/tile field system for treatment and disposal.

3.6.3 Steam Cycle Water Treatment

The steam cycle water will be treated with an oxygen scavenger for dissolved oxygen control and with an amine, such as ammonia solution, for pH control. The oxygen scavenger will break down to ammonia at the system operating temperature. A phosphate solution will be fed to control scaling, corrosion, and boiling water pH in the steam generators. The phosphate will react with any calcium hardness in the steam generators to form a nonadherent precipitate. The cycle chemical feed systems will be located in curbed areas and any accidental spillage will be routed to the neutralization basin for treatment.

Boiler blowdown will be relatively high purity water with small amounts of suspended solids and phosphate. Boiler blowdown will be collected and transferred to the Kissimmee effluent pipeline.



3.6.4 Makeup Water Demineralization

As discussed in Section 3.5.4, the makeup water to the steam cycle will be demineralized using a demineralization system consisting of ion exchange resin beds. The demineralization system will use sulfuric acid for cation resin regeneration and sodium hydroxide for anion resin regeneration. The sulfuric acid and sodium hydroxide will be stored in tanks located in curbed concrete containment areas in or near the treatment areas. Any spillage of chemicals in the curbed areas will be routed to the neutralization basin for treatment. The use of these chemicals will be dependent on demineralized water requirements.

Wastewater from the cation resin regeneration will include regenerant water containing unreacted sulfuric acid and dissolved sulfate salts of cations removed from the resin during regeneration. Wastewater from anion resin regeneration will include regenerant water containing unreacted sodium hydroxide and dissolved sodium salts of anions removed from the resin during regeneration.

The estimated regenerant waste flow will average approximately 9,000 gpd when all units are operating. The demineralizer regenerant wastes will be routed to the neutralization basin, as described in Section 3.6.7, for pH adjustment prior to discharge to the Kissimmee effluent pipeline.

3.6.5 Chemical Cleaning Wastes

The Unit 3 heat recovery steam generator and preboiler piping will be chemically cleaned during commissioning. The Units 2 and 3 steam generators will also be cleaned periodically during the life of each unit. Chemicals used for these cleanings will not be stored onsite and will be administered utilizing a temporary system. The makeup of the chemical cleaning solutions to be used for acid and alkaline cleaning of the heat recovery steam generators will be dependent to a limited extent on the boiler manufacturer. Chemicals typically used in boiler and preboiler chemical cleaning include the following:

- Inhibited citric acid
- Ammonium bifluoride
- Disodium phosphate
- Trisodium phosphate
- Nonfoaming wetting agents



- Foam inhibitors
- Chelates, such as EDTA

Chemical cleaning wastewaters will consist of the cleaning solutions and material removed during the cleaning process. Since chemical cleaning is a maintenance operation, it will not contribute to the liquid wastes produced by the normal operation of the Power Park.

The acid and alkaline cleaning solutions will be neutralized onsite in temporary tanks and transported offsite by a licensed waste disposal contractor. Flush and rinse waters will be routed to the neutralization basin for treatment.

3.6.6 *Miscellaneous Chemical Drains*

Chemical wastewater can result from draining a chemical storage tank, overflowing a chemical tank during filling, or from maintenance operations such as hosing down chemical storage areas. Miscellaneous chemical drains will be routed to the neutralization basin via the chemical drains system. Flows from miscellaneous chemical drains will be intermittent and will not normally contribute to the wastewater flows.

3.6.7 *Neutralization Basin*

A neutralization basin provides treatment of chemical wastes prior to discharge to the Kissimmee effluent pipeline. The basin will accommodate the wastewaters produced during regeneration of the makeup demineralizer. The neutralization basin will be constructed of reinforced concrete with a chemical resistant liner. A chemical waste mixer, mounted on a walkway spanning the basin, will be provided to hasten the pH adjustment of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the makeup demineralizer regeneration equipment. Neutralized water will be directed to the Kissimmee effluent pipeline.

3.7 Solid and Hazardous Waste

The Power Park does not and will not generate any solid waste, such as combustion ash or FGD scrubber waste, from the generation process. The firing of natural gas, or fuel oil, does not create significant combustion byproducts. The Power Park does not have any landfills or solid waste disposal areas.



Waste oil is the only potentially hazardous substance generated by Power Park operation. Three processes generate waste oil: combustion turbine cleaning, false starts of the combustion turbines, and oil/water separator operation. The internal components of the combustion turbines are periodically cleaned using a solvent solution. This wash water may contain oily residues and metal particles. The wash water is collected in an underground combustion turbine drain tank and hauled offsite as needed by a licensed contractor for ultimate disposal. The combustion turbines are occasionally started to check operation during oil firing. The residual oil resulting from any false starts is also collected in the combustion turbine drain tank. Waste oil collected in the oil/water separators is hauled offsite as needed by a licensed contractor for ultimate disposal.

3.8 Onsite Drainage System

3.8.1 Uncontaminated Areas

The existing site area is fairly flat and is crowned in the center. Generally, the existing drainage is directed in easterly and westerly directions into Reedy Creek Swamp. Storm water runoff from the existing Units 1 and 2 area is directed to an existing storm water pond. Details on the existing surficial hydrology are provided in Section 2.3.4.

The onsite drainage facilities will be designed in accordance with the requirements of the SFWMD and FDEP. Figure 3.8-1 shows preliminary grading and drainage for the various facility areas. Open channels and drainage structures (culverts, piping systems, etc.) will be designed to collect and direct the runoff resulting from a 25 year 72 hour storm event. Site runoff facilities (ditches, detention basin, etc.) will provide storage to satisfy criteria for maintenance of water quality and quantity, and to provide storage to attenuate peak discharge rates.

The requirements for quality treatment include retention of the first one half inch of runoff from the developed portions of the site. This volume will be provided in the onsite detention basins. The retained runoff and direct precipitation on the basin associated with this storm event will percolate from the basin in less than 24 hours due to the highly permeable soils.



The requirements for quantity treatment include the limitation that the postdevelopment peak discharge does not exceed the predevelopment peak discharge. The detention ponds will assist in attenuating the peak discharge flows from the developed site to meet this requirement.

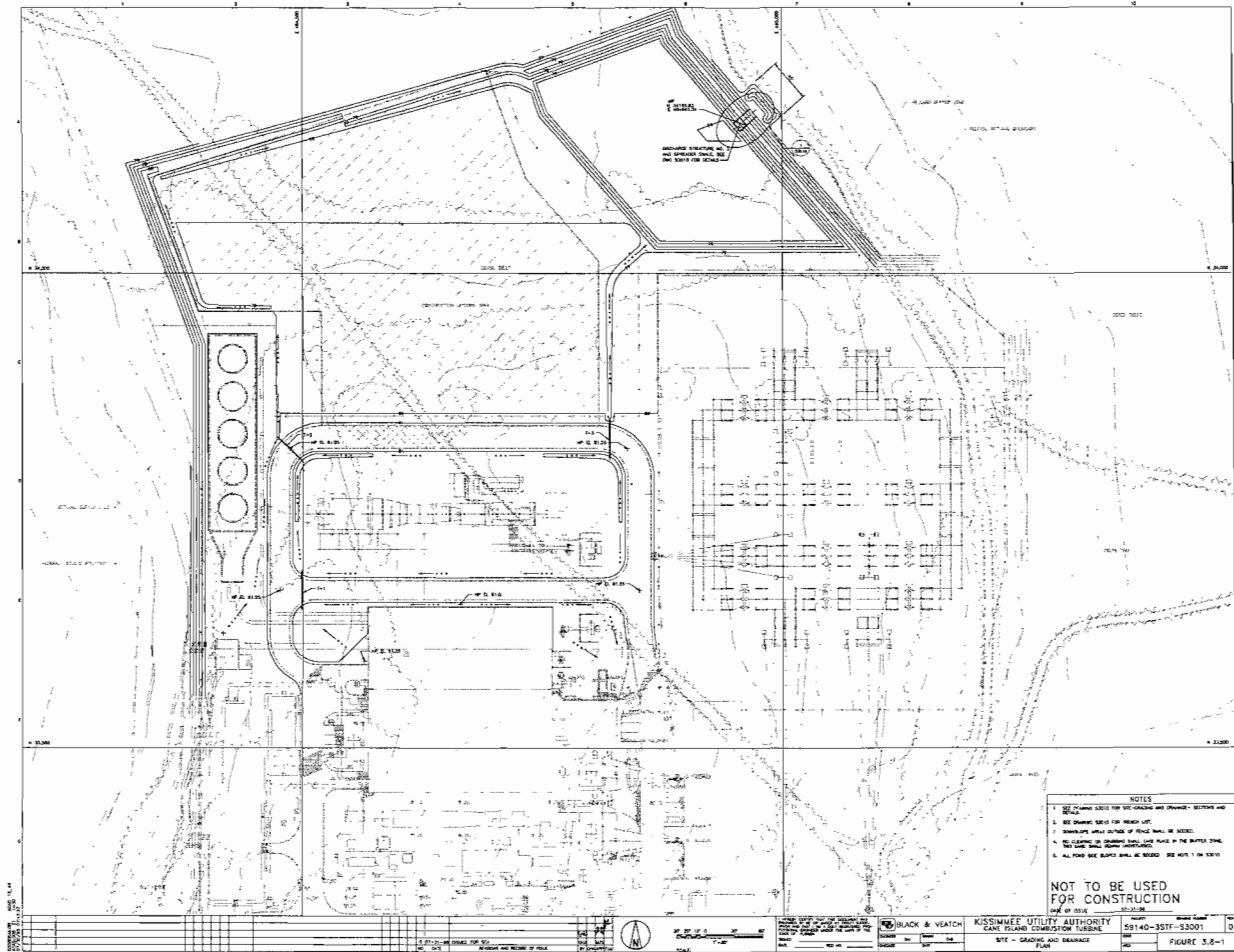
Runoff from areas of the site not disturbed by construction activities or plant operations will be maintained in the existing state to the greatest extent possible. When it is necessary to direct this flow around developed portions of the site, diversion ditches will be constructed. These diversion ditches will collect runoff flow from the undisturbed areas and direct the flow to natural drainage patterns. Runoff from areas of the site disturbed by construction activities or plant operations will be collected in a ditch system and directed to the onsite runoff basins as described below. Drainage systems will be designed for gravity flow wherever site conditions allow. Generally, the drainage in the areas of the new facility will be directed away from the structures and routed to the onsite storage basins. Figure 3.8-1 indicates the general flow paths at the Power Park site once construction is completed.

Supporting calculations are included in Section 3.10.

3.8.2 Drainage Areas

Limited construction will be required in the existing Units 1 and 2 area. In this area, the existing drainage facilities will be used as much as possible; storm water runoff will continue to be directed to the existing storm water pond. The existing facilities will be reviewed to ensure that capacities are sufficient to handle any additional impact from the new construction.

Most of the construction will occur in the Unit 3 power block area. A construction lay-down/staging area to the north of the power block will also be used during construction. These areas will drain into a new 1 acre site runoff basin during construction and operation of Unit 3. The combined area of the Unit 3 power block, construction lay-down/staging area, and storm water facilities is approximately 8 acres.





The new runoff basin will serve as a wet detention basin to provide both quality and quantity treatment to the storm water. The quality treatment will be accomplished by detention and reduction of suspended solids load. The basin will also provide quantity treatment by providing surge capacity to attenuate the maximum discharge rate into Reedy Creek Swamp.

Again, there will be no source of leachate associated with the Power Park or Unit 3, thereby eliminating this potential pollution source.

3.8.3 Design Criteria

The management and storage of surface waters (MSSW) system will be designed in accordance with the regulations and requirements of the SFWMD, "Management and Storage of Surface Waters Permit Information Manual Volume IV," and the Florida Department of Environmental Regulation (FDER), "The Florida Manual--A Guide to Sound Land and Water Management Storm Water Management Practices." Areas subject to potential contamination of storm water runoff will be designed for zero discharge.

The MSSW system at the Unit 3 site is designed to maintain the existing drainage patterns wherever possible. The existing drainage patterns generally flow from the central portion of Cane Island in an easterly or westerly direction towards Reedy Creek Swamp.

The MSSW system for the developed areas of the Power Park will be designed to ensure that the post development peak discharge will not exceed that of the predevelopment peak discharge at the project site boundary.

The following design criteria are specified in the SFWMD Permit Manual:

Design Storm: 25 year 72 hour

Rainfall frequencies obtained from the SFWMD Permit Manual are as follows:

- 10 year 24 hour--7.10 inches.
- 10 year 72 hour--9.65 inches.
- 25 year 24 hour--9.00 inches.
- 25 year 72 hour--12.23 inches.

Rainfall Distribution: SFWMD 72 Hour Synthetic Storm Distribution.



Outlet structures:

- Emergency spillways are designed to pass the 100 year recurrence interval storm event.
- Existing grading and drainage in the Units 1 and 2 areas has been permitted by SFWMD.

3.8.4 Runoff Analysis

The area associated with the Unit 3 power block and construction lay-down/staging area consists of approximately 5.2 acres of pervious area and 1.4 acres of impervious area. These areas will drain into a new storm water detention pond. The 25 year 72 hour rainfall event was used to size the onsite runoff detention basin. The predevelopment curve number (CN) was estimated to be 47, with a predevelopment time of concentration of 0.41 hours. The postdevelopment CN and time of concentration were estimated to be 65 and 0.43 hours, respectively. The curve numbers and time of concentrations were determined using the methods outlined in the Soil Conservation Service TR-55 manual.

The Unit 3 MSSW system will consist of ditches, drainage structures, and a site runoff detention basin. This system will function as a storm water quality and quantity treatment facility. The quality treatment of runoff will be accomplished through percolation and detention in the site detention basin.

The discharge structure of the detention basin is designed for the 25 year 72 hour event peak flow. The storm water detention pond and discharge structure are sized to meet the design criteria outlined in Section 3.8.3. Storm water enters the pond through direct precipitation and from ditches conveying runoff from the Unit 3 power block and construction staging/lay-down areas.

The predevelopment and postdevelopment peak flows that the system discharges for the design event are both approximately 2 cfs. The discharges will enter Reedy Creek Swamp. A spreader swale at the discharge location distributes the flow and prevents erosion.

3.8.5 Erosion and Sediment Control Measures

Erosion and sediment control measures will be installed as necessary during Unit 3 construction to control sediment disposition. The primary destination of construction runoff will be the Unit 3 site runoff basin. The runoff basin will provide reduction of suspended solids load through detention.



Before construction begins, silt fence or other appropriate control measures will be installed around the perimeter of construction areas. Figure 3.8-2 shows silt fence details. Diversion ditches will be equipped with straw bale dikes to aid in minimizing the amount of sediments flowing into the onsite runoff basin and offsite (refer to Figure 3.8-2 for typical detail). Construction accessways and parking areas will be surfaced with aggregate to provide a stabilized subgrade. Erosion control measures will also include minimizing fugitive dust through periodic spraying of water.

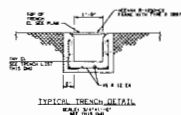
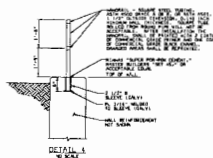
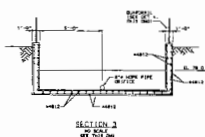
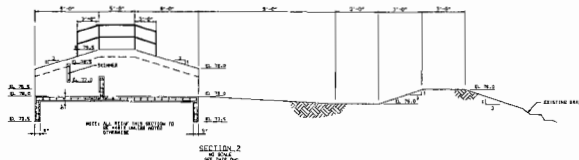
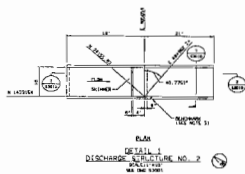
3.8.5.1 Staging of Earthmoving Activities. Initial construction will remove all significant vegetation (trees, brush, etc). If possible, some trees will be retained in the construction lay-down/staging area. The runoff basin and associated drainageways will be constructed concurrently with initial clearing activities. Topsoil will be removed and stockpiled for finished grading and site restoration after construction is completed. Once the topsoil has been removed, site preparation will be directly related to the construction of specific power plant facilities. Once the earthmoving and construction are completed, the stockpiled topsoil will be used for finished grading. Seeding and mulching activities will begin within 30 days.

3.8.5.2 Construction Monitoring and Maintenance. In general, all erosion and sedimentation control measures will be checked weekly and after each significant rainfall event. Items including the following will be checked:

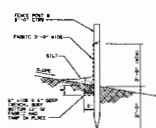
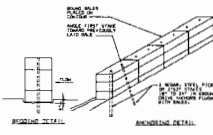
- Silt fences and straw bale dikes will be inspected after each significant rainfall and during prolonged periods of rainfall. Required repairs will be made immediately.
- Sediment deposits at barriers will be removed when the deposit depth reaches approximately one half the height of the barrier.

An EPA issued NPDES General Permit for construction storm water discharges, and accompanying Storm Water Pollution Prevention Plan, will be required.

3.8.5.3 Permanent Control Measures. Permanent erosion and sedimentation control measures within the project plant site will include the runoff collection system (ditches, culverts, trenches), surfaced traffic and work areas, nonworking areas with established vegetation, and the site runoff detention basin. These measures will minimize erosion and potential sedimentation into Reedy Creek Swamp.



TRENCH LIST									
TRENCH	LENGTH	WIDTH	DEPTH	START	END	START	END	START	END
1-1	10.00	1.00	1.00	100.00	110.00	100.00	110.00	100.00	110.00
1-2	10.00	1.00	1.00	110.00	120.00	110.00	120.00	110.00	120.00
1-3	10.00	1.00	1.00	120.00	130.00	120.00	130.00	120.00	130.00
1-4	10.00	1.00	1.00	130.00	140.00	130.00	140.00	130.00	140.00

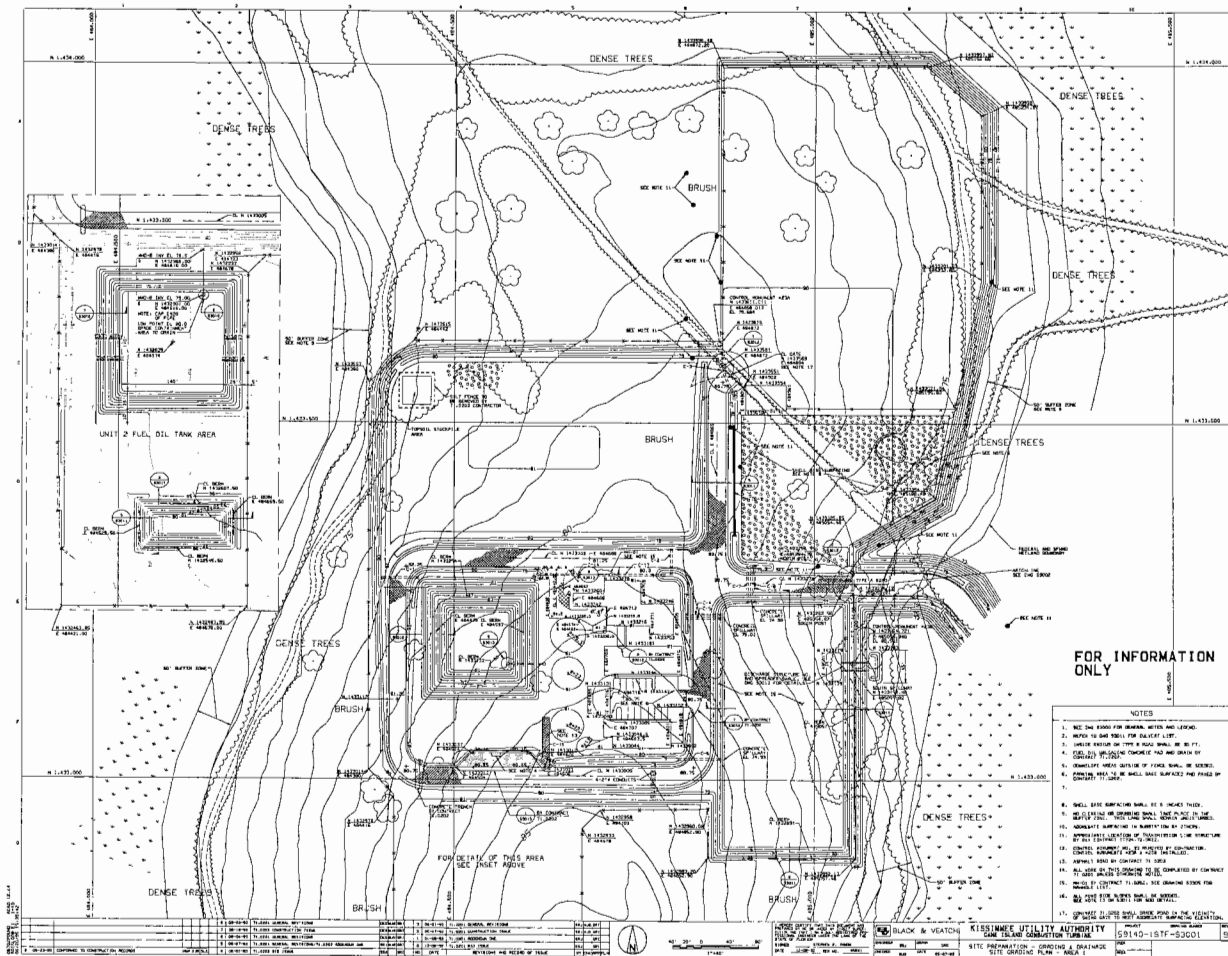


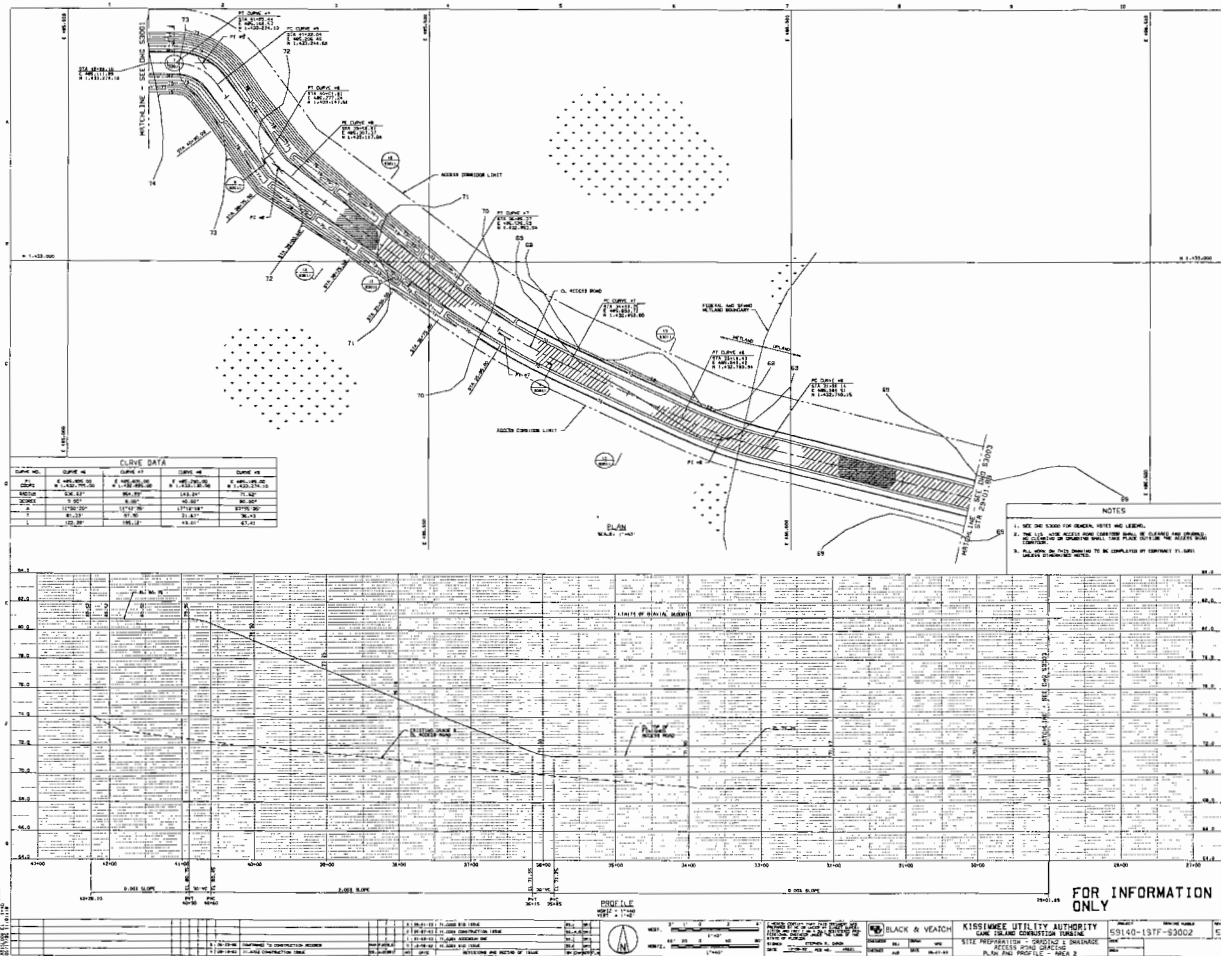
NOTES

1. ALL TRENCHES SHALL BE CONSTRUCTED TO THE DEPTH AND WIDTH SHOWN ON THE PLAN AND SECTION. THE TRENCHES SHALL BE BACKFILLED WITH THE SAME MATERIAL AS THE ORIGINAL GROUND. THE TRENCHES SHALL BE COVERED WITH A MINIMUM OF 18" OF COMPACTED FILL. THE TRENCHES SHALL BE COVERED WITH A MINIMUM OF 18" OF COMPACTED FILL. THE TRENCHES SHALL BE COVERED WITH A MINIMUM OF 18" OF COMPACTED FILL.
2. THE TRENCHES SHALL BE CONSTRUCTED TO THE DEPTH AND WIDTH SHOWN ON THE PLAN AND SECTION. THE TRENCHES SHALL BE BACKFILLED WITH THE SAME MATERIAL AS THE ORIGINAL GROUND. THE TRENCHES SHALL BE COVERED WITH A MINIMUM OF 18" OF COMPACTED FILL. THE TRENCHES SHALL BE COVERED WITH A MINIMUM OF 18" OF COMPACTED FILL. THE TRENCHES SHALL BE COVERED WITH A MINIMUM OF 18" OF COMPACTED FILL.
3. ALL DISTANCES SHALL BE MEASURED UNLESS NOTED OTHERWISE.

NOT TO BE USED
FOR CONSTRUCTION

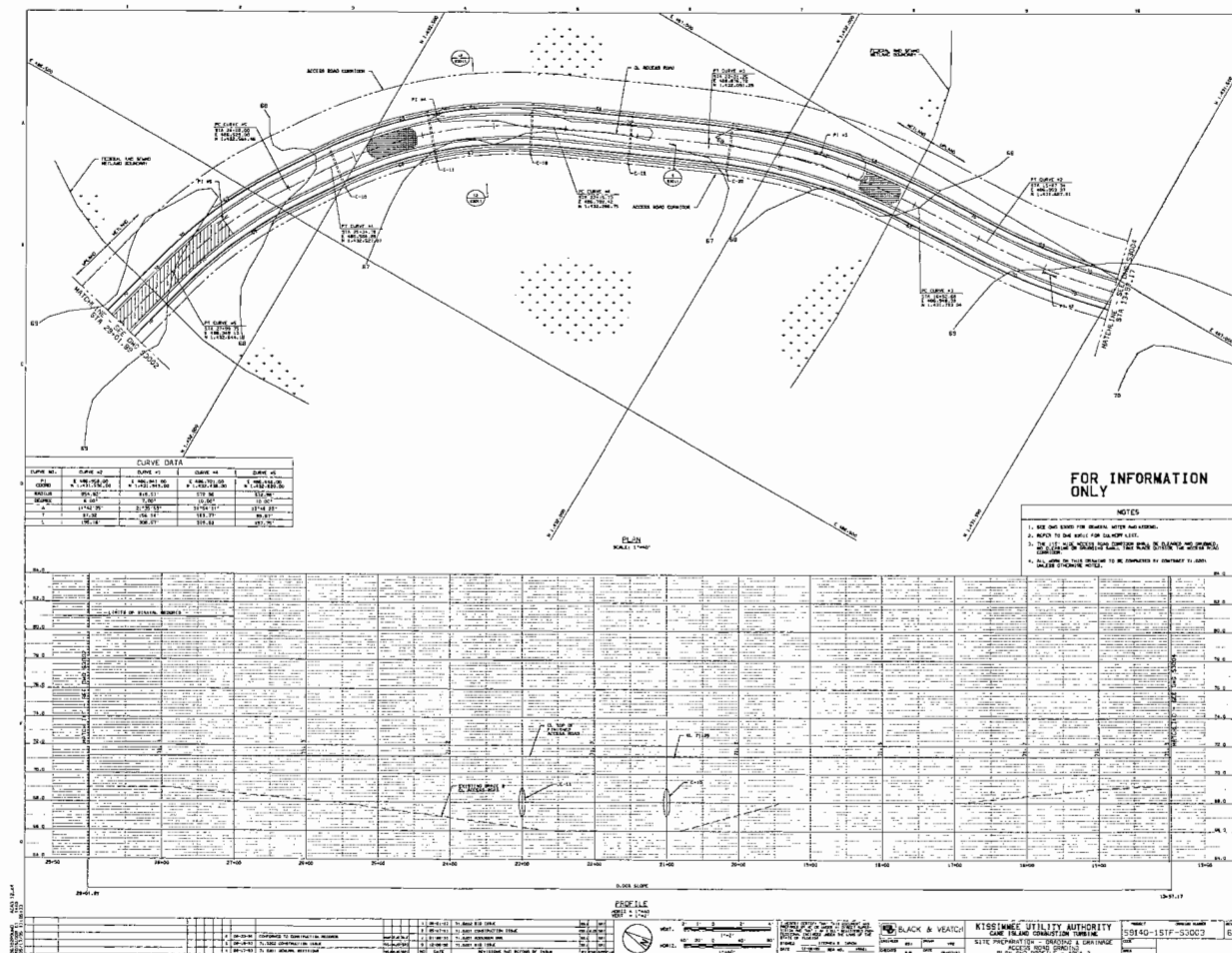
PROJECT NO.	58140-251F-52010	DATE	0
DESIGNED BY	DATE	CHECKED BY	DATE
DRAWN BY	DATE	APPROVED BY	DATE
KISSIMEE UTILITY AUTHORITY ONE ISLAND BOULEVARD, SUITE 100 FORT MYERS, FL 33901			
FIGURE 3.8-2			

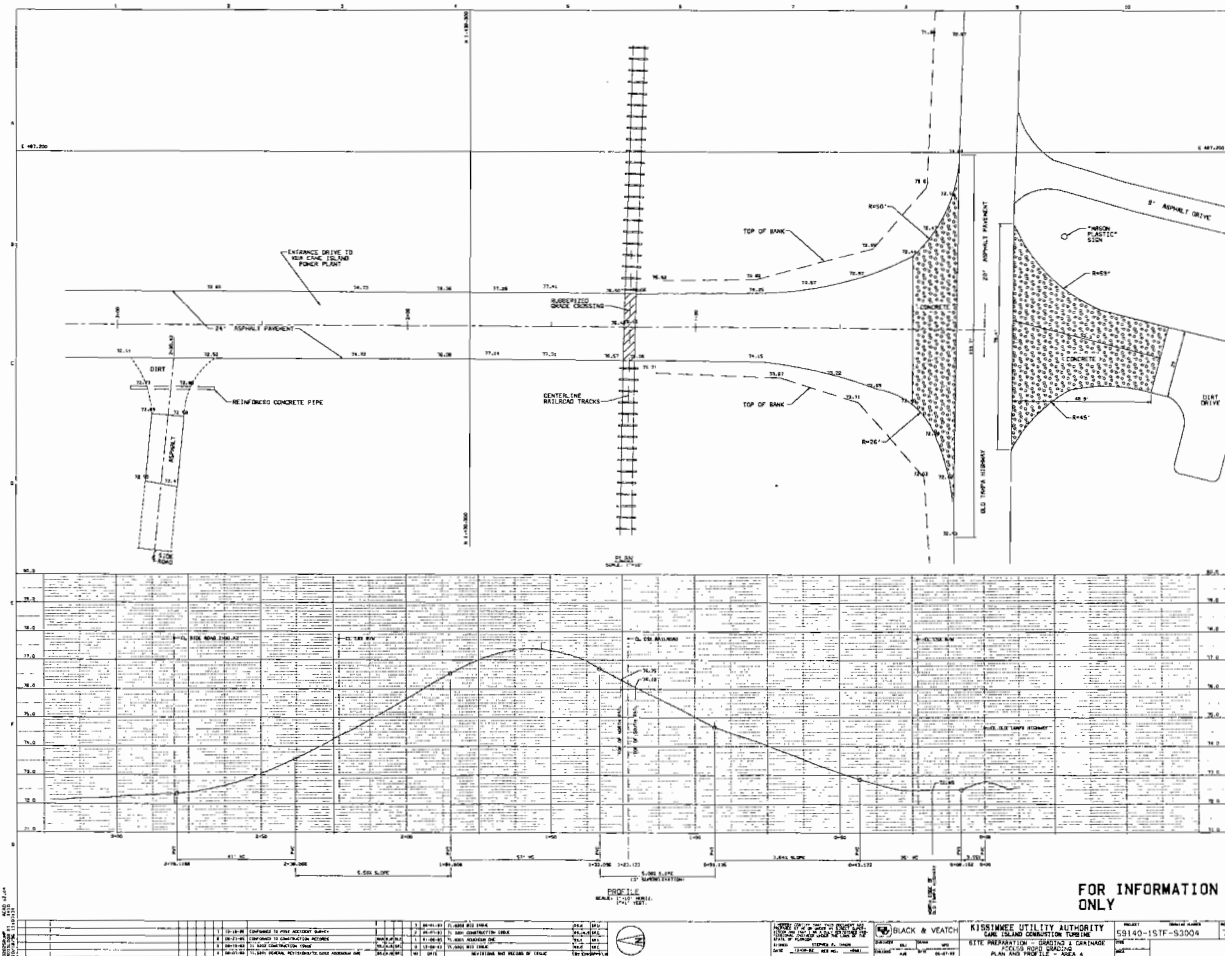


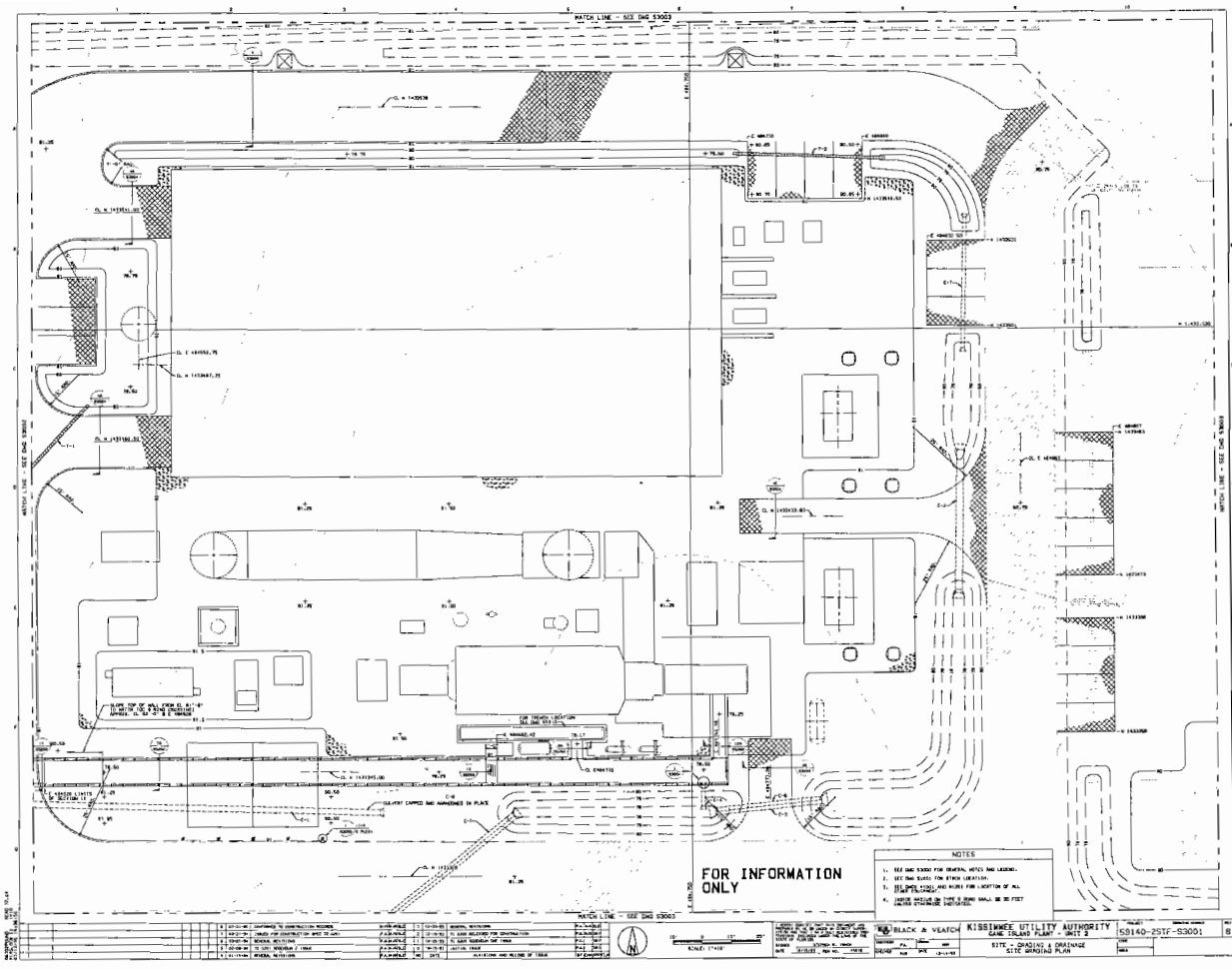


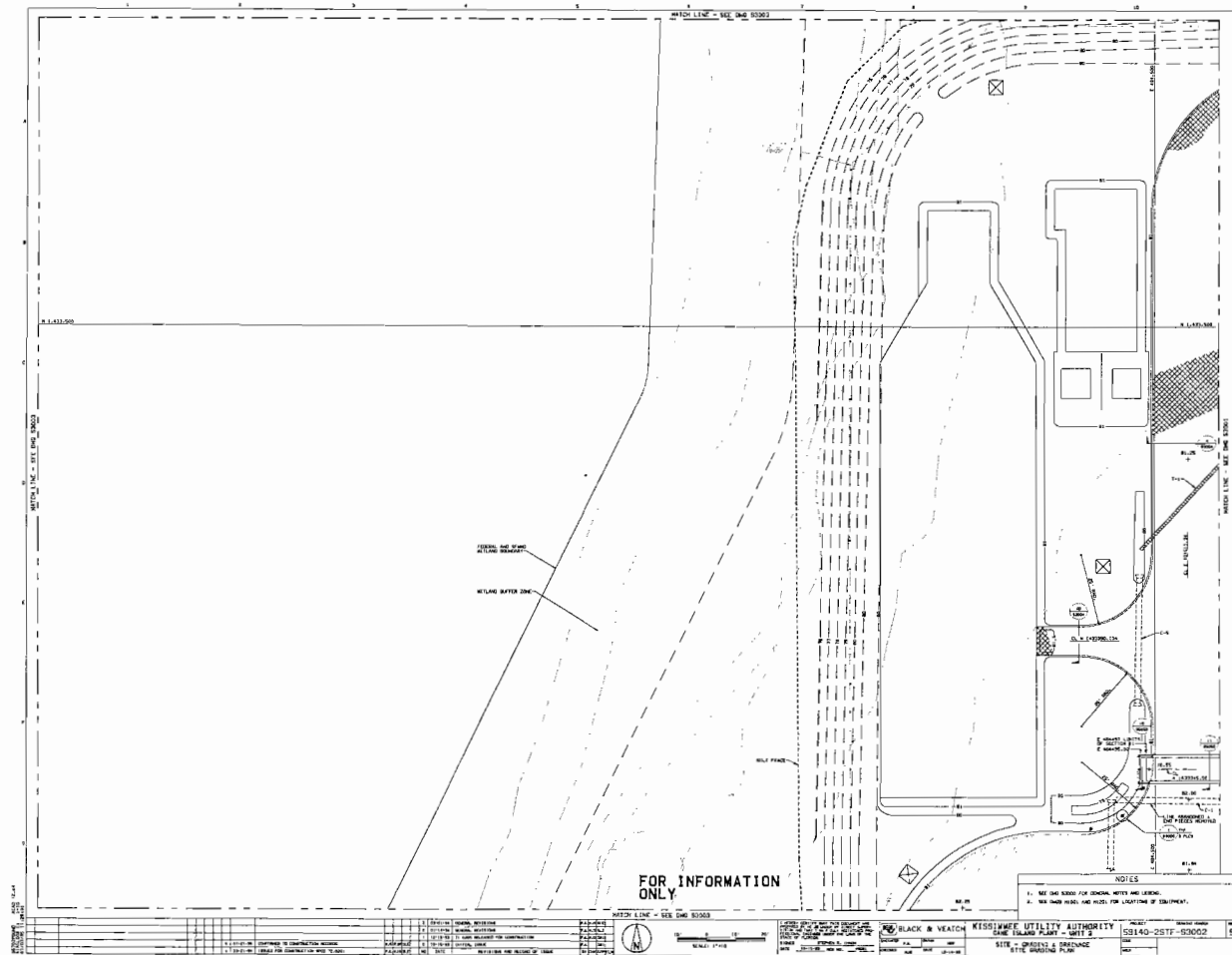
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The permanent erosion and sediment control system will be installed as early as possible during construction and will remain in service throughout the life of the project. The primary components of this system will be established vegetation, surfacing, grassed ditches, culverts, and trenches which will collect the site runoff and direct it to the site runoff basin. The system will be maintained and monitored during construction and operation. Surface water monitoring during construction and operation are described in Sections 4.2.2 and 5.3.5, respectively.

The drainage system will require periodic inspection, maintenance, cleaning, and occasional repair work. Inspection will be completed on a seasonal basis and after any severe rainfall event. The condition of the ditches, culverts, and weirs will be noted. Cleaning or repair of the drainage structures will be completed as required.

Modification of the existing EPA issued NPDES General Permit for operational storm water discharges will be required. The existing Storm Water Pollution Prevention Plan prepared for Units 1 and 2 operations will be amended to include Unit 3 facilities.

3.8.6 Potentially Contaminated Areas

Flows originating from potentially contaminated areas, and any storm water runoff generated in these areas, are not collected in the MSSW system. These flows which include miscellaneous plant drains and drainage from oil containment areas are routed through oil/water separators for treatment prior to discharge.

After passing through the separator, these flows are routed to an onsite percolation pond. Operation of the percolation pond is discussed in detail in Section 5.3 Impacts on Water Supplies.

The following potentially contaminated areas currently exist and will be added with the construction of Unit 3:

- Steam Turbine Step-up Transformer
- Combustion Turbine Step-up Transformer
- Auxiliary Transformers
- Demineralizer Acid Storage Tank
- Fuel Oil Unloading and Storage Areas
- Circulating Water Acid Tank



All of the transformers will be constructed with a curbed secondary containment area. The containment area will be sized to confine 110 percent of the volume of oil stored within the equipment and a sufficient allowance for the design rainfall storm event. The discharge from the containment area will be routed to a new oil/water separator or the existing oil/water separator associated with Units 1 and 2.

The secondary containment associated with the demineralizer acid storage tank will be designed in accordance with applicable FDEP guidelines. The containment area will discharge all rainwater to the neutralization basin. Refer to Sections 3.6.6 and 3.6.7 for descriptions of the Miscellaneous Chemical Drains and Neutralization Basin.

One new No. 2 fuel oil storage tank will be added at the Power Park for Unit 3. Unit 3 will tie into and utilize the existing backup fuel system associated with Units 1 and 2.

The existing fuel oil storage tanks and transformer secondary containment areas are designed such that all of the rainwater is collected and sent to an oil/water separator for treatment prior to discharge. The containment areas are sloped to a drainage collection point (a gate valved discharge pipe). The discharge pipe from each containment area and the fuel oil unloading area are tied together and routed to the oil/water separator by gravity.

Oil/water separators are provided for separation of any oil and grease from contaminated wastewaters and storm waters. Treated separator effluent (water) will be discharged to an onsite percolation pond prior to ground water discharge. Collected oil will be periodically pumped from the separators and disposed offsite by a licensed waste management contractor. The discharge from the separators will be low in the structure to allow the water to underflow while the oil is retained for later removal. The separators are sized to contain the volume of oil produced by the total failure of the single largest source served by that separator, with the exception of the valved fuel oil storage tank containment areas.

Secondary containment will be provided around site facilities containing significant amounts of oil. In the event of a spill from the largest vessel, oil will be contained within the bermed or curbed area. Drains within the containment area will be directed to the oil/water separators. The valves will normally be in the closed position. After visual inspection of the runoff within the containment area, the valves will be opened to drain collected runoff to the oil/water separators.



Runoff collected in the circulating water acid storage tank containment area will be directed to the neutralization basin for treatment prior to disposal.

Again, there will be no source of leachate associated with the Power Park or Unit 3, thereby eliminating this potentially contaminated source.

3.9 Construction Materials and Equipment Handling

The major components associated with the Unit 3 addition at the Power Park include the following:

- Combustion Turbine
- Heat Recovery Steam Generator
- Generator Step-up Transformer
- Cooling Tower
- Steam Turbine
- Steam Turbine Building
- Water Treatment Building and Associated Equipment

The major components and all other required equipment and materials will be delivered to the Power Park by truck. All deliveries associated with construction and operation will utilize the existing plant access road that connects the Power Park to Old Tampa Highway. All deliveries will be cleared through the Control Room or a temporary guardhouse located near the main gate. Once onsite, construction materials will be directed to the construction lay-down area or its permanent location for off-loading and transport to the proper storage area by portable cranes, fork lifts and trucks.

3.10 Unit 3 Hydrologic Analysis

The methods and calculations used to determine runoff rates, storm water detention pond size, and site storm water drainage facilities are included in this section.

Unit 3 Hydrologic Analysis



Owner KUA Computed By GV Johnson
 Plant Cane Island Unit _____ Date July 17 19 98
 Project No. 59140 File No. _____ Verified By WJA
 Title Unit 3 Hydrologic Analysis Date 7/17 19 98
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Objective: For the Unit 3 Site area, determine the pre-development peak runoff in response to the 25 year-72 hour precipitation event, develop a stormwater detention pond that retains the 1st 1/2 inch of runoff from the post-construction site and percolates this volume in less than 24 hours, develop a discharge structure for the pond with an invert elevation above the 1/2 inch storage volume level in the pond, which limits post-development peak discharge to the pre-development rate for the design event (25 year-72 hour), provide an emergency overflow to safely pass the 100 year-72 hour event, size the trenches and ditches on the site.



Owner KUA Computed By GVJ
Plant Cane Island Unit _____ Date 7/17 19 98
Project No. 59140 File No. _____ Verified By MTA
Title Unit 3 Hydrologic Analysis Date 7/17 19 98
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References

- ① KUA Site Certification Application, Draft Copy, July 1998.
- ② South Florida Water Management District, Management and Storage of Surface Waters: Permit Information Manual, Vol. IV
- ③ HEC-1 Flood Hydrograph Package, US Army Corps of Engineers, 1/15/92
- ④ USDA Soil Conservation Service, TR-55 Urban Hydrology for Small Watersheds, June 1986
- ⑤ Haestad Methods, Flowmaster package, 1990.

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Project No. 59140 File No. _____ Verified By MDA
Title Unit 3 Hydrologic Analysis Date 7/17 19 98
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HEC-1 Model Development:

Four HEC-1 output files are attached to this calculation set. These files are for the following cases:

CASE I: Pre-Development Analysis of Unit 3 Site Area

CASE II: Post-Development Analysis of Unit 3 Site Area for precipitation event resulting in $\frac{1}{2}$ " of runoff from the site.

CASE III: Post-Development Analysis of Unit 3 Site Area limiting discharge to Pre-Development rate

CASE IV: Post-Development Analysis of Unit 3 Site Area in response to the 100 year-72 hour precipitation event.



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CASE I:

⇒ reference ①, Figure 3.2-1, Site Arrangement
and Figure 3.8-1, Site Grading & Drainage

$$\text{Total Area} = 330,190 \text{ ft}^2 \approx 0.01184 \text{ mi}^2$$

Determine composite CN based on ref ④

- Construction laydown/staging Area = 112,065 ft² C

$$\text{CN} = \underline{49} \quad \{ \text{H66} = \text{A, Open space, fair cond} \}$$

- roads = 10,000 ft² w/ CN = 98

- Aggregate Surface Area = 3200 ft² w/ CN = 76

- Undisturbed Area = 204,925 ft²

$$\text{CN} = \underline{43}$$

⇒ Composite CN = 47

Time of Concentration:

from ref ④ worksheet (next page)

$$t_c = \underline{0.41 \text{ hours}}$$

$$\text{time lag} = 0.16 t_c = \underline{0.25 \text{ hours}}$$

DO NOT WRITE IN THIS SPACE

Worksheet 3: Time of concentration (T_c) or travel time (T_t)

5/14

Project KUA - SCA By GVJ Date 5/18/98
 Location _____ Checked MR Date 7/17/99
 Circle one: Present Developed _____
 Circle one: T_c T_t through subarea _____

NOTES: Space for as many as two segments per flow type can be used for each worksheet.

Include a map, schematic, or description of flow segments.

Sheet flow (Applicable to T_c only)

Segment ID

1. Surface description (table 3-1)
2. Manning's roughness coeff., n (table 3-1) ..
3. Flow length, L (total $L \leq 300$ ft) ft
4. Two-yr 24-hr rainfall, P_2 in
5. Land slope, s ft/ft
6. $T_t = \frac{0.007 (nL)^{0.8}}{P_2^{0.5} s^{0.4}}$ Compute T_t hr

SHORT GRASS	
0.15	
200	
4.75	
0.01	
0.31	+
	=

Shallow concentrated flow

Segment ID

7. Surface description (paved or unpaved)
8. Flow length, L ft
9. Watercourse slope, s ft/ft
10. Average velocity, V (figure 3-1) ft/s
11. $T_t = \frac{L}{3600 V}$ Compute T_t hr

UNPAVED	
250	
0.006	
1.25	
0.06	+
	=

Channel flow

Segment ID

12. Cross sectional flow area, a ft²
13. Wetted perimeter, P_w ft
14. Hydraulic radius, $r = \frac{a}{P_w}$ Compute r ft
15. Channel slope, s ft/ft
16. Manning's roughness coeff., n
17. $V = \frac{1.49 r^{2/3} s^{1/2}}{n}$ Compute V ft/s
18. Flow length, L ft
19. $T_t = \frac{L}{3600 V}$ Compute T_t hr
20. Watershed or subarea T_c or T_t (add T_t in steps 6, 11, and 19) hr

8.0	
11.32	
0.707	
0.0047	
0.035	
2.32	
320	
0.04	+
	=
	0.41



Owner KUA Computed By GVJ
Plant Cane Island Unit _____ Date 7/17 19 98
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Title Unit 3 Hydrologic Analysis Date 7/17 19 98
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Design Precipitation & Distribution:

25 year - 72 hour precip. = 12.23 inches (ref ①)

Distribution is input into HEC Model from ref ②.

RESULTS: (CASE I)

The pre-development peak runoff for this site is 2 cfs.

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 Title Unit 3 Hydrologic Analysis Date 7/17 19 98
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POST-DEVELOPMENT MODEL (CASES II, III & IV)

Determine SCS CN

→ Site & Construction laydown/staging areas:

laydown = 111,554 ft² CN = 49 (open space, fair cond)

roads & buildings = 58,994 ft² CN = 98 (impervious)

Aggregate surfaced = 54,781 ft² CN = 71 (gravel)

Grassed Areas = 42,809 ft² CN = 49 (open space, fair)

↳ Composite CN = 65

Note: Containment Area do not contribute to runoff.

Pond = 42,337 ft² CN = 49 (100% pond)

⇒ Rainfall event & distribution same as pre-dev. case.

Time of concentration = 0.43 hours (p. 8)

↳ ∴ time lag = (0.43)(0.6) = 0.26 hours

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Worksheet 3: Time of concentration (T_c) or travel time (T_t)

8/14

Project KUA - SCA By GVJ Date 5/15/98
 Location Cane Island Site Checked GVJ Date 7/17/98

Circle one: Present Developed

Circle one: T_c T_t through subarea

NOTES: Space for as many as two segments per flow type can be used for each worksheet.

Include a map, schematic, or description of flow segments.

Sheet flow (Applicable to T_c only)

Segment ID

1. Surface description (table 3-1) Short grass
2. Manning's roughness coeff., n (table 3-1) ..
3. Flow length, L (total $L \leq 300$ ft) ft
4. Two-yr 24-hr rainfall, P_2 in
5. Land slope, s ft/ft
6. $T_t = \frac{0.007 (nL)^{0.8}}{P_2^{0.5} s^{0.4}}$ Compute T_t hr

SHORT GRASS	
0.15	
150	
4.75	
0.005	
0.32	+

=

Shallow concentrated flow

Segment ID

7. Surface description (paved or unpaved)
8. Flow length, L ft
9. Watercourse slope, s ft/ft
10. Average velocity, V (figure 3-1) ft/s
11. $T_t = \frac{L}{3600 V}$ Compute T_t hr

UNPAVED	
150	
0.005	
1.15	
0.04	+

=

Channel flow

Segment ID

12. Cross sectional flow area, a ft²
13. Wetted perimeter, p_w ft
14. Hydraulic radius, $r = \frac{a}{p_w}$ Compute r ft
15. Channel slope, s ft/ft
16. Manning's roughness coeff., n
17. $V = \frac{1.49 r^{2/3} s^{1/2}}{n}$ Compute V ft/s
18. Flow length, L ft
19. $T_t = \frac{L}{3600 V}$ Compute T_t hr
20. Watershed or subarea T_c or T_t (add T_t in steps 6, 11, and 19) hr

8.0	
11.32	
0.707	
0.005	
0.035	
2.38	
600	
0.07	+

= 0.43



Owner KUA Computed By GVJ
 Plant Cane Island Unit _____ Date 7/17 19 98
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Reservoir Routing Data:

⇒ Stage-Area information for the model is from figure 3.8-1 of the SCA (ref ①)

Stage-Discharge: ② see fig. 3.8-2 of ref ① for details)

Use 8" ϕ orifice w/ invert @ elev. 76.0

⇒ $Q = CA(2gh)^{1/2}$ — discharge relationship.

⇒ @ elev. 78, $h = 1.667$ ft $\Rightarrow C = 0.61$

⇒ $Q = \underline{2.2 \text{ cfs}}$

@ elev. 79, $h = 2.667$ ft $\Rightarrow Q = \underline{\underline{2.8 \text{ cfs}}}$

Emergency Overflow

10 foot long sharp crested weir w/ inv. @ elev. 78.0

⇒ @ elev. 79 $\Rightarrow Q = CLH^{3/2}$

$$= (3.09)(10)(1)^{3/2} = \underline{30.9 \text{ cfs}}$$

⇒

STAGE	76	78	79
DISCHARGE	0	2.2	$30.9 + 2.8 = 33.7$



Owner KUA Computed By GVS
 Plant Cane Island Unit _____ Date 7/17 19 98
 Project No. 59140 File No. _____ Verified By MSA
 Title Unit 3 Hydrologic Analysis Date 7/17 19 98
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RESULTS:

CASE II: A 2.99 inch rainfall event produces $\frac{1}{2}$ inch of runoff from the site.

This results in a peak stage in the pond of elev. 75.29. Therefore, w/ orifice crest @ elev. 76.0, $\frac{1}{2}$ " of runoff will be retained. This volume will percolate from the pond in much less than 24 hours based on the percolation rates by G. Sommerfeld included with the SCA (ref ①).

CASE III: For the 25 year - 72 hour event, the peak discharge from the pond is 2 cfs. This equals the pre-development peak discharge (OK). The peak stage in the pond is 77.77 ft msl. Therefore, the crest elev. of 78.0 for the emergency spillway is OK.

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CASE IV: The pond safely passes the
100 year - 22 hour storm event.
Peak Stage = 77.92 ft MSL.

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Owner KUA Computed By GVJ
Plant Cane Island Unit _____ Date 7/17 19 98
Project No. 59140 File No. _____ Verified By MDK
Title Unit 3 Hydrologic Analysis Date 7/17 19 98
Page 12 of 14

Ditch and trench flows:

Ditch and trench flows are analyzed using
ref. (5) on pages 13 & 14. These calcs.
verify the design presented in figure 3.8-2
of the SCA.

DO NOT WRITE IN THIS SPACE

Trapezoidal Channel Analysis & Design
Open Channel - Uniform flow

13/14

MTH
7/17/98

Worksheet Name: KUA - SCA

Comment: Typical Ditch Flow for Tc Calculation

Solve For Discharge

Given Input Data:

Bottom Width.....	5.00 ft
Left Side Slope..	3.00:1 (H:V)
Right Side Slope.	3.00:1 (H:V)
Manning's n.....	0.035
Channel Slope....	0.0050 ft/ft
Depth.....	1.00 ft

Computed Results:

Discharge.....	19.05 cfs
Velocity.....	2.38 fps
Flow Area.....	8.00 sf
Flow Top Width...	11.00 ft
Wetted Perimeter.	11.32 ft
Critical Depth...	0.67 ft
Critical Slope...	0.0230 ft/ft
Froude Number....	0.49 (flow is Subcritical)

Rectangular Channel Analysis & Design
Open Channel - Uniform flow

14/14

MM
7/17/98

Worksheet Name: KUA-SCA Trench Flow

Comment: Check Trench Flow on KUA - SCA

Solve For Depth

Given Input Data:

Bottom Width.....	1.00 ft
Manning's n.....	0.014
Channel Slope....	0.0061 ft/ft
Discharge.....	2.00 cfs

Computed Results:

Depth.....	0.58 ft
Velocity.....	3.45 fps
Flow Area.....	0.58 sf
Flow Top Width...	1.00 ft
Wetted Perimeter.	2.16 ft
Critical Depth...	0.50 ft
Critical Slope...	0.0091 ft/ft
Froude Number....	0.80 (flow is Subcritical)



Owner KUA Computed By GV Johnson
 Plant Cane Island Unit _____ Date July 17 19 98
 Project No. 59140 File No. _____ Verified By MDA
 Title Units 1 & 2 Date 7/17 19 98
Watershed Changes Page 1 of 2

Objective: Determine the impact on runoff to the
 Units 1 & 2 Stormwater pond to changes due
 to Unit 3 construction.

Changes: { Reference Figure 3.2-1 Site Arrangement }

1. Added Warehouse & Parking (40) { From Legend } { existing }

$$\text{Area} = 180' \times 150' + 100' \times 85' = \underline{35,500 \text{ ft}^2}$$

$$\begin{aligned} \hookrightarrow \text{previous CN} &= \underline{76} \\ \text{new CN} &= \underline{98} \end{aligned}$$

2. Added fuel oil storage (67) & containment

$$\text{Area} = 200' \times 150' = \underline{30,000 \text{ ft}^2}$$

$$\begin{aligned} \text{previous CN} &= \underline{76} \\ \text{new CN} &= \underline{\text{CONTAINMENT AREA - NO RUNOFF}} \end{aligned}$$

3. Added Demin Water Storage tank

$$\text{Area} = \pi/4 (67')^2 = \underline{3525 \text{ ft}^2}$$

$$\begin{aligned} \text{previous CN} &= \underline{76} \\ \text{new CN} &= \underline{98} \end{aligned}$$

DO NOT WRITE IN THIS SPACE



Owner KUA Computed By GVJ
 Plant Cane Island Unit _____ Date 7/17 19 98
 Project No. 59140 File No. _____ Verified By MTA
 Title Units 1 & 2 Date 7/17 19 98
Watershed Changes Page 2 of 2

4. Added Water Treatment Facilities (58, 59, 60)

$$\text{Area} = 85' \times 40' + 10' \times 20' + \frac{\pi}{4} (22')^2 = \underline{3980 \text{ ft}^2}$$

$$\text{previous CN} = \underline{76}$$

$$\text{new CN} = \underline{98}$$

5. Added perc. pond area

$$\text{Area} = 195' \times 70' = \underline{13,650 \text{ ft}^2}$$

$$\text{previous CN} = \underline{76}$$

$$\text{New CN} = \underline{\text{CONTAINMENT AREA} - \text{NO RUNOFF}}$$

Determine Runoff Volume from TR-55 (SCS CN Method)

$$\hookrightarrow 25 \text{ yr-72 hour precip.} = \underline{12.23 \text{ inches}}$$

Previous =

$$\text{Area} = \underline{86,655 \text{ ft}^2}$$

$$\text{CN} = \underline{76}$$

$$\text{Runoff} = \underline{9.12 \text{ inches}} \quad (\text{TR-55, Table 2-1})$$

$$\Rightarrow \text{Vol.} = (9.12/12) (86,655) = \underline{65,858 \text{ ft}^3}$$

$$\text{New: Area} = \underline{43,005 \text{ ft}^2} \quad \text{CN} = \underline{98}$$

$$\text{Runoff} = \underline{11.99 \text{ inches}} \quad \Rightarrow \text{Vol} = \underline{42,969 \text{ ft}^3}$$

$\Rightarrow$ RUNOFF VOLUME IS REDUCED i.e. OK

REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED,
INITIALED AND DATED BY THE RESPONSIBLE INDIVIDUAL

DO NOT WRITE IN THIS SPACE

CASE I

* FLOOD HYDROGRAPH PACKAGE (HEC-1) *

* FEBRUARY 1981 *
* REVISED 02 AUG 88 *

* RUN DATE 06/09/1998 TIME 08:53:52 *

* U.S. ARMY CORPS OF ENGINEERS

* THE HYDROLOGIC ENGINEERING CENTER *
* 609 SECOND STREET *
* DAVIS, CALIFORNIA 95616 *
* (916) 551-1748 *

*mtk
7/17/98*

```

X  X XXXXXXXX XXXXX      X
X  X X      X  X      XX
X  X X      X      X
XXXXXXXX XXXX  X  XXXXX  X
X  X X      X      X
X  X X      X  X      X
X  X XXXXXXXX XXXXX      XXX
  
```

THIS PROGRAM REPLACES ALL PREVIOUS VERSIONS OF HEC-1 KNOWN AS HEC1 (JAN 73), HEC1GS, HEC1DB, AND HEC1KW.

THE DEFINITIONS OF VARIABLES -RTIMP- AND -RTIOR- HAVE CHANGED FROM THOSE USED WITH THE 1973-STYLE INPUT STRUCTURE.

THE DEFINITION OF -AMSKK- ON RM-CARD WAS CHANGED WITH REVISIONS DATED 28 SEP 81. THIS IS THE FORTRAN77 VERSION

NEW OPTIONS: DAMBREAK OUTFLOW SUBMERGENCE, SINGLE EVENT DAMAGE CALCULATION, DSS:WRITE STAGE FREQUENCY,

DSS:READ TIME SERIES AT DESIRED CALCULATION INTERVAL LOSS RATE:GREEN AND AMPT INFILTRATION KINEMATIC WAVE: NEW FINITE DIFFERENCE ALGORITHM

1

HEC-1 INPUT

PAGE 1

LINE	ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10
1	ID KUA - Cane Island Unit 3
2	ID Site Certification Application
3	ID HEC-1 Analysis of Unit 3: 25 Year - 72 Hour Precipitation Event
4	ID Black & Veatch Project No. 59140 Modelled By: Gregory V. Johnson
5	ID Pre-Construction Model
6	ID Input File: kua-pre.in Output File: kua-pre.out
7	IT 10 09JUN98 0600 300
8	IO 0 0
9	IN 15
	* *****
10	KK SITE
11	KM Runoff From Pre-Construction Site Area
12	BA .01184
13	PB 12.23
14	PC 0.002 0.003 0.005 0.006 0.008 0.009 0.011 0.012 0.014 0.015
15	PC 0.017 0.018 0.020 0.021 0.023 0.024 0.026 0.027 0.029 0.030
16	PC 0.032 0.033 0.035 0.036 0.038 0.040 0.041 0.043 0.044 0.046
17	PC 0.047 0.049 0.050 0.052 0.053 0.055 0.056 0.058 0.059 0.061
18	PC 0.062 0.064 0.065 0.067 0.068 0.070 0.071 0.073 0.075 0.076
19	PC 0.078 0.079 0.081 0.082 0.084 0.085 0.087 0.088 0.090 0.091
20	PC 0.093 0.094 0.096 0.097 0.099 0.100 0.102 0.103 0.105 0.106

21	PC	0.108	0.110	0.111	0.113	0.114	0.116	0.117	0.119	0.120	0.122
22	PC	0.123	0.125	0.126	0.128	0.129	0.131	0.132	0.134	0.135	0.137
23	PC	0.138	0.140	0.141	0.143	0.144	0.146	0.148	0.150	0.153	0.155
24	PC	0.157	0.159	0.162	0.164	0.166	0.168	0.170	0.173	0.175	0.177
25	PC	0.179	0.182	0.184	0.186	0.188	0.190	0.193	0.195	0.197	0.199
26	PC	0.201	0.204	0.206	0.208	0.210	0.213	0.215	0.217	0.219	0.221
27	PC	0.224	0.226	0.228	0.230	0.233	0.235	0.237	0.239	0.241	0.244
28	PC	0.246	0.248	0.250	0.252	0.255	0.257	0.259	0.261	0.264	0.266
29	PC	0.268	0.270	0.272	0.275	0.277	0.279	0.281	0.284	0.286	0.288
30	PC	0.290	0.292	0.295	0.297	0.299	0.301	0.304	0.306	0.308	0.310
31	PC	0.312	0.315	0.317	0.319	0.321	0.324	0.326	0.328	0.330	0.332
32	PC	0.335	0.337	0.339	0.341	0.343	0.346	0.348	0.350	0.352	0.355
33	PC	0.357	0.359	0.362	0.364	0.367	0.369	0.372	0.374	0.377	0.379
34	PC	0.382	0.385	0.388	0.391	0.394	0.397	0.400	0.404	0.408	0.412
35	PC	0.417	0.421	0.426	0.431	0.437	0.442	0.448	0.454	0.461	0.467
36	PC	0.474	0.481	0.488	0.496	0.504	0.512	0.521	0.530	0.540	0.550
37	PC	0.561	0.572	0.584	0.596	0.612	0.628	0.653	0.678	0.847	1.015
38	PC	1.052	1.088	1.107	1.126	1.140	1.154	1.166	1.177	1.186	1.194
39	PC	1.202	1.209	1.217	1.224	1.232	1.239	1.243	1.248	1.253	1.257
40	PC	1.262	1.266	1.271	1.275	1.280	1.284	1.289	1.293	1.298	1.302
41	PC	1.307	1.311	1.314	1.317	1.320	1.323	1.326	1.329	1.332	1.335
42	PC	1.338	1.341	1.344	1.347	1.350	1.353	1.356	1.359		
43	LS	0	47	0							
44	UD	0.25									

* *****

*DIAGRAM

45 ZZ

1

SCHEMATIC DIAGRAM OF STREAM NETWORK

INPUT

LINE (V) ROUTING (—>) DIVERSION OR PUMP FLOW

NO. (.) CONNECTOR (<---) RETURN OF DIVERTED OR PUMPED FLOW

10 SITE

(***) RUNOFF ALSO COMPUTED AT THIS LOCATION

1 *****

* FLOOD HYDROGRAPH PACKAGE (HEC-1) *	* U.S. ARMY CORPS OF ENGINEERS
* FEBRUARY 1981 *	* THE HYDROLOGIC ENGINEERING CENTER *
* REVISED 02 AUG 88 *	* 609 SECOND STREET *
* RUN DATE 06/09/1998 TIME 08:53:52 *	* DAVIS, CALIFORNIA 95616 *
	* (916) 551-1748 *

KUA - Cane Island Unit 3
 Site Certification Application
 HEC-1 Analysis of Unit 3: 25 Year - 72 Hour Precipitation Event
 Black & Veatch Project No. 59140 Modelled By: Gregory V. Johnson
 Pre-Construction Model
 Input File: kua-pre.in Output File: kua-pre.out

*** ERROR *** SPECIFIED START AND END DATES RESULT IN TOO MANY TIME PERIODS

8 IO

OUTPUT CONTROL VARIABLES

IPRNT 0 PRINT CONTROL
 IPLOT 0 PLOT CONTROL
 QSCAL 0. HYDROGRAPH PLOT SCALE

COMPUTATION INTERVAL .17 HOURS
TOTAL TIME BASE 49.83 HOURS

ENGLISH UNITS	
DRAINAGE AREA	SQUARE MILES
PRECIPITATION DEPTH	INCHES
LENGTH, ELEVATION	FEET
FLOW	CUBIC FEET PER SECOND
STORAGE VOLUME	ACRE-FEET
SURFACE AREA	ACRES
TEMPERATURE	DEGREES FAHRENHEIT

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*****
*** **

```

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*****
*               *
10 KK  *       SITE *
*               *
*****

```

Runoff From Pre-Construction Site Area

```

9 IN      TIME DATA FOR INPUT TIME SERIES
          JXMIN      15  TIME INTERVAL IN MINUTES
          JXDATE     9JUN98  STARTING DATE
          JXTIME     6000  STARTING TIME

```

SUBBASIN RUNOFF DATA

12 BA	SUBBASIN CHARACTERISTICS
TAREA	.01 SUBBASIN AREA

PRECIPITATION DATA

13 PB STORM 12.23 BASIN TOTAL PRECIPITATION

[illegible]

.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

43 LS SCS LOSS RATE
 STRIL 2.26 INITIAL ABSTRACTION
 CRVNBR 47.00 CURVE NUMBER
 RTIMP .00 PERCENT IMPERVIOUS AREA

44 UD SCS DIMENSIONLESS UNITGRAPH
 TLAG .25 LAG

WARNING *** TIME INTERVAL IS GREATER THAN .29*LAG

UNIT HYDROGRAPH
 10 END-OF-PERIOD ORDINATES

8.	17.	12.	5.	2.	1.	0.	0.	0.	0.
----	-----	-----	----	----	----	----	----	----	----

HYDROGRAPH AT STATION SITE

DA MON HRMN ORD RAIN LOSS EXCESS COMP Q							*	DA MON HRMN ORD RAIN LOSS EXCESS COMP Q						
							*							
11 JUN 1200	1	.00	.00	.00	0.	*	12 JUN 1300	151	.04	.03	.02	1.		
11 JUN 1210	2	.02	.02	.00	0.	*	12 JUN 1310	152	.04	.03	.02	1.		
11 JUN 1220	3	.03	.03	.00	0.	*	12 JUN 1320	153	.05	.03	.02	1.		
11 JUN 1230	4	.04	.04	.00	0.	*	12 JUN 1330	154	.06	.04	.02	1.		
11 JUN 1240	5	.02	.02	.00	0.	*	12 JUN 1340	155	.04	.03	.02	1.		
11 JUN 1250	6	.03	.03	.00	0.	*	12 JUN 1350	156	.04	.03	.02	1.		
11 JUN 1300	7	.04	.04	.00	0.	*	12 JUN 1400	157	.04	.03	.02	1.		
11 JUN 1310	8	.02	.02	.00	0.	*	12 JUN 1410	158	.04	.03	.02	1.		
11 JUN 1320	9	.03	.03	.00	0.	*	12 JUN 1420	159	.04	.03	.02	1.		
11 JUN 1330	10	.04	.04	.00	0.	*	12 JUN 1430	160	.04	.03	.02	1.		
11 JUN 1340	11	.02	.02	.00	0.	*	12 JUN 1440	161	.06	.04	.03	1.		
11 JUN 1350	12	.03	.03	.00	0.	*	12 JUN 1450	162	.05	.03	.02	1.		
11 JUN 1400	13	.04	.04	.00	0.	*	12 JUN 1500	163	.04	.03	.02	1.		
11 JUN 1410	14	.02	.02	.00	0.	*	12 JUN 1510	164	.04	.03	.02	1.		
11 JUN 1420	15	.03	.03	.00	0.	*	12 JUN 1520	165	.04	.03	.02	1.		
11 JUN 1430	16	.04	.04	.00	0.	*	12 JUN 1530	166	.04	.03	.02	1.		
11 JUN 1440	17	.02	.02	.00	0.	*	12 JUN 1540	167	.06	.04	.03	1.		
11 JUN 1450	18	.03	.03	.00	0.	*	12 JUN 1550	168	.05	.03	.02	1.		
11 JUN 1500	19	.04	.04	.00	0.	*	12 JUN 1600	169	.04	.02	.02	1.		
11 JUN 1510	20	.02	.02	.00	0.	*	12 JUN 1610	170	.04	.02	.02	1.		
11 JUN 1520	21	.03	.03	.00	0.	*	12 JUN 1620	171	.04	.02	.02	1.		

11 JUN 1530	22	.04	.04	.00	0.	*	12 JUN 1630	172	.04	.02	.02	1.
11 JUN 1540	23	.02	.02	.00	0.	*	12 JUN 1640	173	.04	.02	.02	1.
11 JUN 1550	24	.03	.03	.00	0.	*	12 JUN 1650	174	.05	.03	.02	1.
11 JUN 1600	25	.04	.04	.00	0.	*	12 JUN 1700	175	.06	.04	.03	1.
11 JUN 1610	26	.02	.02	.00	0.	*	12 JUN 1710	176	.04	.02	.02	1.
11 JUN 1620	27	.03	.03	.00	0.	*	12 JUN 1720	177	.04	.02	.02	1.
11 JUN 1630	28	.04	.04	.00	0.	*	12 JUN 1730	178	.04	.02	.02	1.
11 JUN 1640	29	.02	.02	.00	0.	*	12 JUN 1740	179	.04	.02	.02	1.
11 JUN 1650	30	.03	.03	.00	0.	*	12 JUN 1750	180	.04	.02	.02	1.
11 JUN 1700	31	.04	.04	.00	0.	*	12 JUN 1800	181	.04	.02	.02	1.
11 JUN 1710	32	.02	.02	.00	0.	*	12 JUN 1810	182	.06	.03	.03	1.
11 JUN 1720	33	.03	.03	.00	0.	*	12 JUN 1820	183	.05	.03	.03	1.
11 JUN 1730	34	.04	.04	.00	0.	*	12 JUN 1830	184	.04	.02	.02	1.
11 JUN 1740	35	.02	.02	.00	0.	*	12 JUN 1840	185	.04	.02	.02	1.
11 JUN 1750	36	.03	.03	.00	0.	*	12 JUN 1850	186	.04	.02	.02	1.
11 JUN 1800	37	.04	.04	.00	0.	*	12 JUN 1900	187	.04	.02	.02	1.
11 JUN 1810	38	.04	.04	.00	0.	*	12 JUN 1910	188	.06	.03	.03	1.
11 JUN 1820	39	.03	.03	.00	0.	*	12 JUN 1920	189	.05	.03	.03	1.
11 JUN 1830	40	.02	.02	.00	0.	*	12 JUN 1930	190	.04	.02	.02	1.
11 JUN 1840	41	.04	.04	.00	0.	*	12 JUN 1940	191	.04	.02	.02	1.
11 JUN 1850	42	.03	.03	.00	0.	*	12 JUN 1950	192	.04	.02	.02	1.
11 JUN 1900	43	.02	.02	.00	0.	*	12 JUN 2000	193	.04	.02	.02	1.
11 JUN 1910	44	.04	.04	.00	0.	*	12 JUN 2010	194	.04	.02	.02	1.
11 JUN 1920	45	.03	.03	.00	0.	*	12 JUN 2020	195	.05	.03	.03	1.
11 JUN 1930	46	.02	.02	.00	0.	*	12 JUN 2030	196	.06	.03	.03	1.
11 JUN 1940	47	.04	.04	.00	0.	*	12 JUN 2040	197	.04	.02	.02	1.
11 JUN 1950	48	.03	.03	.00	0.	*	12 JUN 2050	198	.04	.02	.02	1.
11 JUN 2000	49	.02	.02	.00	0.	*	12 JUN 2100	199	.04	.02	.02	1.
11 JUN 2010	50	.04	.04	.00	0.	*	12 JUN 2110	200	.04	.02	.02	1.
11 JUN 2020	51	.03	.03	.00	0.	*	12 JUN 2120	201	.05	.03	.03	1.
11 JUN 2030	52	.02	.02	.00	0.	*	12 JUN 2130	202	.06	.03	.03	1.
11 JUN 2040	53	.04	.04	.00	0.	*	12 JUN 2140	203	.04	.02	.02	1.
11 JUN 2050	54	.03	.03	.00	0.	*	12 JUN 2150	204	.04	.02	.02	1.
11 JUN 2100	55	.02	.02	.00	0.	*	12 JUN 2200	205	.04	.02	.02	1.
11 JUN 2110	56	.04	.04	.00	0.	*	12 JUN 2210	206	.04	.02	.02	1.
11 JUN 2120	57	.03	.03	.00	0.	*	12 JUN 2220	207	.04	.02	.02	1.
11 JUN 2130	58	.02	.02	.00	0.	*	12 JUN 2230	208	.04	.02	.02	1.
11 JUN 2140	59	.04	.04	.00	0.	*	12 JUN 2240	209	.06	.03	.04	1.
11 JUN 2150	60	.03	.03	.00	0.	*	12 JUN 2250	210	.05	.02	.03	1.
11 JUN 2200	61	.02	.02	.00	0.	*	12 JUN 2300	211	.04	.02	.02	1.
11 JUN 2210	62	.04	.04	.00	0.	*	12 JUN 2310	212	.04	.02	.02	1.
11 JUN 2220	63	.03	.03	.00	0.	*	12 JUN 2320	213	.04	.02	.02	1.
11 JUN 2230	64	.02	.02	.00	0.	*	12 JUN 2330	214	.04	.02	.02	1.
11 JUN 2240	65	.04	.04	.00	0.	*	12 JUN 2340	215	.04	.02	.02	1.
11 JUN 2250	66	.03	.03	.00	0.	*	12 JUN 2350	216	.05	.02	.03	1.
11 JUN 2300	67	.02	.02	.00	0.	*	13 JUN 0000	217	.06	.03	.04	1.
11 JUN 2310	68	.04	.04	.00	0.	*	13 JUN 0010	218	.04	.02	.02	1.
11 JUN 2320	69	.03	.03	.00	0.	*	13 JUN 0020	219	.04	.02	.02	1.
11 JUN 2330	70	.02	.02	.00	0.	*	13 JUN 0030	220	.04	.02	.02	1.
11 JUN 2340	71	.04	.04	.00	0.	*	13 JUN 0040	221	.04	.02	.02	1.
11 JUN 2350	72	.04	.04	.00	0.	*	13 JUN 0050	222	.05	.02	.03	1.
12 JUN 0000	73	.04	.04	.00	0.	*	13 JUN 0100	223	.06	.03	.04	1.
12 JUN 0010	74	.02	.02	.00	0.	*	13 JUN 0110	224	.04	.02	.03	1.
12 JUN 0020	75	.03	.03	.00	0.	*	13 JUN 0120	225	.04	.02	.03	1.
12 JUN 0030	76	.04	.04	.00	0.	*	13 JUN 0130	226	.04	.02	.03	1.
12 JUN 0040	77	.02	.02	.00	0.	*	13 JUN 0140	227	.04	.02	.03	1.
12 JUN 0050	78	.03	.03	.00	0.	*	13 JUN 0150	228	.04	.02	.03	1.
12 JUN 0100	79	.04	.04	.00	0.	*	13 JUN 0200	229	.04	.02	.03	1.
12 JUN 0110	80	.02	.02	.00	0.	*	13 JUN 0210	230	.06	.03	.04	1.
12 JUN 0120	81	.03	.03	.00	0.	*	13 JUN 0220	231	.05	.02	.03	1.
12 JUN 0130	82	.04	.04	.00	0.	*	13 JUN 0230	232	.04	.02	.03	1.
12 JUN 0140	83	.02	.02	.00	0.	*	13 JUN 0240	233	.04	.02	.03	1.
12 JUN 0150	84	.03	.03	.00	0.	*	13 JUN 0250	234	.04	.02	.03	1.
12 JUN 0200	85	.04	.04	.00	0.	*	13 JUN 0300	235	.04	.02	.03	1.
12 JUN 0210	86	.02	.02	.00	0.	*	13 JUN 0310	236	.06	.03	.04	1.

12 JUN 0220	87	.03	.03	.00	0.	*	13 JUN 0320	237	.05	.02	.03	1.
12 JUN 0230	88	.04	.04	.00	0.	*	13 JUN 0330	238	.04	.02	.03	1.
12 JUN 0240	89	.02	.02	.00	0.	*	13 JUN 0340	239	.04	.02	.03	1.
12 JUN 0250	90	.03	.03	.00	0.	*	13 JUN 0350	240	.04	.02	.03	1.
12 JUN 0300	91	.04	.04	.00	0.	*	13 JUN 0400	241	.04	.02	.03	1.
12 JUN 0310	92	.02	.02	.00	0.	*	13 JUN 0410	242	.04	.02	.03	1.
12 JUN 0320	93	.03	.03	.00	0.	*	13 JUN 0420	243	.05	.02	.03	1.
12 JUN 0330	94	.04	.04	.01	0.	*	13 JUN 0430	244	.06	.02	.04	1.
12 JUN 0340	95	.02	.02	.00	0.	*	13 JUN 0440	245	.04	.02	.03	2.
12 JUN 0350	96	.03	.03	.00	0.	*	13 JUN 0450	246	.04	.02	.03	1.
12 JUN 0400	97	.04	.04	.01	0.	*	13 JUN 0500	247	.04	.02	.03	1.
12 JUN 0410	98	.02	.02	.00	0.	*	13 JUN 0510	248	.04	.02	.03	1.
12 JUN 0420	99	.03	.03	.00	0.	*	13 JUN 0520	249	.05	.02	.03	1.
12 JUN 0430	100	.04	.04	.01	0.	*	13 JUN 0530	250	.06	.02	.04	1.
12 JUN 0440	101	.02	.02	.00	0.	*	13 JUN 0540	251	.04	.02	.03	2.
12 JUN 0450	102	.03	.03	.01	0.	*	13 JUN 0550	252	.04	.02	.03	1.
12 JUN 0500	103	.04	.04	.01	0.	*	13 JUN 0600	253	.04	.02	.03	1.
12 JUN 0510	104	.02	.02	.00	0.	*	13 JUN 0610	254	.04	.02	.03	1.
12 JUN 0520	105	.03	.03	.01	0.	*	13 JUN 0620	255	.04	.02	.03	1.
12 JUN 0530	106	.04	.04	.01	0.	*	13 JUN 0630	256	.04	.02	.03	1.
12 JUN 0540	107	.04	.04	.01	0.	*	13 JUN 0640	257	.06	.02	.04	1.
12 JUN 0550	108	.03	.03	.01	0.	*	13 JUN 0650	258	.05	.02	.04	2.
12 JUN 0600	109	.02	.02	.00	0.	*	13 JUN 0700	259	.04	.01	.03	2.
12 JUN 0610	110	.04	.03	.01	0.	*	13 JUN 0710	260	.04	.01	.03	1.
12 JUN 0620	111	.03	.03	.01	0.	*	13 JUN 0720	261	.04	.01	.03	1.
12 JUN 0630	112	.02	.02	.00	0.	*	13 JUN 0730	262	.04	.01	.03	1.
12 JUN 0640	113	.04	.03	.01	0.	*	13 JUN 0740	263	.06	.02	.04	1.
12 JUN 0650	114	.03	.03	.01	0.	*	13 JUN 0750	264	.05	.02	.04	2.
12 JUN 0700	115	.02	.02	.00	0.	*	13 JUN 0800	265	.04	.01	.03	2.
12 JUN 0710	116	.04	.03	.01	0.	*	13 JUN 0810	266	.04	.01	.03	1.
12 JUN 0720	117	.03	.03	.01	0.	*	13 JUN 0820	267	.04	.01	.03	1.
12 JUN 0730	118	.02	.02	.00	0.	*	13 JUN 0830	268	.04	.01	.03	1.
12 JUN 0740	119	.04	.03	.01	0.	*	13 JUN 0840	269	.04	.01	.03	1.
12 JUN 0750	120	.03	.02	.01	0.	*	13 JUN 0850	270	.05	.02	.04	1.
12 JUN 0800	121	.02	.02	.01	0.	*	13 JUN 0900	271	.06	.02	.04	2.
12 JUN 0810	122	.04	.03	.01	0.	*	13 JUN 0910	272	.04	.01	.03	2.
12 JUN 0820	123	.03	.02	.01	0.	*	13 JUN 0920	273	.04	.01	.03	2.
12 JUN 0830	124	.02	.02	.01	0.	*	13 JUN 0930	274	.04	.01	.03	1.
12 JUN 0840	125	.04	.03	.01	0.	*	13 JUN 0940	275	.04	.01	.03	1.
12 JUN 0850	126	.03	.02	.01	0.	*	13 JUN 0950	276	.04	.01	.03	1.
12 JUN 0900	127	.02	.02	.01	0.	*	13 JUN 1000	277	.04	.01	.03	1.
12 JUN 0910	128	.04	.03	.01	0.	*	13 JUN 1010	278	.06	.02	.04	1.
12 JUN 0920	129	.03	.02	.01	0.	*	13 JUN 1020	279	.05	.02	.04	2.
12 JUN 0930	130	.02	.02	.01	0.	*	13 JUN 1030	280	.04	.01	.03	2.
12 JUN 0940	131	.04	.03	.01	0.	*	13 JUN 1040	281	.04	.01	.03	2.
12 JUN 0950	132	.03	.02	.01	0.	*	13 JUN 1050	282	.04	.01	.03	1.
12 JUN 1000	133	.02	.02	.01	0.	*	13 JUN 1100	283	.04	.01	.03	1.
12 JUN 1010	134	.04	.03	.01	0.	*	13 JUN 1110	284	.06	.02	.04	2.
12 JUN 1020	135	.03	.02	.01	0.	*	13 JUN 1120	285	.05	.02	.04	2.
12 JUN 1030	136	.02	.02	.01	0.	*	13 JUN 1130	286	.04	.01	.03	2.
12 JUN 1040	137	.04	.03	.01	0.	*	13 JUN 1140	287	.04	.01	.03	2.
12 JUN 1050	138	.03	.02	.01	0.	*	13 JUN 1150	288	.05	.02	.04	2.
12 JUN 1100	139	.02	.02	.01	0.	*	13 JUN 1200	289	.06	.02	.05	2.
12 JUN 1110	140	.04	.03	.01	0.	*	13 JUN 1210	290	.04	.01	.03	2.
12 JUN 1120	141	.03	.02	.01	0.	*	13 JUN 1220	291	.05	.02	.04	2.
12 JUN 1130	142	.02	.01	.01	0.	*	13 JUN 1230	292	.06	.02	.05	2.
12 JUN 1140	143	.04	.03	.01	0.	*	13 JUN 1240	293	.04	.01	.03	2.
12 JUN 1150	144	.04	.03	.01	1.	*	13 JUN 1250	294	.05	.02	.04	2.
12 JUN 1200	145	.04	.03	.01	1.	*	13 JUN 1300	295	.06	.02	.05	2.
12 JUN 1210	146	.04	.03	.01	1.	*	13 JUN 1310	296	.04	.01	.03	2.
12 JUN 1220	147	.05	.04	.02	1.	*	13 JUN 1320	297	.05	.02	.04	2.
12 JUN 1230	148	.06	.04	.02	1.	*	13 JUN 1330	298	.06	.02	.05	2.
12 JUN 1240	149	.04	.03	.01	1.	*	13 JUN 1340	299	.04	.01	.03	2.
12 JUN 1250	150	.04	.03	.02	1.	*	13 JUN 1350	300	.05	.02	.04	2.

*

TOTAL RAINFALL = 12.23, TOTAL LOSS = 7.55, TOTAL EXCESS = 4.68

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
		(CFS)				
+	2.	49.67	2.	1.	1.	1.
		(INCHES)	1.237	4.007	4.603	4.603
		(AC-FT)	1.	3.	3.	3.

CUMULATIVE AREA = .01 SQ MI

1

RUNOFF SUMMARY
FLOW IN CUBIC FEET PER SECOND
TIME IN HOURS, AREA IN SQUARE MILES

OF	PEAK	TIME OF	AVERAGE FLOW FOR MAXIMUM PERIOD			BASIN	MAXIMUM	TIME
OPERATION	STATION	FLOW	PEAK			AREA	STAGE	MAX STAGE
+		6-HOUR	24-HOUR	72-HOUR				
	HYDROGRAPH AT							
+	SITE	2.	49.67	2.	1.	1.	.01	

*** NORMAL END OF HEC-1 ***

CASE II

```

*****
*                                     *
* FLOOD HYDROGRAPH PACKAGE (HEC-1) *
*                                     *
*   FEBRUARY 1981                     *
*   REVISED 02 AUG 88                 *
*                                     *
* RUN DATE 07/09/1998 TIME 13:56:10 *
*                                     *
*****

*****
*                                     *
* U.S. ARMY CORPS OF ENGINEERS
*
* THE HYDROLOGIC ENGINEERING CENTER *
*   609 SECOND STREET
* DAVIS, CALIFORNIA 95616
*   (916) 551-1748
*                                     *
*****

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X  X XXXXXXXX XXXXX  X
X  X X  X  X  XX
X  X X  X  X
XXXXXXX XXXX  X  XXXXX X
X  X X  X  X
X  X X  X  X  X
X  X XXXXXXXX XXXXX  XXX

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THIS PROGRAM REPLACES ALL PREVIOUS VERSIONS OF HEC-1 KNOWN AS HEC1 (JAN 73), HEC1GS, HEC1DB, AND HEC1KW.

THE DEFINITIONS OF VARIABLES -RTIMP- AND -RTIOR- HAVE CHANGED FROM THOSE USED WITH THE 1973-STYLE INPUT STRUCTURE.

THE DEFINITION OF -AMSKK- ON RM-CARD WAS CHANGED WITH REVISIONS DATED 28 SEP 81. THIS IS THE FORTRAN77 VERSION

NEW OPTIONS: DAMBREAK OUTFLOW SUBMERGENCE , SINGLE EVENT DAMAGE CALCULATION, DSS:WRITE STAGE FREQUENCY,

DSS:READ TIME SERIES AT DESIRED CALCULATION INTERVAL LOSS RATE:GREEN AND AMPT INFILTRATION KINEMATIC WAVE: NEW FINITE DIFFERENCE ALGORITHM

1 HEC-1 INPUT PAGE 1

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LINE      ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10

1      ID  KUA - Cane Island Unit 3
2      ID  Site Certification Application
3      ID  HEC-1 Analysis of Unit 3: 2.99 Inch Precipitation Event
4      ID  This Storm Event Produces 0.5 Inches of Runoff.
5      ID  Black & Veatch Project No. 59140   Modelled By: Gregory V. Johnson
6      ID  Post-Construction Model
7      ID  Input File: k299.in  Output File: k299.out
8      IT  10 01JUL98 0600 300
9      IO  0 0
10     IN  15
      * *****

11     KK  SITE
12     KM  Runoff From Unit 3 Power Block and Construction Laydown Area
13     BA  .00964
14     PB  2.99
15     PC  0.002 0.003 0.005 0.006 0.008 0.009 0.011 0.012 0.014 0.015
16     PC  0.017 0.018 0.020 0.021 0.023 0.024 0.026 0.027 0.029 0.030
17     PC  0.032 0.033 0.035 0.036 0.038 0.040 0.041 0.043 0.044 0.046
18     PC  0.047 0.049 0.050 0.052 0.053 0.055 0.056 0.058 0.059 0.061
19     PC  0.062 0.064 0.065 0.067 0.068 0.070 0.071 0.073 0.075 0.076
20     PC  0.078 0.079 0.081 0.082 0.084 0.085 0.087 0.088 0.090 0.091

```

21	PC	0.093	0.094	0.096	0.097	0.099	0.100	0.102	0.103	0.105	0.106
22	PC	0.108	0.110	0.111	0.113	0.114	0.116	0.117	0.119	0.120	0.122
23	PC	0.123	0.125	0.126	0.128	0.129	0.131	0.132	0.134	0.135	0.137
24	PC	0.138	0.140	0.141	0.143	0.144	0.146	0.148	0.150	0.153	0.155
25	PC	0.157	0.159	0.162	0.164	0.166	0.168	0.170	0.173	0.175	0.177
26	PC	0.179	0.182	0.184	0.186	0.188	0.190	0.193	0.195	0.197	0.199
27	PC	0.201	0.204	0.206	0.208	0.210	0.213	0.215	0.217	0.219	0.221
28	PC	0.224	0.226	0.228	0.230	0.233	0.235	0.237	0.239	0.241	0.244
29	PC	0.246	0.248	0.250	0.252	0.255	0.257	0.259	0.261	0.264	0.266
30	PC	0.268	0.270	0.272	0.275	0.277	0.279	0.281	0.284	0.286	0.288
31	PC	0.290	0.292	0.295	0.297	0.299	0.301	0.304	0.306	0.308	0.310
32	PC	0.312	0.315	0.317	0.319	0.321	0.324	0.326	0.328	0.330	0.332
33	PC	0.335	0.337	0.339	0.341	0.343	0.346	0.348	0.350	0.352	0.355
34	PC	0.357	0.359	0.362	0.364	0.367	0.369	0.372	0.374	0.377	0.379
35	PC	0.382	0.385	0.388	0.391	0.394	0.397	0.400	0.404	0.408	0.412
36	PC	0.417	0.421	0.426	0.431	0.437	0.442	0.448	0.454	0.461	0.467
37	PC	0.474	0.481	0.488	0.496	0.504	0.512	0.521	0.530	0.540	0.550
38	PC	0.561	0.572	0.584	0.596	0.612	0.628	0.653	0.678	0.847	1.015
39	PC	1.052	1.088	1.107	1.126	1.140	1.154	1.166	1.177	1.186	1.194
40	PC	1.202	1.209	1.217	1.224	1.232	1.239	1.243	1.248	1.253	1.257
41	PC	1.262	1.266	1.271	1.275	1.280	1.284	1.289	1.293	1.298	1.302
42	PC	1.307	1.311	1.314	1.317	1.320	1.323	1.326	1.329	1.332	1.335
43	PC	1.338	1.341	1.344	1.347	1.350	1.353	1.356	1.359		
44	LS	0	65	0							
45	UD	0.26									

* *****

46 KK POND
 47 KM Unit 3 Stormwater Pond
 48 BA .00152
 49 LS 0 49 100
 50 UD 0.01

* *****

1

HEC-1 INPUT

PAGE 2

LINE ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10

51 KK COMB
 52 KM Combining Two Hydrographs in Reservoir
 53 HC 2
 * *****

54 KK RES1
 55 KM Reservoir Routing Operation
 56 RS 1 ELEV 74.0
 57 SA .01379 0.70644 0.78891 0.99732
 58 SE 74.0 75.0 76.5 80.0
 59 SQ 0 0 0 0
 60 SE 74.0 75.0 76.5 80.0

* *****

*DIAGRAM

61 ZZ

1

SCHEMATIC DIAGRAM OF STREAM NETWORK

INPUT

LINE (V) ROUTING (--->) DIVERSION OR PUMP FLOW

NO. (.) CONNECTOR (<---) RETURN OF DIVERTED OR PUMPED FLOW

11 SITE

46 POND

51 COMB.....
V
V
54 RES1

(***) RUNOFF ALSO COMPUTED AT THIS LOCATION

```
*****
*                                     *
* FLOOD HYDROGRAPH PACKAGE (HEC-1) * * U.S. ARMY CORPS OF ENGINEERS
*
* FEBRUARY 1981 *
* REVISED 02 AUG 88 *
*
* RUN DATE 07/09/1998 TIME 13:56:10 *
*
*****
* THE HYDROLOGIC ENGINEERING CENTER *
* 609 SECOND STREET *
* DAVIS, CALIFORNIA 95616 *
* (916) 551-1748 *
```

KUA - Cane Island Unit 3
Site Certification Application
HEC-1 Analysis of Unit 3: 2.99 Inch Precipitation Event
This Storm Event Produces 0.5 Inches of Runoff.
Black & Veatch Project No. 59140 Modelled By: Gregory V. Johnson
Post-Construction Model
Input File: k299.in Output File: k299.out

*** ERROR *** SPECIFIED START AND END DATES RESULT IN TOO MANY TIME PERIODS

9 IO OUTPUT CONTROL VARIABLES
IPRNT 0 PRINT CONTROL
IPLOT 0 PLOT CONTROL
QSCAL 0. HYDROGRAPH PLOT SCALE

IT HYDROGRAPH TIME DATA
NMIN 10 MINUTES IN COMPUTATION INTERVAL
IDATE 1JUL98 STARTING DATE
ITIME 1200 STARTING TIME
NQ 300 NUMBER OF HYDROGRAPH ORDINATES
NDDATE 5JUL98 ENDING DATE
NDTIME 1350 ENDING TIME
ICENT 19 CENTURY MARK

COMPUTATION INTERVAL .17 HOURS
TOTAL TIME BASE 49.83 HOURS

ENGLISH UNITS
DRAINAGE AREA SQUARE MILES
PRECIPITATION DEPTH INCHES
LENGTH, ELEVATION FEET
FLOW CUBIC FEET PER SECOND
STORAGE VOLUME ACRE-Feet
SURFACE AREA ACRES
TEMPERATURE DEGREES FAHRENHEIT

11 KK * SITE *

Runoff From Unit 3 Power Block and Construction Laydown Area

```

10 IN      TIME DATA FOR INPUT TIME SERIES
          JXMIN      15  TIME INTERVAL IN MINUTES
          JXDATE     1JUL98  STARTING DATE
          JXTIME     6000  STARTING TIME

```

SUBBASIN RUNOFF DATA

13 BA SUBBASIN CHARACTERISTICS
TAREA .01 SUBBASIN AREA

PRECIPITATION DATA

14 PB STORM 2.99 BASIN TOTAL PRECIPITATION

[illegible]

44 LS	SCS LOSS RATE	
	STRIL	1.08 INITIAL ABSTRACTION
	CRVNR	65.00 CURVE NUMBER
	RTIMP	.00 PERCENT IMPERVIOUS AREA

45 UD SCS DIMENSIONLESS UNITGRAPH
TLAG .26 LAG

WARNING *** TIME INTERVAL IS GREATER THAN .29*LAG

UNIT HYDROGRAPH

10 END-OF-PERIOD ORDINATES

6. 14. 10. 4. 2. 1. 0. 0. 0. 0.

HYDROGRAPH AT STATION SITE

* DA MON HRMN ORD RAIN LOSS EXCESS COMP Q							* DA MON HRMN ORD RAIN LOSS EXCESS						
COMP Q													
3 JUL 1200	1	.00	.00	.00	0.	*	4 JUL 1300	151	.01	.01	.00	0.	
3 JUL 1210	2	.01	.01	.00	0.	*	4 JUL 1310	152	.01	.01	.00	0.	
3 JUL 1220	3	.01	.01	.00	0.	*	4 JUL 1320	153	.01	.01	.00	0.	
3 JUL 1230	4	.01	.01	.00	0.	*	4 JUL 1330	154	.02	.01	.00	0.	
3 JUL 1240	5	.01	.01	.00	0.	*	4 JUL 1340	155	.01	.01	.00	0.	
3 JUL 1250	6	.01	.01	.00	0.	*	4 JUL 1350	156	.01	.01	.00	0.	
3 JUL 1300	7	.01	.01	.00	0.	*	4 JUL 1400	157	.01	.01	.00	0.	
3 JUL 1310	8	.01	.01	.00	0.	*	4 JUL 1410	158	.01	.01	.00	0.	
3 JUL 1320	9	.01	.01	.00	0.	*	4 JUL 1420	159	.01	.01	.00	0.	
3 JUL 1330	10	.01	.01	.00	0.	*	4 JUL 1430	160	.01	.01	.00	0.	
3 JUL 1340	11	.01	.01	.00	0.	*	4 JUL 1440	161	.02	.01	.00	0.	
3 JUL 1350	12	.01	.01	.00	0.	*	4 JUL 1450	162	.01	.01	.00	0.	
3 JUL 1400	13	.01	.01	.00	0.	*	4 JUL 1500	163	.01	.01	.00	0.	
3 JUL 1410	14	.01	.01	.00	0.	*	4 JUL 1510	164	.01	.01	.00	0.	
3 JUL 1420	15	.01	.01	.00	0.	*	4 JUL 1520	165	.01	.01	.00	0.	
3 JUL 1430	16	.01	.01	.00	0.	*	4 JUL 1530	166	.01	.01	.00	0.	
3 JUL 1440	17	.01	.01	.00	0.	*	4 JUL 1540	167	.02	.01	.00	0.	
3 JUL 1450	18	.01	.01	.00	0.	*	4 JUL 1550	168	.01	.01	.00	0.	
3 JUL 1500	19	.01	.01	.00	0.	*	4 JUL 1600	169	.01	.01	.00	0.	
3 JUL 1510	20	.01	.01	.00	0.	*	4 JUL 1610	170	.01	.01	.00	0.	
3 JUL 1520	21	.01	.01	.00	0.	*	4 JUL 1620	171	.01	.01	.00	0.	
3 JUL 1530	22	.01	.01	.00	0.	*	4 JUL 1630	172	.01	.01	.00	0.	
3 JUL 1540	23	.01	.01	.00	0.	*	4 JUL 1640	173	.01	.01	.00	0.	
3 JUL 1550	24	.01	.01	.00	0.	*	4 JUL 1650	174	.01	.01	.00	0.	
3 JUL 1600	25	.01	.01	.00	0.	*	4 JUL 1700	175	.02	.01	.00	0.	
3 JUL 1610	26	.01	.01	.00	0.	*	4 JUL 1710	176	.01	.01	.00	0.	
3 JUL 1620	27	.01	.01	.00	0.	*	4 JUL 1720	177	.01	.01	.00	0.	
3 JUL 1630	28	.01	.01	.00	0.	*	4 JUL 1730	178	.01	.01	.00	0.	
3 JUL 1640	29	.01	.01	.00	0.	*	4 JUL 1740	179	.01	.01	.00	0.	
3 JUL 1650	30	.01	.01	.00	0.	*	4 JUL 1750	180	.01	.01	.00	0.	
3 JUL 1700	31	.01	.01	.00	0.	*	4 JUL 1800	181	.01	.01	.00	0.	
3 JUL 1710	32	.01	.01	.00	0.	*	4 JUL 1810	182	.02	.01	.00	0.	
3 JUL 1720	33	.01	.01	.00	0.	*	4 JUL 1820	183	.01	.01	.00	0.	
3 JUL 1730	34	.01	.01	.00	0.	*	4 JUL 1830	184	.01	.01	.00	0.	
3 JUL 1740	35	.01	.01	.00	0.	*	4 JUL 1840	185	.01	.01	.00	0.	
3 JUL 1750	36	.01	.01	.00	0.	*	4 JUL 1850	186	.01	.01	.00	0.	
3 JUL 1800	37	.01	.01	.00	0.	*	4 JUL 1900	187	.01	.01	.00	0.	
3 JUL 1810	38	.01	.01	.00	0.	*	4 JUL 1910	188	.02	.01	.00	0.	
3 JUL 1820	39	.01	.01	.00	0.	*	4 JUL 1920	189	.01	.01	.00	0.	
3 JUL 1830	40	.01	.01	.00	0.	*	4 JUL 1930	190	.01	.01	.00	0.	
3 JUL 1840	41	.01	.01	.00	0.	*	4 JUL 1940	191	.01	.01	.00	0.	
3 JUL 1850	42	.01	.01	.00	0.	*	4 JUL 1950	192	.01	.01	.00	0.	
3 JUL 1900	43	.01	.01	.00	0.	*	4 JUL 2000	193	.01	.01	.00	0.	
3 JUL 1910	44	.01	.01	.00	0.	*	4 JUL 2010	194	.01	.01	.00	0.	
3 JUL 1920	45	.01	.01	.00	0.	*	4 JUL 2020	195	.01	.01	.00	0.	
3 JUL 1930	46	.01	.01	.00	0.	*	4 JUL 2030	196	.02	.01	.00	0.	
3 JUL 1940	47	.01	.01	.00	0.	*	4 JUL 2040	197	.01	.01	.00	0.	
3 JUL 1950	48	.01	.01	.00	0.	*	4 JUL 2050	198	.01	.01	.00	0.	
3 JUL 2000	49	.01	.01	.00	0.	*	4 JUL 2100	199	.01	.01	.00	0.	

3 JUL 2010	50	.01	.01	.00	0.	*	4 JUL 2110	200	.01	.01	.00	0.
3 JUL 2020	51	.01	.01	.00	0.	*	4 JUL 2120	201	.01	.01	.00	0.
3 JUL 2030	52	.01	.01	.00	0.	*	4 JUL 2130	202	.02	.01	.00	0.
3 JUL 2040	53	.01	.01	.00	0.	*	4 JUL 2140	203	.01	.01	.00	0.
3 JUL 2050	54	.01	.01	.00	0.	*	4 JUL 2150	204	.01	.01	.00	0.
3 JUL 2100	55	.01	.01	.00	0.	*	4 JUL 2200	205	.01	.01	.00	0.
3 JUL 2110	56	.01	.01	.00	0.	*	4 JUL 2210	206	.01	.01	.00	0.
3 JUL 2120	57	.01	.01	.00	0.	*	4 JUL 2220	207	.01	.01	.00	0.
3 JUL 2130	58	.01	.01	.00	0.	*	4 JUL 2230	208	.01	.01	.00	0.
3 JUL 2140	59	.01	.01	.00	0.	*	4 JUL 2240	209	.02	.01	.00	0.
3 JUL 2150	60	.01	.01	.00	0.	*	4 JUL 2250	210	.01	.01	.00	0.
3 JUL 2200	61	.01	.01	.00	0.	*	4 JUL 2300	211	.01	.01	.00	0.
3 JUL 2210	62	.01	.01	.00	0.	*	4 JUL 2310	212	.01	.01	.00	0.
3 JUL 2220	63	.01	.01	.00	0.	*	4 JUL 2320	213	.01	.01	.00	0.
3 JUL 2230	64	.01	.01	.00	0.	*	4 JUL 2330	214	.01	.01	.00	0.
3 JUL 2240	65	.01	.01	.00	0.	*	4 JUL 2340	215	.01	.01	.00	0.
3 JUL 2250	66	.01	.01	.00	0.	*	4 JUL 2350	216	.01	.01	.00	0.
3 JUL 2300	67	.01	.01	.00	0.	*	5 JUL 0000	217	.02	.01	.00	0.
3 JUL 2310	68	.01	.01	.00	0.	*	5 JUL 0010	218	.01	.01	.00	0.
3 JUL 2320	69	.01	.01	.00	0.	*	5 JUL 0020	219	.01	.01	.00	0.
3 JUL 2330	70	.01	.01	.00	0.	*	5 JUL 0030	220	.01	.01	.00	0.
3 JUL 2340	71	.01	.01	.00	0.	*	5 JUL 0040	221	.01	.01	.00	0.
3 JUL 2350	72	.01	.01	.00	0.	*	5 JUL 0050	222	.01	.01	.00	0.
4 JUL 0000	73	.01	.01	.00	0.	*	5 JUL 0100	223	.02	.01	.00	0.
4 JUL 0010	74	.01	.01	.00	0.	*	5 JUL 0110	224	.01	.01	.00	0.
4 JUL 0020	75	.01	.01	.00	0.	*	5 JUL 0120	225	.01	.01	.00	0.
4 JUL 0030	76	.01	.01	.00	0.	*	5 JUL 0130	226	.01	.01	.00	0.
4 JUL 0040	77	.01	.01	.00	0.	*	5 JUL 0140	227	.01	.01	.00	0.
4 JUL 0050	78	.01	.01	.00	0.	*	5 JUL 0150	228	.01	.01	.00	0.
4 JUL 0100	79	.01	.01	.00	0.	*	5 JUL 0200	229	.01	.01	.00	0.
4 JUL 0110	80	.01	.01	.00	0.	*	5 JUL 0210	230	.02	.01	.00	0.
4 JUL 0120	81	.01	.01	.00	0.	*	5 JUL 0220	231	.01	.01	.00	0.
4 JUL 0130	82	.01	.01	.00	0.	*	5 JUL 0230	232	.01	.01	.00	0.
4 JUL 0140	83	.01	.01	.00	0.	*	5 JUL 0240	233	.01	.01	.00	0.
4 JUL 0150	84	.01	.01	.00	0.	*	5 JUL 0250	234	.01	.01	.00	0.
4 JUL 0200	85	.01	.01	.00	0.	*	5 JUL 0300	235	.01	.01	.00	0.
4 JUL 0210	86	.01	.01	.00	0.	*	5 JUL 0310	236	.02	.01	.01	0.
4 JUL 0220	87	.01	.01	.00	0.	*	5 JUL 0320	237	.01	.01	.00	0.
4 JUL 0230	88	.01	.01	.00	0.	*	5 JUL 0330	238	.01	.01	.00	0.
4 JUL 0240	89	.01	.01	.00	0.	*	5 JUL 0340	239	.01	.01	.00	0.
4 JUL 0250	90	.01	.01	.00	0.	*	5 JUL 0350	240	.01	.01	.00	0.
4 JUL 0300	91	.01	.01	.00	0.	*	5 JUL 0400	241	.01	.01	.00	0.
4 JUL 0310	92	.01	.01	.00	0.	*	5 JUL 0410	242	.01	.01	.00	0.
4 JUL 0320	93	.01	.01	.00	0.	*	5 JUL 0420	243	.01	.01	.00	0.
4 JUL 0330	94	.01	.01	.00	0.	*	5 JUL 0430	244	.02	.01	.01	0.
4 JUL 0340	95	.01	.01	.00	0.	*	5 JUL 0440	245	.01	.01	.00	0.
4 JUL 0350	96	.01	.01	.00	0.	*	5 JUL 0450	246	.01	.01	.00	0.
4 JUL 0400	97	.01	.01	.00	0.	*	5 JUL 0500	247	.01	.01	.00	0.
4 JUL 0410	98	.01	.01	.00	0.	*	5 JUL 0510	248	.01	.01	.00	0.
4 JUL 0420	99	.01	.01	.00	0.	*	5 JUL 0520	249	.01	.01	.00	0.
4 JUL 0430	100	.01	.01	.00	0.	*	5 JUL 0530	250	.02	.01	.01	0.
4 JUL 0440	101	.01	.01	.00	0.	*	5 JUL 0540	251	.01	.01	.00	0.
4 JUL 0450	102	.01	.01	.00	0.	*	5 JUL 0550	252	.01	.01	.00	0.
4 JUL 0500	103	.01	.01	.00	0.	*	5 JUL 0600	253	.01	.01	.00	0.
4 JUL 0510	104	.01	.01	.00	0.	*	5 JUL 0610	254	.01	.01	.00	0.
4 JUL 0520	105	.01	.01	.00	0.	*	5 JUL 0620	255	.01	.01	.00	0.
4 JUL 0530	106	.01	.01	.00	0.	*	5 JUL 0630	256	.01	.01	.00	0.
4 JUL 0540	107	.01	.01	.00	0.	*	5 JUL 0640	257	.02	.01	.01	0.
4 JUL 0550	108	.01	.01	.00	0.	*	5 JUL 0650	258	.01	.01	.00	0.
4 JUL 0600	109	.01	.01	.00	0.	*	5 JUL 0700	259	.01	.01	.00	0.
4 JUL 0610	110	.01	.01	.00	0.	*	5 JUL 0710	260	.01	.01	.00	0.
4 JUL 0620	111	.01	.01	.00	0.	*	5 JUL 0720	261	.01	.01	.00	0.
4 JUL 0630	112	.01	.01	.00	0.	*	5 JUL 0730	262	.01	.01	.00	0.
4 JUL 0640	113	.01	.01	.00	0.	*	5 JUL 0740	263	.02	.01	.01	0.
4 JUL 0650	114	.01	.01	.00	0.	*	5 JUL 0750	264	.01	.01	.01	0.

4 JUL 0700	115	.01	.01	.00	0.	*	5 JUL 0800	265	.01	.01	.00	0.
4 JUL 0710	116	.01	.01	.00	0.	*	5 JUL 0810	266	.01	.01	.00	0.
4 JUL 0720	117	.01	.01	.00	0.	*	5 JUL 0820	267	.01	.01	.00	0.
4 JUL 0730	118	.01	.01	.00	0.	*	5 JUL 0830	268	.01	.01	.00	0.
4 JUL 0740	119	.01	.01	.00	0.	*	5 JUL 0840	269	.01	.01	.00	0.
4 JUL 0750	120	.01	.01	.00	0.	*	5 JUL 0850	270	.01	.01	.01	0.
4 JUL 0800	121	.01	.01	.00	0.	*	5 JUL 0900	271	.02	.01	.01	0.
4 JUL 0810	122	.01	.01	.00	0.	*	5 JUL 0910	272	.01	.01	.00	0.
4 JUL 0820	123	.01	.01	.00	0.	*	5 JUL 0920	273	.01	.01	.00	0.
4 JUL 0830	124	.01	.01	.00	0.	*	5 JUL 0930	274	.01	.01	.00	0.
4 JUL 0840	125	.01	.01	.00	0.	*	5 JUL 0940	275	.01	.01	.00	0.
4 JUL 0850	126	.01	.01	.00	0.	*	5 JUL 0950	276	.01	.01	.00	0.
4 JUL 0900	127	.01	.01	.00	0.	*	5 JUL 1000	277	.01	.01	.00	0.
4 JUL 0910	128	.01	.01	.00	0.	*	5 JUL 1010	278	.02	.01	.01	0.
4 JUL 0920	129	.01	.01	.00	0.	*	5 JUL 1020	279	.01	.01	.01	0.
4 JUL 0930	130	.01	.01	.00	0.	*	5 JUL 1030	280	.01	.01	.00	0.
4 JUL 0940	131	.01	.01	.00	0.	*	5 JUL 1040	281	.01	.01	.00	0.
4 JUL 0950	132	.01	.01	.00	0.	*	5 JUL 1050	282	.01	.01	.00	0.
4 JUL 1000	133	.01	.01	.00	0.	*	5 JUL 1100	283	.01	.01	.00	0.
4 JUL 1010	134	.01	.01	.00	0.	*	5 JUL 1110	284	.02	.01	.01	0.
4 JUL 1020	135	.01	.01	.00	0.	*	5 JUL 1120	285	.01	.01	.01	0.
4 JUL 1030	136	.01	.01	.00	0.	*	5 JUL 1130	286	.01	.01	.00	0.
4 JUL 1040	137	.01	.01	.00	0.	*	5 JUL 1140	287	.01	.01	.00	0.
4 JUL 1050	138	.01	.01	.00	0.	*	5 JUL 1150	288	.01	.01	.01	0.
4 JUL 1100	139	.01	.01	.00	0.	*	5 JUL 1200	289	.02	.01	.01	0.
4 JUL 1110	140	.01	.01	.00	0.	*	5 JUL 1210	290	.01	.01	.00	0.
4 JUL 1120	141	.01	.01	.00	0.	*	5 JUL 1220	291	.01	.01	.01	0.
4 JUL 1130	142	.01	.01	.00	0.	*	5 JUL 1230	292	.02	.01	.01	0.
4 JUL 1140	143	.01	.01	.00	0.	*	5 JUL 1240	293	.01	.01	.00	0.
4 JUL 1150	144	.01	.01	.00	0.	*	5 JUL 1250	294	.01	.01	.01	0.
4 JUL 1200	145	.01	.01	.00	0.	*	5 JUL 1300	295	.02	.01	.01	0.
4 JUL 1210	146	.01	.01	.00	0.	*	5 JUL 1310	296	.01	.01	.00	0.
4 JUL 1220	147	.01	.01	.00	0.	*	5 JUL 1320	297	.01	.01	.01	0.
4 JUL 1230	148	.02	.02	.00	0.	*	5 JUL 1330	298	.02	.01	.01	0.
4 JUL 1240	149	.01	.01	.00	0.	*	5 JUL 1340	299	.01	.01	.00	0.
4 JUL 1250	150	.01	.01	.00	0.	*	5 JUL 1350	300	.01	.01	.01	0.

TOTAL RAINFALL = 2.99, TOTAL LOSS = 2.49, TOTAL EXCESS = .50

PEAK FLOW (CFS)	TIME (HR)	MAXIMUM AVERAGE FLOW			
		6-HR	24-HR	72-HR	49.83-HR
0.	49.67	0.	0.	0.	0.
	(INCHES)	.183	.483	.489	.489
	(AC-FT)	0.	0.	0.	0.

CUMULATIVE AREA = .01 SQ MI

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46 KK * POND *
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* DA MON HRMN ORD RAIN LOSS EXCESS							COMP Q	*	DA MON HRMN ORD RAIN LOSS EXCESS						
COMP Q															
*															
3 JUL 1200	1	.00	.00	.00	0.	*	4 JUL 1300	151	.01	.00	.01	0.			
3 JUL 1210	2	.01	.00	.01	0.	*	4 JUL 1310	152	.01	.00	.01	0.			
3 JUL 1220	3	.01	.00	.01	0.	*	4 JUL 1320	153	.01	.00	.01	0.			
3 JUL 1230	4	.01	.00	.01	0.	*	4 JUL 1330	154	.02	.00	.02	0.			
3 JUL 1240	5	.01	.00	.01	0.	*	4 JUL 1340	155	.01	.00	.01	0.			
3 JUL 1250	6	.01	.00	.01	0.	*	4 JUL 1350	156	.01	.00	.01	0.			
3 JUL 1300	7	.01	.00	.01	0.	*	4 JUL 1400	157	.01	.00	.01	0.			
3 JUL 1310	8	.01	.00	.01	0.	*	4 JUL 1410	158	.01	.00	.01	0.			
3 JUL 1320	9	.01	.00	.01	0.	*	4 JUL 1420	159	.01	.00	.01	0.			
3 JUL 1330	10	.01	.00	.01	0.	*	4 JUL 1430	160	.01	.00	.01	0.			
3 JUL 1340	11	.01	.00	.01	0.	*	4 JUL 1440	161	.02	.00	.02	0.			
3 JUL 1350	12	.01	.00	.01	0.	*	4 JUL 1450	162	.01	.00	.01	0.			
3 JUL 1400	13	.01	.00	.01	0.	*	4 JUL 1500	163	.01	.00	.01	0.			
3 JUL 1410	14	.01	.00	.01	0.	*	4 JUL 1510	164	.01	.00	.01	0.			
3 JUL 1420	15	.01	.00	.01	0.	*	4 JUL 1520	165	.01	.00	.01	0.			
3 JUL 1430	16	.01	.00	.01	0.	*	4 JUL 1530	166	.01	.00	.01	0.			
3 JUL 1440	17	.01	.00	.01	0.	*	4 JUL 1540	167	.02	.00	.02	0.			
3 JUL 1450	18	.01	.00	.01	0.	*	4 JUL 1550	168	.01	.00	.01	0.			
3 JUL 1500	19	.01	.00	.01	0.	*	4 JUL 1600	169	.01	.00	.01	0.			
3 JUL 1510	20	.01	.00	.01	0.	*	4 JUL 1610	170	.01	.00	.01	0.			
3 JUL 1520	21	.01	.00	.01	0.	*	4 JUL 1620	171	.01	.00	.01	0.			
3 JUL 1530	22	.01	.00	.01	0.	*	4 JUL 1630	172	.01	.00	.01	0.			
3 JUL 1540	23	.01	.00	.01	0.	*	4 JUL 1640	173	.01	.00	.01	0.			
3 JUL 1550	24	.01	.00	.01	0.	*	4 JUL 1650	174	.01	.00	.01	0.			
3 JUL 1600	25	.01	.00	.01	0.	*	4 JUL 1700	175	.02	.00	.02	0.			
3 JUL 1610	26	.01	.00	.01	0.	*	4 JUL 1710	176	.01	.00	.01	0.			
3 JUL 1620	27	.01	.00	.01	0.	*	4 JUL 1720	177	.01	.00	.01	0.			
3 JUL 1630	28	.01	.00	.01	0.	*	4 JUL 1730	178	.01	.00	.01	0.			
3 JUL 1640	29	.01	.00	.01	0.	*	4 JUL 1740	179	.01	.00	.01	0.			
3 JUL 1650	30	.01	.00	.01	0.	*	4 JUL 1750	180	.01	.00	.01	0.			
3 JUL 1700	31	.01	.00	.01	0.	*	4 JUL 1800	181	.01	.00	.01	0.			
3 JUL 1710	32	.01	.00	.01	0.	*	4 JUL 1810	182	.02	.00	.02	0.			
3 JUL 1720	33	.01	.00	.01	0.	*	4 JUL 1820	183	.01	.00	.01	0.			
3 JUL 1730	34	.01	.00	.01	0.	*	4 JUL 1830	184	.01	.00	.01	0.			
3 JUL 1740	35	.01	.00	.01	0.	*	4 JUL 1840	185	.01	.00	.01	0.			
3 JUL 1750	36	.01	.00	.01	0.	*	4 JUL 1850	186	.01	.00	.01	0.			
3 JUL 1800	37	.01	.00	.01	0.	*	4 JUL 1900	187	.01	.00	.01	0.			
3 JUL 1810	38	.01	.00	.01	0.	*	4 JUL 1910	188	.02	.00	.02	0.			
3 JUL 1820	39	.01	.00	.01	0.	*	4 JUL 1920	189	.01	.00	.01	0.			
3 JUL 1830	40	.01	.00	.01	0.	*	4 JUL 1930	190	.01	.00	.01	0.			
3 JUL 1840	41	.01	.00	.01	0.	*	4 JUL 1940	191	.01	.00	.01	0.			
3 JUL 1850	42	.01	.00	.01	0.	*	4 JUL 1950	192	.01	.00	.01	0.			
3 JUL 1900	43	.01	.00	.01	0.	*	4 JUL 2000	193	.01	.00	.01	0.			
3 JUL 1910	44	.01	.00	.01	0.	*	4 JUL 2010	194	.01	.00	.01	0.			
3 JUL 1920	45	.01	.00	.01	0.	*	4 JUL 2020	195	.01	.00	.01	0.			
3 JUL 1930	46	.01	.00	.01	0.	*	4 JUL 2030	196	.02	.00	.02	0.			
3 JUL 1940	47	.01	.00	.01	0.	*	4 JUL 2040	197	.01	.00	.01	0.			
3 JUL 1950	48	.01	.00	.01	0.	*	4 JUL 2050	198	.01	.00	.01	0.			
3 JUL 2000	49	.01	.00	.01	0.	*	4 JUL 2100	199	.01	.00	.01	0.			
3 JUL 2010	50	.01	.00	.01	0.	*	4 JUL 2110	200	.01	.00	.01	0.			
3 JUL 2020	51	.01	.00	.01	0.	*	4 JUL 2120	201	.01	.00	.01	0.			
3 JUL 2030	52	.01	.00	.01	0.	*	4 JUL 2130	202	.02	.00	.02	0.			
3 JUL 2040	53	.01	.00	.01	0.	*	4 JUL 2140	203	.01	.00	.01	0.			
3 JUL 2050	54	.01	.00	.01	0.	*	4 JUL 2150	204	.01	.00	.01	0.			
3 JUL 2100	55	.01	.00	.01	0.	*	4 JUL 2200	205	.01	.00	.01	0.			
3 JUL 2110	56	.01	.00	.01	0.	*	4 JUL 2210	206	.01	.00	.01	0.			
3 JUL 2120	57	.01	.00	.01	0.	*	4 JUL 2220	207	.01	.00	.01	0.			
3 JUL 2130	58	.01	.00	.01	0.	*	4 JUL 2230	208	.01	.00	.01	0.			

3 JUL 2140	59	.01	.00	.01	0.	*	4 JUL 2240	209	.02	.00	.02	0.
3 JUL 2150	60	.01	.00	.01	0.	*	4 JUL 2250	210	.01	.00	.01	0.
3 JUL 2200	61	.01	.00	.01	0.	*	4 JUL 2300	211	.01	.00	.01	0.
3 JUL 2210	62	.01	.00	.01	0.	*	4 JUL 2310	212	.01	.00	.01	0.
3 JUL 2220	63	.01	.00	.01	0.	*	4 JUL 2320	213	.01	.00	.01	0.
3 JUL 2230	64	.01	.00	.01	0.	*	4 JUL 2330	214	.01	.00	.01	0.
3 JUL 2240	65	.01	.00	.01	0.	*	4 JUL 2340	215	.01	.00	.01	0.
3 JUL 2250	66	.01	.00	.01	0.	*	4 JUL 2350	216	.01	.00	.01	0.
3 JUL 2300	67	.01	.00	.01	0.	*	5 JUL 0000	217	.02	.00	.02	0.
3 JUL 2310	68	.01	.00	.01	0.	*	5 JUL 0010	218	.01	.00	.01	0.
3 JUL 2320	69	.01	.00	.01	0.	*	5 JUL 0020	219	.01	.00	.01	0.
3 JUL 2330	70	.01	.00	.01	0.	*	5 JUL 0030	220	.01	.00	.01	0.
3 JUL 2340	71	.01	.00	.01	0.	*	5 JUL 0040	221	.01	.00	.01	0.
3 JUL 2350	72	.01	.00	.01	0.	*	5 JUL 0050	222	.01	.00	.01	0.
4 JUL 0000	73	.01	.00	.01	0.	*	5 JUL 0100	223	.02	.00	.02	0.
4 JUL 0010	74	.01	.00	.01	0.	*	5 JUL 0110	224	.01	.00	.01	0.
4 JUL 0020	75	.01	.00	.01	0.	*	5 JUL 0120	225	.01	.00	.01	0.
4 JUL 0030	76	.01	.00	.01	0.	*	5 JUL 0130	226	.01	.00	.01	0.
4 JUL 0040	77	.01	.00	.01	0.	*	5 JUL 0140	227	.01	.00	.01	0.
4 JUL 0050	78	.01	.00	.01	0.	*	5 JUL 0150	228	.01	.00	.01	0.
4 JUL 0100	79	.01	.00	.01	0.	*	5 JUL 0200	229	.01	.00	.01	0.
4 JUL 0110	80	.01	.00	.01	0.	*	5 JUL 0210	230	.02	.00	.02	0.
4 JUL 0120	81	.01	.00	.01	0.	*	5 JUL 0220	231	.01	.00	.01	0.
4 JUL 0130	82	.01	.00	.01	0.	*	5 JUL 0230	232	.01	.00	.01	0.
4 JUL 0140	83	.01	.00	.01	0.	*	5 JUL 0240	233	.01	.00	.01	0.
4 JUL 0150	84	.01	.00	.01	0.	*	5 JUL 0250	234	.01	.00	.01	0.
4 JUL 0200	85	.01	.00	.01	0.	*	5 JUL 0300	235	.01	.00	.01	0.
4 JUL 0210	86	.01	.00	.01	0.	*	5 JUL 0310	236	.02	.00	.02	0.
4 JUL 0220	87	.01	.00	.01	0.	*	5 JUL 0320	237	.01	.00	.01	0.
4 JUL 0230	88	.01	.00	.01	0.	*	5 JUL 0330	238	.01	.00	.01	0.
4 JUL 0240	89	.01	.00	.01	0.	*	5 JUL 0340	239	.01	.00	.01	0.
4 JUL 0250	90	.01	.00	.01	0.	*	5 JUL 0350	240	.01	.00	.01	0.
4 JUL 0300	91	.01	.00	.01	0.	*	5 JUL 0400	241	.01	.00	.01	0.
4 JUL 0310	92	.01	.00	.01	0.	*	5 JUL 0410	242	.01	.00	.01	0.
4 JUL 0320	93	.01	.00	.01	0.	*	5 JUL 0420	243	.01	.00	.01	0.
4 JUL 0330	94	.01	.00	.01	0.	*	5 JUL 0430	244	.02	.00	.02	0.
4 JUL 0340	95	.01	.00	.01	0.	*	5 JUL 0440	245	.01	.00	.01	0.
4 JUL 0350	96	.01	.00	.01	0.	*	5 JUL 0450	246	.01	.00	.01	0.
4 JUL 0400	97	.01	.00	.01	0.	*	5 JUL 0500	247	.01	.00	.01	0.
4 JUL 0410	98	.01	.00	.01	0.	*	5 JUL 0510	248	.01	.00	.01	0.
4 JUL 0420	99	.01	.00	.01	0.	*	5 JUL 0520	249	.01	.00	.01	0.
4 JUL 0430	100	.01	.00	.01	0.	*	5 JUL 0530	250	.02	.00	.02	0.
4 JUL 0440	101	.01	.00	.01	0.	*	5 JUL 0540	251	.01	.00	.01	0.
4 JUL 0450	102	.01	.00	.01	0.	*	5 JUL 0550	252	.01	.00	.01	0.
4 JUL 0500	103	.01	.00	.01	0.	*	5 JUL 0600	253	.01	.00	.01	0.
4 JUL 0510	104	.01	.00	.01	0.	*	5 JUL 0610	254	.01	.00	.01	0.
4 JUL 0520	105	.01	.00	.01	0.	*	5 JUL 0620	255	.01	.00	.01	0.
4 JUL 0530	106	.01	.00	.01	0.	*	5 JUL 0630	256	.01	.00	.01	0.
4 JUL 0540	107	.01	.00	.01	0.	*	5 JUL 0640	257	.02	.00	.02	0.
4 JUL 0550	108	.01	.00	.01	0.	*	5 JUL 0650	258	.01	.00	.01	0.
4 JUL 0600	109	.01	.00	.01	0.	*	5 JUL 0700	259	.01	.00	.01	0.
4 JUL 0610	110	.01	.00	.01	0.	*	5 JUL 0710	260	.01	.00	.01	0.
4 JUL 0620	111	.01	.00	.01	0.	*	5 JUL 0720	261	.01	.00	.01	0.
4 JUL 0630	112	.01	.00	.01	0.	*	5 JUL 0730	262	.01	.00	.01	0.
4 JUL 0640	113	.01	.00	.01	0.	*	5 JUL 0740	263	.02	.00	.02	0.
4 JUL 0650	114	.01	.00	.01	0.	*	5 JUL 0750	264	.01	.00	.01	0.
4 JUL 0700	115	.01	.00	.01	0.	*	5 JUL 0800	265	.01	.00	.01	0.
4 JUL 0710	116	.01	.00	.01	0.	*	5 JUL 0810	266	.01	.00	.01	0.
4 JUL 0720	117	.01	.00	.01	0.	*	5 JUL 0820	267	.01	.00	.01	0.
4 JUL 0730	118	.01	.00	.01	0.	*	5 JUL 0830	268	.01	.00	.01	0.
4 JUL 0740	119	.01	.00	.01	0.	*	5 JUL 0840	269	.01	.00	.01	0.
4 JUL 0750	120	.01	.00	.01	0.	*	5 JUL 0850	270	.01	.00	.01	0.
4 JUL 0800	121	.01	.00	.01	0.	*	5 JUL 0900	271	.02	.00	.02	0.
4 JUL 0810	122	.01	.00	.01	0.	*	5 JUL 0910	272	.01	.00	.01	0.
4 JUL 0820	123	.01	.00	.01	0.	*	5 JUL 0920	273	.01	.00	.01	0.

4 JUL 0830	124	.01	.00	.01	0.	*	5 JUL 0930	274	.01	.00	.01	0.
4 JUL 0840	125	.01	.00	.01	0.	*	5 JUL 0940	275	.01	.00	.01	0.
4 JUL 0850	126	.01	.00	.01	0.	*	5 JUL 0950	276	.01	.00	.01	0.
4 JUL 0900	127	.01	.00	.01	0.	*	5 JUL 1000	277	.01	.00	.01	0.
4 JUL 0910	128	.01	.00	.01	0.	*	5 JUL 1010	278	.02	.00	.02	0.
4 JUL 0920	129	.01	.00	.01	0.	*	5 JUL 1020	279	.01	.00	.01	0.
4 JUL 0930	130	.01	.00	.01	0.	*	5 JUL 1030	280	.01	.00	.01	0.
4 JUL 0940	131	.01	.00	.01	0.	*	5 JUL 1040	281	.01	.00	.01	0.
4 JUL 0950	132	.01	.00	.01	0.	*	5 JUL 1050	282	.01	.00	.01	0.
4 JUL 1000	133	.01	.00	.01	0.	*	5 JUL 1100	283	.01	.00	.01	0.
4 JUL 1010	134	.01	.00	.01	0.	*	5 JUL 1110	284	.02	.00	.02	0.
4 JUL 1020	135	.01	.00	.01	0.	*	5 JUL 1120	285	.01	.00	.01	0.
4 JUL 1030	136	.01	.00	.01	0.	*	5 JUL 1130	286	.01	.00	.01	0.
4 JUL 1040	137	.01	.00	.01	0.	*	5 JUL 1140	287	.01	.00	.01	0.
4 JUL 1050	138	.01	.00	.01	0.	*	5 JUL 1150	288	.01	.00	.01	0.
4 JUL 1100	139	.01	.00	.01	0.	*	5 JUL 1200	289	.02	.00	.02	0.
4 JUL 1110	140	.01	.00	.01	0.	*	5 JUL 1210	290	.01	.00	.01	0.
4 JUL 1120	141	.01	.00	.01	0.	*	5 JUL 1220	291	.01	.00	.01	0.
4 JUL 1130	142	.01	.00	.01	0.	*	5 JUL 1230	292	.02	.00	.02	0.
4 JUL 1140	143	.01	.00	.01	0.	*	5 JUL 1240	293	.01	.00	.01	0.
4 JUL 1150	144	.01	.00	.01	0.	*	5 JUL 1250	294	.01	.00	.01	0.
4 JUL 1200	145	.01	.00	.01	0.	*	5 JUL 1300	295	.02	.00	.02	0.
4 JUL 1210	146	.01	.00	.01	0.	*	5 JUL 1310	296	.01	.00	.01	0.
4 JUL 1220	147	.01	.00	.01	0.	*	5 JUL 1320	297	.01	.00	.01	0.
4 JUL 1230	148	.02	.00	.02	0.	*	5 JUL 1330	298	.02	.00	.02	0.
4 JUL 1240	149	.01	.00	.01	0.	*	5 JUL 1340	299	.01	.00	.01	0.
4 JUL 1250	150	.01	.00	.01	0.	*	5 JUL 1350	300	.01	.00	.01	0.

TOTAL RAINFALL = 2.99, TOTAL LOSS = .00, TOTAL EXCESS = 2.99

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
+	0.	24.50	0.	0.	0.	0.
		(INCHES)	.440	1.702	2.980	2.980
		(AC-FT)	0.	0.	0.	0.

CUMULATIVE AREA = .00 SQ MI

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51 KK * COMB *
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Combining Two Hydrographs in Reservoir

53 HC HYDROGRAPH COMBINATION
ICOMP 2 NUMBER OF HYDROGRAPHS TO COMBINE

HYDROGRAPH AT STATION COMB SUM OF 2 HYDROGRAPHS

DA MON HRMN ORD	FLOW	*	DA MON HRMN ORD	FLOW	*	DA MON HRMN ORD	FLOW	*	DA MON
3 JUL 1200	1	0.	4 JUL 0030	76	0.	4 JUL 1300	151	0.	5 JUL 0130
3 JUL 1210	2	0.	4 JUL 0040	77	0.	4 JUL 1310	152	0.	5 JUL 0140
3 JUL 1220	3	0.	4 JUL 0050	78	0.	4 JUL 1320	153	0.	5 JUL 0150
3 JUL 1230	4	0.	4 JUL 0100	79	0.	4 JUL 1330	154	0.	5 JUL 0200
3 JUL 1240	5	0.	4 JUL 0110	80	0.	4 JUL 1340	155	0.	5 JUL 0210
3 JUL 1250	6	0.	4 JUL 0120	81	0.	4 JUL 1350	156	0.	5 JUL 0220
3 JUL 1300	7	0.	4 JUL 0130	82	0.	4 JUL 1400	157	0.	5 JUL 0230
3 JUL 1310	8	0.	4 JUL 0140	83	0.	4 JUL 1410	158	0.	5 JUL 0240
3 JUL 1320	9	0.	4 JUL 0150	84	0.	4 JUL 1420	159	0.	5 JUL 0250
3 JUL 1330	10	0.	4 JUL 0200	85	0.	4 JUL 1430	160	0.	5 JUL 0300
3 JUL 1340	11	0.	4 JUL 0210	86	0.	4 JUL 1440	161	0.	5 JUL 0310
3 JUL 1350	12	0.	4 JUL 0220	87	0.	4 JUL 1450	162	0.	5 JUL 0320
3 JUL 1400	13	0.	4 JUL 0230	88	0.	4 JUL 1500	163	0.	5 JUL 0330
3 JUL 1410	14	0.	4 JUL 0240	89	0.	4 JUL 1510	164	0.	5 JUL 0340
3 JUL 1420	15	0.	4 JUL 0250	90	0.	4 JUL 1520	165	0.	5 JUL 0350
3 JUL 1430	16	0.	4 JUL 0300	91	0.	4 JUL 1530	166	0.	5 JUL 0400
3 JUL 1440	17	0.	4 JUL 0310	92	0.	4 JUL 1540	167	0.	5 JUL 0410
3 JUL 1450	18	0.	4 JUL 0320	93	0.	4 JUL 1550	168	0.	5 JUL 0420
3 JUL 1500	19	0.	4 JUL 0330	94	0.	4 JUL 1600	169	0.	5 JUL 0430
3 JUL 1510	20	0.	4 JUL 0340	95	0.	4 JUL 1610	170	0.	5 JUL 0440
3 JUL 1520	21	0.	4 JUL 0350	96	0.	4 JUL 1620	171	0.	5 JUL 0450
3 JUL 1530	22	0.	4 JUL 0400	97	0.	4 JUL 1630	172	0.	5 JUL 0500
3 JUL 1540	23	0.	4 JUL 0410	98	0.	4 JUL 1640	173	0.	5 JUL 0510
3 JUL 1550	24	0.	4 JUL 0420	99	0.	4 JUL 1650	174	0.	5 JUL 0520
3 JUL 1600	25	0.	4 JUL 0430	100	0.	4 JUL 1700	175	0.	5 JUL 0530
3 JUL 1610	26	0.	4 JUL 0440	101	0.	4 JUL 1710	176	0.	5 JUL 0540
3 JUL 1620	27	0.	4 JUL 0450	102	0.	4 JUL 1720	177	0.	5 JUL 0550
3 JUL 1630	28	0.	4 JUL 0500	103	0.	4 JUL 1730	178	0.	5 JUL 0600
3 JUL 1640	29	0.	4 JUL 0510	104	0.	4 JUL 1740	179	0.	5 JUL 0610
3 JUL 1650	30	0.	4 JUL 0520	105	0.	4 JUL 1750	180	0.	5 JUL 0620
3 JUL 1700	31	0.	4 JUL 0530	106	0.	4 JUL 1800	181	0.	5 JUL 0630
3 JUL 1710	32	0.	4 JUL 0540	107	0.	4 JUL 1810	182	0.	5 JUL 0640
3 JUL 1720	33	0.	4 JUL 0550	108	0.	4 JUL 1820	183	0.	5 JUL 0650
3 JUL 1730	34	0.	4 JUL 0600	109	0.	4 JUL 1830	184	0.	5 JUL 0700
3 JUL 1740	35	0.	4 JUL 0610	110	0.	4 JUL 1840	185	0.	5 JUL 0710
3 JUL 1750	36	0.	4 JUL 0620	111	0.	4 JUL 1850	186	0.	5 JUL 0720
3 JUL 1800	37	0.	4 JUL 0630	112	0.	4 JUL 1900	187	0.	5 JUL 0730
3 JUL 1810	38	0.	4 JUL 0640	113	0.	4 JUL 1910	188	0.	5 JUL 0740
3 JUL 1820	39	0.	4 JUL 0650	114	0.	4 JUL 1920	189	0.	5 JUL 0750
3 JUL 1830	40	0.	4 JUL 0700	115	0.	4 JUL 1930	190	0.	5 JUL 0800
3 JUL 1840	41	0.	4 JUL 0710	116	0.	4 JUL 1940	191	0.	5 JUL 0810
3 JUL 1850	42	0.	4 JUL 0720	117	0.	4 JUL 1950	192	0.	5 JUL 0820
3 JUL 1900	43	0.	4 JUL 0730	118	0.	4 JUL 2000	193	0.	5 JUL 0830
3 JUL 1910	44	0.	4 JUL 0740	119	0.	4 JUL 2010	194	0.	5 JUL 0840
3 JUL 1920	45	0.	4 JUL 0750	120	0.	4 JUL 2020	195	0.	5 JUL 0850
3 JUL 1930	46	0.	4 JUL 0800	121	0.	4 JUL 2030	196	0.	5 JUL 0900
3 JUL 1940	47	0.	4 JUL 0810	122	0.	4 JUL 2040	197	0.	5 JUL 0910
3 JUL 1950	48	0.	4 JUL 0820	123	0.	4 JUL 2050	198	0.	5 JUL 0920
3 JUL 2000	49	0.	4 JUL 0830	124	0.	4 JUL 2100	199	0.	5 JUL 0930
3 JUL 2010	50	0.	4 JUL 0840	125	0.	4 JUL 2110	200	0.	5 JUL 0940
3 JUL 2020	51	0.	4 JUL 0850	126	0.	4 JUL 2120	201	0.	5 JUL 0950
3 JUL 2030	52	0.	4 JUL 0900	127	0.	4 JUL 2130	202	0.	5 JUL 1000
3 JUL 2040	53	0.	4 JUL 0910	128	0.	4 JUL 2140	203	0.	5 JUL 1010

3 JUL 2050	54	0.	*	4 JUL 0920	129	0.	*	4 JUL 2150	204	0.	*	5 JUL 1020	279	0.
3 JUL 2100	55	0.	*	4 JUL 0930	130	0.	*	4 JUL 2200	205	0.	*	5 JUL 1030	280	0.
3 JUL 2110	56	0.	*	4 JUL 0940	131	0.	*	4 JUL 2210	206	0.	*	5 JUL 1040	281	0.
3 JUL 2120	57	0.	*	4 JUL 0950	132	0.	*	4 JUL 2220	207	0.	*	5 JUL 1050	282	0.
3 JUL 2130	58	0.	*	4 JUL 1000	133	0.	*	4 JUL 2230	208	0.	*	5 JUL 1100	283	0.
3 JUL 2140	59	0.	*	4 JUL 1010	134	0.	*	4 JUL 2240	209	0.	*	5 JUL 1110	284	0.
3 JUL 2150	60	0.	*	4 JUL 1020	135	0.	*	4 JUL 2250	210	0.	*	5 JUL 1120	285	0.
3 JUL 2200	61	0.	*	4 JUL 1030	136	0.	*	4 JUL 2300	211	0.	*	5 JUL 1130	286	0.
3 JUL 2210	62	0.	*	4 JUL 1040	137	0.	*	4 JUL 2310	212	0.	*	5 JUL 1140	287	0.
3 JUL 2220	63	0.	*	4 JUL 1050	138	0.	*	4 JUL 2320	213	0.	*	5 JUL 1150	288	0.
3 JUL 2230	64	0.	*	4 JUL 1100	139	0.	*	4 JUL 2330	214	0.	*	5 JUL 1200	289	0.
3 JUL 2240	65	0.	*	4 JUL 1110	140	0.	*	4 JUL 2340	215	0.	*	5 JUL 1210	290	0.
3 JUL 2250	66	0.	*	4 JUL 1120	141	0.	*	4 JUL 2350	216	0.	*	5 JUL 1220	291	0.
3 JUL 2300	67	0.	*	4 JUL 1130	142	0.	*	5 JUL 0000	217	0.	*	5 JUL 1230	292	0.
3 JUL 2310	68	0.	*	4 JUL 1140	143	0.	*	5 JUL 0010	218	0.	*	5 JUL 1240	293	0.
3 JUL 2320	69	0.	*	4 JUL 1150	144	0.	*	5 JUL 0020	219	0.	*	5 JUL 1250	294	0.
3 JUL 2330	70	0.	*	4 JUL 1200	145	0.	*	5 JUL 0030	220	0.	*	5 JUL 1300	295	0.
3 JUL 2340	71	0.	*	4 JUL 1210	146	0.	*	5 JUL 0040	221	0.	*	5 JUL 1310	296	0.
3 JUL 2350	72	0.	*	4 JUL 1220	147	0.	*	5 JUL 0050	222	0.	*	5 JUL 1320	297	0.
4 JUL 0000	73	0.	*	4 JUL 1230	148	0.	*	5 JUL 0100	223	0.	*	5 JUL 1330	298	0.
4 JUL 0010	74	0.	*	4 JUL 1240	149	0.	*	5 JUL 0110	224	0.	*	5 JUL 1340	299	0.
4 JUL 0020	75	0.	*	4 JUL 1250	150	0.	*	5 JUL 0120	225	0.	*	5 JUL 1350	300	0.

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
+	0.	49.50	0.	0.	0.	0.
		(INCHES)	.217	.649	.828	.828
		(AC-FT)	0.	0.	0.	0.

CUMULATIVE AREA = .01 SQ MI

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54 KK * RES1 *
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Reservoir Routing Operation

HYDROGRAPH ROUTING DATA

56 RS	STORAGE ROUTING				
	NSTPS	1	NUMBER OF SUBREACHES		
	ITYP	ELEV	TYPE OF INITIAL CONDITION		
	RSVRIC	74.00	INITIAL CONDITION		
	X	.00	WORKING R AND D COEFFICIENT		
57 SA	AREA	.0	.7	.8	1.0
58 SE	ELEVATION	74.00	75.00	76.50	80.00
59 SQ	DISCHARGE	0.	0.	0.	0.

60 SE ELEVATION 74.00 75.00 76.50 80.00

COMPUTED STORAGE-ELEVATION DATA

STORAGE	.00	.27	1.39	4.51
ELEVATION	74.00	75.00	76.50	80.00

COMPUTED STORAGE-OUTFLOW-ELEVATION DATA

STORAGE	.00	.27	1.39	4.51
OUTFLOW	.00	.00	.00	.00
ELEVATION	74.00	75.00	76.50	80.00

HYDROGRAPH AT STATION RES1

DA MON HRMN ORD OUTFLOW STORAGE STAGE * DA MON HRMN ORD OUTFLOW STORAGE STAGE * DA MON
HRMN ORD OUTFLOW STORAGE STAGE

3 JUL 1200	1	0.	.0	74.0	* 4 JUL 0440	101	0.	.1	74.2	* 4 JUL 2120	201	0.	.2	74.7
3 JUL 1210	2	0.	.0	74.0	* 4 JUL 0450	102	0.	.1	74.2	* 4 JUL 2130	202	0.	.2	74.7
3 JUL 1220	3	0.	.0	74.0	* 4 JUL 0500	103	0.	.1	74.2	* 4 JUL 2140	203	0.	.2	74.7
3 JUL 1230	4	0.	.0	74.0	* 4 JUL 0510	104	0.	.1	74.2	* 4 JUL 2150	204	0.	.2	74.7
3 JUL 1240	5	0.	.0	74.0	* 4 JUL 0520	105	0.	.1	74.2	* 4 JUL 2200	205	0.	.2	74.7
3 JUL 1250	6	0.	.0	74.0	* 4 JUL 0530	106	0.	.1	74.2	* 4 JUL 2210	206	0.	.2	74.7
3 JUL 1300	7	0.	.0	74.0	* 4 JUL 0540	107	0.	.1	74.2	* 4 JUL 2220	207	0.	.2	74.7
3 JUL 1310	8	0.	.0	74.0	* 4 JUL 0550	108	0.	.1	74.3	* 4 JUL 2230	208	0.	.2	74.7
3 JUL 1320	9	0.	.0	74.0	* 4 JUL 0600	109	0.	.1	74.3	* 4 JUL 2240	209	0.	.2	74.8
3 JUL 1330	10	0.	.0	74.0	* 4 JUL 0610	110	0.	.1	74.3	* 4 JUL 2250	210	0.	.2	74.8
3 JUL 1340	11	0.	.0	74.0	* 4 JUL 0620	111	0.	.1	74.3	* 4 JUL 2300	211	0.	.2	74.8
3 JUL 1350	12	0.	.0	74.0	* 4 JUL 0630	112	0.	.1	74.3	* 4 JUL 2310	212	0.	.2	74.8
3 JUL 1400	13	0.	.0	74.0	* 4 JUL 0640	113	0.	.1	74.3	* 4 JUL 2320	213	0.	.2	74.8
3 JUL 1410	14	0.	.0	74.0	* 4 JUL 0650	114	0.	.1	74.3	* 4 JUL 2330	214	0.	.2	74.8
3 JUL 1420	15	0.	.0	74.0	* 4 JUL 0700	115	0.	.1	74.3	* 4 JUL 2340	215	0.	.2	74.8
3 JUL 1430	16	0.	.0	74.0	* 4 JUL 0710	116	0.	.1	74.3	* 4 JUL 2350	216	0.	.2	74.8
3 JUL 1440	17	0.	.0	74.0	* 4 JUL 0720	117	0.	.1	74.3	* 5 JUL 0000	217	0.	.2	74.8
3 JUL 1450	18	0.	.0	74.0	* 4 JUL 0730	118	0.	.1	74.3	* 5 JUL 0010	218	0.	.2	74.8
3 JUL 1500	19	0.	.0	74.0	* 4 JUL 0740	119	0.	.1	74.3	* 5 JUL 0020	219	0.	.2	74.9
3 JUL 1510	20	0.	.0	74.0	* 4 JUL 0750	120	0.	.1	74.3	* 5 JUL 0030	220	0.	.2	74.9
3 JUL 1520	21	0.	.0	74.0	* 4 JUL 0800	121	0.	.1	74.3	* 5 JUL 0040	221	0.	.2	74.9
3 JUL 1530	22	0.	.0	74.0	* 4 JUL 0810	122	0.	.1	74.3	* 5 JUL 0050	222	0.	.2	74.9
3 JUL 1540	23	0.	.0	74.0	* 4 JUL 0820	123	0.	.1	74.3	* 5 JUL 0100	223	0.	.2	74.9
3 JUL 1550	24	0.	.0	74.1	* 4 JUL 0830	124	0.	.1	74.3	* 5 JUL 0110	224	0.	.2	74.9
3 JUL 1600	25	0.	.0	74.1	* 4 JUL 0840	125	0.	.1	74.3	* 5 JUL 0120	225	0.	.2	74.9
3 JUL 1610	26	0.	.0	74.1	* 4 JUL 0850	126	0.	.1	74.3	* 5 JUL 0130	226	0.	.3	74.9
3 JUL 1620	27	0.	.0	74.1	* 4 JUL 0900	127	0.	.1	74.3	* 5 JUL 0140	227	0.	.3	74.9
3 JUL 1630	28	0.	.0	74.1	* 4 JUL 0910	128	0.	.1	74.3	* 5 JUL 0150	228	0.	.3	74.9
3 JUL 1640	29	0.	.0	74.1	* 4 JUL 0920	129	0.	.1	74.3	* 5 JUL 0200	229	0.	.3	74.9
3 JUL 1650	30	0.	.0	74.1	* 4 JUL 0930	130	0.	.1	74.3	* 5 JUL 0210	230	0.	.3	75.0
3 JUL 1700	31	0.	.0	74.1	* 4 JUL 0940	131	0.	.1	74.3	* 5 JUL 0220	231	0.	.3	75.0
3 JUL 1710	32	0.	.0	74.1	* 4 JUL 0950	132	0.	.1	74.3	* 5 JUL 0230	232	0.	.3	75.0
3 JUL 1720	33	0.	.0	74.1	* 4 JUL 1000	133	0.	.1	74.3	* 5 JUL 0240	233	0.	.3	75.0
3 JUL 1730	34	0.	.0	74.1	* 4 JUL 1010	134	0.	.1	74.3	* 5 JUL 0250	234	0.	.3	75.0
3 JUL 1740	35	0.	.0	74.1	* 4 JUL 1020	135	0.	.1	74.3	* 5 JUL 0300	235	0.	.3	75.0
3 JUL 1750	36	0.	.0	74.1	* 4 JUL 1030	136	0.	.1	74.3	* 5 JUL 0310	236	0.	.3	75.0
3 JUL 1800	37	0.	.0	74.1	* 4 JUL 1040	137	0.	.1	74.3	* 5 JUL 0320	237	0.	.3	75.0

3 JUL 1810 38	0.	.0	74.1 *	4 JUL 1050 138	0.	.1	74.3 *	5 JUL 0330 238	0.	.3	75.0
3 JUL 1820 39	0.	.0	74.1 *	4 JUL 1100 139	0.	.1	74.3 *	5 JUL 0340 239	0.	.3	75.0
3 JUL 1830 40	0.	.0	74.1 *	4 JUL 1110 140	0.	.1	74.3 *	5 JUL 0350 240	0.	.3	75.0
3 JUL 1840 41	0.	.0	74.1 *	4 JUL 1120 141	0.	.1	74.3 *	5 JUL 0400 241	0.	.3	75.0
3 JUL 1850 42	0.	.0	74.1 *	4 JUL 1130 142	0.	.1	74.3 *	5 JUL 0410 242	0.	.3	75.0
3 JUL 1900 43	0.	.0	74.1 *	4 JUL 1140 143	0.	.1	74.3 *	5 JUL 0420 243	0.	.3	75.0
3 JUL 1910 44	0.	.0	74.1 *	4 JUL 1150 144	0.	.1	74.3 *	5 JUL 0430 244	0.	.3	75.0
3 JUL 1920 45	0.	.0	74.1 *	4 JUL 1200 145	0.	.1	74.3 *	5 JUL 0440 245	0.	.3	75.0
3 JUL 1930 46	0.	.0	74.1 *	4 JUL 1210 146	0.	.1	74.3 *	5 JUL 0450 246	0.	.3	75.0
3 JUL 1940 47	0.	.0	74.1 *	4 JUL 1220 147	0.	.1	74.3 *	5 JUL 0500 247	0.	.3	75.1
3 JUL 1950 48	0.	.0	74.1 *	4 JUL 1230 148	0.	.1	74.4 *	5 JUL 0510 248	0.	.3	75.1
3 JUL 2000 49	0.	.0	74.1 *	4 JUL 1240 149	0.	.1	74.4 *	5 JUL 0520 249	0.	.3	75.1
3 JUL 2010 50	0.	.0	74.1 *	4 JUL 1250 150	0.	.1	74.4 *	5 JUL 0530 250	0.	.3	75.1
3 JUL 2020 51	0.	.0	74.1 *	4 JUL 1300 151	0.	.1	74.4 *	5 JUL 0540 251	0.	.3	75.1
3 JUL 2030 52	0.	.0	74.1 *	4 JUL 1310 152	0.	.1	74.4 *	5 JUL 0550 252	0.	.3	75.1
3 JUL 2040 53	0.	.0	74.1 *	4 JUL 1320 153	0.	.1	74.4 *	5 JUL 0600 253	0.	.3	75.1
3 JUL 2050 54	0.	.0	74.1 *	4 JUL 1330 154	0.	.1	74.4 *	5 JUL 0610 254	0.	.3	75.1
3 JUL 2100 55	0.	.0	74.1 *	4 JUL 1340 155	0.	.1	74.4 *	5 JUL 0620 255	0.	.3	75.1
3 JUL 2110 56	0.	.0	74.1 *	4 JUL 1350 156	0.	.1	74.4 *	5 JUL 0630 256	0.	.3	75.1
3 JUL 2120 57	0.	.0	74.1 *	4 JUL 1400 157	0.	.1	74.4 *	5 JUL 0640 257	0.	.3	75.1
3 JUL 2130 58	0.	.0	74.1 *	4 JUL 1410 158	0.	.1	74.4 *	5 JUL 0650 258	0.	.3	75.1
3 JUL 2140 59	0.	.0	74.1 *	4 JUL 1420 159	0.	.1	74.4 *	5 JUL 0700 259	0.	.3	75.1
3 JUL 2150 60	0.	.0	74.1 *	4 JUL 1430 160	0.	.1	74.4 *	5 JUL 0710 260	0.	.4	75.1
3 JUL 2200 61	0.	.0	74.1 *	4 JUL 1440 161	0.	.1	74.4 *	5 JUL 0720 261	0.	.4	75.1
3 JUL 2210 62	0.	.0	74.1 *	4 JUL 1450 162	0.	.1	74.4 *	5 JUL 0730 262	0.	.4	75.1
3 JUL 2220 63	0.	.0	74.1 *	4 JUL 1500 163	0.	.1	74.4 *	5 JUL 0740 263	0.	.4	75.1
3 JUL 2230 64	0.	.0	74.1 *	4 JUL 1510 164	0.	.1	74.4 *	5 JUL 0750 264	0.	.4	75.1
3 JUL 2240 65	0.	.0	74.1 *	4 JUL 1520 165	0.	.1	74.4 *	5 JUL 0800 265	0.	.4	75.1
3 JUL 2250 66	0.	.0	74.2 *	4 JUL 1530 166	0.	.1	74.4 *	5 JUL 0810 266	0.	.4	75.1
3 JUL 2300 67	0.	.0	74.2 *	4 JUL 1540 167	0.	.1	74.4 *	5 JUL 0820 267	0.	.4	75.1
3 JUL 2310 68	0.	.0	74.2 *	4 JUL 1550 168	0.	.1	74.5 *	5 JUL 0830 268	0.	.4	75.1
3 JUL 2320 69	0.	.0	74.2 *	4 JUL 1600 169	0.	.1	74.5 *	5 JUL 0840 269	0.	.4	75.1
3 JUL 2330 70	0.	.0	74.2 *	4 JUL 1610 170	0.	.1	74.5 *	5 JUL 0850 270	0.	.4	75.1
3 JUL 2340 71	0.	.0	74.2 *	4 JUL 1620 171	0.	.1	74.5 *	5 JUL 0900 271	0.	.4	75.2
3 JUL 2350 72	0.	.0	74.2 *	4 JUL 1630 172	0.	.1	74.5 *	5 JUL 0910 272	0.	.4	75.2
4 JUL 0000 73	0.	.0	74.2 *	4 JUL 1640 173	0.	.1	74.5 *	5 JUL 0920 273	0.	.4	75.2
4 JUL 0010 74	0.	.0	74.2 *	4 JUL 1650 174	0.	.1	74.5 *	5 JUL 0930 274	0.	.4	75.2
4 JUL 0020 75	0.	.0	74.2 *	4 JUL 1700 175	0.	.1	74.5 *	5 JUL 0940 275	0.	.4	75.2
4 JUL 0030 76	0.	.0	74.2 *	4 JUL 1710 176	0.	.1	74.5 *	5 JUL 0950 276	0.	.4	75.2
4 JUL 0040 77	0.	.0	74.2 *	4 JUL 1720 177	0.	.1	74.5 *	5 JUL 1000 277	0.	.4	75.2
4 JUL 0050 78	0.	.0	74.2 *	4 JUL 1730 178	0.	.1	74.5 *	5 JUL 1010 278	0.	.4	75.2
4 JUL 0100 79	0.	.1	74.2 *	4 JUL 1740 179	0.	.1	74.5 *	5 JUL 1020 279	0.	.4	75.2
4 JUL 0110 80	0.	.1	74.2 *	4 JUL 1750 180	0.	.1	74.5 *	5 JUL 1030 280	0.	.4	75.2
4 JUL 0120 81	0.	.1	74.2 *	4 JUL 1800 181	0.	.1	74.5 *	5 JUL 1040 281	0.	.4	75.2
4 JUL 0130 82	0.	.1	74.2 *	4 JUL 1810 182	0.	.1	74.5 *	5 JUL 1050 282	0.	.4	75.2
4 JUL 0140 83	0.	.1	74.2 *	4 JUL 1820 183	0.	.2	74.6 *	5 JUL 1100 283	0.	.4	75.2
4 JUL 0150 84	0.	.1	74.2 *	4 JUL 1830 184	0.	.2	74.6 *	5 JUL 1110 284	0.	.4	75.2
4 JUL 0200 85	0.	.1	74.2 *	4 JUL 1840 185	0.	.2	74.6 *	5 JUL 1120 285	0.	.4	75.2
4 JUL 0210 86	0.	.1	74.2 *	4 JUL 1850 186	0.	.2	74.6 *	5 JUL 1130 286	0.	.4	75.2
4 JUL 0220 87	0.	.1	74.2 *	4 JUL 1900 187	0.	.2	74.6 *	5 JUL 1140 287	0.	.4	75.2
4 JUL 0230 88	0.	.1	74.2 *	4 JUL 1910 188	0.	.2	74.6 *	5 JUL 1150 288	0.	.4	75.2
4 JUL 0240 89	0.	.1	74.2 *	4 JUL 1920 189	0.	.2	74.6 *	5 JUL 1200 289	0.	.4	75.2
4 JUL 0250 90	0.	.1	74.2 *	4 JUL 1930 190	0.	.2	74.6 *	5 JUL 1210 290	0.	.5	75.2
4 JUL 0300 91	0.	.1	74.2 *	4 JUL 1940 191	0.	.2	74.6 *	5 JUL 1220 291	0.	.5	75.2
4 JUL 0310 92	0.	.1	74.2 *	4 JUL 1950 192	0.	.2	74.6 *	5 JUL 1230 292	0.	.5	75.3
4 JUL 0320 93	0.	.1	74.2 *	4 JUL 2000 193	0.	.2	74.6 *	5 JUL 1240 293	0.	.5	75.3
4 JUL 0330 94	0.	.1	74.2 *	4 JUL 2010 194	0.	.2	74.6 *	5 JUL 1250 294	0.	.5	75.3
4 JUL 0340 95	0.	.1	74.2 *	4 JUL 2020 195	0.	.2	74.6 *	5 JUL 1300 295	0.	.5	75.3
4 JUL 0350 96	0.	.1	74.2 *	4 JUL 2030 196	0.	.2	74.6 *	5 JUL 1310 296	0.	.5	75.3
4 JUL 0400 97	0.	.1	74.2 *	4 JUL 2040 197	0.	.2	74.7 *	5 JUL 1320 297	0.	.5	75.3
4 JUL 0410 98	0.	.1	74.2 *	4 JUL 2050 198	0.	.2	74.7 *	5 JUL 1330 298	0.	.5	75.3
4 JUL 0420 99	0.	.1	74.2 *	4 JUL 2100 199	0.	.2	74.7 *	5 JUL 1340 299	0.	.5	75.3
4 JUL 0430 100	0.	.1	74.2 *	4 JUL 2110 200	0.	.2	74.7 *	5 JUL 1350 300	0.	.5	75.3

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
	(CFS)	(HR)	6-HR	24-HR	72-HR	49.83-HR
+	0.	.17	0.	0.	0.	0.
		(CFS)				
		(INCHES)	.000	.000	.000	.000
		(AC-FT)	0.	0.	0.	0.

PEAK STORAGE		TIME	MAXIMUM AVERAGE STORAGE			
	(AC-FT)	(HR)	6-HR	24-HR	72-HR	49.83-HR
+	0.	49.83	0.	0.	0.	0.

PEAK STAGE		TIME	MAXIMUM AVERAGE STAGE			
	(FEET)	(HR)	6-HR	24-HR	72-HR	49.83-HR
+	75.29	49.83	75.20	74.88	74.52	74.52

CUMULATIVE AREA = .01 SQ MI

1

RUNOFF SUMMARY
FLOW IN CUBIC FEET PER SECOND
TIME IN HOURS, AREA IN SQUARE MILES

OF	OPERATION	STATION	PEAK FLOW	AVERAGE FLOW FOR MAXIMUM PERIOD			AREA	BASIN STAGE	MAXIMUM MAX STAGE	TIME
				6-HOUR	24-HOUR	72-HOUR				
+	HYDROGRAPH AT SITE	0.	49.67	0.	0.	0.	.01			
+	HYDROGRAPH AT POND	0.	24.50	0.	0.	0.	.00			
+	2 COMBINED AT COMB	0.	49.50	0.	0.	0.	.01			
+	ROUTED TO RES1	0.	.17	0.	0.	0.	.01			
+								75.29	49.83	

*** NORMAL END OF HEC-1 ***

CASE III

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*****
*                                     *
* FLOOD HYDROGRAPH PACKAGE (HEC-1) *
*                                     *
*   FEBRUARY 1981                     *
*   REVISED 02 AUG 88                *
*                                     *
* RUN DATE 07/17/1998 TIME 10:29:47 *
*                                     *
*****

*****
*                                     *
* U.S. ARMY CORPS OF ENGINEERS
*
* THE HYDROLOGIC ENGINEERING CENTER *
*   609 SECOND STREET
* DAVIS, CALIFORNIA 95616
*   (916) 551-1748
*                                     *
*****

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X  X XXXXXXXX XXXXX      X
X  X X      X  X      XX
X  X X      X      X
XXXXXXX XXXX  X  XXXXX X
X  X X      X      X
X  X X      X  X      X
X  X XXXXXXXX XXXXX      XXX

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THIS PROGRAM REPLACES ALL PREVIOUS VERSIONS OF HEC-1 KNOWN AS HEC1 (JAN 73), HEC1GS, HEC1DB, AND HEC1KW.

THE DEFINITIONS OF VARIABLES -RTIMP- AND -RTIOR- HAVE CHANGED FROM THOSE USED WITH THE 1973-STYLE INPUT STRUCTURE.

THE DEFINITION OF -AMSKK- ON RM-CARD WAS CHANGED WITH REVISIONS DATED 28 SEP 81. THIS IS THE FORTRAN77 VERSION

NEW OPTIONS: DAMBREAK OUTFLOW SUBMERGENCE , SINGLE EVENT DAMAGE CALCULATION, DSS:WRITE STAGE FREQUENCY,

DSS:READ TIME SERIES AT DESIRED CALCULATION INTERVAL LOSS RATE:GREEN AND AMPT INFILTRATION KINEMATIC WAVE: NEW FINITE DIFFERENCE ALGORITHM

1 HEC-1 INPUT PAGE 1

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LINE      ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10

1      ID  KUA - Cane Island Unit 3
2      ID  Site Certification Application
3      ID  HEC-1 Analysis of Unit 3:  25 Year - 72 Hour Precipitation Event
4      ID  Black & Veatch Project No. 59140   Modelled By: Gregory V. Johnson
5      ID  Post-Construction Model
6      ID  Input File: kua-pst.in   Output File: kua-pst.out
7      IT   10 01JUL98   0600   300
8      IO    0    0
9      IN   15
      * *****

10     KK  SITE
11     KM  Runoff From Unit 3 Power Block and Construction Laydown Area
12     BA .00964
13     PB  12.23
14     PC  0.002  0.003  0.005  0.006  0.008  0.009  0.011  0.012  0.014  0.015
15     PC  0.017  0.018  0.020  0.021  0.023  0.024  0.026  0.027  0.029  0.030
16     PC  0.032  0.033  0.035  0.036  0.038  0.040  0.041  0.043  0.044  0.046
17     PC  0.047  0.049  0.050  0.052  0.053  0.055  0.056  0.058  0.059  0.061
18     PC  0.062  0.064  0.065  0.067  0.068  0.070  0.071  0.073  0.075  0.076
19     PC  0.078  0.079  0.081  0.082  0.084  0.085  0.087  0.088  0.090  0.091
20     PC  0.093  0.094  0.096  0.097  0.099  0.100  0.102  0.103  0.105  0.106

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21	PC	0.108	0.110	0.111	0.113	0.114	0.116	0.117	0.119	0.120	0.122
22	PC	0.123	0.125	0.126	0.128	0.129	0.131	0.132	0.134	0.135	0.137
23	PC	0.138	0.140	0.141	0.143	0.144	0.146	0.148	0.150	0.153	0.155
24	PC	0.157	0.159	0.162	0.164	0.166	0.168	0.170	0.173	0.175	0.177
25	PC	0.179	0.182	0.184	0.186	0.188	0.190	0.193	0.195	0.197	0.199
26	PC	0.201	0.204	0.206	0.208	0.210	0.213	0.215	0.217	0.219	0.221
27	PC	0.224	0.226	0.228	0.230	0.233	0.235	0.237	0.239	0.241	0.244
28	PC	0.246	0.248	0.250	0.252	0.255	0.257	0.259	0.261	0.264	0.266
29	PC	0.268	0.270	0.272	0.275	0.277	0.279	0.281	0.284	0.286	0.288
30	PC	0.290	0.292	0.295	0.297	0.299	0.301	0.304	0.306	0.308	0.310
31	PC	0.312	0.315	0.317	0.319	0.321	0.324	0.326	0.328	0.330	0.332
32	PC	0.335	0.337	0.339	0.341	0.343	0.346	0.348	0.350	0.352	0.355
33	PC	0.357	0.359	0.362	0.364	0.367	0.369	0.372	0.374	0.377	0.379
34	PC	0.382	0.385	0.388	0.391	0.394	0.397	0.400	0.404	0.408	0.412
35	PC	0.417	0.421	0.426	0.431	0.437	0.442	0.448	0.454	0.461	0.467
36	PC	0.474	0.481	0.488	0.496	0.504	0.512	0.521	0.530	0.540	0.550
37	PC	0.561	0.572	0.584	0.596	0.612	0.628	0.653	0.678	0.847	1.015
38	PC	1.052	1.088	1.107	1.126	1.140	1.154	1.166	1.177	1.186	1.194
39	PC	1.202	1.209	1.217	1.224	1.232	1.239	1.243	1.248	1.253	1.257
40	PC	1.262	1.266	1.271	1.275	1.280	1.284	1.289	1.293	1.298	1.302
41	PC	1.307	1.311	1.314	1.317	1.320	1.323	1.326	1.329	1.332	1.335
42	PC	1.338	1.341	1.344	1.347	1.350	1.353	1.356	1.359		
43	LS	0	65	0							
44	UD	0.26									

* *****

45 KK POND
 46 KM Unit 3 Stormwater Pond
 47 BA .00152
 48 LS 0 49 100
 49 UD 0.01

* *****

1

HEC-1 INPUT

PAGE 2

LINE ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10

50 KK COMB
 51 KM Combining Two Hydrographs in Reservoir
 52 HC 2
 * *****

53 KK RES1
 54 KM Reservoir Routing Operation
 55 RS 1 ELEV 74.0
 56 SA .01379 0.70644 0.76078 0.99732
 57 SE 74.0 75.0 76.0 79.0
 58 SQ 0 0 0 2.8
 59 SE 74.0 75.0 76.0 79.0

* *****

*DIAGRAM

60 ZZ

1

SCHEMATIC DIAGRAM OF STREAM NETWORK

INPUT

LINE (V) ROUTING (--->) DIVERSION OR PUMP FLOW

NO. (.) CONNECTOR (<---) RETURN OF DIVERTED OR PUMPED FLOW

10 SITE

.
 .
 45 . POND
 .
 .

50 COMB.....
V
V
53 RES1

(***) RUNOFF ALSO COMPUTED AT THIS LOCATION

```
1*****
*
* FLOOD HYDROGRAPH PACKAGE (HEC-1) *
*
* FEBRUARY 1981 *
* REVISED 02 AUG 88 *
*
* RUN DATE 07/17/1998 TIME 10:29:47 *
*
*****
*
* U.S. ARMY CORPS OF ENGINEERS
*
* THE HYDROLOGIC ENGINEERING CENTER *
* 609 SECOND STREET *
* DAVIS, CALIFORNIA 95616 *
* (916) 551-1748 *
*
*****
```

KUA - Cane Island Unit 3
Site Certification Application
HEC-1 Analysis of Unit 3: 25 Year - 72 Hour Precipitation Event
Black & Veatch Project No. 59140 Modelled By: Gregory V. Johnson
Post-Construction Model
Input File: kua-pst.in Output File: kua-pst.out

*** ERROR *** SPECIFIED START AND END DATES RESULT IN TOO MANY TIME PERIODS

8 IO OUTPUT CONTROL VARIABLES
IPRNT 0 PRINT CONTROL
IPLOT 0 PLOT CONTROL
QSCAL 0. HYDROGRAPH PLOT SCALE

IT HYDROGRAPH TIME DATA
NMIN 10 MINUTES IN COMPUTATION INTERVAL
IDATE 1JUL98 STARTING DATE
ITIME 1200 STARTING TIME
NQ 300 NUMBER OF HYDROGRAPH ORDINATES
NDDATE 5JUL98 ENDING DATE
NDTIME 1350 ENDING TIME
ICENT 19 CENTURY MARK

COMPUTATION INTERVAL .17 HOURS
TOTAL TIME BASE 49.83 HOURS

ENGLISH UNITS
DRAINAGE AREA SQUARE MILES
PRECIPITATION DEPTH INCHES
LENGTH, ELEVATION FEET
FLOW CUBIC FEET PER SECOND
STORAGE VOLUME ACRE-FEET
SURFACE AREA ACRES
TEMPERATURE DEGREES FAHRENHEIT

*
*
10 KK * SITE *

Runoff From Unit 3 Power Block and Construction Laydown Area

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9 IN      TIME DATA FOR INPUT TIME SERIES
          JXMIN      15  TIME INTERVAL IN MINUTES
          JXDATE     1JUL98  STARTING DATE
          JXTIME      6000  STARTING TIME

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SUBBASIN RUNOFF DATA

12 BA SUBBASIN CHARACTERISTICS
TAREA .01 SUBBASIN AREA

PRECIPITATION DATA

13 PB STORM 12.23 BASIN TOTAL PRECIPITATION

14 PI INCREMENTAL PRECIPITATION PATTERN

[illegible]

43 LS	SCS LOSS RATE	
	STRTL	1.08 INITIAL ABSTRACTION
	CRVNR	65.00 CURVE NUMBER
	RTIMP	.00 PERCENT IMPERVIOUS AREA

44 UD SCS DIMENSIONLESS UNITGRAPH
 TLAG .26 LAG

WARNING *** TIME INTERVAL IS GREATER THAN .29*LAG

UNIT HYDROGRAPH
10 END-OF-PERIOD ORDINATES

6. 14. 10. 4. 2. 1. 0. 0. 0. 0.

HYDROGRAPH AT STATION SITE

* DA MON HRMN ORD RAIN LOSS EXCESS COMP Q							* DA MON HRMN ORD RAIN LOSS EXCESS						
COMP Q													
*													
3 JUL 1200	1	.00	.00	.00	0.	*	4 JUL 1300	151	.04	.01	.03	1.	
3 JUL 1210	2	.02	.02	.00	0.	*	4 JUL 1310	152	.04	.01	.03	1.	
3 JUL 1220	3	.03	.03	.00	0.	*	4 JUL 1320	153	.05	.02	.04	1.	
3 JUL 1230	4	.04	.04	.00	0.	*	4 JUL 1330	154	.06	.02	.04	1.	
3 JUL 1240	5	.02	.02	.00	0.	*	4 JUL 1340	155	.04	.01	.03	1.	
3 JUL 1250	6	.03	.03	.00	0.	*	4 JUL 1350	156	.04	.01	.03	1.	
3 JUL 1300	7	.04	.04	.00	0.	*	4 JUL 1400	157	.04	.01	.03	1.	
3 JUL 1310	8	.02	.02	.00	0.	*	4 JUL 1410	158	.04	.01	.03	1.	
3 JUL 1320	9	.03	.03	.00	0.	*	4 JUL 1420	159	.04	.01	.03	1.	
3 JUL 1330	10	.04	.04	.00	0.	*	4 JUL 1430	160	.04	.01	.03	1.	
3 JUL 1340	11	.02	.02	.00	0.	*	4 JUL 1440	161	.06	.02	.05	1.	
3 JUL 1350	12	.03	.03	.00	0.	*	4 JUL 1450	162	.05	.02	.04	1.	
3 JUL 1400	13	.04	.04	.00	0.	*	4 JUL 1500	163	.04	.01	.03	1.	
3 JUL 1410	14	.02	.02	.00	0.	*	4 JUL 1510	164	.04	.01	.03	1.	
3 JUL 1420	15	.03	.03	.00	0.	*	4 JUL 1520	165	.04	.01	.03	1.	
3 JUL 1430	16	.04	.04	.00	0.	*	4 JUL 1530	166	.04	.01	.03	1.	
3 JUL 1440	17	.02	.02	.00	0.	*	4 JUL 1540	167	.06	.02	.05	1.	
3 JUL 1450	18	.03	.03	.00	0.	*	4 JUL 1550	168	.05	.02	.04	1.	
3 JUL 1500	19	.04	.04	.00	0.	*	4 JUL 1600	169	.04	.01	.03	1.	
3 JUL 1510	20	.02	.02	.00	0.	*	4 JUL 1610	170	.04	.01	.03	1.	
3 JUL 1520	21	.03	.03	.00	0.	*	4 JUL 1620	171	.04	.01	.03	1.	
3 JUL 1530	22	.04	.04	.00	0.	*	4 JUL 1630	172	.04	.01	.03	1.	
3 JUL 1540	23	.02	.02	.00	0.	*	4 JUL 1640	173	.04	.01	.03	1.	
3 JUL 1550	24	.03	.03	.00	0.	*	4 JUL 1650	174	.05	.01	.04	1.	
3 JUL 1600	25	.04	.04	.00	0.	*	4 JUL 1700	175	.06	.02	.05	1.	
3 JUL 1610	26	.02	.02	.00	0.	*	4 JUL 1710	176	.04	.01	.03	1.	
3 JUL 1620	27	.03	.03	.00	0.	*	4 JUL 1720	177	.04	.01	.03	1.	
3 JUL 1630	28	.04	.04	.00	0.	*	4 JUL 1730	178	.04	.01	.03	1.	
3 JUL 1640	29	.02	.02	.00	0.	*	4 JUL 1740	179	.04	.01	.03	1.	
3 JUL 1650	30	.03	.03	.00	0.	*	4 JUL 1750	180	.04	.01	.03	1.	
3 JUL 1700	31	.04	.04	.00	0.	*	4 JUL 1800	181	.04	.01	.03	1.	
3 JUL 1710	32	.02	.02	.00	0.	*	4 JUL 1810	182	.06	.02	.05	1.	
3 JUL 1720	33	.03	.03	.00	0.	*	4 JUL 1820	183	.05	.01	.04	1.	
3 JUL 1730	34	.04	.04	.00	0.	*	4 JUL 1830	184	.04	.01	.03	1.	
3 JUL 1740	35	.02	.02	.00	0.	*	4 JUL 1840	185	.04	.01	.03	1.	
3 JUL 1750	36	.03	.03	.00	0.	*	4 JUL 1850	186	.04	.01	.03	1.	
3 JUL 1800	37	.04	.04	.00	0.	*	4 JUL 1900	187	.04	.01	.03	1.	
3 JUL 1810	38	.04	.04	.00	0.	*	4 JUL 1910	188	.06	.02	.05	1.	
3 JUL 1820	39	.03	.03	.00	0.	*	4 JUL 1920	189	.05	.01	.04	2.	
3 JUL 1830	40	.02	.02	.00	0.	*	4 JUL 1930	190	.04	.01	.03	2.	
3 JUL 1840	41	.04	.04	.00	0.	*	4 JUL 1940	191	.04	.01	.03	1.	
3 JUL 1850	42	.03	.03	.00	0.	*	4 JUL 1950	192	.04	.01	.03	1.	
3 JUL 1900	43	.02	.02	.00	0.	*	4 JUL 2000	193	.04	.01	.03	1.	
3 JUL 1910	44	.04	.04	.00	0.	*	4 JUL 2010	194	.04	.01	.03	1.	
3 JUL 1920	45	.03	.03	.00	0.	*	4 JUL 2020	195	.05	.01	.04	1.	
3 JUL 1930	46	.02	.02	.00	0.	*	4 JUL 2030	196	.06	.01	.05	1.	
3 JUL 1940	47	.04	.04	.01	0.	*	4 JUL 2040	197	.04	.01	.03	2.	
3 JUL 1950	48	.03	.03	.00	0.	*	4 JUL 2050	198	.04	.01	.03	1.	
3 JUL 2000	49	.02	.02	.00	0.	*	4 JUL 2100	199	.04	.01	.03	1.	
3 JUL 2010	50	.04	.04	.01	0.	*	4 JUL 2110	200	.04	.01	.03	1.	
3 JUL 2020	51	.03	.03	.01	0.	*	4 JUL 2120	201	.05	.01	.04	1.	

3 JUL 2030	52	.02	.02	.00	0.	*	4 JUL 2130	202	.06	.01	.05	1.
3 JUL 2040	53	.04	.03	.01	0.	*	4 JUL 2140	203	.04	.01	.03	2.
3 JUL 2050	54	.03	.03	.01	0.	*	4 JUL 2150	204	.04	.01	.03	1.
3 JUL 2100	55	.02	.02	.00	0.	*	4 JUL 2200	205	.04	.01	.03	1.
3 JUL 2110	56	.04	.03	.01	0.	*	4 JUL 2210	206	.04	.01	.03	1.
3 JUL 2120	57	.03	.03	.01	0.	*	4 JUL 2220	207	.04	.01	.03	1.
3 JUL 2130	58	.02	.02	.00	0.	*	4 JUL 2230	208	.04	.01	.03	1.
3 JUL 2140	59	.04	.03	.01	0.	*	4 JUL 2240	209	.06	.01	.05	1.
3 JUL 2150	60	.03	.02	.01	0.	*	4 JUL 2250	210	.05	.01	.04	2.
3 JUL 2200	61	.02	.02	.01	0.	*	4 JUL 2300	211	.04	.01	.03	2.
3 JUL 2210	62	.04	.03	.01	0.	*	4 JUL 2310	212	.04	.01	.03	1.
3 JUL 2220	63	.03	.02	.01	0.	*	4 JUL 2320	213	.04	.01	.03	1.
3 JUL 2230	64	.02	.02	.01	0.	*	4 JUL 2330	214	.04	.01	.03	1.
3 JUL 2240	65	.04	.03	.01	0.	*	4 JUL 2340	215	.04	.01	.03	1.
3 JUL 2250	66	.03	.02	.01	0.	*	4 JUL 2350	216	.05	.01	.04	1.
3 JUL 2300	67	.02	.02	.01	0.	*	5 JUL 0000	217	.06	.01	.05	2.
3 JUL 2310	68	.04	.03	.01	0.	*	5 JUL 0010	218	.04	.01	.04	2.
3 JUL 2320	69	.03	.02	.01	0.	*	5 JUL 0020	219	.04	.01	.04	2.
3 JUL 2330	70	.02	.01	.01	0.	*	5 JUL 0030	220	.04	.01	.04	1.
3 JUL 2340	71	.04	.03	.01	0.	*	5 JUL 0040	221	.04	.01	.04	1.
3 JUL 2350	72	.04	.03	.01	0.	*	5 JUL 0050	222	.05	.01	.04	1.
4 JUL 0000	73	.04	.03	.01	0.	*	5 JUL 0100	223	.06	.01	.05	2.
4 JUL 0010	74	.02	.01	.01	0.	*	5 JUL 0110	224	.04	.01	.04	2.
4 JUL 0020	75	.03	.02	.01	0.	*	5 JUL 0120	225	.04	.01	.04	2.
4 JUL 0030	76	.04	.03	.02	0.	*	5 JUL 0130	226	.04	.01	.04	1.
4 JUL 0040	77	.02	.01	.01	0.	*	5 JUL 0140	227	.04	.01	.04	1.
4 JUL 0050	78	.03	.02	.01	0.	*	5 JUL 0150	228	.04	.01	.04	1.
4 JUL 0100	79	.04	.03	.02	0.	*	5 JUL 0200	229	.04	.01	.04	1.
4 JUL 0110	80	.02	.01	.01	0.	*	5 JUL 0210	230	.06	.01	.05	1.
4 JUL 0120	81	.03	.02	.01	0.	*	5 JUL 0220	231	.05	.01	.04	2.
4 JUL 0130	82	.04	.03	.02	0.	*	5 JUL 0230	232	.04	.01	.04	2.
4 JUL 0140	83	.02	.01	.01	0.	*	5 JUL 0240	233	.04	.01	.04	2.
4 JUL 0150	84	.03	.02	.01	0.	*	5 JUL 0250	234	.04	.01	.04	1.
4 JUL 0200	85	.04	.03	.02	0.	*	5 JUL 0300	235	.04	.01	.04	1.
4 JUL 0210	86	.02	.01	.01	1.	*	5 JUL 0310	236	.06	.01	.05	1.
4 JUL 0220	87	.03	.02	.01	0.	*	5 JUL 0320	237	.05	.01	.05	2.
4 JUL 0230	88	.04	.02	.02	1.	*	5 JUL 0330	238	.04	.01	.04	2.
4 JUL 0240	89	.02	.01	.01	1.	*	5 JUL 0340	239	.04	.01	.04	2.
4 JUL 0250	90	.03	.02	.01	0.	*	5 JUL 0350	240	.04	.01	.04	1.
4 JUL 0300	91	.04	.02	.02	1.	*	5 JUL 0400	241	.04	.01	.04	1.
4 JUL 0310	92	.02	.01	.01	1.	*	5 JUL 0410	242	.04	.01	.04	1.
4 JUL 0320	93	.03	.02	.01	1.	*	5 JUL 0420	243	.05	.01	.05	1.
4 JUL 0330	94	.04	.02	.02	1.	*	5 JUL 0430	244	.06	.01	.05	2.
4 JUL 0340	95	.02	.01	.01	1.	*	5 JUL 0440	245	.04	.01	.04	2.
4 JUL 0350	96	.03	.02	.02	1.	*	5 JUL 0450	246	.04	.01	.04	2.
4 JUL 0400	97	.04	.02	.02	1.	*	5 JUL 0500	247	.04	.01	.04	1.
4 JUL 0410	98	.02	.01	.01	1.	*	5 JUL 0510	248	.04	.01	.04	1.
4 JUL 0420	99	.03	.02	.02	1.	*	5 JUL 0520	249	.05	.01	.05	1.
4 JUL 0430	100	.04	.02	.02	1.	*	5 JUL 0530	250	.06	.01	.06	2.
4 JUL 0440	101	.02	.01	.01	1.	*	5 JUL 0540	251	.04	.01	.04	2.
4 JUL 0450	102	.03	.02	.02	1.	*	5 JUL 0550	252	.04	.01	.04	2.
4 JUL 0500	103	.04	.02	.02	1.	*	5 JUL 0600	253	.04	.01	.04	1.
4 JUL 0510	104	.02	.01	.01	1.	*	5 JUL 0610	254	.04	.01	.04	1.
4 JUL 0520	105	.03	.02	.02	1.	*	5 JUL 0620	255	.04	.01	.04	1.
4 JUL 0530	106	.04	.02	.02	1.	*	5 JUL 0630	256	.04	.01	.04	1.
4 JUL 0540	107	.04	.02	.02	1.	*	5 JUL 0640	257	.06	.01	.06	1.
4 JUL 0550	108	.03	.02	.02	1.	*	5 JUL 0650	258	.05	.01	.05	2.
4 JUL 0600	109	.02	.01	.01	1.	*	5 JUL 0700	259	.04	.01	.04	2.
4 JUL 0610	110	.04	.02	.02	1.	*	5 JUL 0710	260	.04	.01	.04	2.
4 JUL 0620	111	.03	.02	.02	1.	*	5 JUL 0720	261	.04	.01	.04	1.
4 JUL 0630	112	.02	.01	.01	1.	*	5 JUL 0730	262	.04	.01	.04	1.
4 JUL 0640	113	.04	.02	.02	1.	*	5 JUL 0740	263	.06	.01	.06	2.
4 JUL 0650	114	.03	.01	.02	1.	*	5 JUL 0750	264	.05	.01	.05	2.
4 JUL 0700	115	.02	.01	.01	1.	*	5 JUL 0800	265	.04	.01	.04	2.
4 JUL 0710	116	.04	.02	.02	1.	*	5 JUL 0810	266	.04	.01	.04	2.

4 JUL 0720	117	.03	.01	.02	1.	*	5 JUL 0820	267	.04	.01	.04	1.
4 JUL 0730	118	.02	.01	.01	1.	*	5 JUL 0830	268	.04	.01	.04	1.
4 JUL 0740	119	.04	.02	.02	1.	*	5 JUL 0840	269	.04	.01	.04	1.
4 JUL 0750	120	.03	.01	.02	1.	*	5 JUL 0850	270	.05	.01	.05	1.
4 JUL 0800	121	.02	.01	.01	1.	*	5 JUL 0900	271	.06	.01	.06	2.
4 JUL 0810	122	.04	.02	.02	1.	*	5 JUL 0910	272	.04	.01	.04	2.
4 JUL 0820	123	.03	.01	.02	1.	*	5 JUL 0920	273	.04	.01	.04	2.
4 JUL 0830	124	.02	.01	.01	1.	*	5 JUL 0930	274	.04	.01	.04	2.
4 JUL 0840	125	.04	.02	.03	1.	*	5 JUL 0940	275	.04	.01	.04	1.
4 JUL 0850	126	.03	.01	.02	1.	*	5 JUL 0950	276	.04	.01	.04	1.
4 JUL 0900	127	.02	.01	.01	1.	*	5 JUL 1000	277	.04	.01	.04	1.
4 JUL 0910	128	.04	.02	.03	1.	*	5 JUL 1010	278	.06	.01	.06	2.
4 JUL 0920	129	.03	.01	.02	1.	*	5 JUL 1020	279	.05	.01	.05	2.
4 JUL 0930	130	.02	.01	.01	1.	*	5 JUL 1030	280	.04	.01	.04	2.
4 JUL 0940	131	.04	.02	.03	1.	*	5 JUL 1040	281	.04	.01	.04	2.
4 JUL 0950	132	.03	.01	.02	1.	*	5 JUL 1050	282	.04	.01	.04	1.
4 JUL 1000	133	.02	.01	.01	1.	*	5 JUL 1100	283	.04	.01	.04	1.
4 JUL 1010	134	.04	.02	.03	1.	*	5 JUL 1110	284	.06	.01	.06	2.
4 JUL 1020	135	.03	.01	.02	1.	*	5 JUL 1120	285	.05	.01	.05	2.
4 JUL 1030	136	.02	.01	.01	1.	*	5 JUL 1130	286	.04	.01	.04	2.
4 JUL 1040	137	.04	.02	.03	1.	*	5 JUL 1140	287	.04	.01	.04	2.
4 JUL 1050	138	.03	.01	.02	1.	*	5 JUL 1150	288	.05	.01	.05	2.
4 JUL 1100	139	.02	.01	.01	1.	*	5 JUL 1200	289	.06	.01	.06	2.
4 JUL 1110	140	.04	.02	.03	1.	*	5 JUL 1210	290	.04	.00	.04	2.
4 JUL 1120	141	.03	.01	.02	1.	*	5 JUL 1220	291	.05	.01	.05	2.
4 JUL 1130	142	.02	.01	.01	1.	*	5 JUL 1230	292	.06	.01	.06	2.
4 JUL 1140	143	.04	.02	.03	1.	*	5 JUL 1240	293	.04	.00	.04	2.
4 JUL 1150	144	.04	.02	.03	1.	*	5 JUL 1250	294	.05	.01	.05	2.
4 JUL 1200	145	.04	.02	.03	1.	*	5 JUL 1300	295	.06	.01	.06	2.
4 JUL 1210	146	.04	.02	.03	1.	*	5 JUL 1310	296	.04	.00	.04	2.
4 JUL 1220	147	.05	.02	.04	1.	*	5 JUL 1320	297	.05	.01	.05	2.
4 JUL 1230	148	.06	.02	.04	1.	*	5 JUL 1330	298	.06	.01	.06	2.
4 JUL 1240	149	.04	.01	.03	1.	*	5 JUL 1340	299	.04	.00	.04	2.
4 JUL 1250	150	.04	.01	.03	1.	*	5 JUL 1350	300	.05	.01	.05	2.

TOTAL RAINFALL = 12.23, TOTAL LOSS = 4.71, TOTAL EXCESS = 7.52

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
+	2.	49.67	2.	1.	1.	1.
	(INCHES)		1.578	5.659	7.420	7.420
	(AC-FT)		1.	3.	4.	4.

CUMULATIVE AREA = .01 SQ MI

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45 KK * POND *
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Unit 3 Stormwater Pond

DA MON HRMN ORD RAIN LOSS EXCESS COMP Q							DA MON HRMN ORD RAIN LOSS EXCESS						
COMP Q							COMP Q						
3 JUL 1200	1	.00	.00	.00	0.	*	4 JUL 1300	151	.04	.00	.04	0.	
3 JUL 1210	2	.02	.00	.02	0.	*	4 JUL 1310	152	.04	.00	.04	0.	
3 JUL 1220	3	.03	.00	.03	0.	*	4 JUL 1320	153	.05	.00	.05	0.	
3 JUL 1230	4	.04	.00	.04	0.	*	4 JUL 1330	154	.06	.00	.06	0.	
3 JUL 1240	5	.02	.00	.02	0.	*	4 JUL 1340	155	.04	.00	.04	0.	
3 JUL 1250	6	.03	.00	.03	0.	*	4 JUL 1350	156	.04	.00	.04	0.	
3 JUL 1300	7	.04	.00	.04	0.	*	4 JUL 1400	157	.04	.00	.04	0.	
3 JUL 1310	8	.02	.00	.02	0.	*	4 JUL 1410	158	.04	.00	.04	0.	
3 JUL 1320	9	.03	.00	.03	0.	*	4 JUL 1420	159	.04	.00	.04	0.	
3 JUL 1330	10	.04	.00	.04	0.	*	4 JUL 1430	160	.04	.00	.04	0.	
3 JUL 1340	11	.02	.00	.02	0.	*	4 JUL 1440	161	.06	.00	.06	0.	
3 JUL 1350	12	.03	.00	.03	0.	*	4 JUL 1450	162	.05	.00	.05	0.	
3 JUL 1400	13	.04	.00	.04	0.	*	4 JUL 1500	163	.04	.00	.04	0.	
3 JUL 1410	14	.02	.00	.02	0.	*	4 JUL 1510	164	.04	.00	.04	0.	
3 JUL 1420	15	.03	.00	.03	0.	*	4 JUL 1520	165	.04	.00	.04	0.	
3 JUL 1430	16	.04	.00	.04	0.	*	4 JUL 1530	166	.04	.00	.04	0.	
3 JUL 1440	17	.02	.00	.02	0.	*	4 JUL 1540	167	.06	.00	.06	0.	
3 JUL 1450	18	.03	.00	.03	0.	*	4 JUL 1550	168	.05	.00	.05	0.	
3 JUL 1500	19	.04	.00	.04	0.	*	4 JUL 1600	169	.04	.00	.04	0.	
3 JUL 1510	20	.02	.00	.02	0.	*	4 JUL 1610	170	.04	.00	.04	0.	
3 JUL 1520	21	.03	.00	.03	0.	*	4 JUL 1620	171	.04	.00	.04	0.	
3 JUL 1530	22	.04	.00	.04	0.	*	4 JUL 1630	172	.04	.00	.04	0.	
3 JUL 1540	23	.02	.00	.02	0.	*	4 JUL 1640	173	.04	.00	.04	0.	
3 JUL 1550	24	.03	.00	.03	0.	*	4 JUL 1650	174	.05	.00	.05	0.	
3 JUL 1600	25	.04	.00	.04	0.	*	4 JUL 1700	175	.06	.00	.06	0.	
3 JUL 1610	26	.02	.00	.02	0.	*	4 JUL 1710	176	.04	.00	.04	0.	
3 JUL 1620	27	.03	.00	.03	0.	*	4 JUL 1720	177	.04	.00	.04	0.	
3 JUL 1630	28	.04	.00	.04	0.	*	4 JUL 1730	178	.04	.00	.04	0.	
3 JUL 1640	29	.02	.00	.02	0.	*	4 JUL 1740	179	.04	.00	.04	0.	
3 JUL 1650	30	.03	.00	.03	0.	*	4 JUL 1750	180	.04	.00	.04	0.	
3 JUL 1700	31	.04	.00	.04	0.	*	4 JUL 1800	181	.04	.00	.04	0.	
3 JUL 1710	32	.02	.00	.02	0.	*	4 JUL 1810	182	.06	.00	.06	0.	
3 JUL 1720	33	.03	.00	.03	0.	*	4 JUL 1820	183	.05	.00	.05	0.	
3 JUL 1730	34	.04	.00	.04	0.	*	4 JUL 1830	184	.04	.00	.04	0.	
3 JUL 1740	35	.02	.00	.02	0.	*	4 JUL 1840	185	.04	.00	.04	0.	
3 JUL 1750	36	.03	.00	.03	0.	*	4 JUL 1850	186	.04	.00	.04	0.	
3 JUL 1800	37	.04	.00	.04	0.	*	4 JUL 1900	187	.04	.00	.04	0.	
3 JUL 1810	38	.04	.00	.04	0.	*	4 JUL 1910	188	.06	.00	.06	0.	
3 JUL 1820	39	.03	.00	.03	0.	*	4 JUL 1920	189	.05	.00	.05	0.	
3 JUL 1830	40	.02	.00	.02	0.	*	4 JUL 1930	190	.04	.00	.04	0.	
3 JUL 1840	41	.04	.00	.04	0.	*	4 JUL 1940	191	.04	.00	.04	0.	
3 JUL 1850	42	.03	.00	.03	0.	*	4 JUL 1950	192	.04	.00	.04	0.	
3 JUL 1900	43	.02	.00	.02	0.	*	4 JUL 2000	193	.04	.00	.04	0.	
3 JUL 1910	44	.04	.00	.04	0.	*	4 JUL 2010	194	.04	.00	.04	0.	
3 JUL 1920	45	.03	.00	.03	0.	*	4 JUL 2020	195	.05	.00	.05	0.	
3 JUL 1930	46	.02	.00	.02	0.	*	4 JUL 2030	196	.06	.00	.06	0.	
3 JUL 1940	47	.04	.00	.04	0.	*	4 JUL 2040	197	.04	.00	.04	0.	
3 JUL 1950	48	.03	.00	.03	0.	*	4 JUL 2050	198	.04	.00	.04	0.	
3 JUL 2000	49	.02	.00	.02	0.	*	4 JUL 2100	199	.04	.00	.04	0.	
3 JUL 2010	50	.04	.00	.04	0.	*	4 JUL 2110	200	.04	.00	.04	0.	
3 JUL 2020	51	.03	.00	.03	0.	*	4 JUL 2120	201	.05	.00	.05	0.	
3 JUL 2030	52	.02	.00	.02	0.	*	4 JUL 2130	202	.06	.00	.06	0.	
3 JUL 2040	53	.04	.00	.04	0.	*	4 JUL 2140	203	.04	.00	.04	0.	
3 JUL 2050	54	.03	.00	.03	0.	*	4 JUL 2150	204	.04	.00	.04	0.	
3 JUL 2100	55	.02	.00	.02	0.	*	4 JUL 2200	205	.04	.00	.04	0.	
3 JUL 2110	56	.04	.00	.04	0.	*	4 JUL 2210	206	.04	.00	.04	0.	
3 JUL 2120	57	.03	.00	.03	0.	*	4 JUL 2220	207	.04	.00	.04	0.	
3 JUL 2130	58	.02	.00	.02	0.	*	4 JUL 2230	208	.04	.00	.04	0.	
3 JUL 2140	59	.04	.00	.04	0.	*	4 JUL 2240	209	.06	.00	.06	0.	
3 JUL 2150	60	.03	.00	.03	0.	*	4 JUL 2250	210	.05	.00	.05	0.	

3 JUL 2200	61	.02	.00	.02	0.	*	4 JUL 2300	211	.04	.00	.04	0.
3 JUL 2210	62	.04	.00	.04	0.	*	4 JUL 2310	212	.04	.00	.04	0.
3 JUL 2220	63	.03	.00	.03	0.	*	4 JUL 2320	213	.04	.00	.04	0.
3 JUL 2230	64	.02	.00	.02	0.	*	4 JUL 2330	214	.04	.00	.04	0.
3 JUL 2240	65	.04	.00	.04	0.	*	4 JUL 2340	215	.04	.00	.04	0.
3 JUL 2250	66	.03	.00	.03	0.	*	4 JUL 2350	216	.05	.00	.05	0.
3 JUL 2300	67	.02	.00	.02	0.	*	5 JUL 0000	217	.06	.00	.06	0.
3 JUL 2310	68	.04	.00	.04	0.	*	5 JUL 0010	218	.04	.00	.04	0.
3 JUL 2320	69	.03	.00	.03	0.	*	5 JUL 0020	219	.04	.00	.04	0.
3 JUL 2330	70	.02	.00	.02	0.	*	5 JUL 0030	220	.04	.00	.04	0.
3 JUL 2340	71	.04	.00	.04	0.	*	5 JUL 0040	221	.04	.00	.04	0.
3 JUL 2350	72	.04	.00	.04	0.	*	5 JUL 0050	222	.05	.00	.05	0.
4 JUL 0000	73	.04	.00	.04	0.	*	5 JUL 0100	223	.06	.00	.06	0.
4 JUL 0010	74	.02	.00	.02	0.	*	5 JUL 0110	224	.04	.00	.04	0.
4 JUL 0020	75	.03	.00	.03	0.	*	5 JUL 0120	225	.04	.00	.04	0.
4 JUL 0030	76	.04	.00	.04	0.	*	5 JUL 0130	226	.04	.00	.04	0.
4 JUL 0040	77	.02	.00	.02	0.	*	5 JUL 0140	227	.04	.00	.04	0.
4 JUL 0050	78	.03	.00	.03	0.	*	5 JUL 0150	228	.04	.00	.04	0.
4 JUL 0100	79	.04	.00	.04	0.	*	5 JUL 0200	229	.04	.00	.04	0.
4 JUL 0110	80	.02	.00	.02	0.	*	5 JUL 0210	230	.06	.00	.06	0.
4 JUL 0120	81	.03	.00	.03	0.	*	5 JUL 0220	231	.05	.00	.05	0.
4 JUL 0130	82	.04	.00	.04	0.	*	5 JUL 0230	232	.04	.00	.04	0.
4 JUL 0140	83	.02	.00	.02	0.	*	5 JUL 0240	233	.04	.00	.04	0.
4 JUL 0150	84	.03	.00	.03	0.	*	5 JUL 0250	234	.04	.00	.04	0.
4 JUL 0200	85	.04	.00	.04	0.	*	5 JUL 0300	235	.04	.00	.04	0.
4 JUL 0210	86	.02	.00	.02	0.	*	5 JUL 0310	236	.06	.00	.06	0.
4 JUL 0220	87	.03	.00	.03	0.	*	5 JUL 0320	237	.05	.00	.05	0.
4 JUL 0230	88	.04	.00	.04	0.	*	5 JUL 0330	238	.04	.00	.04	0.
4 JUL 0240	89	.02	.00	.02	0.	*	5 JUL 0340	239	.04	.00	.04	0.
4 JUL 0250	90	.03	.00	.03	0.	*	5 JUL 0350	240	.04	.00	.04	0.
4 JUL 0300	91	.04	.00	.04	0.	*	5 JUL 0400	241	.04	.00	.04	0.
4 JUL 0310	92	.02	.00	.02	0.	*	5 JUL 0410	242	.04	.00	.04	0.
4 JUL 0320	93	.03	.00	.03	0.	*	5 JUL 0420	243	.05	.00	.05	0.
4 JUL 0330	94	.04	.00	.04	0.	*	5 JUL 0430	244	.06	.00	.06	0.
4 JUL 0340	95	.02	.00	.02	0.	*	5 JUL 0440	245	.04	.00	.04	0.
4 JUL 0350	96	.03	.00	.03	0.	*	5 JUL 0450	246	.04	.00	.04	0.
4 JUL 0400	97	.04	.00	.04	0.	*	5 JUL 0500	247	.04	.00	.04	0.
4 JUL 0410	98	.02	.00	.02	0.	*	5 JUL 0510	248	.04	.00	.04	0.
4 JUL 0420	99	.03	.00	.03	0.	*	5 JUL 0520	249	.05	.00	.05	0.
4 JUL 0430	100	.04	.00	.04	0.	*	5 JUL 0530	250	.06	.00	.06	0.
4 JUL 0440	101	.02	.00	.02	0.	*	5 JUL 0540	251	.04	.00	.04	0.
4 JUL 0450	102	.03	.00	.03	0.	*	5 JUL 0550	252	.04	.00	.04	0.
4 JUL 0500	103	.04	.00	.04	0.	*	5 JUL 0600	253	.04	.00	.04	0.
4 JUL 0510	104	.02	.00	.02	0.	*	5 JUL 0610	254	.04	.00	.04	0.
4 JUL 0520	105	.03	.00	.03	0.	*	5 JUL 0620	255	.04	.00	.04	0.
4 JUL 0530	106	.04	.00	.04	0.	*	5 JUL 0630	256	.04	.00	.04	0.
4 JUL 0540	107	.04	.00	.04	0.	*	5 JUL 0640	257	.06	.00	.06	0.
4 JUL 0550	108	.03	.00	.03	0.	*	5 JUL 0650	258	.05	.00	.05	0.
4 JUL 0600	109	.02	.00	.02	0.	*	5 JUL 0700	259	.04	.00	.04	0.
4 JUL 0610	110	.04	.00	.04	0.	*	5 JUL 0710	260	.04	.00	.04	0.
4 JUL 0620	111	.03	.00	.03	0.	*	5 JUL 0720	261	.04	.00	.04	0.
4 JUL 0630	112	.02	.00	.02	0.	*	5 JUL 0730	262	.04	.00	.04	0.
4 JUL 0640	113	.04	.00	.04	0.	*	5 JUL 0740	263	.06	.00	.06	0.
4 JUL 0650	114	.03	.00	.03	0.	*	5 JUL 0750	264	.05	.00	.05	0.
4 JUL 0700	115	.02	.00	.02	0.	*	5 JUL 0800	265	.04	.00	.04	0.
4 JUL 0710	116	.04	.00	.04	0.	*	5 JUL 0810	266	.04	.00	.04	0.
4 JUL 0720	117	.03	.00	.03	0.	*	5 JUL 0820	267	.04	.00	.04	0.
4 JUL 0730	118	.02	.00	.02	0.	*	5 JUL 0830	268	.04	.00	.04	0.
4 JUL 0740	119	.04	.00	.04	0.	*	5 JUL 0840	269	.04	.00	.04	0.
4 JUL 0750	120	.03	.00	.03	0.	*	5 JUL 0850	270	.05	.00	.05	0.
4 JUL 0800	121	.02	.00	.02	0.	*	5 JUL 0900	271	.06	.00	.06	0.
4 JUL 0810	122	.04	.00	.04	0.	*	5 JUL 0910	272	.04	.00	.04	0.
4 JUL 0820	123	.03	.00	.03	0.	*	5 JUL 0920	273	.04	.00	.04	0.
4 JUL 0830	124	.02	.00	.02	0.	*	5 JUL 0930	274	.04	.00	.04	0.
4 JUL 0840	125	.04	.00	.04	0.	*	5 JUL 0940	275	.04	.00	.04	0.

4 JUL 0850	126	.03	.00	.03	0.	*	5 JUL 0950	276	.04	.00	.04	0.
4 JUL 0900	127	.02	.00	.02	0.	*	5 JUL 1000	277	.04	.00	.04	0.
4 JUL 0910	128	.04	.00	.04	0.	*	5 JUL 1010	278	.06	.00	.06	0.
4 JUL 0920	129	.03	.00	.03	0.	*	5 JUL 1020	279	.05	.00	.05	0.
4 JUL 0930	130	.02	.00	.02	0.	*	5 JUL 1030	280	.04	.00	.04	0.
4 JUL 0940	131	.04	.00	.04	0.	*	5 JUL 1040	281	.04	.00	.04	0.
4 JUL 0950	132	.03	.00	.03	0.	*	5 JUL 1050	282	.04	.00	.04	0.
4 JUL 1000	133	.02	.00	.02	0.	*	5 JUL 1100	283	.04	.00	.04	0.
4 JUL 1010	134	.04	.00	.04	0.	*	5 JUL 1110	284	.06	.00	.06	0.
4 JUL 1020	135	.03	.00	.03	0.	*	5 JUL 1120	285	.05	.00	.05	0.
4 JUL 1030	136	.02	.00	.02	0.	*	5 JUL 1130	286	.04	.00	.04	0.
4 JUL 1040	137	.04	.00	.04	0.	*	5 JUL 1140	287	.04	.00	.04	0.
4 JUL 1050	138	.03	.00	.03	0.	*	5 JUL 1150	288	.05	.00	.05	0.
4 JUL 1100	139	.02	.00	.02	0.	*	5 JUL 1200	289	.06	.00	.06	0.
4 JUL 1110	140	.04	.00	.04	0.	*	5 JUL 1210	290	.04	.00	.04	0.
4 JUL 1120	141	.03	.00	.03	0.	*	5 JUL 1220	291	.05	.00	.05	0.
4 JUL 1130	142	.02	.00	.02	0.	*	5 JUL 1230	292	.06	.00	.06	0.
4 JUL 1140	143	.04	.00	.04	0.	*	5 JUL 1240	293	.04	.00	.04	0.
4 JUL 1150	144	.04	.00	.04	0.	*	5 JUL 1250	294	.05	.00	.05	0.
4 JUL 1200	145	.04	.00	.04	0.	*	5 JUL 1300	295	.06	.00	.06	0.
4 JUL 1210	146	.04	.00	.04	0.	*	5 JUL 1310	296	.04	.00	.04	0.
4 JUL 1220	147	.05	.00	.05	0.	*	5 JUL 1320	297	.05	.00	.05	0.
4 JUL 1230	148	.06	.00	.06	0.	*	5 JUL 1330	298	.06	.00	.06	0.
4 JUL 1240	149	.04	.00	.04	0.	*	5 JUL 1340	299	.04	.00	.04	0.
4 JUL 1250	150	.04	.00	.04	0.	*	5 JUL 1350	300	.05	.00	.05	0.

TOTAL RAINFALL = 12.23, TOTAL LOSS = .00, TOTAL EXCESS = 12.23

PEAK FLOW + (CFS)	TIME (HR)	MAXIMUM AVERAGE FLOW			
		6-HR	24-HR	72-HR	49.83-HR
0.	48.50	0.	0.	0.	0.
(INCHES)		1.800	6.960	12.187	12.187
(AC-FT)		0.	1.	1.	1.

CUMULATIVE AREA = .00 SQ MI

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50 KK * COMB *
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Combining Two Hydrographs in Reservoir

52 HC HYDROGRAPH COMBINATION
ICOMP 2 NUMBER OF HYDROGRAPHS TO COMBINE


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DA MON HRMN ORD				FLOW	DA MON HRMN ORD				FLOW	DA MON HRMN ORD				FLOW	DA MON HRMN ORD			
HRMN	ORD	FLOW			HRMN	ORD	FLOW			HRMN	ORD	FLOW			HRMN	ORD	FLOW	
3 JUL 1200	1	0.	*		4 JUL 0030	76	1.	*		4 JUL 1300	151	1.	*		5 JUL 0130	226	2.	
3 JUL 1210	2	0.	*		4 JUL 0040	77	1.	*		4 JUL 1310	152	1.	*		5 JUL 0140	227	2.	
3 JUL 1220	3	0.	*		4 JUL 0050	78	1.	*		4 JUL 1320	153	1.	*		5 JUL 0150	228	2.	
3 JUL 1230	4	0.	*		4 JUL 0100	79	1.	*		4 JUL 1330	154	2.	*		5 JUL 0200	229	2.	
3 JUL 1240	5	0.	*		4 JUL 0110	80	1.	*		4 JUL 1340	155	2.	*		5 JUL 0210	230	2.	
3 JUL 1250	6	0.	*		4 JUL 0120	81	1.	*		4 JUL 1350	156	2.	*		5 JUL 0220	231	2.	
3 JUL 1300	7	0.	*		4 JUL 0130	82	1.	*		4 JUL 1400	157	1.	*		5 JUL 0230	232	2.	
3 JUL 1310	8	0.	*		4 JUL 0140	83	1.	*		4 JUL 1410	158	1.	*		5 JUL 0240	233	2.	
3 JUL 1320	9	0.	*		4 JUL 0150	84	1.	*		4 JUL 1420	159	1.	*		5 JUL 0250	234	2.	
3 JUL 1330	10	0.	*		4 JUL 0200	85	1.	*		4 JUL 1430	160	1.	*		5 JUL 0300	235	2.	
3 JUL 1340	11	0.	*		4 JUL 0210	86	1.	*		4 JUL 1440	161	2.	*		5 JUL 0310	236	2.	
3 JUL 1350	12	0.	*		4 JUL 0220	87	1.	*		4 JUL 1450	162	2.	*		5 JUL 0320	237	2.	
3 JUL 1400	13	0.	*		4 JUL 0230	88	1.	*		4 JUL 1500	163	2.	*		5 JUL 0330	238	2.	
3 JUL 1410	14	0.	*		4 JUL 0240	89	1.	*		4 JUL 1510	164	2.	*		5 JUL 0340	239	2.	
3 JUL 1420	15	0.	*		4 JUL 0250	90	1.	*		4 JUL 1520	165	1.	*		5 JUL 0350	240	2.	
3 JUL 1430	16	0.	*		4 JUL 0300	91	1.	*		4 JUL 1530	166	1.	*		5 JUL 0400	241	2.	
3 JUL 1440	17	0.	*		4 JUL 0310	92	1.	*		4 JUL 1540	167	2.	*		5 JUL 0410	242	2.	
3 JUL 1450	18	0.	*		4 JUL 0320	93	1.	*		4 JUL 1550	168	2.	*		5 JUL 0420	243	2.	
3 JUL 1500	19	0.	*		4 JUL 0330	94	1.	*		4 JUL 1600	169	2.	*		5 JUL 0430	244	2.	
3 JUL 1510	20	0.	*		4 JUL 0340	95	1.	*		4 JUL 1610	170	2.	*		5 JUL 0440	245	2.	
3 JUL 1520	21	0.	*		4 JUL 0350	96	1.	*		4 JUL 1620	171	1.	*		5 JUL 0450	246	2.	
3 JUL 1530	22	0.	*		4 JUL 0400	97	1.	*		4 JUL 1630	172	1.	*		5 JUL 0500	247	2.	
3 JUL 1540	23	0.	*		4 JUL 0410	98	1.	*		4 JUL 1640	173	1.	*		5 JUL 0510	248	2.	
3 JUL 1550	24	0.	*		4 JUL 0420	99	1.	*		4 JUL 1650	174	2.	*		5 JUL 0520	249	2.	
3 JUL 1600	25	0.	*		4 JUL 0430	100	1.	*		4 JUL 1700	175	2.	*		5 JUL 0530	250	2.	
3 JUL 1610	26	0.	*		4 JUL 0440	101	1.	*		4 JUL 1710	176	2.	*		5 JUL 0540	251	2.	
3 JUL 1620	27	0.	*		4 JUL 0450	102	1.	*		4 JUL 1720	177	2.	*		5 JUL 0550	252	2.	
3 JUL 1630	28	0.	*		4 JUL 0500	103	1.	*		4 JUL 1730	178	2.	*		5 JUL 0600	253	2.	
3 JUL 1640	29	0.	*		4 JUL 0510	104	1.	*		4 JUL 1740	179	1.	*		5 JUL 0610	254	2.	
3 JUL 1650	30	0.	*		4 JUL 0520	105	1.	*		4 JUL 17								

3 JUL 2110	56	0.	*	4 JUL 0940	131	1.	*	4 JUL 2210	206	2.	*	5 JUL 1040	281	2.
3 JUL 2120	57	0.	*	4 JUL 0950	132	1.	*	4 JUL 2220	207	2.	*	5 JUL 1050	282	2.
3 JUL 2130	58	0.	*	4 JUL 1000	133	1.	*	4 JUL 2230	208	2.	*	5 JUL 1100	283	2.
3 JUL 2140	59	0.	*	4 JUL 1010	134	1.	*	4 JUL 2240	209	2.	*	5 JUL 1110	284	2.
3 JUL 2150	60	0.	*	4 JUL 1020	135	1.	*	4 JUL 2250	210	2.	*	5 JUL 1120	285	2.
3 JUL 2200	61	0.	*	4 JUL 1030	136	1.	*	4 JUL 2300	211	2.	*	5 JUL 1130	286	2.
3 JUL 2210	62	1.	*	4 JUL 1040	137	1.	*	4 JUL 2310	212	2.	*	5 JUL 1140	287	2.
3 JUL 2220	63	1.	*	4 JUL 1050	138	1.	*	4 JUL 2320	213	2.	*	5 JUL 1150	288	2.
3 JUL 2230	64	0.	*	4 JUL 1100	139	1.	*	4 JUL 2330	214	2.	*	5 JUL 1200	289	2.
3 JUL 2240	65	1.	*	4 JUL 1110	140	1.	*	4 JUL 2340	215	2.	*	5 JUL 1210	290	2.
3 JUL 2250	66	1.	*	4 JUL 1120	141	1.	*	4 JUL 2350	216	2.	*	5 JUL 1220	291	2.
3 JUL 2300	67	0.	*	4 JUL 1130	142	1.	*	5 JUL 0000	217	2.	*	5 JUL 1230	292	2.
3 JUL 2310	68	1.	*	4 JUL 1140	143	1.	*	5 JUL 0010	218	2.	*	5 JUL 1240	293	2.
3 JUL 2320	69	1.	*	4 JUL 1150	144	1.	*	5 JUL 0020	219	2.	*	5 JUL 1250	294	2.
3 JUL 2330	70	1.	*	4 JUL 1200	145	1.	*	5 JUL 0030	220	2.	*	5 JUL 1300	295	2.
3 JUL 2340	71	1.	*	4 JUL 1210	146	1.	*	5 JUL 0040	221	2.	*	5 JUL 1310	296	2.
3 JUL 2350	72	1.	*	4 JUL 1220	147	1.	*	5 JUL 0050	222	2.	*	5 JUL 1320	297	2.
4 JUL 0000	73	1.	*	4 JUL 1230	148	2.	*	5 JUL 0100	223	2.	*	5 JUL 1330	298	2.
4 JUL 0010	74	1.	*	4 JUL 1240	149	2.	*	5 JUL 0110	224	2.	*	5 JUL 1340	299	2.
4 JUL 0020	75	1.	*	4 JUL 1250	150	1.	*	5 JUL 0120	225	2.	*	5 JUL 1350	300	2.

* * *

PEAK FLOW + (CFS)	TIME (HR)	MAXIMUM AVERAGE FLOW			
		6-HR	24-HR	72-HR	49.83-HR
+ 2.	49.50	2.	2.	1.	1.
	(INCHES)	1.608	5.836	8.069	8.069
	(AC-FT)	1.	3.	5.	5.

CUMULATIVE AREA = .01 SQ MI

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* *
53 KK * RES1 *
* *

Reservoir Routing Operation

HYDROGRAPH ROUTING DATA

55 RS	STORAGE ROUTING				
	NSTPS	1	NUMBER OF SUBREACHES		
	ITYP	ELEV	TYPE OF INITIAL CONDITION		
	RSVRIC	74.00	INITIAL CONDITION		
	X	.00	WORKING R AND D COEFFICIENT		
56 SA	AREA	.0	.7	.8	1.0
57 SE	ELEVATION	74.00	75.00	76.00	79.00
58 SQ	DISCHARGE	0.	0.	0.	3.
59 SE	ELEVATION	74.00	75.00	76.00	79.00

COMPUTED STORAGE-ELEVATION DATA

STORAGE	.00	.27	1.01	3.64
ELEVATION	74.00	75.00	76.00	79.00

COMPUTED STORAGE-OUTFLOW-ELEVATION DATA

STORAGE	.00	.27	1.01	3.64
OUTFLOW	.00	.00	.00	2.80
ELEVATION	74.00	75.00	76.00	79.00

HYDROGRAPH AT STATION RES1

DA MON HRMN ORD				OUTFLOW				STORAGE				STAGE				* DA MON HRMN ORD				OUTFLOW				STORAGE				STAGE				* DA MON			
HRMN	ORD	OUTFLOW	STORAGE	STAGE	HRMN	ORD	OUTFLOW	STORAGE	STAGE	HRMN	ORD	OUTFLOW	STORAGE	STAGE	HRMN	ORD	OUTFLOW	STORAGE	STAGE	HRMN	ORD	OUTFLOW	STORAGE	STAGE	HRMN	ORD	OUTFLOW	STORAGE	STAGE						

3 JUL 1200	1	0.	.0	74.0	*	4 JUL 0440	101	0.	.6	75.4	*	4 JUL 2120	201	1.	1.9	77.0
3 JUL 1210	2	0.	.0	74.0	*	4 JUL 0450	102	0.	.6	75.4	*	4 JUL 2130	202	1.	1.9	77.0
3 JUL 1220	3	0.	.0	74.0	*	4 JUL 0500	103	0.	.6	75.4	*	4 JUL 2140	203	1.	1.9	77.0
3 JUL 1230	4	0.	.0	74.0	*	4 JUL 0510	104	0.	.6	75.4	*	4 JUL 2150	204	1.	1.9	77.0
3 JUL 1240	5	0.	.0	74.0	*	4 JUL 0520	105	0.	.6	75.5	*	4 JUL 2200	205	1.	1.9	77.0
3 JUL 1250	6	0.	.0	74.0	*	4 JUL 0530	106	0.	.6	75.5	*	4 JUL 2210	206	1.	1.9	77.1
3 JUL 1300	7	0.	.0	74.0	*	4 JUL 0540	107	0.	.6	75.5	*	4 JUL 2220	207	1.	1.9	77.1
3 JUL 1310	8	0.	.0	74.1	*	4 JUL 0550	108	0.	.6	75.5	*	4 JUL 2230	208	1.	1.9	77.1
3 JUL 1320	9	0.	.0	74.1	*	4 JUL 0600	109	0.	.7	75.5	*	4 JUL 2240	209	1.	2.0	77.1
3 JUL 1330	10	0.	.0	74.1	*	4 JUL 0610	110	0.	.7	75.5	*	4 JUL 2250	210	1.	2.0	77.1
3 JUL 1340	11	0.	.0	74.1	*	4 JUL 0620	111	0.	.7	75.6	*	4 JUL 2300	211	1.	2.0	77.1
3 JUL 1350	12	0.	.0	74.1	*	4 JUL 0630	112	0.	.7	75.6	*	4 JUL 2310	212	1.	2.0	77.1
3 JUL 1400	13	0.	.0	74.1	*	4 JUL 0640	113	0.	.7	75.6	*	4 JUL 2320	213	1.	2.0	77.1
3 JUL 1410	14	0.	.0	74.1	*	4 JUL 0650	114	0.	.7	75.6	*	4 JUL 2330	214	1.	2.0	77.1
3 JUL 1420	15	0.	.0	74.1	*	4 JUL 0700	115	0.	.7	75.6	*	4 JUL 2340	215	1.	2.0	77.1
3 JUL 1430	16	0.	.0	74.1	*	4 JUL 0710	116	0.	.7	75.6	*	4 JUL 2350	216	1.	2.0	77.2
3 JUL 1440	17	0.	.0	74.1	*	4 JUL 0720	117	0.	.8	75.7	*	5 JUL 0000	217	1.	2.0	77.2
3 JUL 1450	18	0.	.0	74.2	*	4 JUL 0730	118	0.	.8	75.7	*	5 JUL 0010	218	1.	2.0	77.2
3 JUL 1500	19	0.	.0	74.2	*	4 JUL 0740	119	0.	.8	75.7	*	5 JUL 0020	219	1.	2.1	77.2
3 JUL 1510	20	0.	.0	74.2	*	4 JUL 0750	120	0.	.8	75.7	*	5 JUL 0030	220	1.	2.1	77.2
3 JUL 1520	21	0.	.0	74.2	*	4 JUL 0800	121	0.	.8	75.7	*	5 JUL 0040	221	1.	2.1	77.2
3 JUL 1530	22	0.	.1	74.2	*	4 JUL 0810	122	0.	.8	75.7	*	5 JUL 0050	222	1.	2.1	77.2
3 JUL 1540	23	0.	.1	74.2	*	4 JUL 0820	123	0.	.8	75.8	*	5 JUL 0100	223	1.	2.1	77.2
3 JUL 1550	24	0.	.1	74.2	*	4 JUL 0830	124	0.	.8	75.8	*	5 JUL 0110	224	1.	2.1	77.2
3 JUL 1600	25	0.	.1	74.2	*	4 JUL 0840	125	0.	.8	75.8	*	5 JUL 0120	225	1.	2.1	77.3
3 JUL 1610	26	0.	.1	74.2	*	4 JUL 0850	126	0.	.9	75.8	*	5 JUL 0130	226	1.	2.1	77.3
3 JUL 1620	27	0.	.1	74.2	*	4 JUL 0900	127	0.	.9	75.8	*	5 JUL 0140	227	1.	2.1	77.3
3 JUL 1630	28	0.	.1	74.2	*	4 JUL 0910	128	0.	.9	75.8	*	5 JUL 0150	228	1.	2.1	77.3
3 JUL 1640	29	0.	.1	74.3	*	4 JUL 0920	129	0.	.9	75.9	*	5 JUL 0200	229	1.	2.1	77.3
3 JUL 1650	30	0.	.1	74.3	*	4 JUL 0930	130	0.	.9	75.9	*	5 JUL 0210	230	1.	2.1	77.3
3 JUL 1700	31	0.	.1	74.3	*	4 JUL 0940	131	0.	.9	75.9	*	5 JUL 0220	231	1.	2.1	77.3
3 JUL 1710	32	0.	.1	74.3	*	4 JUL 0950	132	0.	.9	75.9	*	5 JUL 0230	232	1.	2.2	77.3
3 JUL 1720	33	0.	.1	74.3	*	4 JUL 1000	133	0.	.9	75.9	*	5 JUL 0240	233	1.	2.2	77.3
3 JUL 1730	34	0.	.1	74.3	*	4 JUL 1010	134	0.	1.0	75.9	*	5 JUL 0250	234	1.	2.2	77.3
3 JUL 1740	35	0.	.1	74.3	*	4 JUL 1020	135	0.	1.0	76.0	*	5 JUL 0300	235	1.	2.2	77.3
3 JUL 1750	36	0.	.1	74.3	*	4 JUL 1030	136	0.	1.0	76.0	*	5 JUL 0310	236	1.	2.2	77.3
3 JUL 1800	37	0.	.1	74.3	*	4 JUL 1040	137	0.	1.0	76.0	*	5 JUL 0320	237	1.	2.2	77.4
3 JUL 1810	38	0.	.1	74.3	*	4 JUL 1050	138	0.	1.0	76.0	*	5 JUL 0330	238	1.	2.2	77.4
3 JUL 1820	39	0.	.1	74.4	*	4 JUL 1100	139	0.	1.0	76.0	*	5 JUL 0340	239	1.	2.2	77.4

3 JUL 1830 40	0.	.1	74.4 *	4 JUL 1110 140	0.	1.0	76.0 *	5 JUL 0350 240	1.	2.2	77.4
3 JUL 1840 41	0.	.1	74.4 *	4 JUL 1120 141	0.	1.1	76.1 *	5 JUL 0400 241	1.	2.2	77.4
3 JUL 1850 42	0.	.1	74.4 *	4 JUL 1130 142	0.	1.1	76.1 *	5 JUL 0410 242	1.	2.2	77.4
3 JUL 1900 43	0.	.1	74.4 *	4 JUL 1140 143	0.	1.1	76.1 *	5 JUL 0420 243	1.	2.2	77.4
3 JUL 1910 44	0.	.1	74.4 *	4 JUL 1150 144	0.	1.1	76.1 *	5 JUL 0430 244	1.	2.2	77.4
3 JUL 1920 45	0.	.1	74.4 *	4 JUL 1200 145	0.	1.1	76.1 *	5 JUL 0440 245	1.	2.2	77.4
3 JUL 1930 46	0.	.1	74.5 *	4 JUL 1210 146	0.	1.1	76.1 *	5 JUL 0450 246	1.	2.3	77.4
3 JUL 1940 47	0.	.1	74.5 *	4 JUL 1220 147	0.	1.1	76.1 *	5 JUL 0500 247	1.	2.3	77.4
3 JUL 1950 48	0.	.1	74.5 *	4 JUL 1230 148	0.	1.2	76.2 *	5 JUL 0510 248	1.	2.3	77.4
3 JUL 2000 49	0.	.1	74.5 *	4 JUL 1240 149	0.	1.2	76.2 *	5 JUL 0520 249	1.	2.3	77.4
3 JUL 2010 50	0.	.1	74.5 *	4 JUL 1250 150	0.	1.2	76.2 *	5 JUL 0530 250	1.	2.3	77.5
3 JUL 2020 51	0.	.1	74.5 *	4 JUL 1300 151	0.	1.2	76.2 *	5 JUL 0540 251	1.	2.3	77.5
3 JUL 2030 52	0.	.2	74.6 *	4 JUL 1310 152	0.	1.2	76.2 *	5 JUL 0550 252	1.	2.3	77.5
3 JUL 2040 53	0.	.2	74.6 *	4 JUL 1320 153	0.	1.2	76.3 *	5 JUL 0600 253	1.	2.3	77.5
3 JUL 2050 54	0.	.2	74.6 *	4 JUL 1330 154	0.	1.3	76.3 *	5 JUL 0610 254	1.	2.3	77.5
3 JUL 2100 55	0.	.2	74.6 *	4 JUL 1340 155	0.	1.3	76.3 *	5 JUL 0620 255	1.	2.3	77.5
3 JUL 2110 56	0.	.2	74.7 *	4 JUL 1350 156	0.	1.3	76.3 *	5 JUL 0630 256	1.	2.3	77.5
3 JUL 2120 57	0.	.2	74.7 *	4 JUL 1400 157	0.	1.3	76.3 *	5 JUL 0640 257	1.	2.3	77.5
3 JUL 2130 58	0.	.2	74.7 *	4 JUL 1410 158	0.	1.3	76.4 *	5 JUL 0650 258	1.	2.3	77.5
3 JUL 2140 59	0.	.2	74.7 *	4 JUL 1420 159	0.	1.3	76.4 *	5 JUL 0700 259	1.	2.3	77.5
3 JUL 2150 60	0.	.2	74.7 *	4 JUL 1430 160	0.	1.4	76.4 *	5 JUL 0710 260	1.	2.3	77.5
3 JUL 2200 61	0.	.2	74.8 *	4 JUL 1440 161	0.	1.4	76.4 *	5 JUL 0720 261	1.	2.3	77.5
3 JUL 2210 62	0.	.2	74.8 *	4 JUL 1450 162	0.	1.4	76.4 *	5 JUL 0730 262	1.	2.3	77.5
3 JUL 2220 63	0.	.2	74.8 *	4 JUL 1500 163	0.	1.4	76.5 *	5 JUL 0740 263	1.	2.4	77.5
3 JUL 2230 64	0.	.2	74.8 *	4 JUL 1510 164	0.	1.4	76.5 *	5 JUL 0750 264	1.	2.4	77.5
3 JUL 2240 65	0.	.2	74.9 *	4 JUL 1520 165	0.	1.4	76.5 *	5 JUL 0800 265	1.	2.4	77.6
3 JUL 2250 66	0.	.2	74.9 *	4 JUL 1530 166	0.	1.4	76.5 *	5 JUL 0810 266	1.	2.4	77.6
3 JUL 2300 67	0.	.3	74.9 *	4 JUL 1540 167	0.	1.5	76.5 *	5 JUL 0820 267	1.	2.4	77.6
3 JUL 2310 68	0.	.3	74.9 *	4 JUL 1550 168	0.	1.5	76.5 *	5 JUL 0830 268	1.	2.4	77.6
3 JUL 2320 69	0.	.3	75.0 *	4 JUL 1600 169	1.	1.5	76.6 *	5 JUL 0840 269	1.	2.4	77.6
3 JUL 2330 70	0.	.3	75.0 *	4 JUL 1610 170	1.	1.5	76.6 *	5 JUL 0850 270	1.	2.4	77.6
3 JUL 2340 71	0.	.3	75.0 *	4 JUL 1620 171	1.	1.5	76.6 *	5 JUL 0900 271	1.	2.4	77.6
3 JUL 2350 72	0.	.3	75.0 *	4 JUL 1630 172	1.	1.5	76.6 *	5 JUL 0910 272	1.	2.4	77.6
4 JUL 0000 73	0.	.3	75.0 *	4 JUL 1640 173	1.	1.5	76.6 *	5 JUL 0920 273	1.	2.4	77.6
4 JUL 0010 74	0.	.3	75.1 *	4 JUL 1650 174	1.	1.6	76.6 *	5 JUL 0930 274	1.	2.4	77.6
4 JUL 0020 75	0.	.3	75.1 *	4 JUL 1700 175	1.	1.6	76.6 *	5 JUL 0940 275	1.	2.4	77.6
4 JUL 0030 76	0.	.3	75.1 *	4 JUL 1710 176	1.	1.6	76.7 *	5 JUL 0950 276	2.	2.4	77.6
4 JUL 0040 77	0.	.3	75.1 *	4 JUL 1720 177	1.	1.6	76.7 *	5 JUL 1000 277	2.	2.4	77.6
4 JUL 0050 78	0.	.3	75.1 *	4 JUL 1730 178	1.	1.6	76.7 *	5 JUL 1010 278	2.	2.4	77.6
4 JUL 0100 79	0.	.4	75.1 *	4 JUL 1740 179	1.	1.6	76.7 *	5 JUL 1020 279	2.	2.4	77.6
4 JUL 0110 80	0.	.4	75.1 *	4 JUL 1750 180	1.	1.6	76.7 *	5 JUL 1030 280	2.	2.4	77.6
4 JUL 0120 81	0.	.4	75.1 *	4 JUL 1800 181	1.	1.6	76.7 *	5 JUL 1040 281	2.	2.4	77.6
4 JUL 0130 82	0.	.4	75.1 *	4 JUL 1810 182	1.	1.7	76.7 *	5 JUL 1050 282	2.	2.4	77.6
4 JUL 0140 83	0.	.4	75.2 *	4 JUL 1820 183	1.	1.7	76.8 *	5 JUL 1100 283	2.	2.4	77.6
4 JUL 0150 84	0.	.4	75.2 *	4 JUL 1830 184	1.	1.7	76.8 *	5 JUL 1110 284	2.	2.5	77.6
4 JUL 0200 85	0.	.4	75.2 *	4 JUL 1840 185	1.	1.7	76.8 *	5 JUL 1120 285	2.	2.5	77.7
4 JUL 0210 86	0.	.4	75.2 *	4 JUL 1850 186	1.	1.7	76.8 *	5 JUL 1130 286	2.	2.5	77.7
4 JUL 0220 87	0.	.4	75.2 *	4 JUL 1900 187	1.	1.7	76.8 *	5 JUL 1140 287	2.	2.5	77.7
4 JUL 0230 88	0.	.4	75.2 *	4 JUL 1910 188	1.	1.7	76.8 *	5 JUL 1150 288	2.	2.5	77.7
4 JUL 0240 89	0.	.4	75.2 *	4 JUL 1920 189	1.	1.7	76.8 *	5 JUL 1200 289	2.	2.5	77.7
4 JUL 0250 90	0.	.5	75.2 *	4 JUL 1930 190	1.	1.8	76.9 *	5 JUL 1210 290	2.	2.5	77.7
4 JUL 0300 91	0.	.5	75.3 *	4 JUL 1940 191	1.	1.8	76.9 *	5 JUL 1220 291	2.	2.5	77.7
4 JUL 0310 92	0.	.5	75.3 *	4 JUL 1950 192	1.	1.8	76.9 *	5 JUL 1230 292	2.	2.5	77.7
4 JUL 0320 93	0.	.5	75.3 *	4 JUL 2000 193	1.	1.8	76.9 *	5 JUL 1240 293	2.	2.5	77.7
4 JUL 0330 94	0.	.5	75.3 *	4 JUL 2010 194	1.	1.8	76.9 *	5 JUL 1250 294	2.	2.5	77.7
4 JUL 0340 95	0.	.5	75.3 *	4 JUL 2020 195	1.	1.8	76.9 *	5 JUL 1300 295	2.	2.5	77.7
4 JUL 0350 96	0.	.5	75.3 *	4 JUL 2030 196	1.	1.8	76.9 *	5 JUL 1310 296	2.	2.5	77.7
4 JUL 0400 97	0.	.5	75.3 *	4 JUL 2040 197	1.	1.8	77.0 *	5 JUL 1320 297	2.	2.5	77.7
4 JUL 0410 98	0.	.5	75.4 *	4 JUL 2050 198	1.	1.9	77.0 *	5 JUL 1330 298	2.	2.5	77.8
4 JUL 0420 99	0.	.5	75.4 *	4 JUL 2100 199	1.	1.9	77.0 *	5 JUL 1340 299	2.	2.5	77.8
4 JUL 0430 100	0.	.6	75.4 *	4 JUL 2110 200	1.	1.9	77.0 *	5 JUL 1350 300	2.	2.6	77.8

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
+	2.	49.83	2.	1.	1.	1.
	(CFS)					
	(INCHES)		1.280	3.718	3.779	3.779
	(AC-FT)		1.	2.	2.	2.

PEAK STORAGE		TIME	MAXIMUM AVERAGE STORAGE			
			6-HR	24-HR	72-HR	49.83-HR
+	(AC-FT)	(HR)				
+	3.	49.83	2.	2.	1.	1.

PEAK STAGE		TIME	MAXIMUM AVERAGE STAGE			
			6-HR	24-HR	72-HR	49.83-HR
+	(FEET)	(HR)				
+	77.77	49.83	77.65	77.20	76.09	76.09

CUMULATIVE AREA = .01 SQ MI

1

RUNOFF SUMMARY
FLOW IN CUBIC FEET PER SECOND
TIME IN HOURS, AREA IN SQUARE MILES

OF	OPERATION	STATION	PEAK	TIME OF	AVERAGE FLOW FOR MAXIMUM PERIOD			BASIN	MAXIMUM	TIME
			FLOW	PEAK						
					6-HOUR	24-HOUR	72-HOUR			
+	HYDROGRAPH AT									
+	SITE	2.	49.67	2.	1.	1.	.01			
+	HYDROGRAPH AT									
+	POND	0.	48.50	0.	0.	0.	.00			
+	2 COMBINED AT									
+	COMB	2.	49.50	2.	2.	1.	.01			
+	ROUTED TO									
+	RES1	2.	49.83	2.	1.	1.	.01			
+								77.77	49.83	

*** NORMAL END OF HEC-1 ***

CASE IV

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*                                     *
* FLOOD HYDROGRAPH PACKAGE (HEC-1) *
*
*   FEBRUARY 1981
*   REVISED 02 AUG 88
*
* RUN DATE 07/17/1998 TIME 11:13:49 *
*
*****
*                                     *
* U.S. ARMY CORPS OF ENGINEERS
*
* THE HYDROLOGIC ENGINEERING CENTER *
*   609 SECOND STREET
* DAVIS, CALIFORNIA 95616
*   (916) 551-1748
*
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X  X XXXXXXXX XXXXX      X
X  X X      X  X      XX
X  X X      X      X
XXXXXXXX XXXX  X  XXXXX X
X  X X      X      X
X  X X      X  X      X
X  X XXXXXXXX XXXXX      XXX

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THIS PROGRAM REPLACES ALL PREVIOUS VERSIONS OF HEC-1 KNOWN AS HEC1 (JAN 73), HEC1GS, HEC1DB, AND HEC1KW.

THE DEFINITIONS OF VARIABLES -RTIMP- AND -RTIOR- HAVE CHANGED FROM THOSE USED WITH THE 1973-STYLE INPUT STRUCTURE.

THE DEFINITION OF -AMSKK- ON RM-CARD WAS CHANGED WITH REVISIONS DATED 28 SEP 81. THIS IS THE FORTRAN77 VERSION

NEW OPTIONS: DAMBREAK OUTFLOW SUBMERGENCE , SINGLE EVENT DAMAGE CALCULATION, DSS:WRITE STAGE FREQUENCY,

DSS:READ TIME SERIES AT DESIRED CALCULATION INTERVAL LOSS RATE:GREEN AND AMPT INFILTRATION KINEMATIC WAVE: NEW FINITE DIFFERENCE ALGORITHM

1 HEC-1 INPUT PAGE 1

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LINE      ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10

1      ID  KUA - Cane Island Unit 3
2      ID  Site Certification Application
3      ID  HEC-1 Analysis of Unit 3: 100 Year - 72 Hour Precipitation Event
4      ID  Discharge rating curve of emergency spillway (crest elev. 78.0 ft msl)
5      ID  added to reservoir routing cards.
6      ID  Black & Veatch Project No. 59140   Modelled By: Gregory V. Johnson
7      ID  Post-Construction Model
8      ID  Input File: kua100.in  Output File: kua100.out
9      IT  10 17JUL98  0600   300
10     IO  0    0
11     IN  15
      * *****

12     KK  SITE
13     KM  Runoff From Unit 3 Power Block and Construction Laydown Area
14     BA  .00964
15     PB  14.27
16     PC  0.002 0.003 0.005 0.006 0.008 0.009 0.011 0.012 0.014 0.015
17     PC  0.017 0.018 0.020 0.021 0.023 0.024 0.026 0.027 0.029 0.030
18     PC  0.032 0.033 0.035 0.036 0.038 0.040 0.041 0.043 0.044 0.046
19     PC  0.047 0.049 0.050 0.052 0.053 0.055 0.056 0.058 0.059 0.061
20     PC  0.062 0.064 0.065 0.067 0.068 0.070 0.071 0.073 0.075 0.076

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21	PC	0.078	0.079	0.081	0.082	0.084	0.085	0.087	0.088	0.090	0.091
22	PC	0.093	0.094	0.096	0.097	0.099	0.100	0.102	0.103	0.105	0.106
23	PC	0.108	0.110	0.111	0.113	0.114	0.116	0.117	0.119	0.120	0.122
24	PC	0.123	0.125	0.126	0.128	0.129	0.131	0.132	0.134	0.135	0.137
25	PC	0.138	0.140	0.141	0.143	0.144	0.146	0.148	0.150	0.153	0.155
26	PC	0.157	0.159	0.162	0.164	0.166	0.168	0.170	0.173	0.175	0.177
27	PC	0.179	0.182	0.184	0.186	0.188	0.190	0.193	0.195	0.197	0.199
28	PC	0.201	0.204	0.206	0.208	0.210	0.213	0.215	0.217	0.219	0.221
29	PC	0.224	0.226	0.228	0.230	0.233	0.235	0.237	0.239	0.241	0.244
30	PC	0.246	0.248	0.250	0.252	0.255	0.257	0.259	0.261	0.264	0.266
31	PC	0.268	0.270	0.272	0.275	0.277	0.279	0.281	0.284	0.286	0.288
32	PC	0.290	0.292	0.295	0.297	0.299	0.301	0.304	0.306	0.308	0.310
33	PC	0.312	0.315	0.317	0.319	0.321	0.324	0.326	0.328	0.330	0.332
34	PC	0.335	0.337	0.339	0.341	0.343	0.346	0.348	0.350	0.352	0.355
35	PC	0.357	0.359	0.362	0.364	0.367	0.369	0.372	0.374	0.377	0.379
36	PC	0.382	0.385	0.388	0.391	0.394	0.397	0.400	0.404	0.408	0.412
37	PC	0.417	0.421	0.426	0.431	0.437	0.442	0.448	0.454	0.461	0.467
38	PC	0.474	0.481	0.488	0.496	0.504	0.512	0.521	0.530	0.540	0.550
39	PC	0.561	0.572	0.584	0.596	0.612	0.628	0.653	0.678	0.847	1.015
40	PC	1.052	1.088	1.107	1.126	1.140	1.154	1.166	1.177	1.186	1.194
41	PC	1.202	1.209	1.217	1.224	1.232	1.239	1.243	1.248	1.253	1.257
42	PC	1.262	1.266	1.271	1.275	1.280	1.284	1.289	1.293	1.298	1.302
43	PC	1.307	1.311	1.314	1.317	1.320	1.323	1.326	1.329	1.332	1.335
44	PC	1.338	1.341	1.344	1.347	1.350	1.353	1.356	1.359		
45	LS	0	65	0							
46	UD	0.26									

* *****

1

HEC-1 INPUT

PAGE 2

LINE ID.....1.....2.....3.....4.....5.....6.....7.....8.....9.....10

47	KK	POND
48	KM	Unit 3 Stormwater Pond
49	BA	.00152
50	LS	0 49 100
51	UD	0.01
* *****		
52	KK	COMB
53	KM	Combining Two Hydrographs in Reservoir
54	HC	2
* *****		
55	KK	RES1
56	KM	Reservoir Routing Operation
57	RS	1 ELEV 74.0
58	SA	.01379 0.70644 0.76078 0.87713 0.99732
59	SE	74.0 75.0 76.0 78.0 79.0
60	SQ	0 0 0 2.2 33.7
61	SE	74.0 75.0 76.0 78.0 79.0
* *****		
*DIAGRAM		
62	ZZ	

1

SCHEMATIC DIAGRAM OF STREAM NETWORK

INPUT

LINE (V) ROUTING (--->) DIVERSION OR PUMP FLOW

NO. (.) CONNECTOR (<---) RETURN OF DIVERTED OR PUMPED FLOW

12 SITE

47 POND

52 COMB.....
V
V
55 RES1

(***) RUNOFF ALSO COMPUTED AT THIS LOCATION

1*****

```

*                                     *
* FLOOD HYDROGRAPH PACKAGE (HEC-1) *
*
*   FEBRUARY 1981
*   REVISED 02 AUG 88
*
* RUN DATE 07/17/1998 TIME 11:13:49 *
*
*****

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*                                     *
* U.S. ARMY CORPS OF ENGINEERS
*
* THE HYDROLOGIC ENGINEERING CENTER *
*   609 SECOND STREET
* DAVIS, CALIFORNIA 95616
*   (916) 551-1748
*
*****

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KUA - Cane Island Unit 3
Site Certification Application
HEC-1 Analysis of Unit 3: 100 Year - 72 Hour Precipitation Event
Discharge rating curve of emergency spillway (crest elev. 78.0 ft msl)
added to reservoir routing cards.
Black & Veatch Project No. 59140 Modelled By: Gregory V. Johnson
Post-Construction Model
Input File: kua100.in Output File: kua100.out

*** ERROR *** SPECIFIED START AND END DATES RESULT IN TOO MANY TIME PERIODS

10 IO OUTPUT CONTROL VARIABLES
IPRNT 0 PRINT CONTROL
IPLOT 0 PLOT CONTROL
QSCAL 0. HYDROGRAPH PLOT SCALE

IT HYDROGRAPH TIME DATA
NMIN 10 MINUTES IN COMPUTATION INTERVAL
IDATE 17JUL98 STARTING DATE
ITIME 1200 STARTING TIME
NQ 300 NUMBER OF HYDROGRAPH ORDINATES
NDDATE 21JUL98 ENDING DATE
NDTIME 1350 ENDING TIME
ICENT 19 CENTURY MARK

COMPUTATION INTERVAL .17 HOURS
TOTAL TIME BASE 49.83 HOURS

ENGLISH UNITS
DRAINAGE AREA SQUARE MILES
PRECIPITATION DEPTH INCHES
LENGTH, ELEVATION FEET
FLOW CUBIC FEET PER SECOND
STORAGE VOLUME ACRE-Feet
SURFACE AREA ACRES
TEMPERATURE DEGREES FAHRENHEIT

*** **
*** **

12 KK * SITE *

Runoff From Unit 3 Power Block and Construction Laydown Area

```

11 IN      TIME DATA FOR INPUT TIME SERIES
          JXMIN      15  TIME INTERVAL IN MINUTES
          JXDATE     17JUL98  STARTING DATE
          JXTIME      6000  STARTING TIME

```

SUBBASIN RUNOFF DATA

14 BA SUBBASIN CHARACTERISTICS
TAREA .01 SUBBASIN AREA

PRECIPITATION DATA

15 PB STORM 14.27 BASIN TOTAL PRECIPITATION

[illegible]

45 LS	SCS LOSS RATE	
	STRTL	1.08 INITIAL ABSTRACTION
	CRVNR	65.00 CURVE NUMBER
	RTIMP	.00 PERCENT IMPERVIOUS AREA

46 UD SCS DIMENSIONLESS UNITGRAPH
 TLAG .26 LAG

WARNING *** TIME INTERVAL IS GREATER THAN .29*LAG

UNIT HYDROGRAPH
10 END-OF-PERIOD ORDINATES

6. 14. 10. 4. 2. 1. 0. 0. 0. 0.

HYDROGRAPH AT STATION SITE

DA MON HRMN ORD RAIN LOSS EXCESS						COMP Q	*	DA MON HRMN ORD RAIN LOSS EXCESS					
COMP Q								COMP Q					
19 JUL 1200	1	.00	.00	.00	0.	*	20 JUL 1300	151	.05	.01	.04	1.	
19 JUL 1210	2	.03	.03	.00	0.	*	20 JUL 1310	152	.05	.01	.04	1.	
19 JUL 1220	3	.04	.04	.00	0.	*	20 JUL 1320	153	.06	.02	.05	1.	
19 JUL 1230	4	.05	.05	.00	0.	*	20 JUL 1330	154	.08	.02	.05	2.	
19 JUL 1240	5	.03	.03	.00	0.	*	20 JUL 1340	155	.05	.01	.04	2.	
19 JUL 1250	6	.04	.04	.00	0.	*	20 JUL 1350	156	.05	.01	.04	2.	
19 JUL 1300	7	.05	.05	.00	0.	*	20 JUL 1400	157	.05	.01	.04	1.	
19 JUL 1310	8	.03	.03	.00	0.	*	20 JUL 1410	158	.05	.01	.04	1.	
19 JUL 1320	9	.04	.04	.00	0.	*	20 JUL 1420	159	.05	.01	.04	1.	
19 JUL 1330	10	.05	.05	.00	0.	*	20 JUL 1430	160	.05	.01	.04	1.	
19 JUL 1340	11	.03	.03	.00	0.	*	20 JUL 1440	161	.08	.02	.06	2.	
19 JUL 1350	12	.04	.04	.00	0.	*	20 JUL 1450	162	.06	.02	.05	2.	
19 JUL 1400	13	.05	.05	.00	0.	*	20 JUL 1500	163	.05	.01	.04	2.	
19 JUL 1410	14	.03	.03	.00	0.	*	20 JUL 1510	164	.05	.01	.04	2.	
19 JUL 1420	15	.04	.04	.00	0.	*	20 JUL 1520	165	.05	.01	.04	1.	
19 JUL 1430	16	.05	.05	.00	0.	*	20 JUL 1530	166	.05	.01	.04	1.	
19 JUL 1440	17	.03	.03	.00	0.	*	20 JUL 1540	167	.08	.02	.06	2.	
19 JUL 1450	18	.04	.04	.00	0.	*	20 JUL 1550	168	.06	.01	.05	2.	
19 JUL 1500	19	.05	.05	.00	0.	*	20 JUL 1600	169	.05	.01	.04	2.	
19 JUL 1510	20	.03	.03	.00	0.	*	20 JUL 1610	170	.05	.01	.04	2.	
19 JUL 1520	21	.04	.04	.00	0.	*	20 JUL 1620	171	.05	.01	.04	2.	
19 JUL 1530	22	.05	.05	.00	0.	*	20 JUL 1630	172	.05	.01	.04	1.	
19 JUL 1540	23	.03	.03	.00	0.	*	20 JUL 1640	173	.05	.01	.04	1.	
19 JUL 1550	24	.04	.04	.00	0.	*	20 JUL 1650	174	.06	.01	.05	2.	
19 JUL 1600	25	.05	.05	.00	0.	*	20 JUL 1700	175	.08	.02	.06	2.	
19 JUL 1610	26	.03	.03	.00	0.	*	20 JUL 1710	176	.05	.01	.04	2.	
19 JUL 1620	27	.04	.04	.00	0.	*	20 JUL 1720	177	.05	.01	.04	2.	
19 JUL 1630	28	.05	.05	.00	0.	*	20 JUL 1730	178	.05	.01	.04	2.	
19 JUL 1640	29	.03	.03	.00	0.	*	20 JUL 1740	179	.05	.01	.04	2.	
19 JUL 1650	30	.04	.04	.00	0.	*	20 JUL 1750	180	.05	.01	.04	1.	
19 JUL 1700	31	.05	.05	.00	0.	*	20 JUL 1800	181	.05	.01	.04	1.	
19 JUL 1710	32	.03	.02	.00	0.	*	20 JUL 1810	182	.08	.02	.06	2.	
19 JUL 1720	33	.04	.04	.00	0.	*	20 JUL 1820	183	.06	.01	.05	2.	
19 JUL 1730	34	.05	.05	.00	0.	*	20 JUL 1830	184	.05	.01	.04	2.	
19 JUL 1740	35	.03	.02	.00	0.	*	20 JUL 1840	185	.05	.01	.04	2.	
19 JUL 1750	36	.04	.03	.00	0.	*	20 JUL 1850	186	.05	.01	.04	2.	
19 JUL 1800	37	.05	.05	.00	0.	*	20 JUL 1900	187	.05	.01	.04	2.	
19 JUL 1810	38	.05	.05	.01	0.	*	20 JUL 1910	188	.08	.01	.06	2.	
19 JUL 1820	39	.04	.03	.00	0.	*	20 JUL 1920	189	.06	.01	.05	2.	
19 JUL 1830	40	.03	.02	.00	0.	*	20 JUL 1930	190	.05	.01	.04	2.	
19 JUL 1840	41	.05	.04	.01	0.	*	20 JUL 1940	191	.05	.01	.04	2.	
19 JUL 1850	42	.04	.03	.01	0.	*	20 JUL 1950	192	.05	.01	.04	2.	
19 JUL 1900	43	.03	.02	.00	0.	*	20 JUL 2000	193	.05	.01	.04	2.	
19 JUL 1910	44	.05	.04	.01	0.	*	20 JUL 2010	194	.05	.01	.04	2.	
19 JUL 1920	45	.04	.03	.01	0.	*	20 JUL 2020	195	.06	.01	.05	2.	
19 JUL 1930	46	.03	.02	.00	0.	*	20 JUL 2030	196	.08	.01	.06	2.	
19 JUL 1940	47	.05	.04	.01	0.	*	20 JUL 2040	197	.05	.01	.04	2.	
19 JUL 1950	48	.04	.03	.01	0.	*	20 JUL 2050	198	.05	.01	.04	2.	

19 JUL 2000	49	.03	.02	.01	0.	*	20 JUL 2100	199	.05	.01	.04	2.
19 JUL 2010	50	.05	.04	.01	0.	*	20 JUL 2110	200	.05	.01	.04	2.
19 JUL 2020	51	.04	.03	.01	0.	*	20 JUL 2120	201	.06	.01	.05	2.
19 JUL 2030	52	.03	.02	.01	0.	*	20 JUL 2130	202	.08	.01	.06	2.
19 JUL 2040	53	.05	.04	.01	0.	*	20 JUL 2140	203	.05	.01	.04	2.
19 JUL 2050	54	.04	.03	.01	0.	*	20 JUL 2150	204	.05	.01	.04	2.
19 JUL 2100	55	.03	.02	.01	0.	*	20 JUL 2200	205	.05	.01	.04	2.
19 JUL 2110	56	.05	.04	.01	0.	*	20 JUL 2210	206	.05	.01	.04	2.
19 JUL 2120	57	.04	.03	.01	0.	*	20 JUL 2220	207	.05	.01	.04	2.
19 JUL 2130	58	.03	.02	.01	0.	*	20 JUL 2230	208	.05	.01	.04	2.
19 JUL 2140	59	.05	.03	.02	0.	*	20 JUL 2240	209	.08	.01	.06	2.
19 JUL 2150	60	.04	.03	.01	0.	*	20 JUL 2250	210	.06	.01	.05	2.
19 JUL 2200	61	.03	.02	.01	0.	*	20 JUL 2300	211	.05	.01	.04	2.
19 JUL 2210	62	.05	.03	.02	0.	*	20 JUL 2310	212	.05	.01	.04	2.
19 JUL 2220	63	.04	.02	.01	0.	*	20 JUL 2320	213	.05	.01	.04	2.
19 JUL 2230	64	.03	.02	.01	0.	*	20 JUL 2330	214	.05	.01	.04	2.
19 JUL 2240	65	.05	.03	.02	0.	*	20 JUL 2340	215	.05	.01	.04	2.
19 JUL 2250	66	.04	.02	.01	1.	*	20 JUL 2350	216	.06	.01	.05	2.
19 JUL 2300	67	.03	.02	.01	1.	*	21 JUL 0000	217	.08	.01	.06	2.
19 JUL 2310	68	.05	.03	.02	0.	*	21 JUL 0010	218	.05	.01	.04	2.
19 JUL 2320	69	.04	.02	.01	1.	*	21 JUL 0020	219	.05	.01	.04	2.
19 JUL 2330	70	.03	.02	.01	1.	*	21 JUL 0030	220	.05	.01	.04	2.
19 JUL 2340	71	.05	.03	.02	1.	*	21 JUL 0040	221	.05	.01	.04	2.
19 JUL 2350	72	.05	.03	.02	1.	*	21 JUL 0050	222	.06	.01	.05	2.
20 JUL 0000	73	.05	.03	.02	1.	*	21 JUL 0100	223	.08	.01	.06	2.
20 JUL 0010	74	.03	.01	.01	1.	*	21 JUL 0110	224	.05	.01	.04	2.
20 JUL 0020	75	.04	.02	.02	1.	*	21 JUL 0120	225	.05	.01	.04	2.
20 JUL 0030	76	.05	.03	.02	1.	*	21 JUL 0130	226	.05	.01	.04	2.
20 JUL 0040	77	.03	.01	.01	1.	*	21 JUL 0140	227	.05	.01	.04	2.
20 JUL 0050	78	.04	.02	.02	1.	*	21 JUL 0150	228	.05	.01	.04	2.
20 JUL 0100	79	.05	.03	.02	1.	*	21 JUL 0200	229	.05	.01	.04	2.
20 JUL 0110	80	.03	.01	.01	1.	*	21 JUL 0210	230	.08	.01	.07	2.
20 JUL 0120	81	.04	.02	.02	1.	*	21 JUL 0220	231	.06	.01	.05	2.
20 JUL 0130	82	.05	.03	.02	1.	*	21 JUL 0230	232	.05	.01	.04	2.
20 JUL 0140	83	.03	.01	.01	1.	*	21 JUL 0240	233	.05	.01	.04	2.
20 JUL 0150	84	.04	.02	.02	1.	*	21 JUL 0250	234	.05	.01	.04	2.
20 JUL 0200	85	.05	.03	.02	1.	*	21 JUL 0300	235	.05	.01	.04	2.
20 JUL 0210	86	.03	.01	.01	1.	*	21 JUL 0310	236	.08	.01	.07	2.
20 JUL 0220	87	.04	.02	.02	1.	*	21 JUL 0320	237	.06	.01	.05	2.
20 JUL 0230	88	.05	.03	.03	1.	*	21 JUL 0330	238	.05	.01	.04	2.
20 JUL 0240	89	.03	.01	.01	1.	*	21 JUL 0340	239	.05	.01	.04	2.
20 JUL 0250	90	.04	.02	.02	1.	*	21 JUL 0350	240	.05	.01	.04	2.
20 JUL 0300	91	.05	.02	.03	1.	*	21 JUL 0400	241	.05	.01	.04	2.
20 JUL 0310	92	.03	.01	.01	1.	*	21 JUL 0410	242	.05	.01	.04	2.
20 JUL 0320	93	.04	.02	.02	1.	*	21 JUL 0420	243	.06	.01	.06	2.
20 JUL 0330	94	.05	.02	.03	1.	*	21 JUL 0430	244	.08	.01	.07	2.
20 JUL 0340	95	.03	.01	.01	1.	*	21 JUL 0440	245	.05	.01	.04	2.
20 JUL 0350	96	.04	.02	.02	1.	*	21 JUL 0450	246	.05	.01	.04	2.
20 JUL 0400	97	.05	.02	.03	1.	*	21 JUL 0500	247	.05	.01	.04	2.
20 JUL 0410	98	.03	.01	.01	1.	*	21 JUL 0510	248	.05	.01	.04	2.
20 JUL 0420	99	.04	.02	.02	1.	*	21 JUL 0520	249	.06	.01	.06	2.
20 JUL 0430	100	.05	.02	.03	1.	*	21 JUL 0530	250	.08	.01	.07	2.
20 JUL 0440	101	.03	.01	.01	1.	*	21 JUL 0540	251	.05	.01	.04	2.
20 JUL 0450	102	.04	.02	.02	1.	*	21 JUL 0550	252	.05	.01	.04	2.
20 JUL 0500	103	.05	.02	.03	1.	*	21 JUL 0600	253	.05	.01	.04	2.
20 JUL 0510	104	.03	.01	.01	1.	*	21 JUL 0610	254	.05	.01	.04	2.
20 JUL 0520	105	.04	.02	.02	1.	*	21 JUL 0620	255	.05	.01	.04	2.
20 JUL 0530	106	.05	.02	.03	1.	*	21 JUL 0630	256	.05	.01	.04	2.
20 JUL 0540	107	.05	.02	.03	1.	*	21 JUL 0640	257	.08	.01	.07	2.
20 JUL 0550	108	.04	.02	.02	1.	*	21 JUL 0650	258	.06	.01	.06	2.
20 JUL 0600	109	.03	.01	.01	1.	*	21 JUL 0700	259	.05	.01	.04	2.
20 JUL 0610	110	.05	.02	.03	1.	*	21 JUL 0710	260	.05	.01	.04	2.
20 JUL 0620	111	.04	.02	.02	1.	*	21 JUL 0720	261	.05	.01	.04	2.
20 JUL 0630	112	.03	.01	.02	1.	*	21 JUL 0730	262	.05	.01	.04	2.
20 JUL 0640	113	.05	.02	.03	1.	*	21 JUL 0740	263	.08	.01	.07	2.

20 JUL 0650	114	.04	.01	.02	1.	*	21 JUL 0750	264	.06	.01	.06	2.
20 JUL 0700	115	.03	.01	.02	1.	*	21 JUL 0800	265	.05	.01	.04	2.
20 JUL 0710	116	.05	.02	.03	1.	*	21 JUL 0810	266	.05	.01	.05	2.
20 JUL 0720	117	.04	.01	.02	1.	*	21 JUL 0820	267	.05	.01	.05	2.
20 JUL 0730	118	.03	.01	.02	1.	*	21 JUL 0830	268	.05	.01	.05	2.
20 JUL 0740	119	.05	.02	.03	1.	*	21 JUL 0840	269	.05	.01	.05	2.
20 JUL 0750	120	.04	.01	.02	1.	*	21 JUL 0850	270	.06	.01	.06	2.
20 JUL 0800	121	.03	.01	.02	1.	*	21 JUL 0900	271	.08	.01	.07	2.
20 JUL 0810	122	.05	.02	.03	1.	*	21 JUL 0910	272	.05	.01	.05	2.
20 JUL 0820	123	.04	.01	.02	1.	*	21 JUL 0920	273	.05	.01	.05	2.
20 JUL 0830	124	.03	.01	.02	1.	*	21 JUL 0930	274	.05	.01	.05	2.
20 JUL 0840	125	.05	.02	.03	1.	*	21 JUL 0940	275	.05	.01	.05	2.
20 JUL 0850	126	.04	.01	.02	1.	*	21 JUL 0950	276	.05	.00	.05	2.
20 JUL 0900	127	.03	.01	.02	1.	*	21 JUL 1000	277	.05	.00	.05	2.
20 JUL 0910	128	.05	.02	.03	1.	*	21 JUL 1010	278	.08	.01	.07	2.
20 JUL 0920	129	.04	.01	.02	1.	*	21 JUL 1020	279	.06	.01	.06	2.
20 JUL 0930	130	.03	.01	.02	1.	*	21 JUL 1030	280	.05	.00	.05	2.
20 JUL 0940	131	.05	.02	.03	1.	*	21 JUL 1040	281	.05	.00	.05	2.
20 JUL 0950	132	.04	.01	.03	1.	*	21 JUL 1050	282	.05	.00	.05	2.
20 JUL 1000	133	.03	.01	.02	1.	*	21 JUL 1100	283	.05	.00	.05	2.
20 JUL 1010	134	.05	.02	.03	1.	*	21 JUL 1110	284	.08	.01	.07	2.
20 JUL 1020	135	.04	.01	.03	1.	*	21 JUL 1120	285	.06	.01	.06	2.
20 JUL 1030	136	.03	.01	.02	1.	*	21 JUL 1130	286	.05	.00	.05	2.
20 JUL 1040	137	.05	.02	.03	1.	*	21 JUL 1140	287	.05	.00	.05	2.
20 JUL 1050	138	.04	.01	.03	1.	*	21 JUL 1150	288	.06	.01	.06	2.
20 JUL 1100	139	.03	.01	.02	1.	*	21 JUL 1200	289	.08	.01	.07	2.
20 JUL 1110	140	.05	.02	.03	1.	*	21 JUL 1210	290	.05	.00	.05	2.
20 JUL 1120	141	.04	.01	.03	1.	*	21 JUL 1220	291	.06	.01	.06	2.
20 JUL 1130	142	.03	.01	.02	1.	*	21 JUL 1230	292	.08	.01	.07	2.
20 JUL 1140	143	.05	.02	.03	1.	*	21 JUL 1240	293	.05	.00	.05	2.
20 JUL 1150	144	.05	.02	.03	1.	*	21 JUL 1250	294	.06	.01	.06	2.
20 JUL 1200	145	.05	.02	.04	1.	*	21 JUL 1300	295	.08	.01	.07	2.
20 JUL 1210	146	.05	.02	.04	1.	*	21 JUL 1310	296	.05	.00	.05	2.
20 JUL 1220	147	.06	.02	.04	1.	*	21 JUL 1320	297	.06	.01	.06	2.
20 JUL 1230	148	.08	.02	.05	2.	*	21 JUL 1330	298	.08	.01	.07	2.
20 JUL 1240	149	.05	.01	.04	2.	*	21 JUL 1340	299	.05	.00	.05	2.
20 JUL 1250	150	.05	.01	.04	2.	*	21 JUL 1350	300	.06	.01	.06	2.

TOTAL RAINFALL = 14.27, TOTAL LOSS = 4.90, TOTAL EXCESS = 9.37

PEAK FLOW + (CFS)	TIME (HR)	MAXIMUM AVERAGE FLOW			
		6-HR	24-HR	72-HR	49.83-HR
2.	49.67	2.	2.	1.	1.
(INCHES)		1.893	6.881	9.248	9.248
(AC-FT)		1.	4.	5.	5.

CUMULATIVE AREA = .01 SQ MI

*** **
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*
47 KK * POND *
*

Unit 3 Stormwater Pond

SUBBASIN RUNOFF DATA

49 BA SUBBASIN CHARACTERISTICS
TAREA .00 SUBBASIN AREA

PRECIPITATION DATA

15 PB STORM 14.27 BASIN TOTAL PRECIPITATION

16 PI INCREMENTAL PRECIPITATION PATTERN

[illegible]

50 LS	SCS LOSS RATE
	STRTL 2.08 INITIAL ABSTRACTION
	CRVNB 49.00 CURVE NUMBER
	RTIMP 100.00 PERCENT IMPERVIOUS AREA

51 UD SCS DIMENSIONLESS UNITGRAPH
 TLAG .01 LAG

WARNING *** TIME INTERVAL IS GREATER THAN .29*LAG

UNIT HYDROGRAPH
5 END-OF-PERIOD ORDINATES

4. 1. 0. 0. 0.

HYDROGRAPH AT STATION POND

* DA MON HRMN ORD RAIN LOSS EXCESS COMP Q *							* DA MON HRMN ORD RAIN LOSS EXCESS						
COMP Q													
*													
19 JUL 1200	1	.00	.00	.00	0.	*	20 JUL 1300	151	.05	.00	.05	0.	
19 JUL 1210	2	.03	.00	.03	0.	*	20 JUL 1310	152	.05	.00	.05	0.	
19 JUL 1220	3	.04	.00	.04	0.	*	20 JUL 1320	153	.06	.00	.06	0.	
19 JUL 1230	4	.05	.00	.05	0.	*	20 JUL 1330	154	.08	.00	.08	0.	
19 JUL 1240	5	.03	.00	.03	0.	*	20 JUL 1340	155	.05	.00	.05	0.	
19 JUL 1250	6	.04	.00	.04	0.	*	20 JUL 1350	156	.05	.00	.05	0.	
19 JUL 1300	7	.05	.00	.05	0.	*	20 JUL 1400	157	.05	.00	.05	0.	
19 JUL 1310	8	.03	.00	.03	0.	*	20 JUL 1410	158	.05	.00	.05	0.	
19 JUL 1320	9	.04	.00	.04	0.	*	20 JUL 1420	159	.05	.00	.05	0.	
19 JUL 1330	10	.05	.00	.05	0.	*	20 JUL 1430	160	.05	.00	.05	0.	
19 JUL 1340	11	.03	.00	.03	0.	*	20 JUL 1440	161	.08	.00	.08	0.	
19 JUL 1350	12	.04	.00	.04	0.	*	20 JUL 1450	162	.06	.00	.06	0.	
19 JUL 1400	13	.05	.00	.05	0.	*	20 JUL 1500	163	.05	.00	.05	0.	
19 JUL 1410	14	.03	.00	.03	0.	*	20 JUL 1510	164	.05	.00	.05	0.	
19 JUL 1420	15	.04	.00	.04	0.	*	20 JUL 1520	165	.05	.00	.05	0.	
19 JUL 1430	16	.05	.00	.05	0.	*	20 JUL 1530	166	.05	.00	.05	0.	
19 JUL 1440	17	.03	.00	.03	0.	*	20 JUL 1540	167	.08	.00	.08	0.	
19 JUL 1450	18	.04	.00	.04	0.	*	20 JUL 1550	168	.06	.00	.06	0.	
19 JUL 1500	19	.05	.00	.05	0.	*	20 JUL 1600	169	.05	.00	.05	0.	
19 JUL 1510	20	.03	.00	.03	0.	*	20 JUL 1610	170	.05	.00	.05	0.	
19 JUL 1520	21	.04	.00	.04	0.	*	20 JUL 1620	171	.05	.00	.05	0.	
19 JUL 1530	22	.05	.00	.05	0.	*	20 JUL 1630	172	.05	.00	.05	0.	
19 JUL 1540	23	.03	.00	.03	0.	*	20 JUL 1640	173	.05	.00	.05	0.	
19 JUL 1550	24	.04	.00	.04	0.	*	20 JUL 1650	174	.06	.00	.06	0.	
19 JUL 1600	25	.05	.00	.05	0.	*	20 JUL 1700	175	.08	.00	.08	0.	
19 JUL 1610	26	.03	.00	.03	0.	*	20 JUL 1710	176	.05	.00	.05	0.	
19 JUL 1620	27	.04	.00	.04	0.	*	20 JUL 1720	177	.05	.00	.05	0.	
19 JUL 1630	28	.05	.00	.05	0.	*	20 JUL 1730	178	.05	.00	.05	0.	
19 JUL 1640	29	.03	.00	.03	0.	*	20 JUL 1740	179	.05	.00	.05	0.	
19 JUL 1650	30	.04	.00	.04	0.	*	20 JUL 1750	180	.05	.00	.05	0.	
19 JUL 1700	31	.05	.00	.05	0.	*	20 JUL 1800	181	.05	.00	.05	0.	
19 JUL 1710	32	.03	.00	.03	0.	*	20 JUL 1810	182	.08	.00	.08	0.	
19 JUL 1720	33	.04	.00	.04	0.	*	20 JUL 1820	183	.06	.00	.06	0.	
19 JUL 1730	34	.05	.00	.05	0.	*	20 JUL 1830	184	.05	.00	.05	0.	
19 JUL 1740	35	.03	.00	.03	0.	*	20 JUL 1840	185	.05	.00	.05	0.	
19 JUL 1750	36	.04	.00	.04	0.	*	20 JUL 1850	186	.05	.00	.05	0.	
19 JUL 1800	37	.05	.00	.05	0.	*	20 JUL 1900	187	.05	.00	.05	0.	
19 JUL 1810	38	.05	.00	.05	0.	*	20 JUL 1910	188	.08	.00	.08	0.	
19 JUL 1820	39	.04	.00	.04	0.	*	20 JUL 1920	189	.06	.00	.06	0.	
19 JUL 1830	40	.03	.00	.03	0.	*	20 JUL 1930	190	.05	.00	.05	0.	
19 JUL 1840	41	.05	.00	.05	0.	*	20 JUL 1940	191	.05	.00	.05	0.	
19 JUL 1850	42	.04	.00	.04	0.	*	20 JUL 1950	192	.05	.00	.05	0.	
19 JUL 1900	43	.03	.00	.03	0.	*	20 JUL 2000	193	.05	.00	.05	0.	
19 JUL 1910	44	.05	.00	.05	0.	*	20 JUL 2010	194	.05	.00	.05	0.	
19 JUL 1920	45	.04	.00	.04	0.	*	20 JUL 2020	195	.06	.00	.06	0.	
19 JUL 1930	46	.03	.00	.03	0.	*	20 JUL 2030	196	.08	.00	.08	0.	
19 JUL 1940	47	.05	.00	.05	0.	*	20 JUL 2040	197	.05	.00	.05	0.	
19 JUL 1950	48	.04	.00	.04	0.	*	20 JUL 2050	198	.05	.00	.05	0.	
19 JUL 2000	49	.03	.00	.03	0.	*	20 JUL 2100	199	.05	.00	.05	0.	
19 JUL 2010	50	.05	.00	.05	0.	*	20 JUL 2110	200	.05	.00	.05	0.	
19 JUL 2020	51	.04	.00	.04	0.	*	20 JUL 2120	201	.06	.00	.06	0.	
19 JUL 2030	52	.03	.00	.03	0.	*	20 JUL 2130	202	.08	.00	.08	0.	
19 JUL 2040	53	.05	.00	.05	0.	*	20 JUL 2140	203	.05	.00	.05	0.	
19 JUL 2050	54	.04	.00	.04	0.	*	20 JUL 2150	204	.05	.00	.05	0.	
19 JUL 2100	55	.03	.00	.03	0.	*	20 JUL 2200	205	.05	.00	.05	0.	
19 JUL 2110	56	.05	.00	.05	0.	*	20 JUL 2210	206	.05	.00	.05	0.	
19 JUL 2120	57	.04	.00	.04	0.	*	20 JUL 2220	207	.05	.00	.05	0.	

19 JUL 2130	58	.03	.00	.03	0.	*	20 JUL 2230	208	.05	.00	.05	0.
19 JUL 2140	59	.05	.00	.05	0.	*	20 JUL 2240	209	.08	.00	.08	0.
19 JUL 2150	60	.04	.00	.04	0.	*	20 JUL 2250	210	.06	.00	.06	0.
19 JUL 2200	61	.03	.00	.03	0.	*	20 JUL 2300	211	.05	.00	.05	0.
19 JUL 2210	62	.05	.00	.05	0.	*	20 JUL 2310	212	.05	.00	.05	0.
19 JUL 2220	63	.04	.00	.04	0.	*	20 JUL 2320	213	.05	.00	.05	0.
19 JUL 2230	64	.03	.00	.03	0.	*	20 JUL 2330	214	.05	.00	.05	0.
19 JUL 2240	65	.05	.00	.05	0.	*	20 JUL 2340	215	.05	.00	.05	0.
19 JUL 2250	66	.04	.00	.04	0.	*	20 JUL 2350	216	.06	.00	.06	0.
19 JUL 2300	67	.03	.00	.03	0.	*	21 JUL 0000	217	.08	.00	.08	0.
19 JUL 2310	68	.05	.00	.05	0.	*	21 JUL 0010	218	.05	.00	.05	0.
19 JUL 2320	69	.04	.00	.04	0.	*	21 JUL 0020	219	.05	.00	.05	0.
19 JUL 2330	70	.03	.00	.03	0.	*	21 JUL 0030	220	.05	.00	.05	0.
19 JUL 2340	71	.05	.00	.05	0.	*	21 JUL 0040	221	.05	.00	.05	0.
19 JUL 2350	72	.05	.00	.05	0.	*	21 JUL 0050	222	.06	.00	.06	0.
20 JUL 0000	73	.05	.00	.05	0.	*	21 JUL 0100	223	.08	.00	.08	0.
20 JUL 0010	74	.03	.00	.03	0.	*	21 JUL 0110	224	.05	.00	.05	0.
20 JUL 0020	75	.04	.00	.04	0.	*	21 JUL 0120	225	.05	.00	.05	0.
20 JUL 0030	76	.05	.00	.05	0.	*	21 JUL 0130	226	.05	.00	.05	0.
20 JUL 0040	77	.03	.00	.03	0.	*	21 JUL 0140	227	.05	.00	.05	0.
20 JUL 0050	78	.04	.00	.04	0.	*	21 JUL 0150	228	.05	.00	.05	0.
20 JUL 0100	79	.05	.00	.05	0.	*	21 JUL 0200	229	.05	.00	.05	0.
20 JUL 0110	80	.03	.00	.03	0.	*	21 JUL 0210	230	.08	.00	.08	0.
20 JUL 0120	81	.04	.00	.04	0.	*	21 JUL 0220	231	.06	.00	.06	0.
20 JUL 0130	82	.05	.00	.05	0.	*	21 JUL 0230	232	.05	.00	.05	0.
20 JUL 0140	83	.03	.00	.03	0.	*	21 JUL 0240	233	.05	.00	.05	0.
20 JUL 0150	84	.04	.00	.04	0.	*	21 JUL 0250	234	.05	.00	.05	0.
20 JUL 0200	85	.05	.00	.05	0.	*	21 JUL 0300	235	.05	.00	.05	0.
20 JUL 0210	86	.03	.00	.03	0.	*	21 JUL 0310	236	.08	.00	.08	0.
20 JUL 0220	87	.04	.00	.04	0.	*	21 JUL 0320	237	.06	.00	.06	0.
20 JUL 0230	88	.05	.00	.05	0.	*	21 JUL 0330	238	.05	.00	.05	0.
20 JUL 0240	89	.03	.00	.03	0.	*	21 JUL 0340	239	.05	.00	.05	0.
20 JUL 0250	90	.04	.00	.04	0.	*	21 JUL 0350	240	.05	.00	.05	0.
20 JUL 0300	91	.05	.00	.05	0.	*	21 JUL 0400	241	.05	.00	.05	0.
20 JUL 0310	92	.03	.00	.03	0.	*	21 JUL 0410	242	.05	.00	.05	0.
20 JUL 0320	93	.04	.00	.04	0.	*	21 JUL 0420	243	.06	.00	.06	0.
20 JUL 0330	94	.05	.00	.05	0.	*	21 JUL 0430	244	.08	.00	.08	0.
20 JUL 0340	95	.03	.00	.03	0.	*	21 JUL 0440	245	.05	.00	.05	0.
20 JUL 0350	96	.04	.00	.04	0.	*	21 JUL 0450	246	.05	.00	.05	0.
20 JUL 0400	97	.05	.00	.05	0.	*	21 JUL 0500	247	.05	.00	.05	0.
20 JUL 0410	98	.03	.00	.03	0.	*	21 JUL 0510	248	.05	.00	.05	0.
20 JUL 0420	99	.04	.00	.04	0.	*	21 JUL 0520	249	.06	.00	.06	0.
20 JUL 0430	100	.05	.00	.05	0.	*	21 JUL 0530	250	.08	.00	.08	0.
20 JUL 0440	101	.03	.00	.03	0.	*	21 JUL 0540	251	.05	.00	.05	0.
20 JUL 0450	102	.04	.00	.04	0.	*	21 JUL 0550	252	.05	.00	.05	0.
20 JUL 0500	103	.05	.00	.05	0.	*	21 JUL 0600	253	.05	.00	.05	0.
20 JUL 0510	104	.03	.00	.03	0.	*	21 JUL 0610	254	.05	.00	.05	0.
20 JUL 0520	105	.04	.00	.04	0.	*	21 JUL 0620	255	.05	.00	.05	0.
20 JUL 0530	106	.05	.00	.05	0.	*	21 JUL 0630	256	.05	.00	.05	0.
20 JUL 0540	107	.05	.00	.05	0.	*	21 JUL 0640	257	.08	.00	.08	0.
20 JUL 0550	108	.04	.00	.04	0.	*	21 JUL 0650	258	.06	.00	.06	0.
20 JUL 0600	109	.03	.00	.03	0.	*	21 JUL 0700	259	.05	.00	.05	0.
20 JUL 0610	110	.05	.00	.05	0.	*	21 JUL 0710	260	.05	.00	.05	0.
20 JUL 0620	111	.04	.00	.04	0.	*	21 JUL 0720	261	.05	.00	.05	0.
20 JUL 0630	112	.03	.00	.03	0.	*	21 JUL 0730	262	.05	.00	.05	0.
20 JUL 0640	113	.05	.00	.05	0.	*	21 JUL 0740	263	.08	.00	.08	0.
20 JUL 0650	114	.04	.00	.04	0.	*	21 JUL 0750	264	.06	.00	.06	0.
20 JUL 0700	115	.03	.00	.03	0.	*	21 JUL 0800	265	.05	.00	.05	0.
20 JUL 0710	116	.05	.00	.05	0.	*	21 JUL 0810	266	.05	.00	.05	0.
20 JUL 0720	117	.04	.00	.04	0.	*	21 JUL 0820	267	.05	.00	.05	0.
20 JUL 0730	118	.03	.00	.03	0.	*	21 JUL 0830	268	.05	.00	.05	0.
20 JUL 0740	119	.05	.00	.05	0.	*	21 JUL 0840	269	.05	.00	.05	0.
20 JUL 0750	120	.04	.00	.04	0.	*	21 JUL 0850	270	.06	.00	.06	0.
20 JUL 0800	121	.03	.00	.03	0.	*	21 JUL 0900	271	.08	.00	.08	0.
20 JUL 0810	122	.05	.00	.05	0.	*	21 JUL 0910	272	.05	.00	.05	0.

20 JUL 0820	123	.04	.00	.04	0.	*	21 JUL 0920	273	.05	.00	.05	0.
20 JUL 0830	124	.03	.00	.03	0.	*	21 JUL 0930	274	.05	.00	.05	0.
20 JUL 0840	125	.05	.00	.05	0.	*	21 JUL 0940	275	.05	.00	.05	0.
20 JUL 0850	126	.04	.00	.04	0.	*	21 JUL 0950	276	.05	.00	.05	0.
20 JUL 0900	127	.03	.00	.03	0.	*	21 JUL 1000	277	.05	.00	.05	0.
20 JUL 0910	128	.05	.00	.05	0.	*	21 JUL 1010	278	.08	.00	.08	0.
20 JUL 0920	129	.04	.00	.04	0.	*	21 JUL 1020	279	.06	.00	.06	0.
20 JUL 0930	130	.03	.00	.03	0.	*	21 JUL 1030	280	.05	.00	.05	0.
20 JUL 0940	131	.05	.00	.05	0.	*	21 JUL 1040	281	.05	.00	.05	0.
20 JUL 0950	132	.04	.00	.04	0.	*	21 JUL 1050	282	.05	.00	.05	0.
20 JUL 1000	133	.03	.00	.03	0.	*	21 JUL 1100	283	.05	.00	.05	0.
20 JUL 1010	134	.05	.00	.05	0.	*	21 JUL 1110	284	.08	.00	.08	0.
20 JUL 1020	135	.04	.00	.04	0.	*	21 JUL 1120	285	.06	.00	.06	0.
20 JUL 1030	136	.03	.00	.03	0.	*	21 JUL 1130	286	.05	.00	.05	0.
20 JUL 1040	137	.05	.00	.05	0.	*	21 JUL 1140	287	.05	.00	.05	0.
20 JUL 1050	138	.04	.00	.04	0.	*	21 JUL 1150	288	.06	.00	.06	0.
20 JUL 1100	139	.03	.00	.03	0.	*	21 JUL 1200	289	.08	.00	.08	0.
20 JUL 1110	140	.05	.00	.05	0.	*	21 JUL 1210	290	.05	.00	.05	0.
20 JUL 1120	141	.04	.00	.04	0.	*	21 JUL 1220	291	.06	.00	.06	0.
20 JUL 1130	142	.03	.00	.03	0.	*	21 JUL 1230	292	.08	.00	.08	0.
20 JUL 1140	143	.05	.00	.05	0.	*	21 JUL 1240	293	.05	.00	.05	0.
20 JUL 1150	144	.05	.00	.05	0.	*	21 JUL 1250	294	.06	.00	.06	0.
20 JUL 1200	145	.05	.00	.05	0.	*	21 JUL 1300	295	.08	.00	.08	0.
20 JUL 1210	146	.05	.00	.05	0.	*	21 JUL 1310	296	.05	.00	.05	0.
20 JUL 1220	147	.06	.00	.06	0.	*	21 JUL 1320	297	.06	.00	.06	0.
20 JUL 1230	148	.08	.00	.08	0.	*	21 JUL 1330	298	.08	.00	.08	0.
20 JUL 1240	149	.05	.00	.05	0.	*	21 JUL 1340	299	.05	.00	.05	0.
20 JUL 1250	150	.05	.00	.05	0.	*	21 JUL 1350	300	.06	.00	.06	0.

TOTAL RAINFALL = 14.27, TOTAL LOSS = .00, TOTAL EXCESS = 14.27

PEAK FLOW + (CFS)	TIME (HR)	MAXIMUM AVERAGE FLOW			
		6-HR	24-HR	72-HR	49.83-HR
+ 0.	48.50	0.	0.	0.	0.
	(INCHES)	2.101	8.121	14.220	14.220
	(AC-FT)	0.	1.	1.	1.

CUMULATIVE AREA = .00 SQ MI

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52 KK * COMB *
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Combining Two Hydrographs in Reservoir

54 HC HYDROGRAPH COMBINATION
ICOMP 2 NUMBER OF HYDROGRAPHS TO COMBINE

HYDROGRAPH AT STATION COMB SUM OF 2 HYDROGRAPHS

DA MON HRMN	ORD	FLOW	*	DA MON HRMN	ORD	FLOW	*	DA MON HRMN	ORD	FLOW	*	DA MON		
HRMN	ORD	FLOW		HRMN	ORD			HRMN	ORD			HRMN		
19 JUL 1200	1	0.	*	20 JUL 0030	76	1.	*	20 JUL 1300	151	2.	*	21 JUL 0130	226	2.
19 JUL 1210	2	0.	*	20 JUL 0040	77	1.	*	20 JUL 1310	152	2.	*	21 JUL 0140	227	2.
19 JUL 1220	3	0.	*	20 JUL 0050	78	1.	*	20 JUL 1320	153	2.	*	21 JUL 0150	228	2.
19 JUL 1230	4	0.	*	20 JUL 0100	79	1.	*	20 JUL 1330	154	2.	*	21 JUL 0200	229	2.
19 JUL 1240	5	0.	*	20 JUL 0110	80	1.	*	20 JUL 1340	155	2.	*	21 JUL 0210	230	2.
19 JUL 1250	6	0.	*	20 JUL 0120	81	1.	*	20 JUL 1350	156	2.	*	21 JUL 0220	231	2.
19 JUL 1300	7	0.	*	20 JUL 0130	82	1.	*	20 JUL 1400	157	2.	*	21 JUL 0230	232	2.
19 JUL 1310	8	0.	*	20 JUL 0140	83	1.	*	20 JUL 1410	158	2.	*	21 JUL 0240	233	2.
19 JUL 1320	9	0.	*	20 JUL 0150	84	1.	*	20 JUL 1420	159	2.	*	21 JUL 0250	234	2.
19 JUL 1330	10	0.	*	20 JUL 0200	85	1.	*	20 JUL 1430	160	2.	*	21 JUL 0300	235	2.
19 JUL 1340	11	0.	*	20 JUL 0210	86	1.	*	20 JUL 1440	161	2.	*	21 JUL 0310	236	2.
19 JUL 1350	12	0.	*	20 JUL 0220	87	1.	*	20 JUL 1450	162	2.	*	21 JUL 0320	237	2.
19 JUL 1400	13	0.	*	20 JUL 0230	88	1.	*	20 JUL 1500	163	2.	*	21 JUL 0330	238	2.
19 JUL 1410	14	0.	*	20 JUL 0240	89	1.	*	20 JUL 1510	164	2.	*	21 JUL 0340	239	2.
19 JUL 1420	15	0.	*	20 JUL 0250	90	1.	*	20 JUL 1520	165	2.	*	21 JUL 0350	240	2.
19 JUL 1430	16	0.	*	20 JUL 0300	91	1.	*	20 JUL 1530	166	2.	*	21 JUL 0400	241	2.
19 JUL 1440	17	0.	*	20 JUL 0310	92	1.	*	20 JUL 1540	167	2.	*	21 JUL 0410	242	2.
19 JUL 1450	18	0.	*	20 JUL 0320	93	1.	*	20 JUL 1550	168	2.	*	21 JUL 0420	243	2.
19 JUL 1500	19	0.	*	20 JUL 0330	94	1.	*	20 JUL 1600	169	2.	*	21 JUL 0430	244	2.
19 JUL 1510	20	0.	*	20 JUL 0340	95	1.	*	20 JUL 1610	170	2.	*	21 JUL 0440	245	2.
19 JUL 1520	21	0.	*	20 JUL 0350	96	1.	*	20 JUL 1620	171	2.	*	21 JUL 0450	246	2.
19 JUL 1530	22	0.	*	20 JUL 0400	97	1.	*	20 JUL 1630	172	2.	*	21 JUL 0500	247	2.
19 JUL 1540	23	0.	*	20 JUL 0410	98	1.	*	20 JUL 1640	173	2.	*	21 JUL 0510	248	2.
19 JUL 1550	24	0.	*	20 JUL 0420	99	1.	*	20 JUL 1650	174	2.	*	21 JUL 0520	249	2.
19 JUL 1600	25	0.	*	20 JUL 0430	100	1.	*	20 JUL 1700	175	2.	*	21 JUL 0530	250	2.
19 JUL 1610	26	0.	*	20 JUL 0440	101	1.	*	20 JUL 1710	176	2.	*	21 JUL 0540	251	2.
19 JUL 1620	27	0.	*	20 JUL 0450	102	1.	*	20 JUL 1720	177	2.	*	21 JUL 0550	252	2.
19 JUL 1630	28	0.	*	20 JUL 0500	103	1.	*	20 JUL 1730	178	2.	*	21 JUL 0600	253	2.
19 JUL 1640	29	0.	*	20 JUL 0510	104	1.	*	20 JUL 1740	179	2.	*	21 JUL 0610	254	2.
19 JUL 1650	30	0.	*	20 JUL 0520	105	1.	*	20 JUL 1750	180	2.	*	21 JUL 0620	255	2.
19 JUL 1700	31	0.	*	20 JUL 0530	106	1.	*	20 JUL 1800	181	2.	*	21 JUL 0630	256	2.
19 JUL 1710	32	0.	*	20 JUL 0540	107	1.	*	20 JUL 1810	182	2.	*	21 JUL 0640	257	2.
19 JUL 1720	33	0.	*	20 JUL 0550	108	1.	*	20 JUL 1820	183	2.	*	21 JUL 0650	258	2.
19 JUL 1730	34	0.	*	20 JUL 0600	109	1.	*	20 JUL 1830	184	2.	*	21 JUL 0700	259	2.
19 JUL 1740	35	0.	*	20 JUL 0610	110	1.	*	20 JUL 1840	185	2.	*	21 JUL 0710	260	2.
19 JUL 1750	36	0.	*	20 JUL 0620	111	1.	*	20 JUL 1850	186	2.	*	21 JUL 0720	261	2.
19 JUL 1800	37	0.	*	20 JUL 0630	112	1.	*	20 JUL 1900	187	2.	*	21 JUL 0730	262	2.
19 JUL 1810	38	0.	*	20 JUL 0640	113	1.	*	20 JUL 1910	188	2.	*	21 JUL 0740	263	2.
19 JUL 1820	39	0.	*	20 JUL 0650	114	1.	*	20 JUL 1920	189	2.	*	21 JUL 0750	264	2.
19 JUL 1830	40	0.	*	20 JUL 0700	115	1.	*	20 JUL 1930	190	2.	*	21 JUL 0800	265	2.
19 JUL 1840	41	0.	*	20 JUL 0710	116	1.	*	20 JUL 1940	191	2.	*	21 JUL 0810	266	2.
19 JUL 1850	42	0.	*	20 JUL 0720	117	1.	*	20 JUL 1950	192	2.	*	21 JUL 0820	267	2.
19 JUL 1900	43	0.	*	20 JUL 0730	118	1.	*	20 JUL 2000	193	2.	*	21 JUL 0830	268	2.
19 JUL 1910	44	0.	*	20 JUL 0740	119	1.	*	20 JUL 2010	194	2.	*	21 JUL 0840	269	2.
19 JUL 1920	45	0.	*	20 JUL 0750	120	1.	*	20 JUL 2020	195	2.	*	21 JUL 0850	270	2.
19 JUL 1930	46	0.	*	20 JUL 0800	121	1.	*	20 JUL 2030	196	2.	*	21 JUL 0900	271	2.
19 JUL 1940	47	1.	*	20 JUL 0810	122	1.	*	20 JUL 2040	197	2.	*	21 JUL 0910	272	2.
19 JUL 1950	48	1.	*	20 JUL 0820	123	1.	*	20 JUL 2050	198	2.	*	21 JUL 0920	273	2.
19 JUL 2000	49	0.	*	20 JUL 0830	124	1.	*	20 JUL 2100	199	2.	*	21 JUL 0930	274	2.
19 JUL 2010	50	1.	*	20 JUL 0840	125	1.	*	20 JUL 2110	200	2.	*	21 JUL 0940	275	2.
19 JUL 2020	51	1.	*	20 JUL 0850	126	1.	*	20 JUL 2120	201	2.	*	21 JUL 0950	276	2.
19 JUL 2030	52	1.	*	20 JUL 0900	127	1.	*	20 JUL 2130	202	2.	*	21 JUL 1000	277	2.

19 JUL 2040	53	1.	*	20 JUL 0910	128	1.	*	20 JUL 2140	203	2.	*	21 JUL 1010	278	2.
19 JUL 2050	54	1.	*	20 JUL 0920	129	1.	*	20 JUL 2150	204	2.	*	21 JUL 1020	279	2.
19 JUL 2100	55	1.	*	20 JUL 0930	130	1.	*	20 JUL 2200	205	2.	*	21 JUL 1030	280	2.
19 JUL 2110	56	1.	*	20 JUL 0940	131	1.	*	20 JUL 2210	206	2.	*	21 JUL 1040	281	2.
19 JUL 2120	57	1.	*	20 JUL 0950	132	1.	*	20 JUL 2220	207	2.	*	21 JUL 1050	282	2.
19 JUL 2130	58	1.	*	20 JUL 1000	133	1.	*	20 JUL 2230	208	2.	*	21 JUL 1100	283	2.
19 JUL 2140	59	1.	*	20 JUL 1010	134	1.	*	20 JUL 2240	209	2.	*	21 JUL 1110	284	2.
19 JUL 2150	60	1.	*	20 JUL 1020	135	1.	*	20 JUL 2250	210	2.	*	21 JUL 1120	285	2.
19 JUL 2200	61	1.	*	20 JUL 1030	136	1.	*	20 JUL 2300	211	2.	*	21 JUL 1130	286	2.
19 JUL 2210	62	1.	*	20 JUL 1040	137	1.	*	20 JUL 2310	212	2.	*	21 JUL 1140	287	2.
19 JUL 2220	63	1.	*	20 JUL 1050	138	1.	*	20 JUL 2320	213	2.	*	21 JUL 1150	288	2.
19 JUL 2230	64	1.	*	20 JUL 1100	139	1.	*	20 JUL 2330	214	2.	*	21 JUL 1200	289	2.
19 JUL 2240	65	1.	*	20 JUL 1110	140	1.	*	20 JUL 2340	215	2.	*	21 JUL 1210	290	2.
19 JUL 2250	66	1.	*	20 JUL 1120	141	1.	*	20 JUL 2350	216	2.	*	21 JUL 1220	291	2.
19 JUL 2300	67	1.	*	20 JUL 1130	142	1.	*	21 JUL 0000	217	2.	*	21 JUL 1230	292	3.
19 JUL 2310	68	1.	*	20 JUL 1140	143	1.	*	21 JUL 0010	218	2.	*	21 JUL 1240	293	3.
19 JUL 2320	69	1.	*	20 JUL 1150	144	1.	*	21 JUL 0020	219	2.	*	21 JUL 1250	294	2.
19 JUL 2330	70	1.	*	20 JUL 1200	145	1.	*	21 JUL 0030	220	2.	*	21 JUL 1300	295	3.
19 JUL 2340	71	1.	*	20 JUL 1210	146	2.	*	21 JUL 0040	221	2.	*	21 JUL 1310	296	3.
19 JUL 2350	72	1.	*	20 JUL 1220	147	2.	*	21 JUL 0050	222	2.	*	21 JUL 1320	297	2.
20 JUL 0000	73	1.	*	20 JUL 1230	148	2.	*	21 JUL 0100	223	2.	*	21 JUL 1330	298	3.
20 JUL 0010	74	1.	*	20 JUL 1240	149	2.	*	21 JUL 0110	224	2.	*	21 JUL 1340	299	3.
20 JUL 0020	75	1.	*	20 JUL 1250	150	2.	*	21 JUL 0120	225	2.	*	21 JUL 1350	300	2.

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
		(CFS)				
+	3.	49.50	2.	2.	1.	1.
		(INCHES)	1.920	7.050	9.925	9.925
		(AC-FT)	1.	4.	6.	6.

CUMULATIVE AREA = .01 SQ MI

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55 KK * RES1 *
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Reservoir Routing Operation

HYDROGRAPH ROUTING DATA

57 RS	STORAGE ROUTING					
	NSTPS	1 NUMBER OF SUBREACHES				
	ITYP	ELEV TYPE OF INITIAL CONDITION				
	RSVRIC	74.00 INITIAL CONDITION				
	X	.00 WORKING R AND D COEFFICIENT				
58 SA	AREA	.0	.7	.8	.9	1.0
59 SE	ELEVATION	74.00	75.00	76.00	78.00	79.00
60 SQ	DISCHARGE	0.	0.	0.	2.	34.

61 SE ELEVATION 74.00 75.00 76.00 78.00 79.00

COMPUTED STORAGE-ELEVATION DATA

STORAGE	.00	.27	1.01	2.64	3.58
ELEVATION	74.00	75.00	76.00	78.00	79.00

COMPUTED STORAGE-OUTFLOW-ELEVATION DATA

STORAGE	.00	.27	1.01	2.64	3.58
OUTFLOW	.00	.00	.00	2.20	33.70
ELEVATION	74.00	75.00	76.00	78.00	79.00

HYDROGRAPH AT STATION RES1

DA MON HRMN ORD OUTFLOW STORAGE STAGE * DA MON HRMN ORD OUTFLOW STORAGE STAGE * DA MON
HRMN ORD OUTFLOW STORAGE STAGE

19 JUL 1200	1	0.	.0	74.0 * 20 JUL 0440	101	0.	.8	75.7 * 20 JUL 2120	201	1.	2.1	77.3
19 JUL 1210	2	0.	.0	74.0 * 20 JUL 0450	102	0.	.8	75.7 * 20 JUL 2130	202	1.	2.1	77.3
19 JUL 1220	3	0.	.0	74.0 * 20 JUL 0500	103	0.	.8	75.7 * 20 JUL 2140	203	1.	2.1	77.3
19 JUL 1230	4	0.	.0	74.0 * 20 JUL 0510	104	0.	.8	75.7 * 20 JUL 2150	204	1.	2.1	77.3
19 JUL 1240	5	0.	.0	74.0 * 20 JUL 0520	105	0.	.8	75.7 * 20 JUL 2200	205	1.	2.1	77.3
19 JUL 1250	6	0.	.0	74.0 * 20 JUL 0530	106	0.	.8	75.8 * 20 JUL 2210	206	1.	2.1	77.3
19 JUL 1300	7	0.	.0	74.1 * 20 JUL 0540	107	0.	.8	75.8 * 20 JUL 2220	207	1.	2.1	77.4
19 JUL 1310	8	0.	.0	74.1 * 20 JUL 0550	108	0.	.9	75.8 * 20 JUL 2230	208	1.	2.1	77.4
19 JUL 1320	9	0.	.0	74.1 * 20 JUL 0600	109	0.	.9	75.8 * 20 JUL 2240	209	2.	2.1	77.4
19 JUL 1330	10	0.	.0	74.1 * 20 JUL 0610	110	0.	.9	75.8 * 20 JUL 2250	210	2.	2.1	77.4
19 JUL 1340	11	0.	.0	74.1 * 20 JUL 0620	111	0.	.9	75.9 * 20 JUL 2300	211	2.	2.1	77.4
19 JUL 1350	12	0.	.0	74.1 * 20 JUL 0630	112	0.	.9	75.9 * 20 JUL 2310	212	2.	2.2	77.4
19 JUL 1400	13	0.	.0	74.1 * 20 JUL 0640	113	0.	.9	75.9 * 20 JUL 2320	213	2.	2.2	77.4
19 JUL 1410	14	0.	.0	74.1 * 20 JUL 0650	114	0.	.9	75.9 * 20 JUL 2330	214	2.	2.2	77.4
19 JUL 1420	15	0.	.0	74.1 * 20 JUL 0700	115	0.	1.0	75.9 * 20 JUL 2340	215	2.	2.2	77.4
19 JUL 1430	16	0.	.0	74.2 * 20 JUL 0710	116	0.	1.0	76.0 * 20 JUL 2350	216	2.	2.2	77.4
19 JUL 1440	17	0.	.0	74.2 * 20 JUL 0720	117	0.	1.0	76.0 * 21 JUL 0000	217	2.	2.2	77.4
19 JUL 1450	18	0.	.0	74.2 * 20 JUL 0730	118	0.	1.0	76.0 * 21 JUL 0010	218	2.	2.2	77.4
19 JUL 1500	19	0.	.1	74.2 * 20 JUL 0740	119	0.	1.0	76.0 * 21 JUL 0020	219	2.	2.2	77.5
19 JUL 1510	20	0.	.1	74.2 * 20 JUL 0750	120	0.	1.0	76.0 * 21 JUL 0030	220	2.	2.2	77.5
19 JUL 1520	21	0.	.1	74.2 * 20 JUL 0800	121	0.	1.0	76.1 * 21 JUL 0040	221	2.	2.2	77.5
19 JUL 1530	22	0.	.1	74.2 * 20 JUL 0810	122	0.	1.1	76.1 * 21 JUL 0050	222	2.	2.2	77.5
19 JUL 1540	23	0.	.1	74.2 * 20 JUL 0820	123	0.	1.1	76.1 * 21 JUL 0100	223	2.	2.2	77.5
19 JUL 1550	24	0.	.1	74.2 * 20 JUL 0830	124	0.	1.1	76.1 * 21 JUL 0110	224	2.	2.2	77.5
19 JUL 1600	25	0.	.1	74.3 * 20 JUL 0840	125	0.	1.1	76.1 * 21 JUL 0120	225	2.	2.2	77.5
19 JUL 1610	26	0.	.1	74.3 * 20 JUL 0850	126	0.	1.1	76.1 * 21 JUL 0130	226	2.	2.2	77.5
19 JUL 1620	27	0.	.1	74.3 * 20 JUL 0900	127	0.	1.1	76.2 * 21 JUL 0140	227	2.	2.3	77.5
19 JUL 1630	28	0.	.1	74.3 * 20 JUL 0910	128	0.	1.1	76.2 * 21 JUL 0150	228	2.	2.3	77.5
19 JUL 1640	29	0.	.1	74.3 * 20 JUL 0920	129	0.	1.2	76.2 * 21 JUL 0200	229	2.	2.3	77.5
19 JUL 1650	30	0.	.1	74.3 * 20 JUL 0930	130	0.	1.2	76.2 * 21 JUL 0210	230	2.	2.3	77.5
19 JUL 1700	31	0.	.1	74.3 * 20 JUL 0940	131	0.	1.2	76.2 * 21 JUL 0220	231	2.	2.3	77.5
19 JUL 1710	32	0.	.1	74.3 * 20 JUL 0950	132	0.	1.2	76.2 * 21 JUL 0230	232	2.	2.3	77.6
19 JUL 1720	33	0.	.1	74.3 * 20 JUL 1000	133	0.	1.2	76.2 * 21 JUL 0240	233	2.	2.3	77.6
19 JUL 1730	34	0.	.1	74.4 * 20 JUL 1010	134	0.	1.2	76.3 * 21 JUL 0250	234	2.	2.3	77.6
19 JUL 1740	35	0.	.1	74.4 * 20 JUL 1020	135	0.	1.2	76.3 * 21 JUL 0300	235	2.	2.3	77.6
19 JUL 1750	36	0.	.1	74.4 * 20 JUL 1030	136	0.	1.2	76.3 * 21 JUL 0310	236	2.	2.3	77.6
19 JUL 1800	37	0.	.1	74.4 * 20 JUL 1040	137	0.	1.3	76.3 * 21 JUL 0320	237	2.	2.3	77.6

19 JUL 1810 38	0.	.1	74.4 * 20 JUL 1050 138	0.	1.3	76.3 * 21 JUL 0330 238	2.	2.3	77.6
19 JUL 1820 39	0.	.1	74.4 * 20 JUL 1100 139	0.	1.3	76.3 * 21 JUL 0340 239	2.	2.3	77.6
19 JUL 1830 40	0.	.1	74.5 * 20 JUL 1110 140	0.	1.3	76.3 * 21 JUL 0350 240	2.	2.3	77.6
19 JUL 1840 41	0.	.1	74.5 * 20 JUL 1120 141	0.	1.3	76.4 * 21 JUL 0400 241	2.	2.3	77.6
19 JUL 1850 42	0.	.1	74.5 * 20 JUL 1130 142	0.	1.3	76.4 * 21 JUL 0410 242	2.	2.3	77.6
19 JUL 1900 43	0.	.1	74.5 * 20 JUL 1140 143	0.	1.3	76.4 * 21 JUL 0420 243	2.	2.3	77.6
19 JUL 1910 44	0.	.1	74.5 * 20 JUL 1150 144	0.	1.3	76.4 * 21 JUL 0430 244	2.	2.3	77.6
19 JUL 1920 45	0.	.2	74.6 * 20 JUL 1200 145	0.	1.3	76.4 * 21 JUL 0440 245	2.	2.3	77.6
19 JUL 1930 46	0.	.2	74.6 * 20 JUL 1210 146	0.	1.4	76.4 * 21 JUL 0450 246	2.	2.4	77.6
19 JUL 1940 47	0.	.2	74.6 * 20 JUL 1220 147	0.	1.4	76.5 * 21 JUL 0500 247	2.	2.4	77.7
19 JUL 1950 48	0.	.2	74.6 * 20 JUL 1230 148	1.	1.4	76.5 * 21 JUL 0510 248	2.	2.4	77.7
19 JUL 2000 49	0.	.2	74.7 * 20 JUL 1240 149	1.	1.4	76.5 * 21 JUL 0520 249	2.	2.4	77.7
19 JUL 2010 50	0.	.2	74.7 * 20 JUL 1250 150	1.	1.4	76.5 * 21 JUL 0530 250	2.	2.4	77.7
19 JUL 2020 51	0.	.2	74.7 * 20 JUL 1300 151	1.	1.5	76.5 * 21 JUL 0540 251	2.	2.4	77.7
19 JUL 2030 52	0.	.2	74.7 * 20 JUL 1310 152	1.	1.5	76.6 * 21 JUL 0550 252	2.	2.4	77.7
19 JUL 2040 53	0.	.2	74.8 * 20 JUL 1320 153	1.	1.5	76.6 * 21 JUL 0600 253	2.	2.4	77.7
19 JUL 2050 54	0.	.2	74.8 * 20 JUL 1330 154	1.	1.5	76.6 * 21 JUL 0610 254	2.	2.4	77.7
19 JUL 2100 55	0.	.2	74.8 * 20 JUL 1340 155	1.	1.5	76.6 * 21 JUL 0620 255	2.	2.4	77.7
19 JUL 2110 56	0.	.2	74.9 * 20 JUL 1350 156	1.	1.5	76.6 * 21 JUL 0630 256	2.	2.4	77.7
19 JUL 2120 57	0.	.2	74.9 * 20 JUL 1400 157	1.	1.5	76.7 * 21 JUL 0640 257	2.	2.4	77.7
19 JUL 2130 58	0.	.3	74.9 * 20 JUL 1410 158	1.	1.6	76.7 * 21 JUL 0650 258	2.	2.4	77.7
19 JUL 2140 59	0.	.3	75.0 * 20 JUL 1420 159	1.	1.6	76.7 * 21 JUL 0700 259	2.	2.4	77.7
19 JUL 2150 60	0.	.3	75.0 * 20 JUL 1430 160	1.	1.6	76.7 * 21 JUL 0710 260	2.	2.4	77.7
19 JUL 2200 61	0.	.3	75.0 * 20 JUL 1440 161	1.	1.6	76.7 * 21 JUL 0720 261	2.	2.4	77.7
19 JUL 2210 62	0.	.3	75.0 * 20 JUL 1450 162	1.	1.6	76.7 * 21 JUL 0730 262	2.	2.4	77.7
19 JUL 2220 63	0.	.3	75.0 * 20 JUL 1500 163	1.	1.6	76.8 * 21 JUL 0740 263	2.	2.4	77.7
19 JUL 2230 64	0.	.3	75.0 * 20 JUL 1510 164	1.	1.7	76.8 * 21 JUL 0750 264	2.	2.4	77.7
19 JUL 2240 65	0.	.3	75.1 * 20 JUL 1520 165	1.	1.7	76.8 * 21 JUL 0800 265	2.	2.4	77.7
19 JUL 2250 66	0.	.3	75.1 * 20 JUL 1530 166	1.	1.7	76.8 * 21 JUL 0810 266	2.	2.4	77.8
19 JUL 2300 67	0.	.3	75.1 * 20 JUL 1540 167	1.	1.7	76.8 * 21 JUL 0820 267	2.	2.4	77.8
19 JUL 2310 68	0.	.3	75.1 * 20 JUL 1550 168	1.	1.7	76.9 * 21 JUL 0830 268	2.	2.4	77.8
19 JUL 2320 69	0.	.4	75.1 * 20 JUL 1600 169	1.	1.7	76.9 * 21 JUL 0840 269	2.	2.4	77.8
19 JUL 2330 70	0.	.4	75.1 * 20 JUL 1610 170	1.	1.7	76.9 * 21 JUL 0850 270	2.	2.4	77.8
19 JUL 2340 71	0.	.4	75.1 * 20 JUL 1620 171	1.	1.7	76.9 * 21 JUL 0900 271	2.	2.5	77.8
19 JUL 2350 72	0.	.4	75.2 * 20 JUL 1630 172	1.	1.8	76.9 * 21 JUL 0910 272	2.	2.5	77.8
20 JUL 0000 73	0.	.4	75.2 * 20 JUL 1640 173	1.	1.8	76.9 * 21 JUL 0920 273	2.	2.5	77.8
20 JUL 0010 74	0.	.4	75.2 * 20 JUL 1650 174	1.	1.8	76.9 * 21 JUL 0930 274	2.	2.5	77.8
20 JUL 0020 75	0.	.4	75.2 * 20 JUL 1700 175	1.	1.8	77.0 * 21 JUL 0940 275	2.	2.5	77.8
20 JUL 0030 76	0.	.4	75.2 * 20 JUL 1710 176	1.	1.8	77.0 * 21 JUL 0950 276	2.	2.5	77.8
20 JUL 0040 77	0.	.5	75.2 * 20 JUL 1720 177	1.	1.8	77.0 * 21 JUL 1000 277	2.	2.5	77.8
20 JUL 0050 78	0.	.5	75.3 * 20 JUL 1730 178	1.	1.8	77.0 * 21 JUL 1010 278	2.	2.5	77.8
20 JUL 0100 79	0.	.5	75.3 * 20 JUL 1740 179	1.	1.8	77.0 * 21 JUL 1020 279	2.	2.5	77.8
20 JUL 0110 80	0.	.5	75.3 * 20 JUL 1750 180	1.	1.9	77.0 * 21 JUL 1030 280	2.	2.5	77.8
20 JUL 0120 81	0.	.5	75.3 * 20 JUL 1800 181	1.	1.9	77.0 * 21 JUL 1040 281	2.	2.5	77.8
20 JUL 0130 82	0.	.5	75.3 * 20 JUL 1810 182	1.	1.9	77.1 * 21 JUL 1050 282	2.	2.5	77.8
20 JUL 0140 83	0.	.5	75.3 * 20 JUL 1820 183	1.	1.9	77.1 * 21 JUL 1100 283	2.	2.5	77.8
20 JUL 0150 84	0.	.5	75.4 * 20 JUL 1830 184	1.	1.9	77.1 * 21 JUL 1110 284	2.	2.5	77.8
20 JUL 0200 85	0.	.5	75.4 * 20 JUL 1840 185	1.	1.9	77.1 * 21 JUL 1120 285	2.	2.5	77.8
20 JUL 0210 86	0.	.6	75.4 * 20 JUL 1850 186	1.	1.9	77.1 * 21 JUL 1130 286	2.	2.5	77.8
20 JUL 0220 87	0.	.6	75.4 * 20 JUL 1900 187	1.	1.9	77.1 * 21 JUL 1140 287	2.	2.5	77.8
20 JUL 0230 88	0.	.6	75.4 * 20 JUL 1910 188	1.	1.9	77.1 * 21 JUL 1150 288	2.	2.5	77.8
20 JUL 0240 89	0.	.6	75.4 * 20 JUL 1920 189	1.	1.9	77.2 * 21 JUL 1200 289	2.	2.5	77.8
20 JUL 0250 90	0.	.6	75.5 * 20 JUL 1930 190	1.	2.0	77.2 * 21 JUL 1210 290	2.	2.5	77.9
20 JUL 0300 91	0.	.6	75.5 * 20 JUL 1940 191	1.	2.0	77.2 * 21 JUL 1220 291	2.	2.5	77.9
20 JUL 0310 92	0.	.6	75.5 * 20 JUL 1950 192	1.	2.0	77.2 * 21 JUL 1230 292	2.	2.5	77.9
20 JUL 0320 93	0.	.6	75.5 * 20 JUL 2000 193	1.	2.0	77.2 * 21 JUL 1240 293	2.	2.5	77.9
20 JUL 0330 94	0.	.7	75.5 * 20 JUL 2010 194	1.	2.0	77.2 * 21 JUL 1250 294	2.	2.5	77.9
20 JUL 0340 95	0.	.7	75.5 * 20 JUL 2020 195	1.	2.0	77.2 * 21 JUL 1300 295	2.	2.6	77.9
20 JUL 0350 96	0.	.7	75.6 * 20 JUL 2030 196	1.	2.0	77.2 * 21 JUL 1310 296	2.	2.6	77.9
20 JUL 0400 97	0.	.7	75.6 * 20 JUL 2040 197	1.	2.0	77.2 * 21 JUL 1320 297	2.	2.6	77.9
20 JUL 0410 98	0.	.7	75.6 * 20 JUL 2050 198	1.	2.0	77.3 * 21 JUL 1330 298	2.	2.6	77.9
20 JUL 0420 99	0.	.7	75.6 * 20 JUL 2100 199	1.	2.0	77.3 * 21 JUL 1340 299	2.	2.6	77.9
20 JUL 0430 100	0.	.7	75.6 * 20 JUL 2110 200	1.	2.1	77.3 * 21 JUL 1350 300	2.	2.6	77.9

*

*

PEAK FLOW		TIME	MAXIMUM AVERAGE FLOW			
			6-HR	24-HR	72-HR	49.83-HR
+	(CFS)	(HR)				
+	2.	49.83	2.	2.	1.	1.
		(CFS)				
		(INCHES)	1.669	5.291	5.589	5.589
		(AC-FT)	1.	3.	3.	3.

PEAK STORAGE		TIME	MAXIMUM AVERAGE STORAGE			
			6-HR	24-HR	72-HR	49.83-HR
+	(AC-FT)	(HR)				
	3.	49.83	2.	2.	1.	1.

PEAK STAGE		TIME	MAXIMUM AVERAGE STAGE			
			6-HR	24-HR	72-HR	49.83-HR
+	(FEET)	(HR)				
	77.92	49.83	77.82	77.44	76.31	76.31

CUMULATIVE AREA = .01 SQ MI

1

RUNOFF SUMMARY
FLOW IN CUBIC FEET PER SECOND
TIME IN HOURS, AREA IN SQUARE MILES

OF	OPERATION	STATION	PEAK FLOW	TIME OF FLOW	AVERAGE FLOW FOR MAXIMUM PERIOD			AREA	BASIN	MAXIMUM STAGE	TIME
					6-HOUR	24-HOUR	72-HOUR				
+	HYDROGRAPH AT SITE	2.	49.67	2.	2.	1.	.01				
+	HYDROGRAPH AT POND	0.	48.50	0.	0.	0.	.00				
+	2 COMBINED AT COMB	3.	49.50	2.	2.	1.	.01				
+	ROUTED TO RES1	2.	49.83	2.	2.	1.	.01				
+								77.92	49.83		

*** NORMAL END OF HEC-1 ***



4.0 Effects of Site Preparation, and Plant and Associated Facilities Construction

4.1 Land Impact

Construction of Cane Island Power Park Unit 3 (Unit 3) will occur entirely within the previously permitted area on the central portion of Cane Island, with the exception of the treated effluent pumping station near the Power Park entrance. Approximately 8 acres will be impacted during construction. Approximately 5 acres will be permanently impacted by Unit 3 operation. As described in Section 2.3.9 - Other Environmental Features, ultimate power block area development was delineated and mitigated during the permitting of Units 1 and 2. The effects of construction of the Cane Island-Intercession City Transmission Line are described in Section 6.

4.1.1 General Construction Impacts

The Cane Island Power Park (Power Park) includes 1,027 acres. Units 1 and 2 and associated facilities occupy 15 acres on Cane Island. Unit 3 and associated facilities will require an additional 5 acres. Therefore, 20 acres, or 43 percent of the permitted 47 acres on Cane Island proper, will be occupied with the addition of Unit 3. Construction of Unit 3 will permanently alter additional lands on Cane Island to an industrial use for the life of the facility.

The area proposed for development of the Unit 3 facilities is, for the most part, the construction equipment/materials lay-down area that was used during construction of Units 1 and 2. This 4 acre area is generally grassland with scattered trees located immediately north of Unit 2. The 1 acre storm water pond associated with Unit 3 will be located immediately north of the existing switchyard in sand pine scrub area. A new 3 acre construction equipment/materials lay-down area for Unit 3 will be located immediately north of the Unit 3 power block and west of the new storm water pond in mostly sand pine scrub habitat. Facility locations are shown on Figure 2.1-3 in Section 2.

No explosives will be used during construction. No paved roads will be required for Unit 3 construction access. Unimproved trails are available in the construction area such that new roads will not be needed for Power Park or Unit 3 construction area access. No railroad spur will be required. The CSX Railroad operates a track adjacent to the southern property boundary that could be used for deliveries.



Construction of Unit 3 will modify the existing terrain. The Unit 3 facilities areas will be cleared and grubbed. The power block area will be raised to the minimum floor elevation of 81.5 feet NGVD. The new storm water pond will require excavation. Construction materials, such as concrete, steel, and aggregate, will be delivered to the site by trucks.

Waste oils, grease, hydraulic fluids, construction wastes, and garbage will be collected, stored, and removed appropriately from the Power Park for disposal at a properly licensed landfill or resource recovery facility by the general services contractor or individual construction contractors. Such activities will be supervised and controlled by the Construction Manager.

Vegetative matter removed during site clearing will be burned onsite after receiving the proper authorizations from Osceola County. Some trees may be removed from the proposed lay-down area, but this area will not require total clearing.

4.1.2 Roads

No new roads connecting to state roads will be required for Unit 3 construction or operation. Therefore, the "Utility Accommodation Guide" assessment is not required.

The existing paved plant loop road on the north side of Unit 2 will be removed for placement of the Unit 3 generation building. A new paved road will be constructed around the Unit 3 generation building and connected to the plant road system as shown on Figure 2.1-3 in Section 2.

4.1.3 Flood Zones

The plant access road and Units 1 and 2 buildings were placed above the 10 year 24 hour, and 100 year 72 hour design rainfall events, respectively, as required by the SFWMD for issuance of the Surface Water Management Permit. Unit 3 buildings will also be placed above the 100 year, 72 hour design rainfall event. Compensating storage volume to offset the loss of flood storage capacity from Unit 3 construction will be provided by a new storm water detention pond.

4.1.4 Topography and Soils

As described in Section 4.1.1 above, the proposed construction area is, for the most part, the construction lay-down area used during construction of Units 1 and 2. This area is a



relatively flat grassland with scattered trees. The storm water pond associated with Unit 3 will be located in a relatively flat sand pine scrub area. The soils in both of these areas are generally sandy.

Construction will begin with the installation of erosion and sedimentation control structures at the perimeter of the construction areas. The construction areas will then be cleared, grubbed, and prepared for buildings and foundations. The storm water pond will be excavated early to collect storm water runoff from the construction area and provide fill material. A minimal amount of fill will be required in the construction area to match elevations and facilitate drainage. Final paving, grading, and landscaping will complete Unit 3 construction. In addition to the erosion and sedimentation control measures, water sprays will be used to control fugitive dust.

Subsurface modifications may also be required in the power block area, after testing, due to the karst topography of the project area. Modification techniques may include vibroflotation, vibroreplacement, or possibly sinkhole grouting. The purpose of these modifications is to increase the load bearing strength of the in situ soils and subsoils.

The modifications will minimize the potential for sinkhole formation in the power block area. The results of the modifications and construction will increase the amount of impervious area, reduce the permeability and percolation rates of the site, and increase the site runoff rate. As described above, the purpose of the storm water detention pond is to compensate for the loss of pervious area and provide runoff/flood storage capacity. These modifications will not alter the aesthetics or viewshed features of the project area due to the flat terrain and extensive buffer surrounding the power block.

4.2 Impact on Surface Water Bodies and Uses

Reedy Creek crosses the southwest portion of the Power Park, more than one-half mile from the power block area. The Bonnet Creek Canal is offsite, one-half mile west of the power block area at its nearest point. Onsite Reedy Creek Swamp wetlands buffer these surface waters from the power block area.

4.2.1 Impact Assessment

Construction of Unit 3 will have no significant impact on Reedy Creek, the Bonnet Creek Canal, or the onsite wetlands. The erosion and sedimentation control measures will control



and minimize such impacts beyond the 8 acre construction zone. The Unit 3 storm water pond, and temporary drainage ditches, will be developed early in the construction sequence to serve as the construction drainage system, providing treatment of storm waters and dewatering discharges through detention. In the event of storm water pond overflow, treated waters could enter the wetlands surrounding Cane Island.

4.2.2 Measuring and Monitoring Programs

If required during construction, KUA will collect water quality grab samples from storm water pond overflow discharges. The sample will be tested in accordance with FDEP standards.

The size (8 acres) of the construction area will require KUA to obtain a federal NPDES Storm Water General Permit for storm water discharges associated with construction activity. One condition of this permit is the preparation and implementation of a pollution prevention plan specific to the construction site. In addition to a description of the project, potential pollutant sources, and the storm water management control plan, the pollution prevention plan must include spill prevention and system maintenance/inspection procedures.

4.3 Groundwater Impacts

4.3.1 Impact Assessment

During Unit 3 construction, two facilities will be constructed below the surface of the upper unconfined ground water system in the power block area. It will be necessary to dewater the excavations for construction of the new neutralization basin and oil/water separator. The locations of these facilities are shown on Figure 2.1-3 Site Arrangement.

The majority of the underground utilities, circulating water lines, miscellaneous pits, and sumps will be constructed above the groundwater surface and will have no impact on the groundwater at the site.

Dewatering for the neutralization basin and the oil/water separator will be completed with a series of wellpoints installed around the perimeter of the excavation. The dewatering activity duration will be short term, less than 120 days, with total withdrawal volumes of less than 1 million gpd. Discharge from the dewatering activities will be directed to the Units 1 and 2 storm water pond. Much of the discharge into the storm water pond is expected to percolate through the base of the pond.



The dewatering effects will be temporary and limited to the power block area. The ground water system will return to its original state after completion of the dewatering.

4.3.2 Measuring and Monitoring Program

A ground water monitoring system has been established at the Power Park to measure the seasonal ground water level fluctuations and perform water quality testing of samples. A description of the existing monitoring program is presented in Section 5.3.5. Monitoring of these wells will continue during construction.

4.4 Ecological Impacts

Site preparation and construction of Unit 3 facilities will impact upland habitats and resident wildlife. Site preparation and construction of Units 1 and 2 impacted upland and wetland habitats, and resident wildlife. Black & Veatch, at the request of KUA and as required by resource agencies, acquired the necessary permits for construction and prepared and implemented the *Cane Island Project Mitigation Plan* (1993) to mitigate and compensate for ecological impacts associated with ultimate site development. Table 4.4-1 lists the resource agencies involved in the ecological aspects of the Power Park and the permits issued by each.

4.4.1 Impact Assessment

Site preparation for construction of the proposed Unit 3 facilities and the effluent pumping station will permanently impact wildlife habitat. All vegetation will be permanently removed from Unit 3 power block area and pumping station location during site preparation. As a result, there will be a decrease of wildlife habitat which will reduce the primary productivity at the Power Park and displace wildlife from the impact areas. Additionally, wildlife species may also be temporarily displaced from adjacent communities by the noise, fugitive dust, and activity caused by construction.

The Unit 3 facility will clear 5 acres of grassland and sand pine scrub vegetation. Gopher tortoises were taken and displaced during the clearing and construction of Units 1 and 2 during development, and may be taken during site preparation and construction of Unit 3 and associated facilities. The FGFWFC issued Permit No. OSC-6 for the incidental take of gopher tortoises and their burrows during construction. This permit is still current.



Table 4.4-1
Resource Agencies and Permits for Ecological Impacts

Agency	Permit Name	Permit Number
Osceola County	Conditional Use/Site Development Plan	CU/SDP 92-86
Florida Game and Fresh Water Fish Commission	Gopher Tortoise Incidental Take Permit	OSC-6
South Florida Water Management District	Surface Water Management Permit	49-00672-S
USCOE/USFWS	Work in Wetlands	199200600 (IP-SL)
Florida Department of Environmental Protection	Work in Wetlands	49-211129-4



4.4.2 Measuring and Monitoring Programs

Vegetation and wildlife monitoring and management is required by the resource agencies as mitigation for Power Park development. These efforts are conducted in compliance with the *Cane Island Project Mitigation Plan* (1993). Monitoring efforts were conducted in 1993 (preconstruction) and 1997 (post-construction) and will be conducted once every 5 years until 2017. Monitoring reports are submitted annually to the SFWMD and other interested agencies. Wildlife at the Power Park is surveyed by opportunistic observations, pedestrian surveys, and live-trapping. Vegetation is sampled by direct measurement methods. Unit 3 and associated facilities development will not require alteration or modification of the wildlife monitoring program described in Subsection 2.3.6.3 or the *Cane Island Project Mitigation Plan*.

4.5 Air Impacts

During the Unit 3 construction phase, atmospheric dust (particulate matter) will be generated from the mechanical disturbance of granular material that becomes exposed to the wind at the construction site. The particulate matter dust is often referred to as fugitive dust, as its source is particulate matter that cannot be reasonably discharged to the atmosphere in a confined flow stream.

4.5.1 Sources of Construction Fugitive Dust

Construction activities, including material moving activities, site preparation, and vehicle traffic, if not properly monitored and controlled, have the potential to generate large amounts of fugitive dust. The construction activities at the Power Park may be generally broken down into three phases as related to generating fugitive dust.

Phase 1 - Debris Removal: Debris removal consists of removing any manmade or natural obstructions from the site. Under extreme circumstances, this phase of construction may require blasting, explosion, or mechanical dismemberment of the obstructions in order to clear the site. However, this level of debris removal is not anticipated, and will likely be limited to material loading/unloading, small disturbed areas, and vehicular travel on unpaved surfaces.



Phase 2 - Site Preparation: Site development includes the general site grading and soil stabilization techniques used to bring the site to a final or near final grade. These techniques will typically include cut and fill as well as aggregate surfacing operations. Typical fugitive dust emission sources of this phase include movement of large earth moving equipment (e.g., scrapers and dozers) over disturbed surfaces, material/aggregate loading and unloading, and vehicular travel on unpaved surfaces.

Phase 3 - General Construction: The construction phase is the final, but generally the longest phase of the construction activities. This phase includes everything from foundation work, structural and reinforcing steel erection, exterior/interior operations, to piping/electrical work and final landscaping. In contrast to Phases 1 and 2, fugitive dust emissions during Phase 3 are somewhat sporadic in nature, depending on the delivery schedule of parts and materials, with many simultaneous operations throughout the construction site.

Within each of the major construction phases described above, there may be one or more specific construction activities occurring during that phase that can be a source(s) of fugitive dust. The fugitive dust emission sources resulting from these construction activities are typically assigned into one of four categories which include: disturbed surface areas, open storage piles, earth moving, and vehicular traffic. The following sections describe each of these fugitive dust emission sources as applicable to the Unit 3 construction site.

4.5.1.1 Disturbed Surface Areas. Many of the construction activities will result in disturbed surface areas in the power block area which may be subject to wind erosion. A disturbed surface refers to a portion of the earth's surface which has been physically moved, uncovered, destabilized, or otherwise modified from its undisturbed natural soil condition, thereby increasing the potential for emissions of fugitive dust. Disturbed surfaces do not include those areas which have been restored to a natural state such that the vegetative ground cover is similar to any adjacent natural conditions, or which have been paved or covered by a permanent structure.

4.5.1.2 Storage Piles. A storage pile is any accumulation of bulk material, generally with a 5 percent or greater silt content, that is not fully enclosed or otherwise covered or chemically stabilized. The storage pile may be composed of soil, stored temporarily during



cut and fill operations, or may be composed of aggregate used in foundation work and construction materials. Storage piles of this nature are typically left uncovered because of the frequent need to transfer material into and out of storage.

Fugitive dust emissions may occur at several points in the storage pile cycle, including material loading or unloading (material handling), and dust entrainment in wind currents on the exposed slopes of the storage pile.

4.5.1.3 Earth Moving. Earth moving refers to a broad range of construction activities using heavy equipment to clear land, excavate, cut and fill, etc. The activities may directly expose material to wind erosion through excavation, scraping, hauling, loading, transferring and other material moving activities.

4.5.1.4 Vehicular Traffic. Vehicular traffic associated with the construction activities will include worker vehicles, equipment deliveries, and heavy construction vehicle traffic over unpaved surfaces. When a vehicle travels on an unpaved surface, the force of the wheels on the surface causes the material on the road to become lifted, dropped, and then entrained into the turbulent air currents caused by the velocity of the vehicle. As such, the vehicle's speed and size, silt content of the road surface, and material moisture content all play a role in determining the magnitude of the fugitive dust emissions from unpaved roads.

4.5.2 Available Control Methods

Fugitive dust emissions may result from a variety of activities that may require a multitude of different emission control alternatives. Additionally, the relatively short-term nature of construction activities make some fugitive dust control methods more cost effective and practical than others. Tables 4.5-1 through 4.5-4 describe several available fugitive dust control methods and practices associated with disturbed surfaces, storage piles, earth moving, and vehicular traffic that may be employed to control fugitive dust during construction. The available control methods identified in each table are summarized in the following subsections. The control methods ultimately used will be agreed upon by the Contractor and Construction Manager.

4.5.2.1 Watering. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder by either maintaining soil moisture content or establishing a crust which prevents soil movement under windy



Table 4.5-1
Available Fugitive Dust Control Methods for
Disturbed Surface Areas

Control Method	Description/Remarks
Work Practice Controls	Paving identified roads and access points early in the construction process, phasing of earth moving activities to reduce disturbed surface extent, compaction and/or stabilization of disturbed surfaces as quickly as practical. Onsite traffic control program to direct, control, and restrict unnecessary traffic.
Watering	Use of water or water plus a wetting agent to suppress fugitive dust over disturbed areas. Typically applied with spray nozzles attached to a special truck adapted for this purpose. Temporary in nature, but cost-effective even with frequent reapplication.
Graveling	Graveling of high volume traffic areas within the disturbed area of the construction site provides a physical stabilization of the exposed surface and covers the surface with a material having a lower silt content.
Wind Fencing	Wind fencing provides a sheltered region behind the fence line which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence around the disturbed surface.
Physical Stabilization	Physical stabilization methods involve the application of materials such as rock, bark, wood chips, straw, or other suitable materials to cover the exposed surface, thus preventing the wind from disturbing the surface particles. Graveling is one example of physical stabilization.
Vegetative Stabilization	Vegetative cover provides a physical stabilization and wind shelter of the disturbed surface. However, it is effective only on inactive areas of the disturbed surfaces where frequent mechanical (i.e., earth moving) activities are not anticipated. As such, it is typically not implemented during short-term construction activities.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.



Table 4.5-2
Available Fugitive Dust Control Methods for
Storage Piles

Control Method	Description/Remarks
Work Practice Controls	Minimize temporary material storage pile(s) size and number by utilizing phased earth moving activities. Minimized drop height when adding material to the pile(s), and perform loading and unloading operations on the leeward (down wind) side of the pile. Cleanup spillage and maintain material to the confines of the pile.
Watering	Use of water or water plus a wetting agent to suppress fugitive dust from the storage pile. Temporary in nature, but cost-effective even with frequent reapplication.
Wind Fencing/Barriers	Wind fencing or partial temporary barriers or enclosures provides a sheltered region in the vicinity of the storage pile which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence or barrier.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.



Table 4.5-3
Available Fugitive Dust Control Methods for
Earth Moving

Control Method	Description/Remarks
Work Practice Controls	Onsite traffic control program to direct, control speed, and restrict unnecessary traffic. Reduce offsite hauling with balanced cut and fill operations and construction management. Cover truck beds during material hauling operations.
Watering	Preapplication of water or water plus a wetting agent to suppress fugitive dust prior to, and to the extent possible, during earth moving operations. Temporary in nature, but cost-effective even with frequent reapplication.
Wheel Washing	Water washing of heavy construction equipment wheels and undercarriages at construction site egress points to prevent material trackout and deposition outside of the construction site. System may include automatic or manual sprayers, and/or drive-through wheel washing basins.
Wind Fencing/ Barriers	Wind fencing or partial temporary barriers or enclosures provides a sheltered region in the vicinity of the storage pile which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence or barrier.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.



Table 4.5-4
Available Fugitive Dust Control Methods for
Vehicular Traffic

Control Method	Description/Remarks
Work Practice Controls	Onsite traffic control program to direct, control speed, and restrict unnecessary traffic. Reduce offsite hauling with balanced cut and fill operations and construction management. Cover truck beds during material hauling operations.
Watering	UNPAVED ROADS Application of water or water plus a wetting agent to suppress fugitive dust prior to, and to the extent possible, during earth moving operations. Temporary in nature, but cost-effective even with frequent reapplication.
Graveling	Graveling of high volume unpaved traffic areas provides a physical stabilization of the exposed surface and covers the surface with a material having a lower silt content.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.



conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. Watering is most effective when an area or road surface is prewatered, with frequent reapplication as necessary.

4.5.2.2 Chemical Stabilizers. Chemical stabilizers are commercially available and contain approved chemical soil binding agents to artificially crust soil and prevent soil movement during windy conditions. Stabilizers are effective for temporary periods. Depending on the application rates and/or materials involved, stabilizer use may extend the durability and longevity of the artificial soil crust for longer periods. As such, stabilizers are best suited for areas not subject to daily disturbance.

4.5.2.3 Physical Barriers. Physical barriers provide a sheltered region behind the barrier to allow gravitational settling of larger fugitive dust particles, as well as a reduction in the wind's erosion potential. Physical barriers reduce the mechanical turbulence generated by the ambient winds for a downwind distance proportional to the height of the barrier and porosity. Physical barriers include portable wind screens and fences, partial enclosures, hay/straw bales, tree lines, and terraces for example. Wind screens and fences can be used to control a wide variety of fugitive dust sources at a construction site, including disturbed areas, storage piles, and providing shelter for material handling operations such as storage pile loading or unloading. Furthermore, fences and screens are portable and thus capable of being relocated around the construction site as necessary.

4.5.2.4 Vegetative Stabilization. Vegetative stabilization uses established cover or locally recommended varieties and seeding rates that approximate native cover to stabilize soil against wind erosion and emission of fugitive dust. Either temporary or permanent cover can be established using standard agricultural methods, hydroseeding, or hand seeding. Temporary cover for areas that will be disturbed again after a short period is best established by using rapidly emerging varieties of vegetation with rapid initial growth. Maintenance of the original vegetative cover and opportunistic vegetation such as weeds and native species are also options, but may require some watering to establish.

Vegetative stabilization as a fugitive dust control method is most effective only on inactive areas of the disturbed surfaces where frequent mechanical (i.e., earth moving)



activities are not anticipated. As such, it is typically not implemented on a large scale for control of fugitive dust emissions during short-term construction activities.

4.5.2.5 Work Practice Controls. There are a number of work practice controls that can be applied to reduce the fugitive dust emissions during construction activities. These work practices include both active and preventive fugitive dust control methods which are typically integrated into a comprehensive construction management plan. The following list contains several common work practice activities that may be applied to reduce fugitive dust emissions during construction.

- Pave designated roads, construction parking areas, and site access points early on in the construction project.
- Compact or stabilize disturbed areas as quickly as practical.
- Phase earth moving activities to reduce disturbed surface extent.
- Maintain original vegetative ground cover as long as practical.
- Establish a traffic control plan to decrease disturbance of soil and fugitive dust generated from unnecessary vehicle traffic by posting speed limit signs (generally less than 10 mph), erecting fencing and/or placing barriers to direct traffic, designating specific haul and/or access roads, designating offsite or limited access onsite parking for construction workers, and limiting public vehicle access.
- Reduce offsite hauling via balanced cut and fill operations.

4.5.2.6 Physical Stabilization. Physical stabilization methods, which involve covering a disturbed surface with a material that prevents the wind from entraining the surface particles, may be used during many phases of the construction project. Common physical stabilizing materials include rock, gravel, crushed or granulated slag, bark, wood chips, straw, or hay that are harrowed into the top few inches of the disturbed surface.

4.6 Impact on Human Populations

4.6.1 Project Location and Description of Nearby Housing

Despite being in the center of a large area experiencing tremendous economic and population growth over the last 10 years, the Power Park is unpopulated. To the north, west,



and northeast of the Power Park are uninhabited conservation areas. Adjacent to the south boundary of the Power Park is the CSX railway line, Old Tampa Highway and, a few hundred yards farther south, Highway 17/92. The rail line and these two highways run roughly east-west at this location. Approximately 14 houses are located due south of the Power Park in a triangle shaped area formed by the confluence of Old Tampa Highway and Highway 17/92. South of Highway 17/92 is open agricultural land. The unincorporated community of Intercession City lies about 1 mile to the east along Old Tampa Highway. The eastern portion of Kissimmee lies about 5 miles to the east.

The nearest residents to the power block are located 3,200 feet to the south along Old Tampa Highway and 4,000 feet to the southeast off Wooten Road. Residential density increases progressively toward Intercession City, about 1 mile east of the Power Park entrance.

4.6.2 Project Description

Development of Unit 3 consists of the installation and operation of a combined cycle combustion turbine electric generator. The Power Park has two existing electric generating units in operation that have been active since 1995. The Unit 3 construction project will consist of several phases. The first phase will include grading, excavating, and creating necessary foundations for the HRSG and steam turbine buildings and combustion turbine, spill containment and neutralization basins, oil/water separators, a false start tank, and a storm water detention pond. The second phase will consist of the actual construction of the structures to house the HRSG and steam turbine, as well as the cooling tower. After the structures are in-place, the HRSG and steam turbine will be delivered and installed. Finally, electric equipment such as wiring and transformers will be delivered and installed. The new cooling tower will use treated effluent from City of Kissimmee Water & Sewer Department, as does the Unit 2 cooling tower. The cooling tower blowdown will be returned to the effluent pipeline which runs adjacent to the southern boundary of the Power Park.

4.6.2.1 Project Workforce. The construction project is anticipated to employ, at peak, approximately 240 construction workers. The entire construction phase is expected to last approximately 20 months.



The current operating staff at the Power Park is 28 employees. The addition of the new generating unit is expected to require only an additional 2 full-time operational workers.

4.6.3 Effects of Construction on Local Human Population

Large scale construction projects have the potential to affect many people over a wide geographic area. However, the current construction project is expected to be similar to the Units 1 and 2 construction project. Unit 3 construction is not expected produce any significant negative impacts on the local population due to the combination of the level and duration of recent construction activity in nearby areas, and the remote and isolated area in which the project is located.

4.6.3.1 Storm Water Impacts. The construction phase will disturb more than 5 acres of land and will alter the amount of storm water discharged from the site. However, the amount of additional runoff from the construction site is not expected to be sufficient to negatively effect any of the nearby residences. This is due to the fact that storm water runoff control efforts will be designed and installed, including grading, a storm water detention pond, and strategically placed barriers of silt fences and/or straw bales to control runoff speeds and avenues. Even without control efforts, the distance to the nearest residence and the intervening swamp would prevent any additional runoff from the construction site from creating any negative impact on residents.

4.6.3.2 Visual Impacts. No significant negative visual impacts are anticipated from the Unit 3 construction project. The new combustion turbine unit will be located entirely within the established Power Park boundaries. Heavy forest vegetation exists between the power block area and Old Tampa Highway, the closest public thoroughfare, and location of the nearest residences. The combination of the setback distance and the type and density of the buffer vegetation renders the power block nearly invisible from public view. The heights and locations of the Unit 3 facilities will not significantly alter the aesthetics of the Power Park or region.

Potentially the most visible aspect of the Unit 3 project will be the stack. The HRSG stack will be approximately 130 feet tall and located in the north end of the power block. With the 100 foot Unit 2 stack already in this area, the net visual effect is not expected to be



significant. However, the top of the stack may be visible from Old Tampa Highway or US-17/92 directly south of the Power Park. No fogging or visible plume is anticipated from the new Unit 3 cooling tower under normal operating conditions. Exhaust stack plume visibility is expected to be minimal.

Trees will need to be removed for Unit 3 construction. In compliance with Osceola County Ordinance 87-15, which is designed to preserve and maintain a minimum amount of tree canopy, an application to remove trees greater than 4"- 6" DBH is included in this Site Certification Application in Appendix 10.6. The trees to be removed are not expected to be large or numerous enough to cause a significant loss of aesthetic value of the power block location.

4.6.3.3 Impacts on Local Housing. The construction of Unit 3 is not expected to have any negative impacts on the availability of housing stock in the impact area. Due to the tremendous availability of construction workers in the project impact area, and the multiple highway access routes to the Power Park, it is anticipated that the vast majority of workers for the construction phase will commute daily from their established residences. These workers will, therefore, have no effect on housing patterns. Of the remaining workers, most are expected to commute weekly from more distant residences, traveling without their families and spending nights in temporary housing such as recreational vehicle campgrounds or hotel rooms. Studies have indicated that construction workers often commute in this fashion since the temporary nature of the positions do not make it economically feasible for complete relocation.

Due to the fact that the impact area is a popular vacation and tourist destination, sufficient capacity of short-term housing exists. As mentioned previously in this application, thousands of hotel rooms, apartments, and recreational vehicle campgrounds are available throughout the impact area.

It is possible that a few construction workers will decide to relocate into the project impact area. However, the number of these workers is not expected to be large enough to overwhelm the existing available housing stock. Not only does sufficient housing stock already exist, but the high-growth history of the project impact area has already led builders and developers to plan for and begin new housing facilities.



4.6.3.4 Impacts on Educational Opportunities. Since the majority of workers are expected to either commute daily from their established residences within the impact area or commute weekly without their families, there are no anticipated impacts on opportunities for any level of education.

4.6.3.5 Impacts from Noise. Noise emissions attributable to construction activities are highly variable, depending upon the location and operating load of the construction equipment. The following sections discuss the methodology for calculating the construction activity noise emissions, the offsite noise levels associated with Unit 3 construction, and the evaluation of the noise levels.

Construction Activities

Major construction phases will consist of site clearing and preparation, foundation construction, building and equipment erection, site cleanup, and facility startup. Noise emissions will vary with each phase of construction depending on the construction activity and the associated equipment.

Site clearing and preparation will require the use of heavy diesel-powered earth moving equipment. This equipment will include bulldozers, scrapers, dump trucks, and front end loaders. Noise emissions during this construction phase will be dominated by the diesel engine noise. Site clearing and preparation activities will occur at all locations where equipment will be installed.

Foundation construction primarily will involve concrete handling equipment such as concrete trucks, mixers, vibrators, and pumps. Some earth moving equipment will also be required to backfill the foundations. Foundation construction activities will be centered at the Unit 3 Generation Building, and Unit 3 combustion turbine.

The building and equipment installation will involve mobile cranes, equipment delivery, impact wrenches, and air compressors. Because combustion turbine installation will require minimal onsite assembly of equipment, installation noise emissions are expected to be less than during other phases of construction. The activities will be centered at the Generation Building and the location of the Unit 3 HRSG, with less activity occurring at the other equipment locations.



Site cleanup and facility startup will generally result in minimal noise emissions. The one significant noise emission associated with facility startup will be steam blowout of the HRSG and steam lines. At the end of construction, high-pressure steam is passed through the HRSG to remove any debris within the steam lines prior to hookup with the steam turbine. Noise is produced when the high-pressure steam is vented to the atmosphere. Typical steam blow schedules will involve several steam releases lasting about 2 to 3 minutes each, occurring within a 2 week period. The steam piping will be equipped with a temporary silencer to reduce noise emissions.

Construction activities will be scheduled during daytime and early evening periods (7:00 a.m. to 10:00 p.m.) to the fullest extent possible. Some activities will require extended hours of operation due to scheduling constraints or to maintain structural integrity of concrete pours. Any nighttime construction will be limited to low noise activities to the fullest extent possible.

Equipment Noise Emissions

The variable nature of construction noise is best represented by an average noise level. The average noise levels account for the type and quantity of equipment, the typical usage of each piece of equipment, and typical noise levels of the equipment used during each phase of construction. The type of equipment, equipment usage, and equipment noise emissions for each phase of construction are listed in Table 4.6-1. Estimates of the construction equipment usage and noise levels are based on information provided in the EPA Document PB-250 430, Noise Emission Standards for Construction Equipment (EPA 1975).

Noise Modeling Methodology

The offsite levels of Unit 3 construction noise emissions were calculated using a computer sound propagation model. The model simulates the propagation of sound from point sources of noise by considering wave divergence, atmospheric absorption, directional



Table 4.6-1 Typical Construction Equipment Noise Emissions					
Phase	Equipment	LP* (15m) (dBA)	Quantity	Usage	Leq** (15m) (dBA)
Clearing	Backhoe	85	1	.20	78
	Concrete Vibrator	76	5	.16	75
	Drill	85	1	.16	77
	Grader	85	1	.30	80
	Diesel Generator	78	1	.16	70
	Trencher	82	1	.21	75
	Mobile Crane	83	1	.33	78
	Dozer	87	2	.33	85
	Front End Loader	84	2	.33	82
	Compactor	80	2	.25	77
	Truck, Large	88	4	.16	88
Foundation	Mobile Crane	83	1	.16	88
	Front End Loader	84	2	.33	82
	Concrete Vibrator	76	4	.16	76
	Drill	85	1	.16	77
	Saw	78	2	.21	74
	Torque Wrench	85	2	.16	80
	Dozer	87	1	.33	82



Table 4.6-1 (Continued) Typical Construction Equipment Noise Emissions					
Phase	Equipment	LP* (15m) (dBA)	Quantity	Usage	Leq** (15m) (dBA)
Erection	Stationary Crane	88	2	.33	86
	Backhoe	85	2	.20	81
	Truck, Large	88	4	.16	88
	Diesel Generator	78	1	.16	70
	Compactor	80	2	.25	77
	Air Compressor	81	1	.25	75
	Pile Driver	101	1	.04	87
	Trencher	82	1	.21	75
	Mobile Crane	83	1	.33	78
	Backhoe	85	2	.20	81
	Truck, Large	88	4	.16	88
	Trencher	82	1	.21	75
	Stationary Crane	88	5	.33	90
	Drill	85	1	.16	77
	Torque Wrench	85	7	.16	87
	Air Compressor	81	1	.25	75
Startup	Grader	85	1	.30	80
	Trencher	82	1	.21	75



Table 4.6-1 (Continued) Typical Construction Equipment Noise Emissions					
Phase	Equipment	LP* (15m) (dBA)	Quantity	Usage	Leq** (15m) (dBA)
	Drill	85	1	.16	77
	Torque Wrench	85	5	.16	84
	Diesel Generator	78	1	.16	70
	Truck, Large	88	4	.16	87
	Mobile Crane	83	1	.33	78
	Air Compressor	81	1	.25	75
*Sound pressure level at 15 meters horizontal distance from the equipment.					
**Energy average sound pressure level at 15 meters horizontal distance from the equipment.					



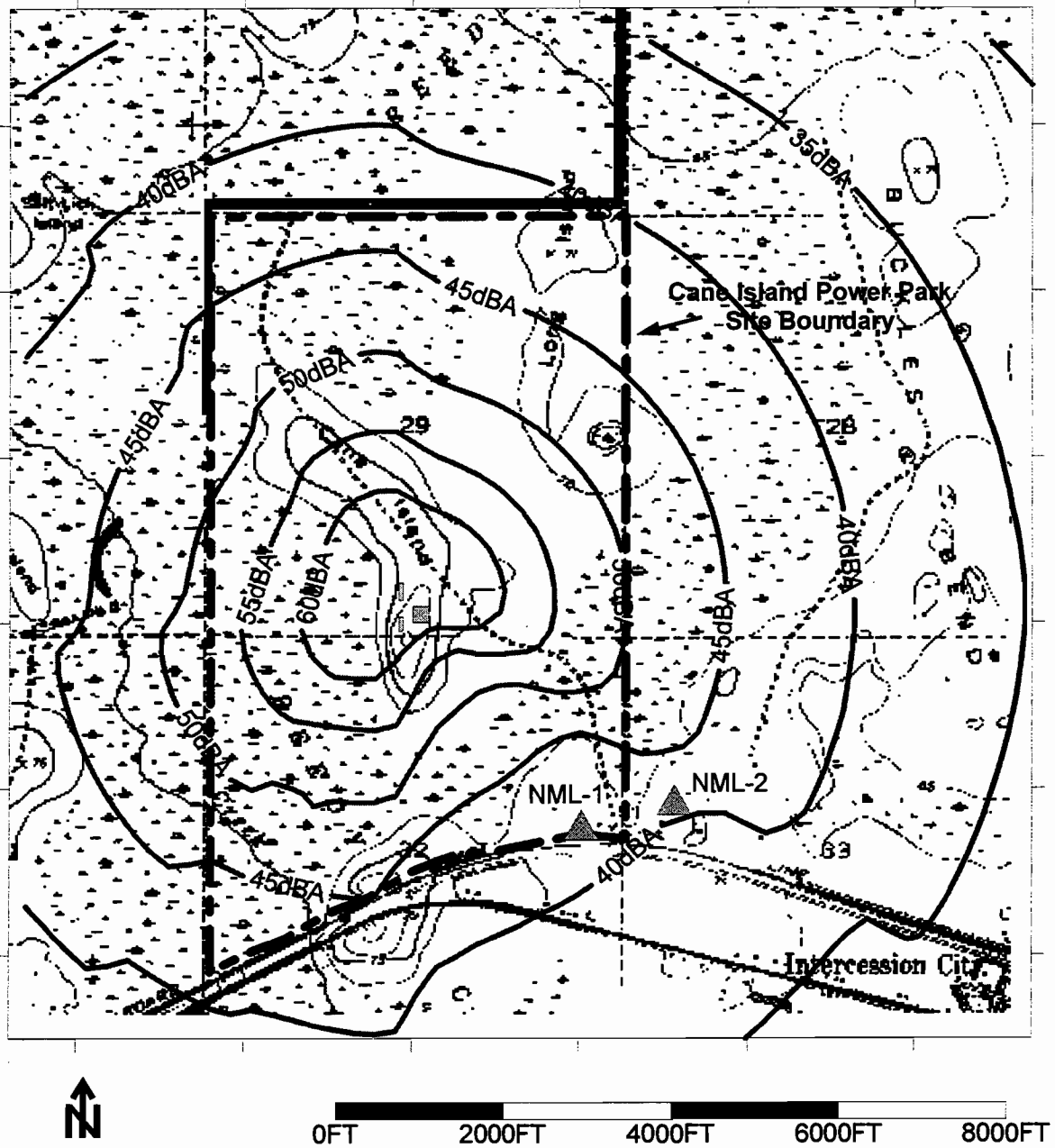
variation of the noise emissions, and blockage of noise by any interceding barriers. The model calculates the sound pressure level from each source at each point on a specified receptor grid. The model then combines the sound pressure level of each individual source at each receptor point to determine the overall noise impact. The sound pressure levels are calculated in each octave band in A-weighted decibels (dBA). The program then produces plots of noise contours (also called isobels).

Evaluation of Construction Noise Impacts

The Unit 3 average construction noise contours during the equipment erection phase are shown on Figure 4.6-1. The construction activities will be focused at the north end of the power block. The existing generation building and other equipment will serve as a barrier to noise emission to the south. The estimated noise levels at the nearest residence (NML-2) will be between 40 to 45 dBA (47-52 dBC). The foundation construction noise emissions are anticipated to be approximately 1 to 2 dBA (1-2 dBC) less than these during the equipment erection stage. The site clearing stage noise emissions are anticipated to be 6 dBA (6 dBC) less than the equipment erection noise emissions.

The variable nature of construction activity makes it difficult to predict construction noise emissions. While the average noise level is representative of construction activities, certain activities will produce temporary elevations in the noise level. Typically, noise emissions will be below the average noise level. Site clearing and preparation activities will be the first activities conducted. Because the erection phase was determined to be the worst-case phase, average noise levels are anticipated to increase as the construction progresses.

4.6.3.6 Impacts Regarding Water. The actual construction of Unit 3 is not anticipated to negatively impact the currently available supply of potable water nor negatively effect the potential of providing sufficient water for the area in the future. A certain amount of potable water will be utilized for consumption and other uses at the Power Park during construction and subsequent operation. However, these amounts are not expected to be large enough to either cause scarcity or to degrade existing service, either in terms of water pressure or quality.



Estimated Construction Noise Emissions.

Figure 4.6-1



Despite this expectation, the potential use of significant amounts of groundwater exists. The cooling tower for the new unit will, like for the existing units, utilize municipal effluent during operation instead of potable water. There exists sufficient capacity in the Kissimmee municipal effluent system for the needs of this tower. However, a backup system is required in the event the effluent delivery system fails. This backup system will be a series of wells drilled onsite to tap into available Floridan Aquifer groundwater supplies.

Before drilling wells, the well installation contractor, on behalf of KUA, will apply for well construction permits from the SFWMD. The SFWMD is expected to approve the wells, verifying that the expected withdrawals will not negatively affect the supply and quality of water for other uses and other users. Issuance of these permits will indicate that the current and proposed water uses will not negatively affect the quality and availability of groundwater for the project impact area as described in Section 5.3.2. Indeed, Units 1 and 2 have been operating since 1995, and neither the construction or operational phases associated with either unit produced negative ground water effects.

No damage to wetlands is expected. Wetlands impacts were identified and mitigated during the construction of Units 1 and 2. The US Army Corps of Engineers (COE), FDEP, and SFWMD have issued permits indicating the acceptability of the efforts of KUA during prior construction phases to protect against any negative effects on any wetlands. These efforts included the construction of an artificial onsite wetland, habitat monitoring and management efforts, and establishment of onsite conservation areas.

4.6.3.7 Impacts on Comprehensive Land Use Plans. The Power Park is and has been consistent with the goals and policies of the State Comprehensive Plan, the Central Florida Comprehensive Regional Policy Plan and the current Osceola County Comprehensive Plan, all created in response to Florida's 1975 Local Government Comprehensive Planning Act and the 1984 State and Regional Planning Act. The construction and operation of Unit 3 will be consistent with, or will further several goals, objectives and policies of each of these planning documents. Copies of the state plan goals and objectives are contained in Section 4.12. The Osceola County Comprehensive Plan was not available for reproduction in this application.



Since the construction of Unit 3 and associated facilities will be consistent with future land use and comprehensive planning programs in Osceola County, the project will not significantly impact the future beneficial use of lands adjacent to the Power Park or the human populations that may benefit therefrom.

4.6.3.8 Impact Regarding Local Zoning Ordinances. Osceola County has zoned the site for industrial use. The construction and operation of Unit 3 is now and will continue to be completely compatible with this zoning designation. Similar to the compliance with the various county, regional and state comprehensive land-use plans, compliance with local zoning ordinances will help mitigate the impact on the human population. Zoning plans give individuals knowledge of future potential land uses and enable these current and potential residents to make informed choices about the sites for their homes and businesses.

A copy of the Conditional Use/Site Development Plan Permit issued to KUA for development of the Power Park is included in Appendix 10.5. A similar application will be submitted for the installation of Unit 3.

4.6.3.9 Traffic Impacts. Traffic impacts are anticipated to be the most significant impact on local human populations. During the peak construction activity, which is expected to last approximately 15 weeks, about 240 workers will be onsite. This will create additional traffic on public roadways, especially along Old Tampa Highway and Highway 17/92, since it is anticipated that workers will commute to work in single occupancy vehicles. This assumption is based on the fact that onsite living quarters will not be provided for this project and because public transportation is not available.

However, despite the increase, traffic is not expected to exceed the Level of Service established by the current roadway and intersection design and construction. During the construction of Units 1 and 2, the additional traffic associated with construction placed a slight temporary burden on the commuters utilizing Old Tampa Highway and Highway 17/92.

Once the construction phase is over, additional personnel will be retained for operational purposes. However, the additional traffic generated by the additional 2 full-time operations employees will not be significant.



4.7 Impact on Landmarks and Sensitive Areas

There are four recorded sensitive areas within 5 miles of the Power Park. These areas include Parcel 3 of the FDEP/Disney Conservation Easement north and west of the site, the playground/park in Intercession City, and the Save Our Rivers properties south of Highway 92 and north of the Power Park. The location of the Intercession City playground is shown on Figures 2.2-1 and 2.2-2.

The Fletcher Park Monument and the South OBT Bridge occur within 1 mile of the Power Park as shown on Figure 2.2-2. The Rodgers House and the Homely Cow Dip area are within 5 miles of the Power Park as shown on Figure 2.2-1. In addition, the Disney 5000 13 Bridge in Intercession City, the Lake Wilson Boy Scout Camp in Kissimmee, and the Homestead Cemetery in Davenport are also within 5 miles of the Power Park. Sixteen historic residences occur along the South Orange Blossom Trail, four residences occur along the Old Tampa Highway, one residence along Tallahassee Boulevard, and one residence along Tomoka Road.

There should be no significant impacts on the FDEP/Disney conservation easement or the Save Our Rivers properties resulting from construction of Unit 3. The distances, buffer zones, and onsite measures to control erosion, sedimentation, fugitive dust, and noise will effectively mitigate potential impacts. The construction work force traffic may have a minimal impact on traffic through Intercession City, particularly during the rush hours. Although the playground/park in Intercession City fronts the Old Tampa Highway, construction traffic will be requested to use US Highway 17/92 to avoid travel on the secondary streets of Intercession City.

The historic landmarks in the project area will not be impacted by project construction. Construction traffic will be requested to use US Highway 17/92 to avoid travel on secondary streets and bridges in Intercession City. Therefore, these landmarks will be avoided.

4.8 Impact on Archaeological and Historic Sites

A Phase I cultural resources investigation of the Power Park property was conducted in May 1992 as previously described in Section 2.2.6. None of the discovered sites were



considered eligible for listing on the *National Register of Historic Places*. The Florida Division of Historical Resources concurred, and indicated that project construction could proceed without further involvement from the Division. Therefore, construction of Unit 3 is not expected to impact any known or recorded archeological or historic resources. If any such resources are discovered during construction, work in that area will stop, and the Division will be contacted within 24 hours for an appropriate plan of action.

4.9 Special Features

Construction debris, trash, and garbage will be collected in appropriate containers and removed from the site by a contractor for disposal at an approved landfill or resource recovery facility.

4.10 Benefits from Construction

The benefits associated with the construction of Unit 3 will include increased employment for regional workers. Attendant to this employment will be the benefits of increased sales tax revenue for Osceola County and the City of Kissimmee.

Increased income due to economic activity will also accrue to the region. Among these benefits are the increased revenue that will be enjoyed by the owners/operators of temporary housing facilities in the area. Although most of the construction employees are expected to commute daily from their established, permanent residences within the impact areas, some workers will be traveling into the impact area from more distant residences. Even though EPRI studies have indicated that these workers travel without their families, their individual housing needs will have to be satisfied. They will predictably patronize the hotels and recreation vehicle campgrounds that already exist in the area. Although this theoretically could cause a shortage of short-term housing, this situation is more optimistically interpreted as meaning that the owners of short-term housing will enjoy an increase in business. Realistically, a shortage of short-term housing is not anticipated since the area is a major tourist destination which has a tremendous amount of short term housing capacity.



A detailed and comprehensive analysis of the benefits created by the site preparation, plant construction and operation of the proposed Power Park expansion is contained in Chapter 7 of this application.

4.11 Variances

No variances from applicable codes or standards are requested for or during construction of Unit 3.

4.12 Florida State Comprehensive Plan Goals

Source: FS 187.201 (1995)

EDUCATION: The creation of an educational environment which is intended to provide adequate skills and knowledge for students to develop their full potential, embrace the highest ideas and accomplishments, make a positive contribution to society, and promote the advancement of knowledge and human dignity.

CHILDREN: Florida shall provide programs sufficient to protect the health, safety, and welfare of all of its children.

FAMILIES: Florida shall strengthen the family and promote its economic independence.

THE ELDERLY: Florida shall improve the quality of life for its elderly citizens by promoting improved provision of services, with an emphasis on independence and self-sufficiency.

HOUSING: The public and private sectors shall increase the affordability and availability of housing for low-income and moderate-income persons, including citizens in rural areas, while at the same time encouraging self-sufficiency of the individual and assuring environmental and structural quality and cost-effective operations.



HEALTH: Healthy residents who protect their own health and the health of others and who actively participate in recovering their own health when they become ill; an environment which supports a healthy population and which does not cause illness; health care services which are of high quality, reasonably accessible, and adequate to meet the needs of the public; and health costs which are contained to a level appropriate to the financial resources of the state and its residents.

PUBLIC SAFETY: Florida shall protect the public by preventing, discouraging, and punishing criminal behavior, lowering the highway death rate, and protecting lives and property from natural and manmade disasters.

WATER RESOURCES: Florida shall assure the availability of an adequate supply of water for all competing uses deemed reasonable and beneficial and shall maintain the functions of natural systems and the overall present level of surface and ground water quality. Florida shall improve and restore the quality of waters not presently meeting water quality standards.

COASTAL AND MARINE RESOURCES: Florida shall ensure that development and marine resource use and beach access improvements in coastal areas do not endanger public safety or important natural resources. Florida shall, through acquisition and access improvements, make available to the state's population additional beaches and marine environment, consistent with sound environmental planning.

NATURAL SYSTEMS AND RECREATIONAL LANDS: Florida shall protect and acquire unique natural habitats and ecological systems, such as wetlands, tropical hardwood hammocks, palm hammocks, and virgin longleaf pine forests, and restore degraded natural systems to a functional condition.

AIR QUALITY: Florida shall comply with all national air quality standards by 1987, and by 1992 meet standards which are more stringent than 1985 state standards.



ENERGY: Florida shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors, while at the same time promoting an increased use of renewable energy resources..

HAZARDOUS AND NONHAZARDOUS MATERIALS AND WASTE: All solid waste, including hazardous waste, wastewater, and all hazardous materials, shall be properly managed, and the use of landfills shall be eventually eliminated.

MINING: Florida shall protect its air, land, and water resources from the adverse effects of resource extraction and ensure that the disturbed areas are reclaimed or restored to beneficial use as soon as reasonably possible.

PROPERTY RIGHTS: Florida shall protect private property rights and recognize the existence of legitimate and often competing public and private interests in land use regulations and other government action.

LAND USE: In recognition of the importance of preserving the natural resources and enhancing the quality of life of the state, development shall be directed to those areas which have in place, or have agreements to provide, the land and water resources, fiscal abilities, and service capacity to accommodate growth in an environmentally acceptable manner.

DOWNTOWN REVITALIZATION: In recognition of the importance of Florida's developing and redeveloping downtowns to the state's ability to use existing infrastructure and to accommodate growth in an orderly, efficient, and environmentally acceptable manner, Florida shall encourage the centralization of commercial, governmental, retail, residential, and cultural activities within downtown areas.

PUBLIC FACILITIES: Florida shall protect the substantial investments in public facilities that already exist and shall plan for and finance new facilities to serve residents in a timely, orderly, and efficient manner.



CULTURAL AND HISTORICAL RESOURCES: By 1995, Florida shall increase access to its historical and cultural resources and programs and encourage the development of cultural programs of national excellence.

TRANSPORTATION: Florida shall direct future transportation improvements to aid in the Management of growth and shall have a state transportation system that integrates highway, air, mass transit, and other transportation modes.

GOVERNMENTAL EFFICIENCY: Florida governments shall economically and efficiently provide the amount and quality of services required by the public.

THE ECONOMY: Florida shall promote an economic climate which provides economic stability, maximizes job opportunities, and increases per capita income for its residents.

AGRICULTURE: Florida shall maintain and strive to expand its food, agriculture, ornamental horticulture, aquaculture, forestry, and related industries in order to be a healthy and competitive force in the national and international marketplace.

TOURISM: Florida will attract at least 55 million tourists annually by 1995 and shall support efforts by all areas of the state wishing to develop or expand tourist-related economies.

EMPLOYMENT: Florida shall promote economic opportunities for its unemployed and economically disadvantaged residents.

PLAN IMPLEMENTATION: Systematic planning capabilities shall be integrated into all levels of government in Florida with particular emphasis on improving intergovernmental coordination and maximizing citizen involvement.



Power Park Units 1-3, once certified, would be affirmatively consistent with all of the subjects, goals, and expressed policies of the State Comprehensive Plan and would also implement applicable agency strategic policy plans.



5.0 Effects of Plant Operation

5.1 Effects of the Operation of the Heat Dissipation System

Cane Island Power Park (Power Park) Units 2 and 3 will use a mechanical draft cooling tower as the major equipment heat dissipation/cooling method. Cooling tower makeup water is taken from, and blowdown is returned to, the City of Kissimmee (Kissimmee) effluent pipeline.

5.1.1 Temperature Effect on Receiving Body of Water

Cooling towers are used to dissipate heat produced during power generation. There will be no discharge of cooling waters from the heat dissipation system to surface waters. Blowdown from the heat dissipation system is combined with neutralization basin effluent and steam cycle blowdown and returned to the Kissimmee effluent pipeline. The pipeline provides water to other users and ultimately discharges to the Imperial site regional percolation pond treatment facility. Temperature of effluent from the Cane Island Power Park (Power Park) is not anticipated to effect the regional percolation ponds.

5.1.2 Effect on Aquatic Life

There will be no discharge of effluent from the site into surface waters; no impacts to aquatic life are expected.

5.1.3 Biological Effects of Modified Circulation

Units 2 and 3 will use municipal effluent water for cooling water. Modified circulation of a water body will not occur; therefore, there will be no biological effects.

5.1.4 Effects of Offstream Cooling

The purpose of this section is to assess the potential environmental impacts associated with the operation of cooling towers at the Power Park. Potential impacts from the cooling towers include plume induced fogging and icing, deposition from circulating water drift, and visible plume formation. The following subsections describe the cooling towers at the Power Park, explain the methodology and assumptions used to quantify the magnitude and extent of the impacts, present the results of the modeling, and discuss the potential environmental effects.



5.1.4.1 Cooling Tower Description. The 250 MW addition to the Power Park will necessitate the construction and operation of a new cooling tower. The proposed new cooling tower will be a linear mechanical draft (LMDCT), cross flow, wet design cooling tower, incorporating plume abatement features. The preliminary design consists of 5 cells in one housing arranged along a north-south axis just to the north of the existing cooling tower. The existing Unit 2 cooling tower is somewhat smaller (approximately 60 percent less heat load than the proposed new tower), consisting of only 3 cells, but of similar design to the new tower. The combined effects from both cooling towers are considered in this analysis.

5.1.4.2 Technical Approach. A computer modeling analysis was performed to evaluate the magnitude and extent of the potential environmental impacts resulting from the operation of the cooling towers at the Power Park. The Electric Power Research Institute (EPRI)-sponsored Seasonal/Annual Cooling Tower Plume Impact (SACTI, Version 1.0 12/93) model was used to quantify the cooling tower impacts. This computer code is an outgrowth of an earlier model evaluation study carried out by A. J. Policastro of the Argonne National Laboratory (ANL). Improved plume and drift models in the code have been calibrated with existing field and laboratory data and then subsequently verified with new data not included in the calibration process. The SACTI model has been widely used by electric utilities and their consultants to assess cooling tower plume impacts for incorporation into various types of environmental impact studies.

The methodology used in the SACTI model is based on the assumption that up to 35 distinct plume categories, based on the local ambient meteorological conditions and cooling tower design characteristics, can be identified at any given site. For mechanical draft cooling tower designs, the SACTI code assumes that 10 additional distinct plume categories may exist which are characteristic of plume induced ground level fogging and icing. In other words, depending on the type of cooling tower and the specific site conditions, a cooling tower plume may exhibit up to 45 distinctly different sets of plume characteristics (e.g., plume height, plume spread, plume downwash, and plume dispersion). In the case of a mechanical draft cooling tower arrangements, the effects of the orientation of the tower with respect to merging cell plumes and structure induced downwash are simulated through the use of representative wind directions and the specific tower configuration.

The cooling tower plume in each of the aforementioned categories is produced by a different set of ambient meteorological conditions. Hourly meteorological data are used by



the SACTI model to compute frequency distributions of the meteorological conditions responsible for each plume type within the assumed plume category. The SACTI model performs the following computational functions in a sequential manner to determine the representative plume categories and plume impacts.

Meteorological Data Preprocessor

The meteorological data preprocessor performs three subtasks to delineate plume categories and calculate representative parameters for each category. In the first subtask, hourly surface meteorological data are read and invalid or missing parameters and hours are discarded. For each valid record, the model uses cooling tower parameters such as tower height, tower effective exit diameter, tower effective heat rejection, and tower effective air flow to calculate additional exit parameters including temperature and velocity, and some nondimensional parameters which characterize the buoyancy of the plume and the stability and saturation of the ambient air.

The second subtask generates frequency distribution tables for ranges of tower, meteorological, and nondimensional parameters as a function of the standard 16 wind directions. These meteorological variables represent the full range of atmospheric conditions affecting plume dispersion and drift deposition. For example, the SACTI model selects temperature ranges from -49°F to 113°F in 9°F intervals. The frequency of actual dry-bulb temperatures occurring in each of those ranges for each of the standard 16 wind directions is tabulated. Likewise, the model tabulates relative humidity values falling between 0 and 100 percent in intervals of 10 percent.

Subtask 3 uses the frequency distributions from Subtask 2 to delineate the distinctly different plume categories that could occur from cooling tower operation. Categories are selected so that all categories are roughly equally populated. A single set of representative tower and ambient conditions is then calculated from the range of conditions in each category, and then reassigned to each category.

Plume Calculations

Using the preprocessor's representative conditions and cooling tower design data (e.g., tower orientation, number of cells, drift droplet spectrum, and salt concentrations), the plume code calculates fogging/icing and the plume's dimensions and depositional characteristics for



each plume category and each representative wind direction. For example, assuming 45 total drift and fogging categories and 4 representative wind directions, a total of 180 plume cases are simulated.

As previously stated, the representative wind directions are used to simulate tower-induced downwash. Therefore, specific output showing the nature and extent of the downwash is not generated by the program. Rather, output is generated for each representative wind direction, and the downwash effects can be inferred from the deposition/fogging/icing gradients.

Impact Calculations

The various plume code prediction results are used in conjunction with the meteorological data preprocessor's frequency distribution of plume categories and actual wind directions to calculate impacts. The resulting cumulative impacts from all plume categories are tabularized and plotted in the SACTI model output as a function of wind direction and distance from the cooling tower.

5.1.4.2.1 Cooling tower plume model input. The SACTI cooling tower model requires as input certain site-specific, tower-specific, and circulating water-specific data. Input data used in the SACTI cooling tower model are discussed below and summarized in Table 5.1-1 with the documented source of the data.

Site-specific data includes the site's latitude and longitude, time zone, surface roughness height, monthly clearness indices, daily solar insolation values, representative hourly recorded surface meteorological data, and average morning and afternoon mixing heights.

Tower-specific data includes information pertaining to the type of cooling tower, dimensions of the tower housing, cell exhaust diameter, heat load, drift rate, design air flow rate, and orientation of the cooling tower cells with respect to the 16 representative wind directions.

Water-specific data includes the circulating water salt concentration, salt density, and the size distribution of the water droplets in the cooling tower drift.



Table 5.1-1
SACTI Cooling Tower Modeling Input Parameters

Site-Specific Data		Data Source/Notes																																				
Site Latitude	28.28° N	Measured																																				
Site Longitude	081.53° E	Measured																																				
Time Zone	-5	Measured																																				
Surface Roughness Height	100 cm	Estimated																																				
Monthly Clearness Indices (K_T)	0.61, 0.61, 0.62, 0.62, 0.63, 0.59, 0.56, 0.55, 0.56, 0.60, 0.64, 0.60	SACTI User's Manual																																				
Monthly Average Daily Total Solar Flux (MJ/m^2)	13.67, 16.35, 19.95, 22.79, 24.88, 23.96, 22.29, 20.70, 18.99, 16.94, 14.93, 12.63	SACTI User's Manual																																				
Meteorological Data (surface data)	Orlando, FL (93-97)	NWS																																				
Average Annual Mixing Height	493 m (morning) 1,359 m (afternoon)	SACTI User's Manual																																				
Wind Instrument Reference Height	10 m (anemometer height)	NWS																																				
Tower-Specific Data																																						
Tower Type	Linear Mechanical Draft	Note 1																																				
Number of Towers	1	Note 1																																				
Effective Exhaust Diameter	25.9m	Note 1																																				
Tower Height	14.5 m	Note 1																																				
Tower Width	15.2 m	Note 1																																				
Tower Length	182.9 m	Note 1																																				
Total Heat Dissipation Rate	896 MBtu/h	Note 1																																				
Total Circulating Water	182,000 gpm	Note 1																																				
Total Drift Loss Rate	574 g/s	Note 1, based on 0.005% drift rate.																																				
Total Airflow Rate	7,172 kg/s	Note 1																																				
Water-Specific Data																																						
Cooling Tower Salt Concentration	0.00141 g Salt/g Soln	Preliminary Design																																				
Salt Density	2.66 g/cm ³	Estimated																																				
Drift Droplet Spectrum	<table><tr><th>Drop Size (μm)</th><th>Mass Fraction</th></tr><tr><td>0-20</td><td>0.0061</td></tr><tr><td>20-40</td><td>0.0508</td></tr><tr><td>40-60</td><td>0.1077</td></tr><tr><td>60-80</td><td>0.1423</td></tr><tr><td>80-100</td><td>0.1382</td></tr><tr><td>100-120</td><td>0.1280</td></tr><tr><td>120-140</td><td>0.0976</td></tr><tr><td>140-160</td><td>0.0772</td></tr><tr><td>160-180</td><td>0.0732</td></tr><tr><td>180-200</td><td>0.0569</td></tr><tr><td>200-220</td><td>0.0447</td></tr><tr><td>220-240</td><td>0.0264</td></tr><tr><td>240-260</td><td>0.0163</td></tr><tr><td>260-280</td><td>0.0142</td></tr><tr><td>280-300</td><td>0.0102</td></tr><tr><td>300-320</td><td>0.0061</td></tr><tr><td>320-340</td><td>0.0041</td></tr></table>	Drop Size (μm)	Mass Fraction	0-20	0.0061	20-40	0.0508	40-60	0.1077	60-80	0.1423	80-100	0.1382	100-120	0.1280	120-140	0.0976	140-160	0.0772	160-180	0.0732	180-200	0.0569	200-220	0.0447	220-240	0.0264	240-260	0.0163	260-280	0.0142	280-300	0.0102	300-320	0.0061	320-340	0.0041	Estimated, based on Hamon cooling tower drift data.
Drop Size (μm)	Mass Fraction																																					
0-20	0.0061																																					
20-40	0.0508																																					
40-60	0.1077																																					
60-80	0.1423																																					
80-100	0.1382																																					
100-120	0.1280																																					
120-140	0.0976																																					
140-160	0.0772																																					
160-180	0.0732																																					
180-200	0.0569																																					
200-220	0.0447																																					
220-240	0.0264																																					
240-260	0.0163																																					
260-280	0.0142																																					
280-300	0.0102																																					
300-320	0.0061																																					
320-340	0.0041																																					
Note 1: Data are representative of a single larger tower composed of the estimated combined heat load and circulating water flow from the existing and proposed new cooling towers.																																						



The Power Park latitude, longitude, time zone, and surface roughness height were either directly measured or estimated. The monthly clearness indices and solar insolation values were obtained from Appendix B of the User's Manual for the SACTI Computer Code for a representative location at approximately the same latitude (EPRI 1984).

Five years (1993-1997) of surface meteorological data from Orlando, Florida, collected by the National Weather Service (NWS) were used in the SACTI modeling analysis. These data contained the complete set of surface meteorological parameters (TD-1440 format) necessary to conduct the cooling tower modeling analysis, and are considered representative of the Power Park site.

The type of cooling tower, dimensions of the tower housing, cell exhaust diameter, heat load, drift rate, design air flow rate, and orientation of the cooling tower cells for the Power Park were all based on data representative of a single larger simulated tower composed of the estimated combined heat load and circulating water flow from the existing and proposed new cooling towers.

The size distribution of drift droplets from the cooling tower is required as input to the SACTI model. The size distribution of drift droplets depends on the details of the interior construction, air and water flow through the fill, and the efficiency of the drift eliminators. The cooling tower drift droplet size spectrum data used in this study are based on representative vendor data. These drift droplet size data are representative of best available technology (BAT) currently utilized in cooling tower drift eliminator design. The concentration of total dissolved solids (TDS) in the cooling tower circulating water was based on the Kissimmee effluent water quality.

5.1.4.3 Cooling Tower Impact Modeling Results. The SACTI cooling tower model was used to predict the magnitude of the cooling tower induced fogging and icing, deposition, and plume length frequency of occurrence while conservatively assuming the cooling towers are operating the entire year under peak conditions. The cooling tower systems will dissipate waste heat by evaporating water and releasing the water vapor into the atmosphere. If the ambient air is cold and/or moist, a portion of the emitted water vapor will condense to form small water droplets. This condition is seen as a visible white plume emanating from the cooling towers.



Potential environmental impacts such as fogging, icing, and deposition associated with the cooling tower plumes may arise depending on the meteorological conditions and the environmental setting.

5.1.4.3.1 Plume fogging modeling results. Ground level fogging occurs when the visible plume from a cooling tower contacts the ground. Meteorological conditions favorable for ground level fogging from a LMDCT are generally associated with strong winds (generally greater than 20 mph) which bend the plume to intercept the ground, and high relative humidity (small dew point depression) for easy plume saturation. The cooling tower fogging results are calculated by the SACTI cooling tower model as the maximum number of hours plume induced fogging from a cooling tower could occur for each wind direction. Table 5.1-2 presents the total hours (based on the 5 year Orlando meteorological database) of predicted plume fogging associated with the cooling towers. The 16 wind direction labels in the columns of the table represent the direction from the cooling towers that the plume is headed. The data represent the total hours (over the 5 year data base) that the cooling tower plume could induce fogging conditions for a particular direction and distance from the cooling tower.

As the data in Table 5.1-2 indicate, the SACTI model predicts that a maximum of 2 hours per year (considering all wind directions) of plume fogging, averaged over the 5 year period modeled, would not extend past 300 m (984 ft) in any direction from the cooling towers.

5.1.4.3.2 Plume icing modeling results. Ground level plume icing (fog ice) is a semi-opaque coating of small granules of ice formed when small water droplets in the visible cooling tower fog freeze rapidly on the ground during conditions of high relative humidity and below freezing temperatures. The SACTI cooling tower model predicted no occurrences of cooling tower plume induced icing based on the 5 year Orlando meteorological database. This is consistent with the climate of the area, as records indicate that freezing temperatures occur less than 1 percent of the year on average.

5.1.4.3.3 Water deposition modeling results. Water deposition from a cooling tower occurs when the airborne water droplets coalesce and precipitate downwind of the cooling tower. The pattern of water deposition and the distance of maximum water deposition from the cooling tower are a function of the physical size of the water droplets in the drift, prevailing wind direction, orientation of the cooling tower cells, and the airflow rate.



Table 5.1-2
Total Hours of Predicted Plume Induced Fogging

Distance From Tower (m)	Fogging in the direction Plume is Headed (Hours)																Total
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100.	1.3	0.2	0.0	0.0	0.0	0.0	0.0	0.2	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
200.	3.0	0.5	0.0	0.0	0.0	0.0	0.1	0.5	2.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	6.2
300.	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
400.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
500.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
600.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
700.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
800.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
900.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1000.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1100.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1200.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1300.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1400.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1500.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1600.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

*Total hours of fogging over 5 years. Average annual hours of cooling tower induced fogging is obtained by dividing the table value by 5.

Source: SACTI cooling tower model.



Table 5.1-3 presents the SACTI model predicted average monthly (based on the 5 year Orlando meteorological database) water deposition rate in scientific notation in units of $\text{kg}/\text{km}^2/\text{month}$ associated with the proposed cooling towers at the Power Park. The 16 wind direction labels in the columns of the table represent the direction from the cooling towers that the water deposition is predicted to occur.

The SACTI model predicted that the maximum cooling tower water deposition will occur approximately 300 m (984 ft) west of the cooling towers at a rate of $150,000 \text{ kg}/\text{km}^2/\text{month}$. The average water deposition at a 300 m (984 ft) radius from the cooling tower (considering all directions of plume travel) is predicted to be $41,000 \text{ kg}/\text{km}^2/\text{month}$.

5.1.4.3.4 Salt deposition modeling results. Salt deposition is primarily a function of the salt concentration in the circulating cooling water and the water deposition rate. Table 5.1-4 presents the SACTI model predicted average monthly (based on the 5 year Orlando meteorological data base) salt deposition rate in units of $\text{kg}/\text{km}^2/\text{month}$ associated with the proposed cooling towers at the Power Park. The 16 wind direction labels in the columns of the table represent the direction from the proposed cooling towers that the salt deposition is predicted to occur.

The maximum salt deposition occurs approximately 300 m (984 ft) west of the cooling towers at a rate of $292 \text{ kg}/\text{km}^2/\text{month}$. The average salt deposition at a radius of 300 m (984 ft) from the cooling towers (considering all directions of plume travel) is predicted to be $74 \text{ kg}/\text{km}^2/\text{month}$. Beyond 400 m (1,312 ft) from the cooling towers, the salt deposition significantly decreases. In fact, the average salt deposition beyond 900 m (2,953 ft) from the cooling towers in all directions is less than $10 \text{ kg}/\text{km}^2/\text{month}$.

5.1.4.3.5 Plume length modeling results. The cooling tower plume lengths are calculated by the SACTI model as the frequency of occurrence of a given plume length from the cooling tower for each wind direction. Table 5.1-5 presents the average annual (based on the 5 year Orlando meteorological data base) predicted plume length frequency of occurrence associated with the cooling towers. The 16 wind direction labels in the columns of the table represent the direction from the cooling towers that the plume is headed. The data represent the probability (by percent of the year) that the cooling tower plume will be as long or longer than the length defined in the table for a particular direction and distance from the cooling tower.

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



Table 5.1-3
Average Monthly Predicted Cooling Tower Water Deposition

Distance From Tower (m)		Water Deposition in the Direction Plume is Beaded (kg/km ² -month)																AVG
		S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100.	.00E+00.00E+00.00E+00.15E+04.77E+03.77E+03.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.85E+04.22E+05.54E+04.00E+00.00E+00.24E+04																	
200.	.00E+00.00E+00.00E+00.40E+05.44E+05.26E+05.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.58E+05.13E+06.41E+05.00E+00.00E+00.21E+05																	
300.	.15E+03.00E+00.00E+00.12E+06.15E+06.90E+05.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.82E+05.14E+06.70E+05.00E+00.00E+00.41E+05																	
400.	.33E+03.00E+00.00E+00.84E+05.10E+06.62E+05.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.00E+00.54E+05.84E+05.47E+05.00E+00.00E+00.27E+05																	
500.	.53E+04.32E+04.18E+04.80E+05.10E+06.61E+05.10E+04.20E+04.49E+04.29E+04.13E+04.51E+05.80E+05.48E+05.71E+03.14E+04.28E+05																	
600.	.11E+05.75E+04.63E+04.58E+05.73E+05.46E+05.37E+04.48E+04.11E+05.66E+04.46E+04.36E+05.59E+05.35E+05.25E+04.34E+04.23E+05																	
700.	.99E+04.62E+04.52E+04.32E+05.41E+05.25E+05.31E+04.39E+04.98E+04.56E+04.39E+04.20E+05.31E+05.20E+05.21E+04.29E+04.14E+05																	
800.	.10E+05.61E+04.40E+04.28E+05.36E+05.22E+05.24E+04.37E+04.98E+04.58E+04.33E+04.17E+05.28E+05.17E+05.17E+04.29E+04.12E+05																	
900.	.10E+05.58E+04.43E+04.22E+05.28E+05.17E+05.25E+04.35E+04.97E+04.58E+04.36E+04.13E+05.21E+05.13E+05.19E+04.28E+04.10E+05																	
1000.	.89E+04.50E+04.34E+04.90E+04.11E+05.66E+04.20E+04.30E+04.83E+04.49E+04.30E+04.58E+04.82E+04.59E+04.15E+04.24E+04.56E+04																	
1100.	.70E+04.39E+04.32E+04.88E+04.11E+05.64E+04.19E+04.23E+04.65E+04.39E+04.27E+04.57E+04.81E+04.57E+04.14E+04.19E+04.50E+04																	
1200.	.64E+04.36E+04.30E+04.85E+04.11E+05.62E+04.18E+04.22E+04.60E+04.35E+04.25E+04.54E+04.78E+04.55E+04.14E+04.17E+04.48E+04																	
1300.	.37E+04.21E+04.18E+04.72E+04.93E+04.56E+04.10E+04.13E+04.34E+04.20E+04.14E+04.42E+04.65E+04.46E+04.79E+03.10E+04.35E+04																	
1400.	.37E+04.20E+04.15E+04.56E+04.71E+04.44E+04.90E+03.13E+04.34E+04.20E+04.13E+04.32E+04.53E+04.37E+04.70E+03.10E+04.29E+04																	
1500.	.30E+04.17E+04.15E+04.52E+04.66E+04.42E+04.90E+03.10E+04.28E+04.17E+04.13E+04.30E+04.49E+04.33E+04.70E+03.82E+03.27E+04																	
1600.	.17E+04.94E+03.89E+03.50E+04.63E+04.40E+04.54E+03.58E+03.16E+04.93E+03.72E+03.28E+04.47E+04.32E+04.43E+03.47E+03.22E+04																	
1700.	.17E+04.94E+03.82E+03.49E+04.63E+04.39E+04.50E+03.58E+03.16E+04.93E+03.66E+03.28E+04.46E+04.31E+04.39E+03.31E+04.21E+04																	
1800.	.17E+04.94E+03.84E+03.47E+04.59E+04.37E+04.50E+03.57E+03.16E+04.93E+03.67E+03.26E+04.43E+04.29E+04.40E+03.46E+03.20E+04																	
1900.	.17E+04.94E+03.86E+03.24E+04.32E+04.18E+04.51E+03.56E+03.15E+04.91E+03.68E+03.15E+04.19E+04.16E+04.41E+03.47E+03.13E+04																	
2000.	.17E+04.91E+03.86E+03.19E+04.24E+04.13E+04.51E+03.54E+03.15E+04.86E+03.68E+03.12E+04.15E+04.13E+04.41E+03.47E+03.11E+04																	
2100.	.47E+03.25E+03.55E+03.11E+04.13E+04.70E+03.33E+03.14E+03.36E+03.20E+03.41E+03.81E+03.99E+03.87E+03.28E+03.16E+03.56E+03																	
2200.	.53E+03.28E+03.33E+03.93E+03.11E+04.60E+03.20E+03.16E+03.41E+03.22E+03.23E+03.72E+03.88E+03.78E+03.19E+03.19E+03.49E+03																	
2300.	.60E+03.31E+03.29E+03.77E+03.92E+03.48E+03.18E+03.18E+03.46E+03.24E+03.20E+03.62E+03.74E+03.66E+03.17E+03.22E+03.44E+03																	
2400.	.60E+03.31E+03.32E+03.62E+03.71E+03.39E+03.19E+03.18E+03.46E+03.24E+03.22E+03.49E+03.58E+03.52E+03.19E+03.22E+03.39E+03																	
2500.	.60E+03.31E+03.38E+03.38E+03.45E+03.27E+03.22E+03.18E+03.45E+03.24E+03.28E+03.28E+03.37E+03.32E+03.24E+03.22E+03.33E+03																	
2600.	.57E+03.30E+03.39E+03.27E+03.34E+03.20E+03.22E+03.17E+03.44E+03.24E+03.27E+03.19E+03.28E+03.22E+03.25E+03.21E+03.29E+03																	
2700.	.55E+03.28E+03.34E+03.24E+03.32E+03.18E+03.19E+03.17E+03.43E+03.23E+03.25E+03.16E+03.25E+03.20E+03.23E+03.20E+03.26E+03																	
2800.	.53E+03.28E+03.24E+03.23E+03.31E+03.17E+03.13E+03.16E+03.42E+03.22E+03.19E+03.15E+03.24E+03.19E+03.17E+03.20E+03.24E+03																	
2900.	.46E+03.24E+03.22E+03.22E+03.30E+03.17E+03.12E+03.14E+03.36E+03.20E+03.18E+03.15E+03.21E+03.18E+03.16E+03.16E+03.22E+03																	
3000.	.43E+03.23E+03.16E+03.22E+03.29E+03.17E+03.93E+02.13E+03.34E+03.19E+03.13E+03.14E+03.19E+03.17E+03.11E+03.15E+03.20E+03																	
3100.	.43E+03.23E+03.15E+03.22E+03.29E+03.17E+03.87E+02.13E+03.34E+03.19E+03.12E+03.14E+03.19E+03.17E+03.97E+02.15E+03.19E+03																	
3200.	.42E+03.23E+03.14E+03.22E+03.29E+03.17E+03.81E+02.13E+03.33E+03.18E+03.11E+03.14E+03.19E+03.17E+03.86E+02.15E+03.19E+03																	
3300.	.39E+03.21E+03.14E+03.19E+03.27E+03.15E+03.81E+02.12E+03.32E+03.18E+03.11E+03.13E+03.18E+03.15E+03.85E+02.13E+03.18E+03																	
3400.	.37E+03.20E+03.13E+03.18E+03.25E+03.14E+03.78E+02.11E+03.30E+03.17E+03.11E+03.12E+03.17E+03.14E+03.82E+02.12E+03.17E+03																	
3500.	.36E+03.20E+03.13E+03.18E+03.25E+03.14E+03.77E+02.11E+03.30E+03.17E+03.11E+03.12E+03.17E+03.14E+03.81E+02.12E+03.17E+03																	
3600.	.21E+03.11E+03.13E+03.16E+03.23E+03.12E+03.73E+02.63E+02.16E+03.88E+02.10E+03.10E+03.15E+03.12E+03.74E+02.80E+02.12E+03																	
3700.	.15E+03.78E+02.83E+02.95E+02.13E+03.69E+02.47E+02.42E+02.11E+03.53E+02.67E+02.62E+02.82E+02.72E+02.53E+02.63E+02.78E+02																	
3800.	.15E+03.77E+02.41E+02.95E+02.13E+03.69E+02.21E+02.42E+02.11E+03.53E+02.32E+02.62E+02.82E+02.72E+02.32E+02.63E+02.71E+02																	
3900.	.14E+03.69E+02.39E+02.92E+02.13E+03.67E+02.20E+02.39E+02.99E+02.49E+02.31E+02.58E+02.77E+02.67E+02.30E+02.59E+02.66E+02																	
4000.	.13E+03.64E+02.38E+02.77E+02.11E+03.59E+02.20E+02.38E+02.94E+02.47E+02.30E+02.44E+02.59E+02.47E+02.29E+02.55E+02.58E+02																	
4100.	.12E+03.59E+02.38E+02.77E+02.11E+03.59E+02.20E+02.35E+02.86E+02.43E+02.30E+02.44E+02.59E+02.47E+02.29E+02.50E+02.56E+02																	
4200.	.90E+02.45E+02.38E+02.42E+02.56E+02.31E+02.20E+02.27E+02.67E+02.34E+02.30E+02.28E+02.35E+02.29E+02.29E+02.37E+02.40E+02																	
4300.	.85E+02.43E+02.38E+02.19E+02.22E+02.11E+02.20E+02.25E+02.63E+02.32E+02.30E+02.16E+02.19E+02.16E+02.29E+02.34E+02.31E+02																	
4400.	.78E+02.40E+02.38E+02.19E+02.22E+02.11E+02.20E+02.23E+02.59E+02.30E+02.30E+02.16E+02.19E+02.16E+02.29E+02.32E+02.30E+02																	
4500.	.78E+02.40E+02.36E+02.19E+02.22E+02.11E+02.19E+02.23E+02.59E+02.30E+02.29E+02.16E+02.19E+02.16E+02.28E+02.32E+02.30E+02																	
4600.	.78E+02.40E+02.36E+02.19E+02.22E+02.11E+02.18E+02.23E+02.58E+02.30E+02.29E+02.16E+02.19E+02.16E+02.27E+02.32E+02.30E+02																	
4700.	.75E+02.39E+02.32E+02.19E+02.22E+02.11E+02.17E+02.22E+02.56E+02.29E+02.25E+02.16E+02.19E+02.16E+02.24E+02.31E+02.28E+02																	
4800.	.75E+02.39E+02.31E+02.19E+02.22E+02.11E+02.16E+02.22E+02.56E+02.29E+02.25E+02.16E+02.19E+02.16E+02.23E+02.31E+02.28E+02																	
4900.	.75E+02.39E+02.30E+02.19E+02.22E+02.11E+02.16E+02.22E+02.56E+02.29E+02.24E+02.16E+02.19E+02.16E+02.22E+02.31E+02.28E+02																	
5000.	.73E+02.38E+02.27E+02.19E+02.22E+02.11E+02.15E+02.22E+02.55E+02.28E+02.22E+02.16E+02.19E+02.16E+02.20E+02.30E+02.27E+02																	

Source: SACT/Leaning tower model



Table 5.1-4
Average Monthly Predicted Cooling Tower Salt Deposition

Distance From Tower (m)	Salt Deposition in the Direction Plume is Seeded (kg/km ² -month)																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	0.00	0.00	0.00	2.19	1.09	1.09	0.00	0.00	0.00	0.00	0.00	12.02	30.54	7.65	0.00	0.00	3.41
200.	0.00	0.00	0.00	66.81	74.35	42.37	0.00	0.00	0.00	0.00	0.00	86.91	193.02	61.54	0.00	0.00	32.81
300.	0.22	0.00	0.00	233.49	291.65	162.21	0.00	0.00	0.00	0.00	0.00	141.64	239.82	122.35	0.00	0.00	74.46
400.	0.46	0.00	0.00	165.59	206.96	116.42	0.00	0.00	0.00	0.00	0.00	98.58	149.53	84.72	0.00	0.00	51.39
500.	8.15	5.11	2.93	124.28	157.02	93.73	1.71	3.25	7.73	4.50	2.16	77.78	121.36	73.05	1.16	2.28	42.89
600.	20.06	14.21	13.35	92.15	116.51	70.56	7.92	9.47	20.43	11.66	9.04	55.47	89.98	54.35	4.95	6.28	37.27
700.	19.24	13.69	13.58	55.71	71.12	41.26	8.03	9.12	19.66	11.21	9.19	33.24	51.38	32.00	5.03	6.07	24.97
800.	20.10	13.52	10.47	49.82	63.29	36.97	6.18	8.84	20.16	11.62	7.57	29.47	46.00	28.51	4.07	6.08	22.67
900.	17.40	10.30	10.56	38.42	49.05	28.75	6.28	6.29	16.48	9.81	7.87	22.29	34.79	21.94	4.21	4.77	18.07
1000.	14.59	8.40	6.31	16.81	21.25	11.63	3.76	5.11	13.71	8.17	5.15	10.89	14.67	10.15	2.68	3.97	9.83
1100.	11.86	6.85	5.60	15.90	20.04	10.87	3.34	4.22	11.24	6.63	4.57	10.33	13.98	9.80	2.45	3.23	8.81
1200.	11.40	6.67	5.35	15.45	19.55	10.54	3.19	4.16	10.84	6.37	4.35	10.01	13.61	9.45	2.34	3.17	8.53
1300.	7.43	4.45	3.49	12.86	16.50	9.42	2.08	2.82	7.11	4.14	2.74	7.57	11.22	7.85	1.51	2.12	6.46
1400.	7.43	4.43	3.18	10.96	13.97	8.17	1.89	2.82	7.10	4.14	2.50	6.30	9.66	6.73	1.40	2.12	5.80
1500.	6.46	3.88	3.18	10.50	13.43	7.87	1.89	2.47	6.18	3.59	2.50	5.96	9.27	6.32	1.40	1.85	5.42
1600.	4.34	2.64	2.28	10.18	13.06	7.64	1.36	1.69	4.11	2.40	1.72	5.77	8.97	6.07	1.00	1.29	4.66
1700.	4.30	2.62	2.18	10.09	12.97	7.57	1.30	1.67	4.08	2.39	1.64	5.70	8.87	5.98	0.96	1.27	4.60
1800.	4.25	2.58	2.26	9.77	12.55	7.28	1.35	1.64	4.03	2.37	1.68	5.54	8.49	5.78	0.99	1.25	4.49
1900.	3.86	2.23	2.37	6.65	8.72	4.60	1.41	1.35	3.52	2.09	1.73	3.92	5.10	3.95	1.04	1.10	3.35
2000.	3.85	2.22	2.27	5.85	7.60	3.96	1.34	1.34	3.43	2.02	1.68	3.52	4.55	3.52	1.02	1.14	3.08
2100.	1.76	1.05	1.72	4.71	5.94	3.02	1.03	0.66	1.50	0.84	1.21	2.97	3.75	2.91	0.79	0.59	2.15
2200.	1.85	1.10	1.28	4.29	5.45	2.75	0.76	0.69	1.57	0.87	0.85	2.77	3.47	2.71	0.63	0.64	1.98
2300.	1.96	1.15	1.29	3.37	4.27	2.15	0.77	0.71	1.65	0.91	0.85	2.31	2.79	2.23	0.64	0.69	1.73
2400.	1.96	1.15	1.35	3.02	3.82	1.96	0.80	0.71	1.65	0.91	0.89	2.00	2.44	1.95	0.67	0.69	1.62
2500.	1.96	1.15	1.43	2.32	3.01	1.63	0.84	0.71	1.65	0.91	0.96	1.35	1.82	1.43	0.76	0.69	1.41
2600.	1.95	1.15	1.42	2.12	2.81	1.51	0.83	0.71	1.65	0.91	0.95	1.19	1.66	1.26	0.76	0.68	1.35
2700.	1.92	1.13	1.28	2.07	2.77	1.48	0.75	0.70	1.63	0.90	0.87	1.15	1.61	1.22	0.70	0.67	1.30
2800.	1.88	1.11	0.95	2.05	2.76	1.47	0.55	0.69	1.61	0.89	0.69	1.13	1.59	1.20	0.54	0.66	1.24
2900.	1.77	1.06	0.93	2.04	2.74	1.46	0.54	0.66	1.53	0.85	0.67	1.13	1.57	1.18	0.52	0.61	1.20
3000.	1.73	1.04	0.83	1.98	2.67	1.42	0.49	0.65	1.50	0.83	0.60	1.10	1.50	1.15	0.44	0.59	1.16
3100.	1.72	1.04	0.81	1.97	2.65	1.41	0.48	0.65	1.49	0.83	0.58	1.09	1.49	1.15	0.41	0.58	1.15
3200.	1.71	1.03	0.79	1.97	2.65	1.41	0.47	0.64	1.48	0.83	0.56	1.09	1.49	1.15	0.39	0.58	1.14
3300.	1.64	1.00	0.79	1.90	2.57	1.35	0.47	0.63	1.44	0.81	0.56	1.03	1.44	1.10	0.39	0.55	1.10
3400.	1.58	0.96	0.78	1.82	2.48	1.30	0.46	0.61	1.41	0.79	0.56	0.98	1.39	1.05	0.39	0.52	1.07
3500.	1.56	0.95	0.78	1.82	2.48	1.30	0.46	0.60	1.40	0.79	0.55	0.98	1.39	1.05	0.38	0.52	1.06
3600.	1.02	0.66	0.77	1.75	2.40	1.24	0.45	0.42	0.91	0.50	0.54	0.94	1.33	0.99	0.37	0.37	0.92
3700.	0.76	0.50	0.62	1.55	2.12	1.09	0.37	0.32	0.65	0.35	0.42	0.81	1.12	0.83	0.30	0.29	0.76
3800.	0.71	0.46	0.47	1.55	2.12	1.09	0.27	0.28	0.60	0.32	0.29	0.81	1.12	0.83	0.22	0.28	0.71
3900.	0.68	0.44	0.46	1.54	2.10	1.08	0.27	0.28	0.58	0.32	0.29	0.80	1.10	0.81	0.22	0.27	0.70
4000.	0.66	0.43	0.45	1.50	2.04	1.06	0.27	0.27	0.57	0.31	0.29	0.75	1.05	0.75	0.21	0.26	0.68
4100.	0.65	0.42	0.41	1.50	2.04	1.06	0.24	0.27	0.56	0.31	0.26	0.75	1.05	0.75	0.20	0.25	0.67
4200.	0.58	0.37	0.40	1.02	1.35	0.68	0.23	0.24	0.50	0.28	0.26	0.53	0.72	0.50	0.19	0.22	0.51
4300.	0.56	0.36	0.39	0.46	0.59	0.28	0.23	0.23	0.49	0.27	0.25	0.27	0.34	0.24	0.19	0.21	0.33
4400.	0.55	0.35	0.37	0.46	0.59	0.28	0.22	0.23	0.48	0.26	0.24	0.27	0.34	0.24	0.18	0.20	0.33
4500.	0.55	0.35	0.33	0.46	0.59	0.28	0.19	0.23	0.48	0.26	0.22	0.27	0.34	0.24	0.17	0.20	0.32
4600.	0.53	0.34	0.32	0.46	0.59	0.28	0.19	0.22	0.47	0.25	0.22	0.27	0.34	0.24	0.16	0.20	0.32
4700.	0.52	0.34	0.32	0.46	0.59	0.28	0.18	0.22	0.46	0.25	0.21	0.27	0.34	0.24	0.15	0.19	0.31
4800.	0.52	0.34	0.31	0.46	0.59	0.28	0.18	0.22	0.46	0.25	0.21	0.27	0.34	0.24	0.15	0.19	0.31
4900.	0.52	0.34	0.31	0.46	0.59	0.28	0.18	0.22	0.46	0.25	0.21	0.27	0.34	0.24	0.15	0.19	0.31
5000.	0.51	0.33	0.31	0.45	0.57	0.27	0.18	0.22	0.45	0.25	0.21	0.27	0.34	0.23	0.15	0.19	0.31

Source: SACTI cooling tower model.



Table 5.1-5
Average Annual Predicted Plume Length Frequency of Occurrence

Distance From Tower (m)	Probability the Plume is Longer in a Given Direction Than the Distance Indicated (percent)																SUM
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100.	10.77	6.58	7.01	7.29	9.56	5.59	4.51	4.67	9.02	4.95	4.54	4.47	6.66	5.06	4.57	4.76	100.00
200.	0.06	0.01	0.01	1.86	2.13	1.21	0.00	0.01	0.05	0.02	0.02	1.39	1.74	1.49	0.02	0.03	10.06
300.	0.06	0.01	0.01	1.80	2.06	1.16	0.00	0.01	0.05	0.02	0.02	1.35	1.68	1.43	0.01	0.03	9.71
400.	0.06	0.01	0.01	1.66	1.91	1.04	0.00	0.01	0.05	0.02	0.02	1.25	1.58	1.32	0.01	0.03	8.99
500.	0.06	0.01	0.01	1.62	1.84	0.99	0.00	0.01	0.05	0.02	0.02	1.22	1.54	1.27	0.01	0.03	8.70
600.	0.06	0.01	0.01	1.51	1.66	0.90	0.00	0.01	0.05	0.02	0.02	1.15	1.41	1.19	0.01	0.03	8.04
700.	0.06	0.01	0.01	1.35	1.50	0.81	0.00	0.01	0.05	0.02	0.02	1.03	1.27	1.05	0.01	0.03	7.24
800.	0.06	0.01	0.01	1.35	1.50	0.81	0.00	0.01	0.05	0.02	0.02	1.03	1.27	1.05	0.01	0.03	7.24
900.	0.06	0.01	0.01	1.35	1.50	0.81	0.00	0.01	0.05	0.02	0.02	1.03	1.27	1.05	0.01	0.03	7.24
1000.	0.06	0.01	0.01	1.24	1.32	0.75	0.00	0.01	0.05	0.02	0.02	0.92	1.12	0.89	0.01	0.03	6.46
1100.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1200.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1300.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1400.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1500.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1600.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1700.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1800.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
1900.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2000.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2100.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2200.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2300.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2400.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2500.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2600.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2700.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2800.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
2900.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3000.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3100.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3200.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3300.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3400.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3500.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3600.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3700.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3800.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
3900.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4000.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4100.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4200.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4300.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4400.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4500.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4600.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4700.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4800.	0.06	0.01	0.01	1.04	1.09	0.67	0.00	0.01	0.05	0.02	0.02	0.72	0.93	0.76	0.01	0.03	5.43
4900.	0.06	0.01	0.01	0.76	0.79	0.48	0.00	0.01	0.05	0.02	0.02	0.48	0.59	0.53	0.01	0.03	3.86
5000.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Source: SACTI cooling tower model.



As the data in Table 5.1-5 indicates, the SACTI model predicts the plume length to be less than 200 m (656 ft) 90 percent of the year considering all directions of plume travel. The median plume length, or that length which the plume is predicted to be longer or shorter than for 50 percent of the year considering all directions of plume travel, is approximately 155 m (509 ft).

As indicated in Table 5.1-5, the percent frequency of occurrence of long cooling tower plumes in any particular direction is very small. The highest probability of a visible plume over a particular location is approximately 11 percent of the year in an area 100 m (328 ft) south of the cooling towers.

5.1.4.4 Environmental Impact. The following sections discuss the potential environmental impacts associated with the operation of the cooling towers at the Power Park. The relative magnitude of the impacts are based on the results of the numerical modeling studies presented in Subsection 5.1.4.3. The environmental impacts are assessed with respect to the transportation arteries, vegetation, aesthetics, and land use.

In addition to assessing the environmental impacts associated with each of the aforementioned categories, this section also discusses many naturally occurring meteorological and atmospheric phenomena such as fog, cloud cover, and precipitation that may tend to mitigate the actual or perceived environmental impacts resulting from the operation of the cooling towers.

5.1.4.4.1 Impact on transportation arteries. Cooling towers may at times produce plume induced fogging and icing in the vicinity of the cooling tower structures which may have an affect on nearby transportation arteries such as roads, highways, bridges, airports, or navigable waters. Several factors influence the cooling tower plume as it leaves the tower which, to varying degrees, determine the location and magnitude of these phenomena.

The cooling tower plume will have thermal buoyancy and momentum as it is exhausted from the cooling tower. Under calm conditions, the plume will ascend vertically due to these forces. However, prolonged periods of calm and stable conditions do not frequently occur in the atmosphere, and are somewhat infrequent along the central Florida peninsula. In fact, winds in the vicinity of the Power Park are calm only about 6 percent of the year, and the subtropical humid climate is frequently unstable. As such, the cooling tower plume's trajectory becomes modified almost immediately as it leaves the cooling tower by persistent winds and atmospheric instability.



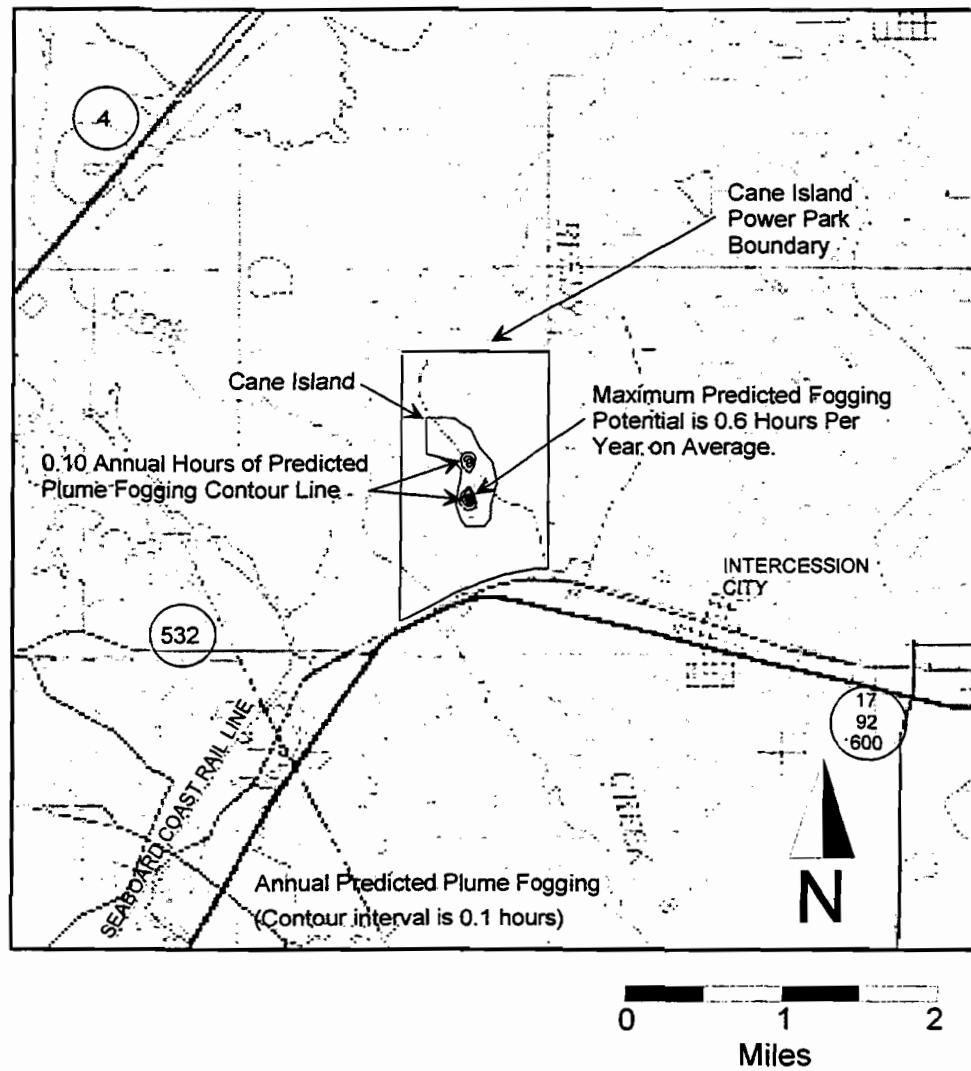
As the wind speed increases, the cooling tower plume begins to assume a trajectory that is sloped in the direction of the wind vector, bringing the plume closer to the ground. The plume will likely undergo further trajectory modification as the result of turbulent airflow over and around terrain features, buildings, or the cooling tower structure itself. This effect, known as structure or building downwash, occurs when the trajectory modification is such that the plume is forced to the ground in the vicinity of the cooling tower. If the plume becomes supersaturated during this process (i.e., becomes visible), then the result is a phenomenon known as cooling tower induced ground level fogging (Ovard and Reisman).

Cooling tower induced fogging can occur at any time during the year, but it is most commonplace during periods of moderate wind speeds (which bend the plume to intercept the ground), high relative humidity, and cool temperatures. These meteorological conditions frequently occur during the late evening and early morning periods of the day.

A land use map of the area, illustrated on Figure 2.3-3, was reviewed to determine the major transportation arteries in the vicinity of the site. Apart from the Power Park entrance road, which is restricted from public access, the nearest transportation arteries include portions of Old Tampa Highway and the CSX rail line just west of Intercession City, approximately one-half mile south of the power block. As discussed in Subsection 5.1.4.3.1, the maximum cooling tower plume induced fogging is predicted to occur less than 1 hour per year on average, and no amount of fogging is predicted to extend beyond a radius of 984 feet (300 m) from the cooling towers.

Figure 5.1-1 illustrates the minimal extent and duration of the predicted cooling tower induced fogging. The outer most contour represents 0.1 hour per year of possible plume fogging, with increasing contours of fogging at 0.1 hour per year intervals. Based on the results of the modeling, the cooling tower plume induced fogging is not predicted to extend significantly beyond the power block limits, and will not significantly impact nearby transportation arteries.

Many of the meteorological conditions that are favorable for the occurrence of cooling tower plume induced fogging are conducive to natural fog. As such, the two events may occur simultaneously and thereby mitigate the relative impact potentially caused by cooling tower plume induced events. Climatologically, natural fog (that which restricts visibility to less than $\frac{1}{4}$ of a mile) occurs an average of 26 days a year based on meteorological data from Orlando. This means that there are at least 26 hours of naturally occurring fog in the vicinity



Cane Island Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results

Average Annual Hours of Predicted Plume Fogging

Figure 5.1-1



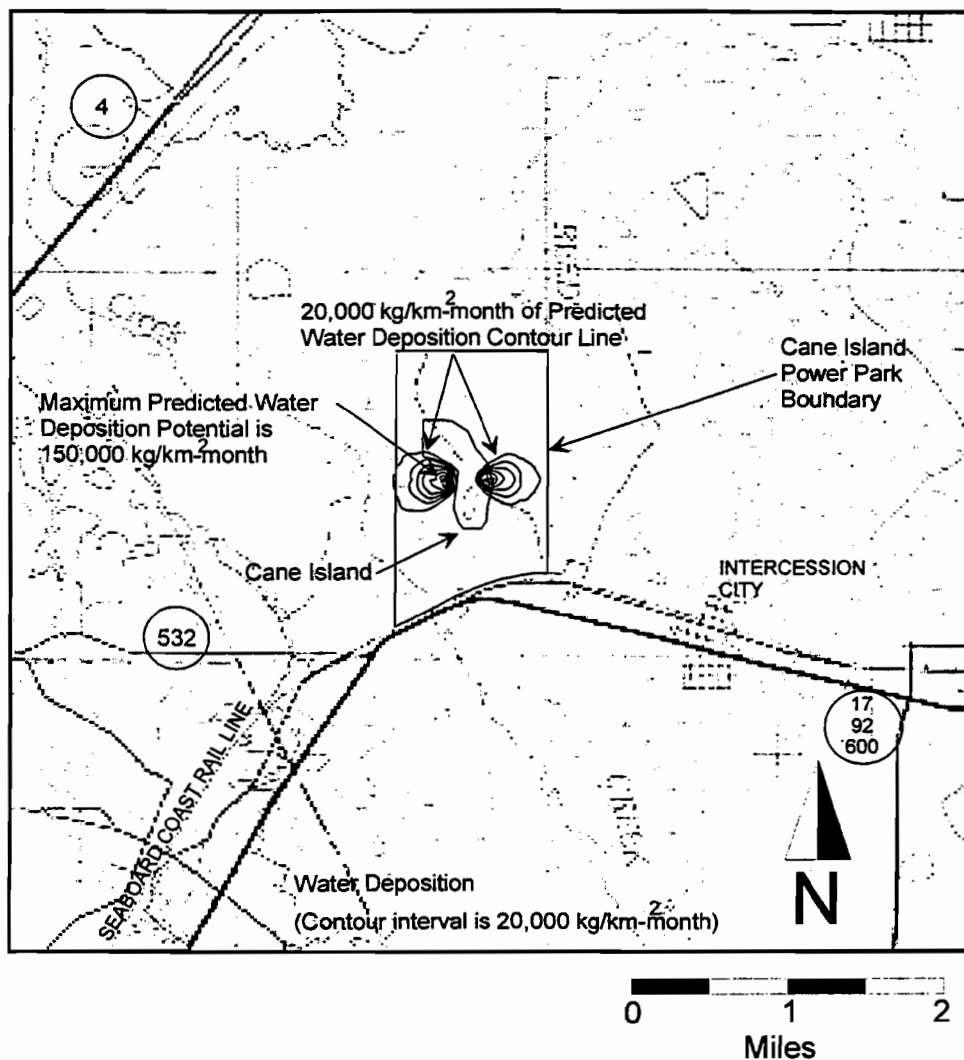
of the Power Park (conservatively assuming that reported fogging events last for only one hour per day), which is approximately 13 times greater than the maximum annual fogging hours predicted by the SACTI model in the vicinity of the Power Park.

A secondary effect of cooling tower fogging is the formation of cooling tower induced ground level icing. However, as temperatures rarely fall below freezing in the area, no cooling tower plume induced icing is predicted to occur.

5.1.4.4.2 Impact on vegetation. The plume exhaust from cooling towers may affect the vegetation in the vicinity as the result of drift deposition. Drift deposition from a cooling tower occurs when airborne water droplets, caused by cooling tower drift, coalesce and precipitate in the vicinity of the cooling tower. The pattern of drift deposition and the distance from the cooling tower to the areas of maximum deposition concentrations are a function of many variables, which include: cooling tower type, prevailing wind direction and speed, orientation of the cooling tower, airflow rate, drift rate, water chemistry, and the physical size of the water droplets (drift droplet size spectrum) in the cooling tower drift. The potential effects associated with cooling tower drift deposition are primarily associated with salt and water deposition. The response of the vegetation to salt and water deposition will vary from year to year depending on the rate of deposit and precipitation patterns during the growing season.

An area map depicting the Power Park location and surrounding vegetation and land use overlaid with an isopleth analysis of the SACTI predicted average monthly water deposition rate is presented on Figure 5.1-2. The predicted location of the maximum water deposition rate occurs approximately 300 m (948 ft) west of the power block at a deposition rate of 150,000 kg/km²/month. Vegetation and land use in this area is characterized as wet natural as illustrated on Figure 2.3-3. Predicted water deposition rates in this area, as well as the upland natural area of Cane Island, range from 20,000 to 150,000 kg/km²/month.

A second predicted location of maximum of water deposition occurs east of the power block, approximately 300 m (984 ft) from the cooling towers as illustrated on Figure 5.1-2. Predicted water deposition rates in this area range from 20,000 to 140,000 kg/km²/month. Vegetation and land use in this area is primarily characterized as wet natural. A potential effect of water deposition on vegetation species is the increased threat of plant fungal diseases associated with the increased precipitation. Based on historical meteorological data for Orlando, the average monthly rainfalls for the driest month (April) and the wettest month



Cane Island Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results

Average Monthly Predicted Cooling Tower Water Deposition

Figure 5.1-2



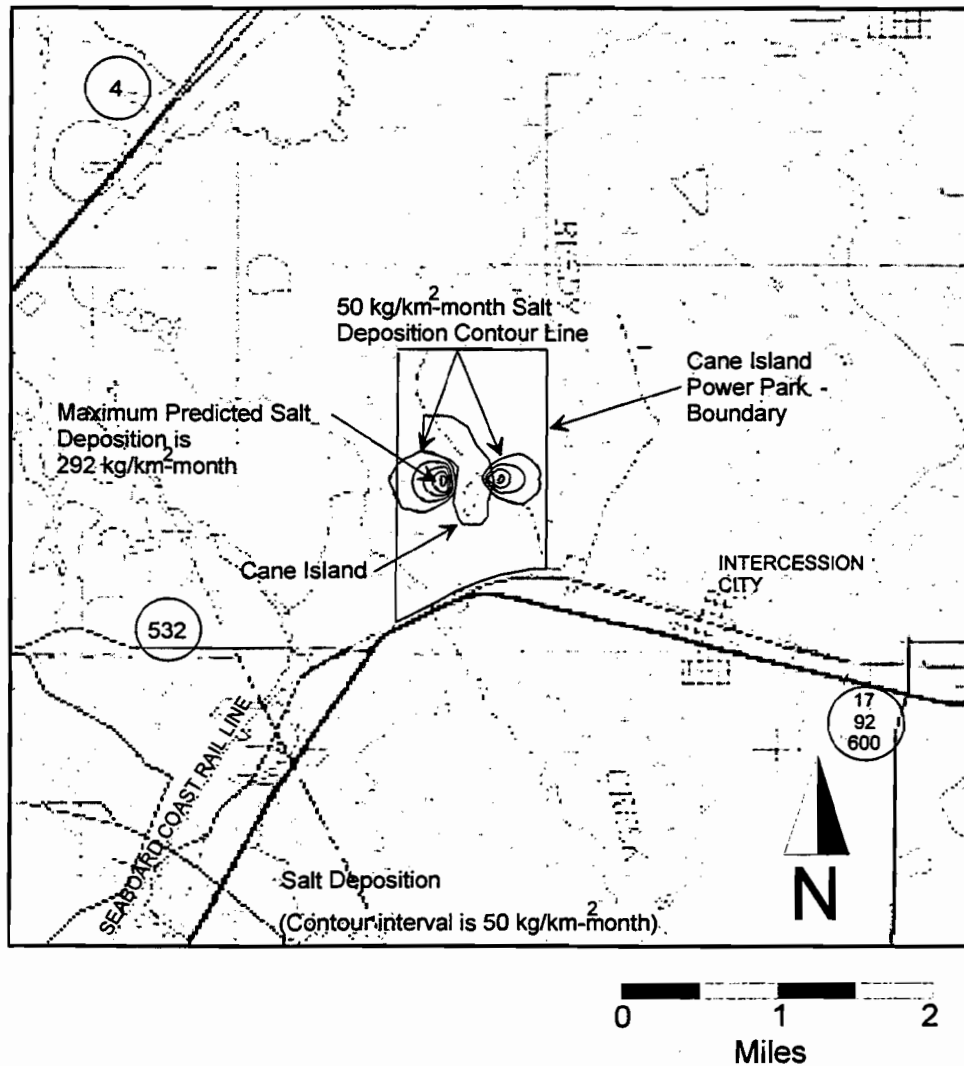
(June) are 46 and 186 mm, respectively. If one conservatively assumes no evaporation of the falling cooling tower drift droplets, then the precipitation rate equivalent of the maximum SACTI model predicted water deposition rate (150,000 kg/km²/month) is approximately 0.15 mm per month. By comparison, this precipitation rate is less than one-half percent of the average monthly rainfall of the driest month.

Dr. Walter Stephenson, a crop pathologist at the University of Wisconsin has experience with plant disease prediction models that consider precipitation and leaf wetness. Dr. Stephenson's research shows that a slight increase in disease occurrence is sometimes observed by U.S. mid-western potato growers when irrigation at a rate of approximately 50 mm per week is applied. A 50 mm per week irrigation rate is equivalent to a water deposition rate of approximately 2×10^8 kg/km²/month, which is more than 1,300 times greater than the maximum Power Park water deposition rate predicted by the SACTI model. This suggests that the water deposition from the cooling towers on vegetation and crops species is insignificant when compared to normal wetting associated with dew, precipitation, and irrigation. Furthermore, because water deposition will occur in conjunction with salt deposition, the additional deposition of salt may be toxic to any pathogenic microorganisms or fungi, and thus negate the effects of water deposition by itself.

An area map depicting the site, surrounding vegetation, and land use overlaid with an isopleth analysis of the SACTI predicted average monthly salt deposition rate is presented on Figure 5.1-3. The predicted location of the maximum salt deposition rate occurs just west of the power block at a deposition rate of 292 kg/km²/month. Vegetation and land use in this area is classified as wet natural. Predicted salt deposition rates in this area, including the upland natural area of Cane Island range from 50 to 292 kg/km²/month.

A second predicted location of maximum of salt deposition occurs just east of the site, approximately 300 m (984 ft) from the proposed location of the cooling tower. Predicted salt deposition rates in this area generally range from 50 to 240 kg/km²/month. Vegetation and land use in this area is characterized primarily as wet natural and upland natural.

Research studies on salt deposition effects have been conducted in response to known or observed cases of vegetation damage. From these studies, it is known that the local climate plays a significant role in increasing or reducing the stress that such deposition can have on vegetation. For example, a species growing in an area with high rainfall during the growing season tends to be less stressed from salt deposition than the same species growing



Cane Island Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results

Average Monthly Predicted Cooling Tower Salt Deposition

Figure 5.1-3



in an area with less rainfall due to the dilution of the deposited salt on the leaf surface. Additionally, vegetation species growing along coastal regions have a higher tolerance for salt deposition because of the relatively high ambient airborne concentration of sea salts in the marine environment.

As salinity levels increase, growth of intolerant plants declines, and yields are reduced. Some plant families tend to show either high or low limits of salt survival. The limit is low in legumes, (pea, beans), medium in cereal grasses (rye, oats, wheat barley), and high in some forage and other crop plants (alfalfa, sunflower, sugar beet, forage beet) (Maianu et al. 1965). Growth suppression is sometimes accompanied by leaf injury. Leaves become smaller and deeper blue-green than normal, and leaf tips or margins become bleached, tan, or brownish in proportion to the degree of salt deposition. Bronzing and early defoliation may also be prominent. Leaf injury may be the most prominent symptom of salt deposition but is not nearly important to yield reductions as the growth suppression (Treshow 1970).

Dr. Charles Mulchi of the University of Maryland at College Park has conducted extensive research on cooling tower salt deposition effects and toxicity levels in several vegetation species. According to Dr. Mulchi (1991), a salt deposition rate of 400 kg/km²/month or greater is sufficient to cause damage to vegetation. The amount and type of damage is dependent on the species involved. For example, one species of pine may show signs of damage while another species may show no signs of damage. The 400 kg/km²/month salt deposition rate is the threshold level for most vegetation species and has been used in many environmental assessments as a screening or trigger level of potentially significant salt deposition rates. Salt deposition rates less than 400 kg/km²/month are generally not considered to have a significant impact on vegetation. The maximum predicted salt deposition rate from the cooling towers is 292 kg/km²/month. Therefore, salt deposition from the cooling tower is expected to have a negligible impact on vegetation and land use.

5.1.4.4.3 Impact on aesthetics and land use. A cooling tower contributes to the impacts on the aesthetics of an area by forming a visible, at times completely opaque, vapor condensate plume emanating from the cooling tower exhaust. The presence of a visible plume and cooling tower are often perceived as a distraction or debasement to the otherwise scenic quality or functional use of an area. This is particularly true if the cooling tower plume and tower structure are in the background or foreground of a view with a particular scenic quality



or land use type. The potential impacts on aesthetics and land use as the result of visible plume formation and the cooling tower structure are discussed below.

Perhaps the most obvious environmental impact from a cooling tower is the formation of a visible plume extending out from the cooling tower cell exhaust ports. The visible plume may extend several hundred yards downwind, potentially obstructing visibility on the site and at nearby residences. The factors that affect visible cooling tower plume formation are discussed in the following paragraphs.

Cooling towers are simple fluid heat exchange systems that dissipate waste heat to the atmosphere through mass and convective heat transfer of water vapor. The exhaust from a cooling tower is essentially a saturated air-water vapor mixture which is warmer than the ambient air as it leaves the tower. Depending on the ambient air temperature and the wet-bulb temperature, a portion of the saturated air-water vapor mixture will become supersaturated and begin to condense into small water droplets as heat transfer with the atmosphere begins to cool the plume. With time, more small water droplets continue to form and grow through condensation and coalescence until the cooling tower exhaust becomes visible as a white plume emanating from the tower. The cooling tower plume will continue to be visible until it is dispersed and evaporated, or until meteorological conditions are no longer favorable for its formation. In the former case, the visible cooling tower plume is transported downwind until turbulent mixing in the atmosphere with the abundant and relatively dryer ambient air causes the small water droplets to disperse and evaporate. As the visible plume becomes thoroughly mixed with the ambient air, the small water droplets completely disperse and evaporate until the plume is no longer visible and becomes transparent.

The frequency, persistence, and size of the visible cooling tower plume depends primarily on the cooling tower type, heat load, orientation of the cooling tower, and the prevailing meteorological conditions. Mechanical draft towers typically present less of a visual distraction because of the relatively low plume exhaust height and profile.

Visible plume formation from cooling towers is more frequent during the cooler seasons when ambient air conditions are capable of rapidly condensing the cooling tower exhaust and allowing only minimal evaporation of the condensed water droplets. Similar conditions exist on a diurnal scale that are also more suitable for visible plume formation. These periods occur during the early morning hours, shortly before and after sunrise, when relatively low ambient



air temperatures and high relative humidity make the environment particularly conducive to visible plume formation.

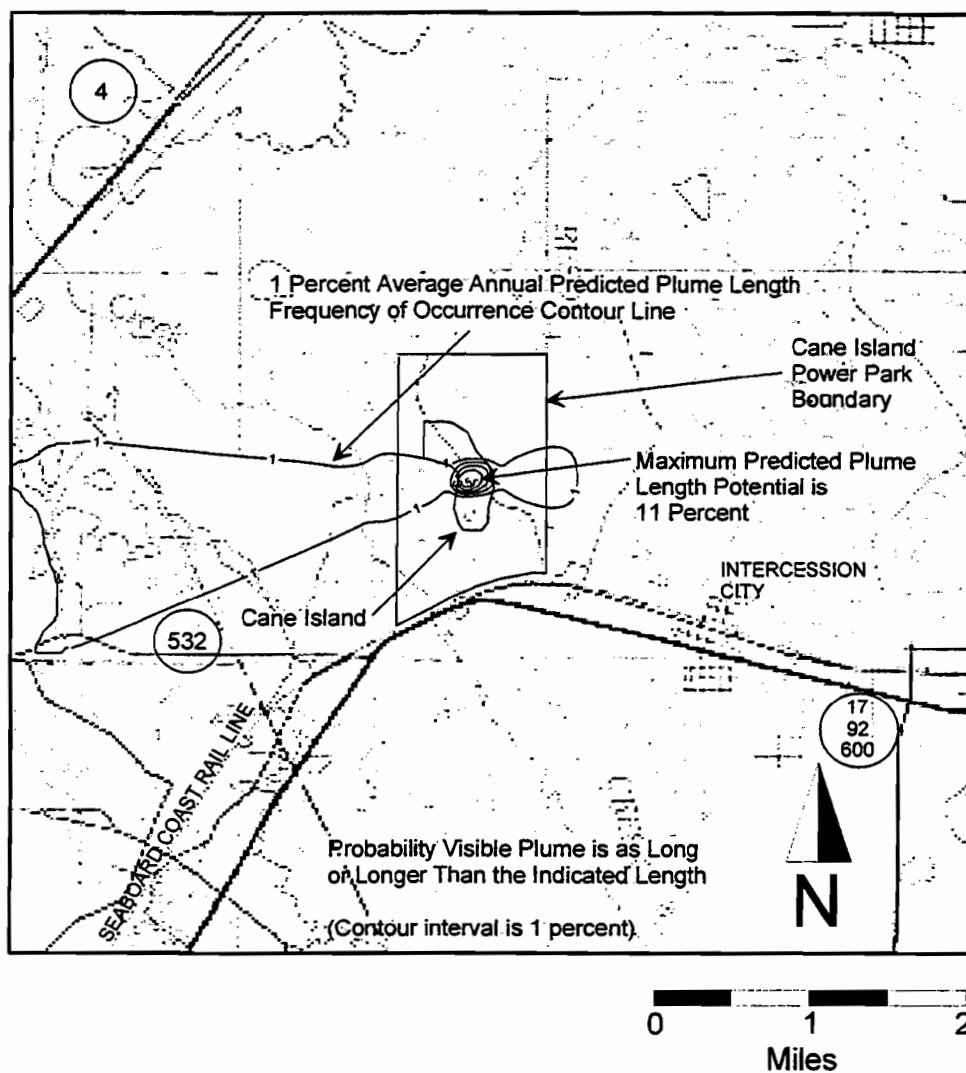
Figure 5.1-4 illustrates the site location overlaid with an isopleth analysis of the average annual predicted plume length frequency of occurrence. The highest probability of a visible plume is predicted to occur in the power block area just south of the cooling towers for approximately 11 percent of the year on average. Over the remaining portions of the Power Park and the immediate vicinity, the frequency of occurrence of a visible plume for a particular location generally ranges from about 3 to 10 percent of the year. Based on these results, it is concluded that the presence of a visible plume from the cooling towers will only minimally contribute to the visible and aesthetic impacts in the area.

The visible plume from the cooling towers is also predicted to periodically extend off-site. However, as shown on Figure 5.1-4, this is predicted to occur only about 1 percent of the year on average, and therefore will have little or no impact on nearby residences or the natural wetlands that surround the power block and Power Park.

It should be noted that the probability of visible plume lengths predicted by the SACTI model are conservative overestimates of actual plume lengths. This is primarily because the SACTI model does not distinguish prevailing meteorological conditions such as haze, overcast skies, fog, and precipitation, which may render the cooling tower plume indiscernible. In certain cases, especially as the distance from the cooling tower increases, the model may predict saturation (thus a visible plume by modeling standards), but due to spreading of the plume it may only be visible as a slight haze. If this is the case, then from an aesthetic perspective, the plume may not be discernible against the background haze that may already exist due to the high humidity, smog, or suspended particulate matter. In other cases, the plume may be dense, but it would not be discernable against the existing cloud deck.

5.1.5 Measurement Program

KUA was issued permit No. FLA010961 by the FDEP for discharge of industrial wastewaters. This permit authorizes KUA to discharge wastewater from the heat dissipation system to the Kissimmee effluent pipeline. The FDEP has set limits for effluent discharges and has required KUA to monitor discharges. Monitoring parameters and the frequency and sample type are listed in Table 5.1-6. No monitoring of surface waters is required.



Cane Island Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results

Average Annual Predicted Plume Length Frequency of Occurrence

Figure 5.1-4



Table 5.1-6
Monitoring Requirements for Effluent Discharges

Parameters (Units)	Frequency of Sampling	Sample Type
Flow (MGD)	Daily	Metered
TDS (mg/l)	2/Month	Grab
Chlorides (mg/l)	2/Month	Grab
Nitrates as N (mg/l)	Weekly	Grab
Nitrates as N (#/day)	Weekly	Grab
Total Nitrogen (mg/l)	Weekly	Grab
Total Nitrogen (#/day)	Weekly	Grab
Sodium (mg/l)	2/Month	Grab
Sulfates (mg/l)	2/Month	Grab
TRPH (mg/l) (c)	Monthly	Grab
pH (SU)	2/Week	Grab



5.2 Effects of Chemical and Biocide Discharges

As shown on the water mass balances (Figures 3.5-1 through 3.5-4) in Section 3, and as described below, there are two industrial wastewater discharges from operations at the Power Park: effluent return and percolation pond. There are no discharges to wetlands or surface waters under normal operating conditions. The Industrial Wastewater Facility Permit issued to KUA for operation of the Units 1 and 2 wastewater treatment and disposal system will require modification to incorporate Unit 3 treatment facilities. A copy of the Units 1 and 2 permit is included in Section 10.3; a permit modification request is included in Section 10.4.

5.2.1 Industrial Wastewater Discharge

Wastewaters potentially contaminated with grease or oil from the plant floor drain system and oil containment areas are treated by an oil/water separator and an onsite dry pre-treatment (percolation) pond prior to onsite discharge to ground water. A second separator will be required to treat similar wastewaters from Unit 3 facilities. Effluent from the oil/water separators will contain no more than 15 ppm oil/grease. However, expansion of the percolation pond will be required with the addition of Unit 3.

5.2.2 Cooling Tower Blowdown

Cooling tower blowdown, boiler blowdown, and neutralization basin effluent will be collected in a sump and returned to the Kissimmee effluent pipeline for additional reuse, by FPC's Intercession City Power Plant, or ultimate disposal at the regional Imperial percolation pond facility. Water quantity estimates are provided on the water mass balance (Figure 3.5-1). No violation of water quality standards are expected at the Imperial site after water use by the Cane Island and Intercession City power facilities.

Potential effluent delivery emergency situations include disruption of effluent delivery due to an upstream treatment facility or pipeline problem, or low effluent supply; therefore, KUA requests approval to use ground water as cooling tower makeup under emergency conditions. Blowdown during such an emergency will be directed to the onsite storm water ponds. The impacts of this discharge scenario are described in Section 5.3.2 below.

The Power Park will not require effluent water during nonoperating periods such as for maintenance or repair. KUA's allotment would then be available for downstream users.



5.2.3 Measurement Program

The Industrial Wastewater Facility Permit issued for the current operations includes conditions that require the monitoring of inflows, discharges, and ground water. The limitations and monitoring requirements are identified in the permit (Section 10.3). It is anticipated that similar monitoring will be required with the addition of Unit 3.

Samples must be collected from the Kissimmee effluent pipeline and the well water system prior to use. Samples of the water must also be collected prior to return to the effluent pipeline and discharge to the percolation pond.

A ground water monitoring system (wells) has also been established to monitor water quality impacts from the percolation pond on the surficial aquifer. One background well and two compliance wells (shown on Site Arrangement) have been installed.

5.3 Impacts on Water Supplies

5.3.1 Surface Water

Surface waters in the Power Park area include Reedy Creek and the Bonnet Creek Canal. Reedy Creek discharges into Lake Russell approximately 13 miles downstream of the Power Park. The Bonnet Creek Canal discharges into Reedy Creek near the west Power Park boundary. There are no natural surface water bodies onsite. Power Park operations do not withdraw or discharge to these waters; therefore, no impacts to these surface waters are expected as a result of Power Park operations.

The Power Park drainage system will be designed to comply with all applicable federal, state, and local regulations regarding discharge into surface waters. Runoff from areas not disturbed by construction or operations will be directed to natural drainage systems within the area. Runoff from disturbed areas will be collected and directed into a drainage system consisting of ditches, swales, and runoff basins for treatment. The runoff from uncontaminated areas will be directed through a detention basin for reduction of the suspended solids load and equalization of peak flows. At the property boundary, the post-development peak flow rate will not exceed the predevelopment peak discharge rate during the applicable design storm event. A detailed description of the onsite drainage system is provided in Section 3.8.



Power Park operations are not expected to affect surface water quality within the area. Undisturbed areas will remain in its existing state. Runoff water quality should at least remain unchanged and is expected to be improved as a result of detention in the storm water pond. Power Park water use and consumption are described in Section 3.5.

5.3.2 Ground Water

The following describes the effects of plant operations on the aquifers underlying the Power Park.

5.3.2.1 Surficial Aquifer. Under normal operating conditions, the Power Park will not have a significant effect on the surficial aquifer quality. No water will be withdrawn from this water table zone. Wastewaters are treated prior to ground water discharge.

In the event that the Kissimmee effluent pipeline is disabled, the combined cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be temporarily discharged to the storm water runoff ponds. Total discharge is estimated to be 436,500 gpd, for a duration of 3 days. The 3 day period is assumed to be the maximum duration that the Kissimmee wastewater treatment plant or effluent pipeline could be out of operation.

The two ponds are currently sized for storm water runoff and have a weir overflow structure to control the discharge of water. The discharge structure for the Unit 1 and 2 pond provides a 2.5 feet storage capacity from the bottom of the pond to the overflow structure. The structure has a 4 inch diameter orifice located at the base of the structure meant to dampen the discharge of storm water from the facility to predevelopment conditions. The Unit 3 pond will have approximately 3 feet storage capacity from the bottom of the pond to the overflow structure and has an 8 inch diameter orifice. A detailed description of the storm water runoff pond operation is presented in Section 3.8. The orifices will be closed in the case that the pond must be utilized as a storage facility for emergency cooling tower blowdown. After closure of the orifices, the ponds will be used as a storage facility that allows percolation through the pond bottom. This disposal method is preferred over release of the blowdown to wetlands adjacent to the power block.



The ponds will be able to store and percolate the total volume for a period of 3 days of discharge. Storage volumes and percolation rates are estimated as follows:

Facility	Storage Volume	Percolation Rate Through Pond Bottom	Total for 3 Day Period
Unit 1 and 2 Storm Water Runoff Pond	734,210 gal	118,120 gal/day	1,088,600 gal
Unit 3 Storm Water Runoff Pond	613,420 gal	106,120 gal/day	931,780 gal
Total Capacity for 3 Days			2,020,380 gal

Total discharge for 3 days at 436,500 gpd is 1.3 million gallons which is less than the available storage and percolation capacity for the two ponds. The Unit 1 and 2 storm water pond and the Unit 3 storm water pond are capable of holding and percolating the total blowdown volume for a period of 3 days. If the effluent line is out of service for longer than 5 days, the daily flow of 436,500 gpd, minus the 224,240 gpd percolation capacity of the two storm water ponds, will be discharged over the ponds' overflow structures into Reedy Creek Swamp. However, the effluent line has never been out of service since the Power Park has been in operation.

During these rare events when there is an interruption in the effluent flow, ground water from the Floridan Aquifer will be used as cooling tower makeup. The ground water quality is better than the effluent quality, and therefore, the cooling tower can be operated at additional cycles of concentration. The blowdown water quality is estimated as follows:

	Design Well Water (ppm)	Cooling Tower Blowdown @ 6 cycles (ppm)
Ca, as CaCO ₃	110	660
MG, as CaCO ₃	30	180
Na, as CaCO ₃	34	204
K, as CaCO ₃	1	6
M-Alkalinity, as CaCO ₃	145	150



	Design Well Water (ppm)	Cooling Tower Blowdown @ 6 cycles (ppm)
SO ₄ , as CaCO ₃	20	840
Cl, as CaCO ₃	10	60
SiO ₂ , as such	12	72
TDS, as such	283	1,512

5.3.2.2 Floridan Aquifer. Water for service water, demineralizer water, miscellaneous drains, and potable water requirements will be supplied by the Floridan Aquifer. The Floridan Aquifer, as defined for the Power Park, is a confined unit. The base of the confining unit is located 135 feet to 195 feet bgs. Hydrogeological and water quality data for the Floridan Aquifer are presented in Section 2.3.2.

Two wells were installed into the Floridan Aquifer during the construction of Units 1 and 2. Withdrawals were permitted by SFWMD Water Use Permit 49-00671-W with an annual allocation not to exceed 75 million gallons, and a maximum daily allocation not to exceed 260,000 gallons. A copy of the SFWMD Water Use Permit is presented in Section 10.3.

Unit 3 water requirements include an additional estimated average daily usage of 126,000 gpd (88 gpm) of well water. The total expected Power Park usage including Unit 3 will be 221,000 gpd (154 gpm) operating on natural gas. Average daily water usage will be supplied from the two existing wells. Each well is capable of producing a maximum of 450 gpm. One well is considered to be a spare, available during periodic maintenance of individual wells.

Cooling tower makeup water will normally be obtained from the Kissimmee effluent pipeline. Cooling tower makeup water requires a daily allocation of 2,865,000 gallons with all units at full load. However, if the Kissimmee effluent pipeline is damaged, taken out of service temporarily, or if flows are temporarily inadequate to supply the Power Park demand, the incremental flow will be obtained from the Floridan Aquifer. Four new wells will be installed into the Floridan Aquifer capable of providing 450 gpm each, in addition to the two existing wells, for a total withdrawal capacity of 2,250 gpm. One of the six total wells will be considered a spare for use in case of an individual well outage. These additional wells will



only be used as an emergency backup system to the effluent pipeline supply. The expected worst case emergency will require that 5 wells pump at 404 gpm each (2,908,800 gpd) for up to 60 days. However, it is expected that the duration of this additional pumping requirement will normally be considerably less than 60 days. Again, the effluent pipeline has never been out of service nor have flows been inadequate since Power Park operation.

Description of Ground Water Model. A modular three-dimensional finite difference ground water flow model developed by the US Geologic Survey titled MODFLOW was used to investigate the impact on the Floridan Aquifer of withdrawals associated with Power Park operations. The objective of the model was to determine the change in piezometric head and associated radius of influence in response to anticipated ground water withdrawals. Input for the model consisted of aquifer parameters and average daily withdrawals for predetermined simulation times and conditions. Aquifer parameters were developed from a literature search of existing aquifer data for the study area. The strongly implicit procedure method was used in the model to iteratively solve the system of finite difference equations and determine changes in piezometric head.

Model Calibration. The model was defined by a series of grids increasing in size from 1 foot to 528 feet extending outward from the wells. Total model dimensions were approximately 52,800 feet (10 miles) per side; therefore, the model boundaries were 5 miles from the power block area. The piezometric head was fixed at the boundaries and allowed to fluctuate at all other locations. Aquifer parameters used for the model calibration are the following:

- The model was one layer with a thickness of 375 feet (Elev +75 to Elev -300).
- The aquifer was assumed to be confined.
- Piezometric head was set at Elevation 70 feet.
- Transmissivity of 200,000 gpd/ft.
- Storage coefficient of 0.002
- Recharge from rainfall, surface water, etc., assumed negligible and was not used in the model.

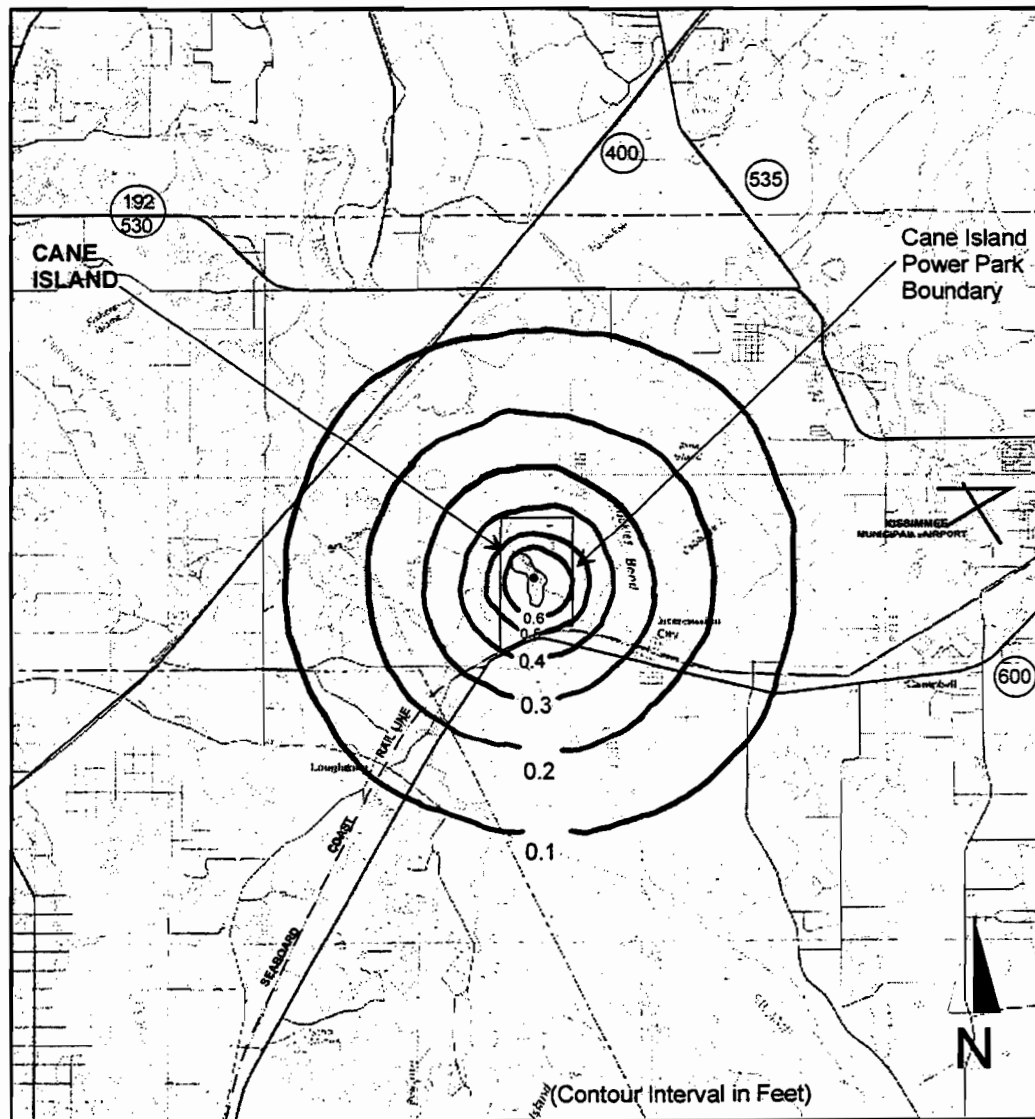


The model calibration used the same aquifer parameters as the model used to permit the existing wells. The initial calibration determined the specific capacity for a single well to be 80 gpm per foot of drawdown (2.5 feet at 200 gpm). The pump tests for the two existing wells found the specific capacity to vary between 90 gpm to 26 gpm per foot of drawdown. Using the previous model's aquifer parameters and the new model grid, the calibration determined the specific capacity of a single well to be 77 gpm per foot of drawdown (2.6 feet at 200 gpm). Therefore, the new model approximates the previous model and the existing conditions.

Predictive Results. Average Daily Flow. The average daily flow model is similar to the calibration model. A single onsite well was modeled to pump at a capacity of 213.5 gpm (307,440 gpd); equivalent to the combined flow for all units. The model was set to run for 10 years in 10 time steps. At the conclusion of the 10 years, the drawdown in the well was determined to be 2.8 feet (76 gpm/foot of drawdown). The model indicated that the drawdown in the aquifer was less than 0.1 feet at a radius of 3.5 miles from the power block. Drawdown contours are presented on Figure 5.3-1.

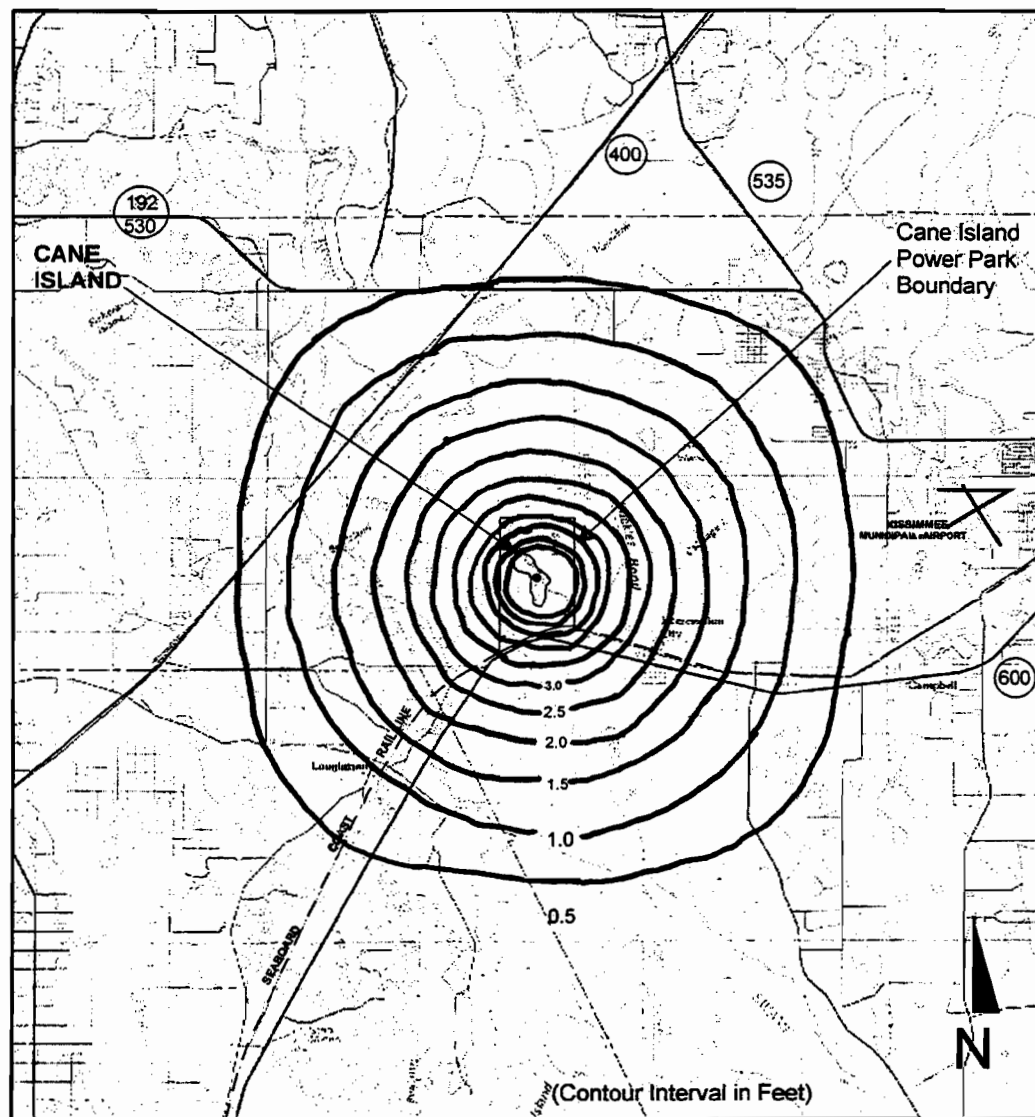
Maximum Daily Flow. The maximum daily flow model used 5 wells to pump at 404 gpm each for a total capacity of 2020 gpm (2,908,800 gpd). In addition to the two existing onsite wells, three new wells (one well remained as a spare) were included in the model. The model grid was changed to include smaller individual grids around each well. This model was set to run for 60 days, the maximum assumed time for the emergency usage condition. At the conclusion of the 60 days, the drawdown was determined to be about 11.5 feet in each well and approximately 10 feet in the power block area. The drawdown was found to be approximately 1.0 foot at a distance of 3.5 miles from the site. Drawdown contours are presented on Figure 5.3-2.

Summary of Ground Water Impacts. The predicted drawdown in the vicinity of the wells indicates that there will be no affects to existing domestic, irrigation, or other public water supply wells due to ground water withdrawal. A review of existing wells indicates that there are no wells located within a 3,500 feet radius of the proposed wells.



Floridan Aquifer
Drawdown Contours
Average Daily Flow
1 Well, 213 gpm

Figure 5.3-1



Floridan Aquifer
Drawdown Contours
Maximum Daily Flow
5 Wells, 404 gpm each

Figure 5.3-2



The literature search conducted for the ground water flow model, as well as the investigation of the site conducted by Black & Veatch indicates that the Floridan Aquifer, the proposed ground water source for the wells, acts as a confined aquifer in the Cane Island area. Therefore, withdrawal of ground water from the aquifer will not affect the adjacent surface water bodies. Withdrawals from the wells will not cause any saltwater intrusion. The Power Park does not have any evidence of existing sinkhole activity, and water use from the wells is not expected to contribute to the future formation rate of sinkholes.

Due to the confined nature of the aquifer, Power Park water use will not effect environmental features that have a direct or indirect relationship to wetland habitats, natural water bodies, intermittent ponds, or upland areas. The water use will not affect any preferred habitats for rare, endangered or threatened species. The drawdown associated with the ground water withdrawal from the Floridan Aquifer will be confined to the aquifer and will not affect surficial ground water elevations. Inter-aquifer communication between the Floridan Aquifer and any surficial water bodies will not occur. There will be no adverse impacts to other users, pollution sources, saline water intrusion, adjacent water bodies, environmental features, or land use caused by the water use.

5.3.3 Drinking Water

The effects of Power Park ground water withdrawals during operation on drinking water supplies are discussed in Section 5.3.2. The effects of leachate and runoff are discussed in Section 5.3.4. The locations and descriptions of existing wells are provided in Section 2.3.3. There will be no harm to any existing legal users or to the resource by any of the activities associated with the Power Park.

5.3.4 Leachate and Runoff

There is no source of leachate associated with the Power Park and there will be no impact on the underlying aquifers due to leachate. The impacts from Power Park operations on the surficial ground water system are monitored as described in Section 5.3.5. Effluent from the oil/water separators is routed to the existing percolation pond for discharge to the surficial aquifer.

5.3.4.1 Description of percolation pond. The expanded percolation pond will operate as a single cell, dry pretreatment pond with berms to prevent overflow and divert general site



runoff. The pond will be used to collect water that has been routed to the oil/water separators for treatment. Water sources include plant and equipment drains, rainfall runoff water from the fuel oil storage tank areas, transformer areas, and fuel oil unloading station. Water collected in the pond will be near service water (well water) or rainfall runoff quality. Collected waters will percolate down to the surficial ground water table below the pond. A series of three ground water monitoring wells have been installed into the surficial ground water table to monitor the performance of the dry pretreatment pond. A description of the monitoring plan is presented in Section 5.3.5.

A mounding study was performed to determine the impact of the operations of the pond to the underlying surficial aquifer. The mounding study was performed to simulate two operating conditions. The first condition simulates the average daily flow from plant and equipment drains. The second condition simulates the storm water runoff from the fuel oil storage containment areas, transformer containment areas, and the fuel oil unloading station for a 24 hour, 10 year storm event including the average daily flow from the plant and equipment drains. The storm water runoff is designed to pass through the percolation pond in 7 days.

The location of the expanded percolation pond and surrounding structures is shown on the Site Arrangement, Figure 2.1-3. The base of the pond is at elevation 80.0 feet. The emergency overflow weir is set at elevation 85.0 feet. Maximum berm height is elevation 86.0 feet. Maximum pond operating elevation for average daily flow is elevation 82.0 feet, 3 feet below the emergency overflow weir elevation. Maximum operating elevation for worst case flow is elevation 84.0 feet, 12 inches below the emergency overflow weir elevation. Effective pond size at elevation 82.0 feet, is 95.5 feet by 103 feet. Final grade adjacent to the percolation pond is approximately elevation 85 feet. Ground elevation will decrease to approximately 73.0 feet at the wetlands, at the edge of Cane Island. Storage capacity and runoff volume for specific areas are presented in Table 5.3-1.

Description of the Mounding Study. The percolation pond was analyzed for two operating conditions. The first condition is average daily flow from plant and equipment drains of 20,000 gallons per day (gpd). The second condition is maximum design flow which includes average daily flow from plant and equipment drains, and runoff from the areas presented for



Table 5.3-1
Storage Capacity and Runoff Volume

Description	Total Storage Volume (gallons)	Runoff from 10 Year, 24 Hour Storm (gallons)	Excess Storage Capacity (gallons)
Unit 1 Fuel Oil Storage Tank	472,050	73,050	399,000
Units 2 and 3 Fuel Oil Storage Tank	1,724,865	241,230	1,483,635
Transformers (6 total)	0	11,220	0
Fuel Unloading Station	0	9,350	0
Percolation Pond	298,616 (Maximum Elevation-84.0 ft.)	119,119	Not Applicable
Total Runoff		453,969	



a 10 year 24 hour storm event. Total runoff from the storm event is 453,969 gallons, which includes the rainfall collected by the percolation pond from the storm event.

The runoff event is collected by the pond in one day; therefore, 139,119 gallons (119,119 + 20,000) is charged to the pond on the day of the storm. The remaining storm water runoff is discharged to the pond over a 7 day period. The maximum daily flow was calculated as follows:

$$[(453,969-119,119)\text{gallons}/7\text{days}] + 20,000 \text{ gpd} = 67,836 \text{ gpd}$$

Runoff from the fuel oil containment areas and transformers will be controlled by valves, thus 325,500 gallons from the storm event will be stored for release to the oil/water separator after the runoff from the unvalved areas is released. Storm water runoff from the fuel oil unloading station (9,350 gallons) will flow directly to the oil/water separator and on to the percolation pond during and immediately after the storm event. Storm water runoff to the pond occurs on the day of the storm.

Storage volume of the percolation pond, with 12 inches of freeboard, is approximately 298,616 gallons. Therefore, the runoff from the transformers, fuel unloading station and the percolation pond, a total of 128,469 gallons, in addition to the 20,000 gpd plant and equipment flow will not exceed the capacity of the percolation pond during the storm event. The fuel oil containment areas will be released after the initial surge from these areas has percolated through the pond. The initial surge will take approximately 1.5 days to percolate, and the runoff contained in the fuel oil tank containments will take approximately 5.5 days.

A subsurface investigation was performed at the Power Park and is presented in the report titled "Kissimmee Utility Authority, Cane Island Combustion Turbine Project, Subsurface Investigation Report," Black & Veatch, March 1993. A copy of the report is included as Section 10.8. This report contains the soil boring logs and piezometer logs for the site.

Soil Boring B-7 and Piezometers P-2, P-3 and P-4 are located in the vicinity of the percolation pond. Boring B-7 indicates that from ground surface to 47 feet below ground surface is a loose, fine grained sand. Below 47 feet, the silt and clay content increases. As a result, the ground water table was considered to be an unconfined aquifer with the base at Elevation 47.0 feet.



Slug tests were performed in Piezometers P-3 and P-4. Piezometer P-3 is screened from Elevation 66.2 to 56.2 feet and P-4 is screened from Elevation 61.6 to 51.6 feet. The horizontal coefficient of permeability was determined to be 27.5 feet/day for P-3 and 53.8 feet/day for P-4. A horizontal coefficient of permeability of 30 feet/day was used for this study.

Ground water conditions were determined from piezometer water level readings installed during the subsurface investigation, visual inspection of subsurface profiles in test pit excavations, and observation of the installed monitoring wells located in the Units 1 and 2 area. Data indicate ground water elevations ranging from approximately elevation 69.0 to 74.0 feet. Normal low ground water across Cane Island was estimated at Elevation 69.0 feet from the piezometer data. Normal high ground water across the island was estimated at Elevation 72.0 feet from the piezometer data. Historical maximum high ground water Elevation at Cane Island was estimated to be Elevation 74.0.

A ground water elevation of 71.0 feet was used in the mounding study for the average daily flow condition. The historical maximum high ground water Elevation of 74.0 feet was used as a conservative basis for the maximum design flow mounding study model.

Mounding Study Analysis. The percolation pond mounding study was performed using the U.S. Geologic Survey three dimensional aquifer computer model MODFLOW. Models were established for average daily flow and maximum design flow. Input parameters common to both models are as follows:

Model Size	5,000 feet by 5,000 feet
Coefficient of Horizontal Permeability	30 feet/day
Storage Coefficient	0.2
Bottom Elevation of Aquifer	47.0 feet

Average Daily Flow. The average daily flow from plant and equipment drains was analyzed by first calibrating the model to establish a realistic ground water elevation profile at the site extending from the wetlands across Cane Island using the normal high ground water elevation 70.0 feet for the wetland and elevation 72.0 feet for Cane Island. The calibration was



performed using an iterative process of inputting a base ground water elevation in combination with varying rainfall recharge into the model to establish an aquifer elevation model that is equivalent to the normal high ground water elevation. The calibration model was initiated using a base ground water elevation of 70.0 feet based on onsite waterlevel monitoring. The calibration model was run for 360 days with three time steps of 120 days each to verify that equilibrium of ground water levels was achieved. Calibrated ground water levels were achieved using rainfall recharges of 16.5 percent of the average yearly rainfall of 52.8 inches/year on Cane Island, and approximately 4 percent in the wetland areas. The recharge applied in the model calculated ground water of elevation 70.0 feet in the wetlands and elevation 70.8 feet below Cane Island. Figure 5.3-3 presents the ground water contours generated from the model calibration.

The ground water heads and rainfall recharge generated from the calibration model were included in the model for average daily flow. The model included the recharge of 20,000 gpd from plant and equipment drains into the effective area of the percolation pond and the calibration model's precipitation recharge to Cane Island and the wetlands. The model was run for 360 days with three time steps of 120 days to verify that the model had reached equilibrium. Ground water contours are presented on Figure 5.3-4.

Results of the average daily flow model indicate a slight mounding of the ground water contours below the percolation pond with a maximum ground water elevation of approximately 73.7 feet. The recharge to the existing ground water from the average daily flow to the percolation pond will not exit the ground surface and will not harm the resource.

Maximum Daily Flow. Maximum design flow into the percolation pond includes the 20,000 gpd average daily flow as well as 453,969 gallons of rainfall runoff from the fuel oil containment areas, the transformers, and the fuel oil unloading station. This total also includes the rainfall on the actual percolation pond.

The maximum daily flow is based on the 10 year 24 hour precipitation event. The rainfall collected by the percolation pond occurs during the day of the event; therefore, 139,119 gallons is passed to the pond in one day, including the daily average flow. The remaining volume of 334,850 gallons is discharged to the pond over a 7 day period; this is equal to 47,836 gpd. In addition, the plant drains discharge to the pond for a total volume of 58,770 gpd for the 7 days after the storm event.

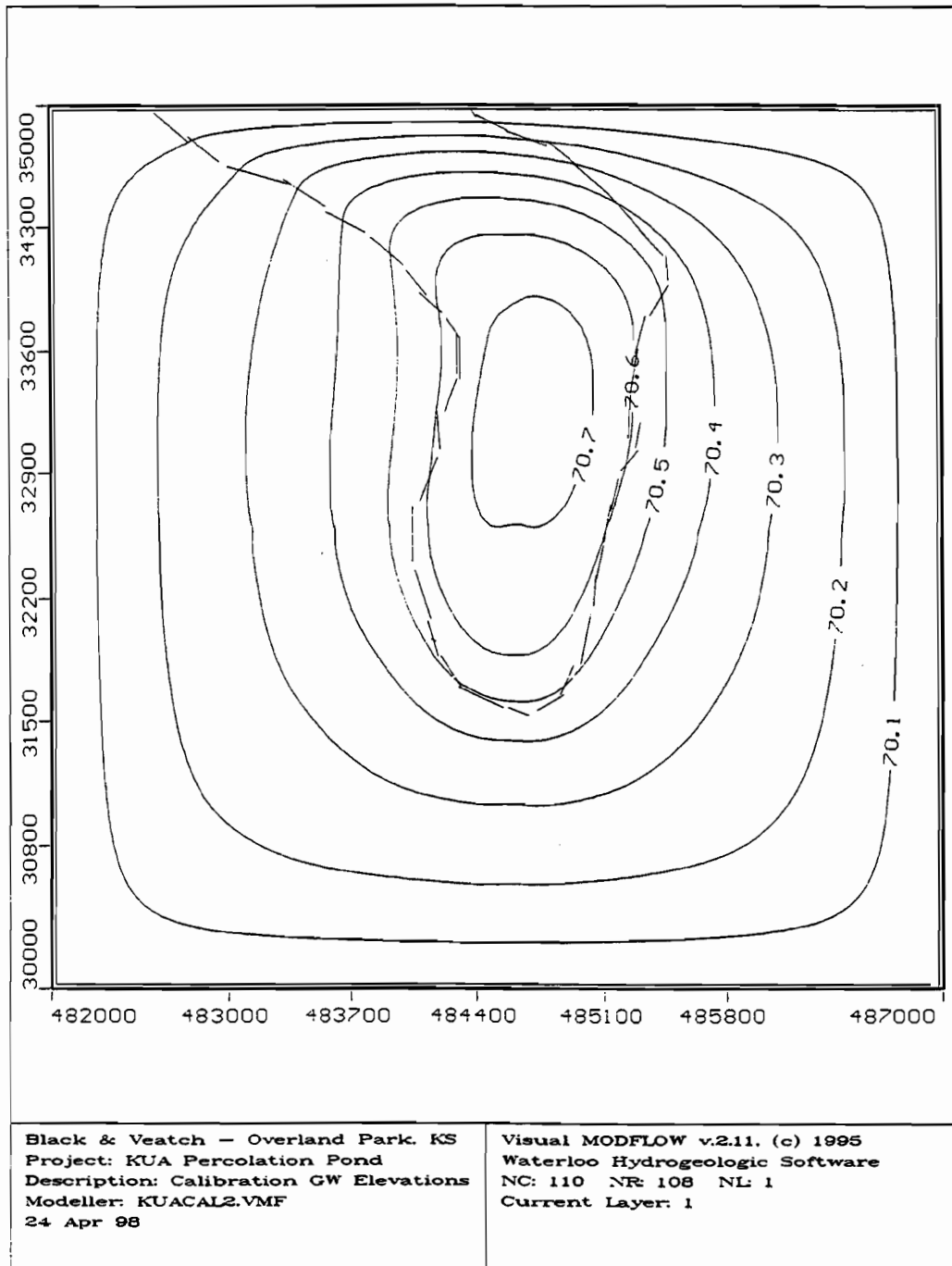


Figure 5.3-3

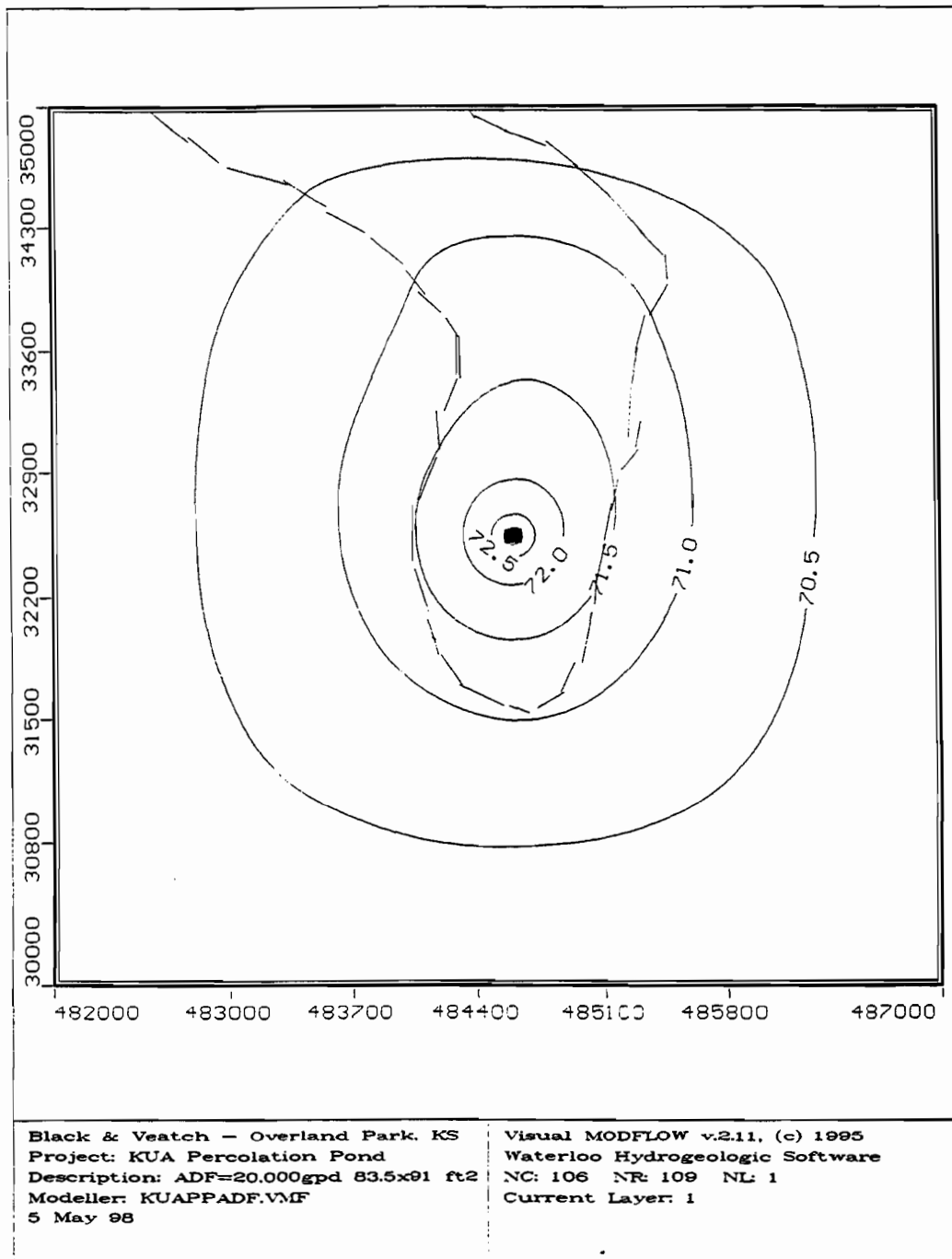


Figure 5.3-4



The model was calibrated in a similar manner as the average daily flow model. The initial time step included the modified starting heads and magnitudes of rainfall recharge to Cane Island and the wetlands, and the average daily flow to the pond. The second time step included a single day discharge to the pond of 139,119 gallons. The third time step included a discharge to the percolation pond of 67,836 gpd for 7 days. The calibrated model initiates the starting heads at 70.0 feet, with rainfall infiltration varying from 16.5 percent for Cane Island areas and 4 percent for the wetlands. The initial time step established ground water at the center of Cane Island at approximately 73.7 feet, the same as the average daily flow model. The second time step determined a ground water elevation of 75.0 below the pond at the end of the day of the 10 year 24 hour storm event. Finally, at the end of the 7th day after the event, the maximum daily flow model indicate a mounding of the ground water contours extending outward from the percolation pond with a maximum ground water elevation of approximately 75.7 feet. Ground water contour levels do not exceed ground surface at any location and will not harm the resource. The ground water contours are presented on Figure 5.3-5.

Conclusion. The mounding study demonstrates that the percolation pond designed for the Power Park has sufficient capacity, with the addition of Unit 3, to percolate the average daily flow and the maximum design flow. There will be no surface water discharges due to ground water mounding. There will be no significant impacts to the surficial aquifer. The predicted mounding effects of the discharge to the percolation pond indicate that there will be no affects to existing domestic, irrigation, or other public water supply wells. Discharge to the percolation pond will not affect the adjacent surface water bodies. The proposed percolation pond use will not effect environmental features that have a direct or indirect relationship to wetland habitats, natural water bodies, intermittent ponds or upland areas. The proposed water use will not affect any preferred habitats for rare, endangered or threatened species. There will be no adverse impacts to other users, pollution sources, saline water intrusion, adjacent water bodies, environmental features or land use caused by percolation pond operation.

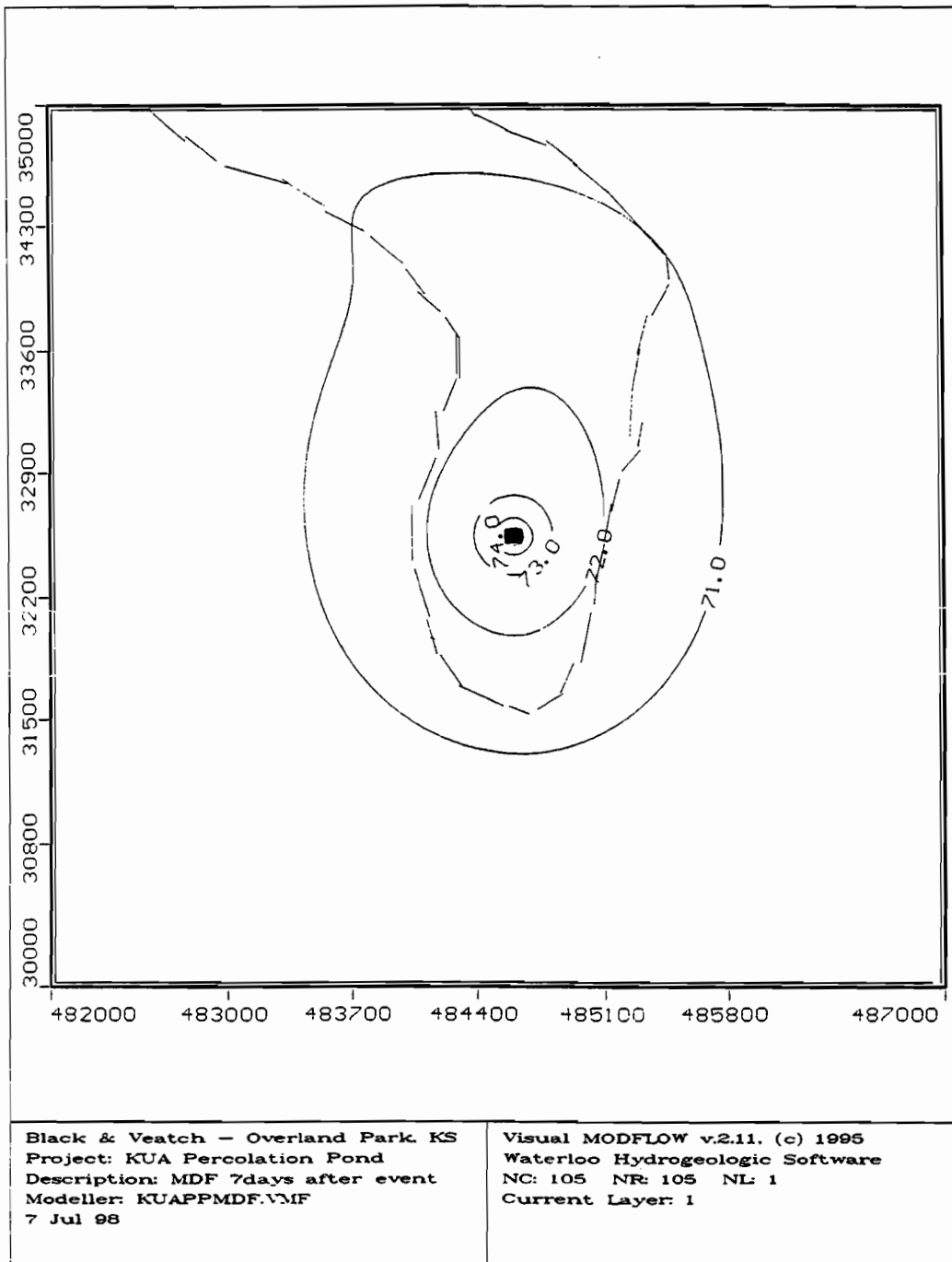


Figure 5.3-5



5.3.5 Measurement Programs

5.3.5.1 Surface Water Monitoring. The general site runoff will be monitored during a rainfall event which causes discharge from the site runoff collection system at the site runoff detention overflow weir. A grab sample will be collected during the event in the vicinity of the basin overflow. The sample will be tested in accordance with applicable local, state, and federal requirements.

5.3.5.2 Ground Water Monitoring. In response to the FDEP, a ground water monitoring plan has been established to monitor the performance of the percolation pond at the Power Park. The ground water monitoring plan, as summarized below, was designed to meet requirements as specified in FAC 17-522, Ground Water Permitting and Monitoring Requirements. No modifications to the plan are proposed.

Ground Water Monitoring Plan Requirements. The ground water monitoring plan consists of a natural background well and two downgradient monitoring wells. The natural background well is used to determine natural background quality and used for assessment of water quality measurements from sampling of the downgradient wells. Figure 2.1-3 indicates the monitoring well locations.

Two monitoring wells have been located downgradient from the percolation pond. Well placement was optimized by inspection of gradients generated from the Units 1 and 2 Percolation Pond Mounding Study. The study indicated that the infiltration through the percolation pond would extend radially away from the pond. These wells should provide adequate coverage of the downgradient flow from the percolation pond at the intermediate distance intended by the FDEP.

A natural background well was placed at the southern most portion of the Unit 1 and 2 site development, and north of the percolation pond where the ground water elevation established in the calibration model was equal to the ground water elevation determined in the predictive model.

Well screens were placed at such a depth as to adequately monitor the upper zone of the surficial aquifer. All of the wells are placed within the fenced enclosure of the developed site for maximum security. The well locations are protected by concrete pads and provided with lockable enclosures to limit access to only qualified personnel.



Reporting requirements for ground water monitoring include the following parameters and are submitted quarterly. Copies of submitted quarterly reports for the current operations are included in Appendix 10.9.

- | | |
|-----------------------|-------------|
| 1. Ground water level | 6. Sulfate |
| 2. pH | 7. Sodium |
| 3. TDS | 8. Chloride |
| 4. Turbidity | 9. TRPH |
| 5. Nitrate | |

5.4 Solid/Hazardous Waste Disposal Impacts

Operation as a combustion turbine facility burning primarily natural gas will not generate solid or hazardous wastes through the combustion process. Consequently, there are no onsite landfills or disposal areas.

Limited amounts of hazardous wastes (acidic and caustic wastes) from the regeneration of the demineralizers will be treated by pH adjustment in the neutralization basin prior to return to the Kissimmee effluent pipeline. A licensed contractor will provide for the disposal of boiler cleaning wastes collected in the combustion turbine drain tanks.

Miscellaneous office trash and maintenance wastes are collected in dumpsters and removed from the site by a licensed contractor.

5.5 Sanitary and Other Waste Discharges

Sanitary wastes are collected and treated by an onsite septic tank/tile field system approved by the Osceola County Health Department. Unit 3 operations will increase the staff at the site, from approximately 28 to 30 people. However, the existing septic system is oversized, and capable of treating the additional load due to Unit 3 staff. The staff numbers and septic system capacity will be confirmed during detailed design, and in the unlikely event that it is determined that the existing system cannot handle the additional load, a second septic system will be incorporated in the Unit 3 design.

There are no other wastes or wastewater discharges from the site other than those previously described.



The only other waste which is not discussed in Section 5.2 is HRSG blowdown. HRSG blowdown will be high purity water with small amounts of suspended solids and phosphate. The HRSG blowdown will be combined with the cooling tower blowdown and neutralization basin effluent and returned to the Kissimmee effluent pipeline.

5.6 Air Quality Impacts

The air quality impacts associated with the addition of Unit 3 are addressed in the PSD Air Permit Application attached to this Site Certification Application as Appendix 10.7 under separate cover.

5.7 Noise Impacts

Noise emitted by a combined cycle combustion turbine facility is the result of the combined effect of each individual noise source located onsite. Predictive noise modeling of a facility involves determining the noise impact of each significant source and combining these individual impacts to determine the overall noise emissions. The modeling procedure accounts for equipment noise emission levels, location of the equipment relative to the receiver, and the absorption of noise by natural sources.

Two sets of modeling were conducted for this assessment. The existing facility (Units 1 and 2) was modeled based upon full load operation. These modeling results were compared to the actual field measurements. Full facility operation, including all three units, was then modeled. The incremental effect of the additional equipment can then be directly evaluated.

5.7.1 Computer Program

The same computer program was used to model the Power Park operational noise emissions as were used to model the construction noise emissions. The Power Park noise emissions were modeled using a computer program developed at Black & Veatch. The model simulates the propagation of sound from point sources of noise by considering wave divergence, atmospheric absorption, directivity of the noise emissions, and blockage of noise by any interceding barriers. The model calculates the sound pressure level from each source per octave band at each point on a specified receptor grid. The model then combines the impact of each individual source to determine the overall noise impact. The resultant sound



level at each receptor grid is tabulated in each of the nine standard octave bands and in terms of overall A-weighted sound pressure level. The program then produces plots of noise contours (also called isobels) based on the calculated sound pressure level at each grid receiver.

The operational noise modeling also includes the attenuation effects of dense vegetative growth. At rural facilities with a relatively large distance to the nearest residence, vegetative growth can have a significant effect on the propagation of noise. The vegetative attenuation is based upon information contained in the Edison Electric Institute (EEI) Guide. To ensure conservative modeling results, the vegetation correction factor used in the modeling is approximately one-third of full vegetative noise attenuation as allowed in the EEI guide.

The location, sound power level per octave band, and source directivity of each source were input into the computer model. The model was used to generate isobel contours for the area surrounding the facility site.

5.7.2 Facility Noise Sources

The primary noise sources at the Power Park include the combustion turbines (including casing radiated and inlet noise), Heat Recovery Steam Generator (HRSG) (including wall radiated and stack emitted noise), steam turbine, generator transformers, and cooling towers. The steam turbine and auxiliary equipment will be located within a building. All modeling represents complete Power Park operation at full load conditions.

5.7.2.1 Equipment Sound Emissions. Equipment noise emissions are based upon noise data provided by the equipment vendors where available. The equipment for which vendor data is not available, the noise emissions were derived from information contained in the EEI report entitled Electric Power Plant Environmental Noise Guide. The EEI report provides methods of estimating equipment sound emissions based on the equipment design parameters. The estimating methods are derived from noise measurements taken from equipment in operation at electrical facilities.

The noise emissions from the combustion turbine inlet, combustion turbine mechanical equipment, the HRSG wall radiated and stack emitted noise are based on available vendor data. Noise emissions associated with the cooling tower and generator transformers were estimated using information provided in the EEI guide.



5.7.3 Predicted Noise Impacts

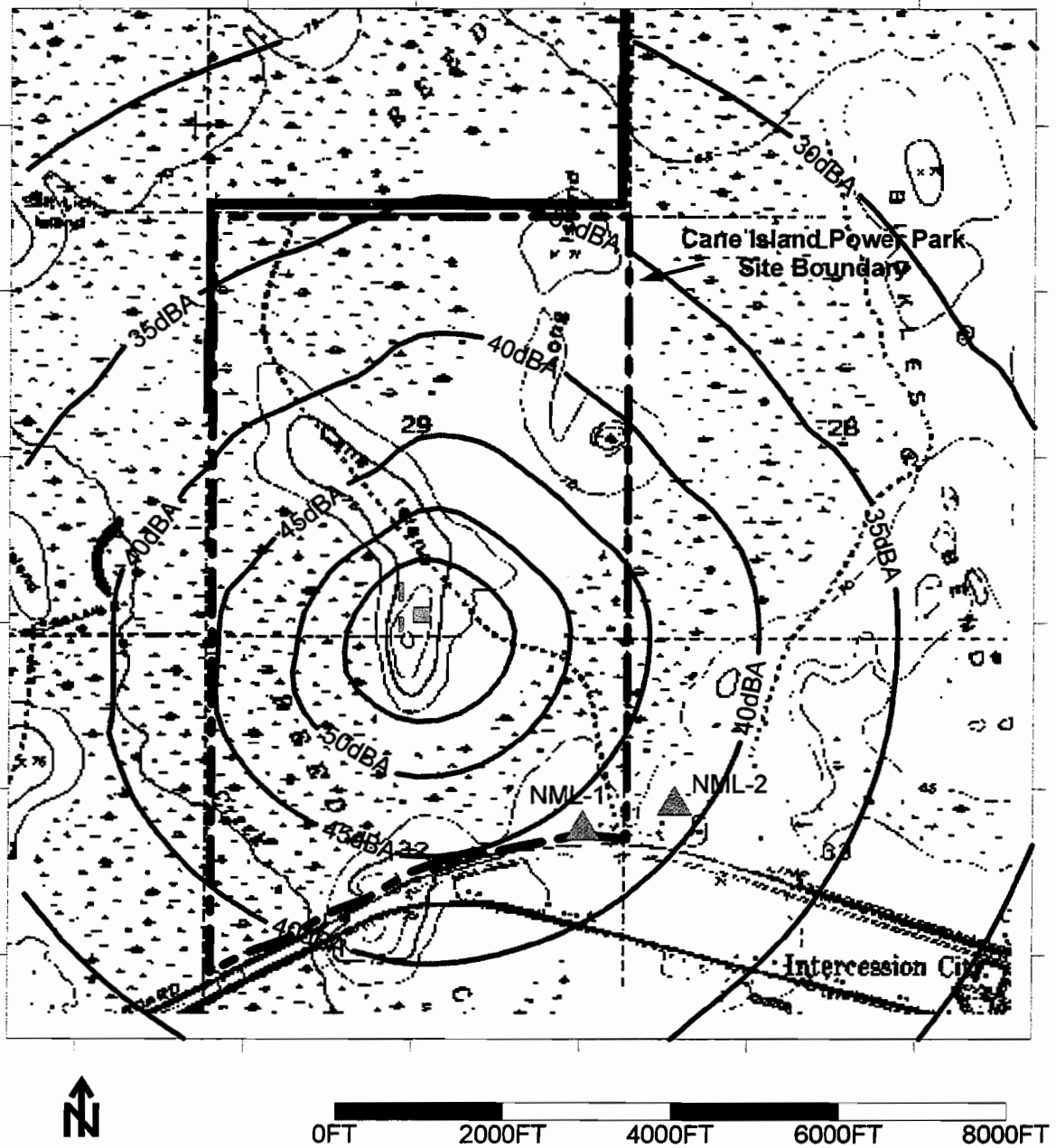
Noise modeling contours for Units 1 and 2 operation are shown on Figure 5.7-1. The predictive contours for the full Power Park operation (Unit 1-3) are shown on Figure 5.7-2.

The modeled sound level results indicate the existing facility noise emission are 43 dBA at the main gate (NML-1), and 42 dBA at the nearest residence (NML-2). The modeled values are therefore slightly higher than the actual measured values of 40 dBA at NML-1, and 33 to 35 dBA at NML-2 (See Section 2.8.3).

The predictive modeled sound level results indicate the full Power Park noise emissions will be 45 dBA at NML-1 and 44 dBA at NML-2. The modeling results, therefore, indicate the addition of Unit 3 will result in a sound level increase of approximately 2 dBA. Auditory testing has indicated that a change in sound level in the range of 2 dBA is imperceptible to the human ear. A sound level increase of 2 dBA would result in an insignificant change in the community sound levels.

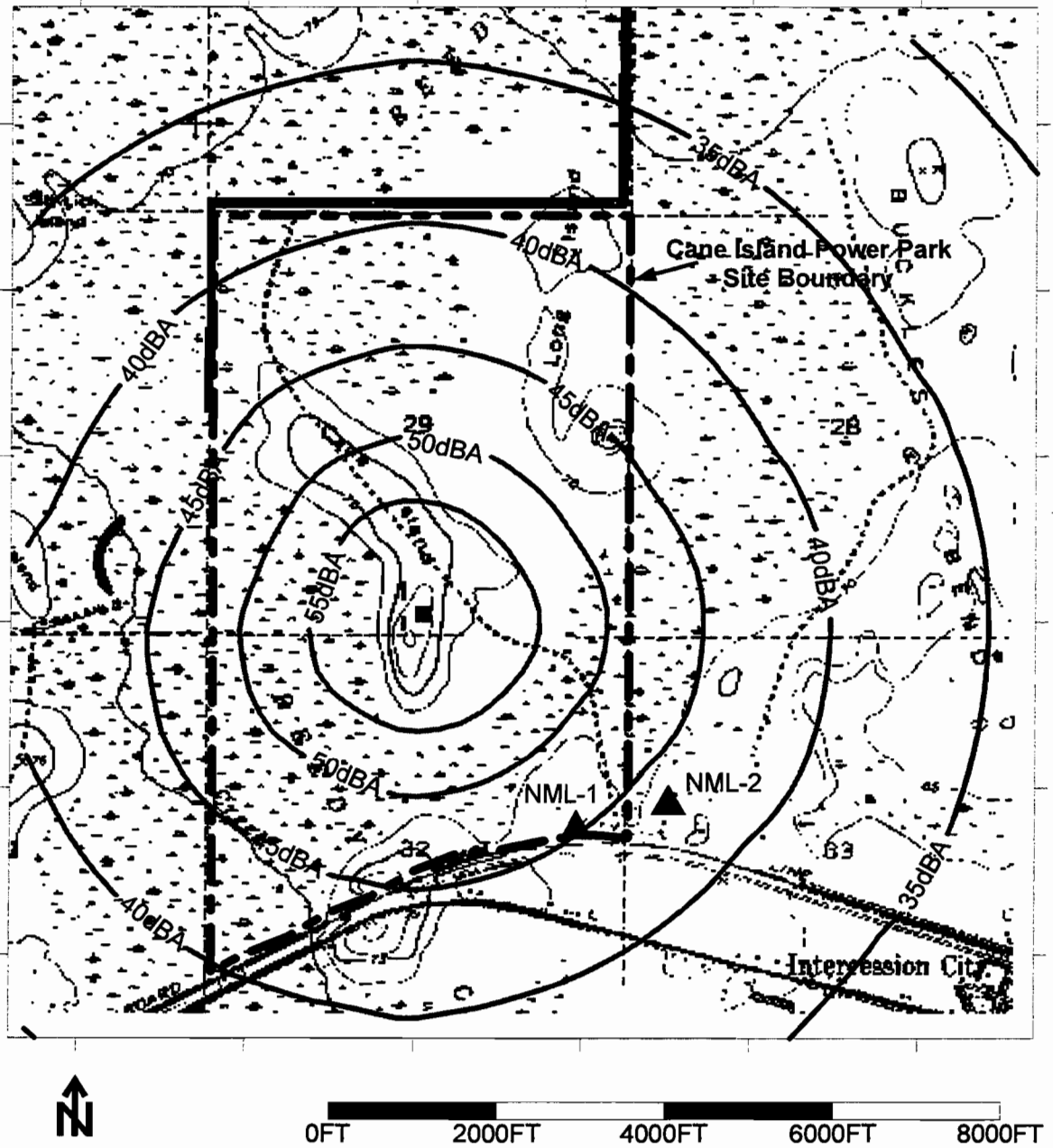
The preconstruction noise survey indicates that the existing C-weighted sound level ranged from 57 dBC to 65 dBC at NML-1, and from 52 dBC to 60 dBC at NML-2 prior to any construction at the Power Park. Predictive modeling results indicate the full Power Park noise emissions will be 66 dBC at NML-1 and 64 dBC at NML-2. Actual field measurements indicate the Power Park C-weighted sound level at both NML-1 and NML-2 is 55 dBC. Therefore, the C-weighted noise modeling is conservative by 9 to 11 dBC. The addition of Unit 3 is anticipated to result in a 1 to 2 dBC increase based on actual sound level measurements. The C-weighted sound level with all 3 units operating is anticipated to be 56 to 57 dBC at both NML-1 and NML-2.

Based on acoustic literature and experience with low frequency noise issues at combustion turbine facilities, recommended C-weighted noise level at a residential locations ranges from 70 to 75 dBC. Sound levels above 80 dBC at a residence will typically cause physical disturbance due to airborne vibrations and may cause windows and wood framed structures to noticeably vibrate. At sound levels below 70 dBC residences are virtually assured of perceiving no noticeable vibration due to low frequency noise emissions, and would be expected to experience no disturbance due to low frequency noise emissions.



Modeled Unit 1 and Unit 2 Facility Noise Emissions.

Figure 5.7-1



Predicted Full Facility Noise Emissions.

Figure 5.7-2



5.7.4 Compliance with Noise Regulations

At the time the Units 1 and 2 were installed, the applicable noise regulations were contained in Ordinance 86-5 of the Osceola County Code. The regulation specifies a maximum overall sound pressure level for each receptor land classification. Table 5.7-1 summarizes the noise limits as contained in Ordinance 86-5. As shown, the maximum overall sound pressure level (nighttime) was 55 dBA at the nearest residential property line and 60 dBA at the nearest business or commercial property boundary.

Sometime after construction of Units 1 and 2, the Osceola County Code was revised to include Article IV, Noise. Article IV, Section 9-110, paragraph (a) *Prohibited sound levels*., states that no person shall create a sound level beyond the property line which exceeds the following sound level limits:

Time of Day	Decibels (A-Scale)
7:00 a.m. through sunset	55
One minute after sunset through 6:59 a.m.	45

Article IV, Section 9-110, Paragraph (c) *Mechanical equipment, air conditioning, and other equipment*, states that no person shall operate any air conditioning, mechanical, ventilating, refrigerating equipment, pump or machinery and equipment of a similar nature, so as to create a sound level beyond the property line which exceeds the following sound level limits:

Time of Day	Decibels (C-Scale)
7:00 a.m. through sunset	50
One minute after sunset through 6:59 a.m.	45

The Power Park operates on a 24 hour basis. Therefore, operations must satisfy the nighttime noise limits, in accordance with the Osceola County Noise Control Ordinance, which are 45 dBA and 45 dBC at all property boundaries.



Table 5.7-1
Osceola County Code Noise Limits by Receiving Land Use in
Effect During Construction and Operation of Units 1 and 2

Receiving Land Use Category	Sound Level Limit L_{10}	
	Daytime (7:00 a.m. - 10:00 p.m.)	Nighttime (10:00 p.m. - 7:00 a.m.)
Residential, Public Space or Institutional	60 dBA	55 dBA
Commercial or Business	65 dBA	60 dBA
Manufacturing, Industrial or Agricultural	75 dBA	75 dBA



The predicted noise emissions, based upon A-weighted sound levels, are indicated on Figure 5.7-2. As shown, predicted A-weighted sound levels at the property boundaries range from 40 to 49 dBA. The sound level will satisfy the 45 dBA criteria at the nearest residential locations. However, the 45 dBA criteria will be exceeded at certain property boundary locations. All locations in excess of 45 dBA are within areas where forested wetlands preclude the possibility of development.

The predicted C-weighted sound level is 64 dBC at the nearest residence. This sound level is in excess of the County noise criteria of 45 dBC. Literature and past experience with combustion turbine low frequency noise indicate that residents are unlikely to experience any disturbance when exposed to broad-band sound levels below 70 dBC. The facility will exceed the 45 dBC noise criteria; however, no disturbance is anticipated to neighboring residences.

5.7.5 Noise Mitigation

The Unit 3 equipment will include several features for the purpose of noise control.

The steam turbine, boiler feed pumps, and a majority of other auxiliary equipment will be located within the generation building. The generation building will significantly contain the equipment noise emissions.

The combustion turbine equipment will be located within an acoustically lined enclosure. This enclosure is constructed of heavy gauge metal panel, with acoustically sealed doors and silenced ventilation openings.

The combustion turbine inlet will be equipped with a silencer.

The HRSG will mitigate the combustion turbine exhaust noise.

The combustion turbine exhaust stack will be equipped with a silencer.

5.8 Changes in Nonaquatic Species Populations

5.8.1 Impacts

The operation of Unit 3, the new transmission line, and effluent pumping station at Power Park may potentially decrease the relative abundance of nonaquatic species in the vicinity of these facilities. Wildlife habitat will be permanently removed from the facility locations, and there may be some loss of individual animals. The activity and noise of plant operation may also temporarily or permanently displace wildlife. Therefore, changes in species diversity,



composition, and dominance may occur, but no long-term changes in populations will result from operation of Unit 3 or its associated facilities.

5.8.2 Monitoring

The monitoring plan currently used, described in Subsection 2.3.5.3 for monitoring vegetation and wildlife at the Power Park, will be sufficient to monitor impacts in the nonaquatic species populations near the Unit 3 power generation facility, the new transmission line, and pumping station areas. No changes in the monitoring plan are proposed.

5.9 Other Plant Operation Effects

The operating staff number will increase slightly from 28 to 30 with the addition of Unit 3. No significant impacts on traffic in the Intercession City area are expected. Most employees are expected to use US 17/92 until they are within 1 mile of the site entrance off Old Tampa Highway. No new offsite roads or road improvements will be required.

5.10 Landmarks, Sensitive Areas, and Archaeological Sites

No landmark, sensitive areas, or archaeological site will be impacted by operation of the Power Park.

The cultural resources investigation of the Power Park site revealed no significant historical or archaeological resources. The distances and buffer zones between the power block and the sensitive areas (FDEP/Disney Conservation Easement, the Save Our Rivers properties, and the Intercession City playground) mitigation and pollution control measures will effectively mitigate any impacts from project operation. Operations staff will be requested to use US Highway 17/92 to avoid travel on secondary streets and bridges in Intercession City. Therefore, any impacts to landmarks and historic residences will be avoided.

5.11 Resources Committed

The Power Park site includes 1,027 acres of Reedy Creek Swamp wetlands and uplands. However, 860 acres onsite have been impressed with conservation easements, preserving valuable wildlife habitat. Plant and associated onsite facilities have 164 acres permitted for



power development. The developed lands may be mostly returned to its original use after the plant ceases operations.

The materials used to construct Cane Island 1 and 2, and Cane Island 3, are and will be dedicated resources. It is possible that some of the materials may be reclaimed after plant closure.

The natural gas and oil burned as fuel will be a permanent commitment of resources. It is estimated that approximately 792 billion cubic feet of natural gas and 504 million gallons of No. 2 fuel oil (720 hours/year) will be consumed annually over the 30 year operating period.

5.12 Variances

The need for a variance from the Osceola County noise ordinance is under investigation at this time. This will be the only variance required for operation of the expanded Power Park if it is determined such a variance is needed.

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6.0 Transmission Lines &
Other Linear Facilities



6.0 Transmission Lines and Other Linear Facilities

6.1 Transmission Line

One new transmission line is proposed to connect the Cane Island Power Park (Power Park) with Florida Power Corporation's Intercession City Plant, one-quarter mile west of the Power Park boundary.

The proposed line will be installed on the existing Clay Street Transmission Line structures as it exits the Power Park switchyard, paralleling the east side of the access road to a point near the CSX Railroad where the new line will turn west. New structures will be required from this point to the interconnection at the Intercession City Plant. The proposed transmission line route is shown on Figure 6.1-1.

6.1.1 Project Introduction

The Cane Island-Intercession City 230 kV transmission line will be a single circuit, heavy-duty, single pole line. This transmission line is proposed for certification as an associated facility under the Florida Electrical Power Plant Siting Act (Siting Act). This transmission line will be located entirely within Osceola County.

A single 120 foot wide right-of-way is proposed for the line beginning at the point where the line turns west from the Clay Street structures to the Intercession City Plant. Steel pole structures with drilled concrete pier foundations capable of supporting a double circuit, are proposed.

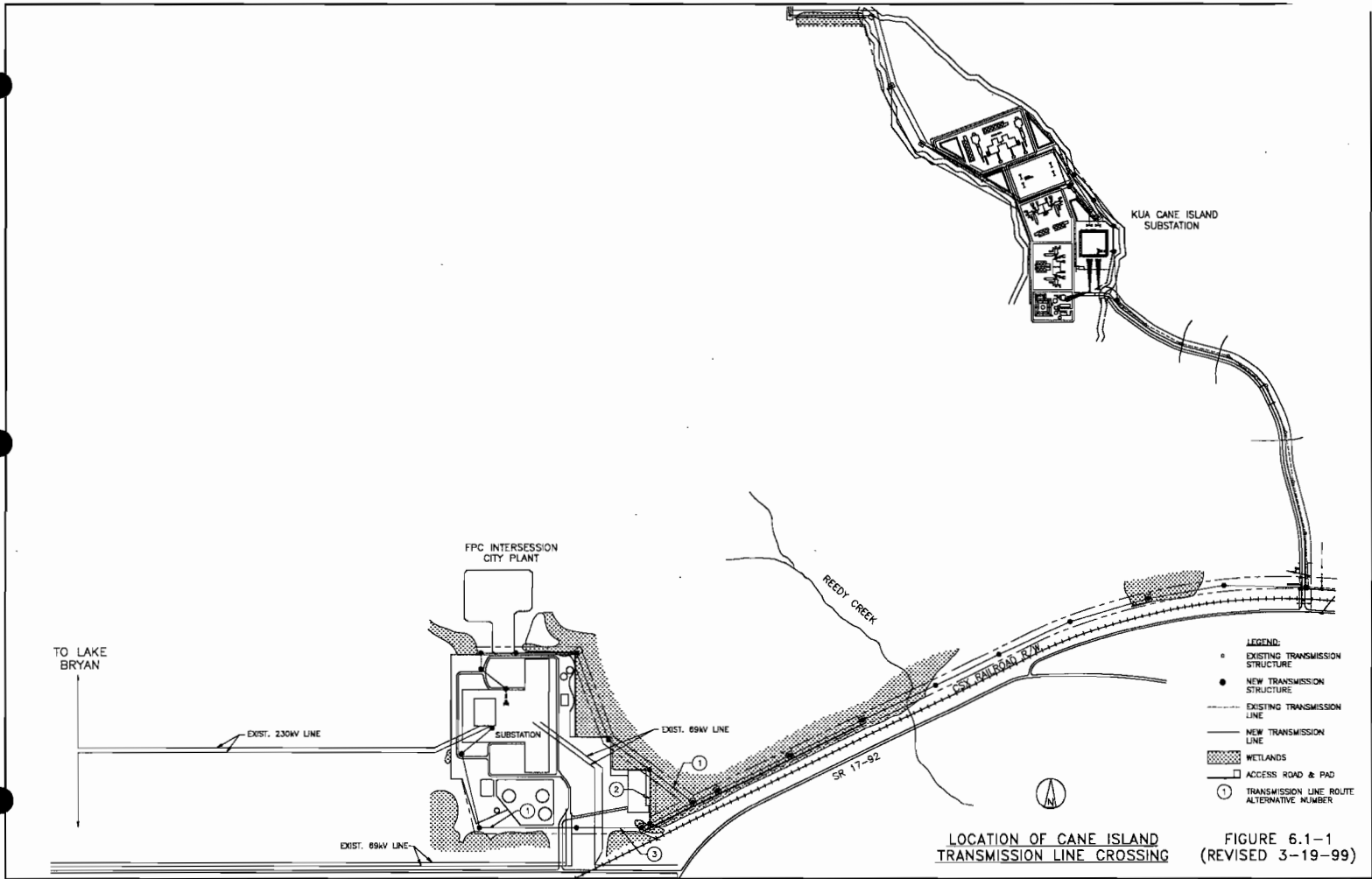
The determination of need for the Cane Island-Intercession City 230 kV transmission line is under consideration by the Public Service Commission pursuant to the Joint Petition for a Determination of Need.

6.1.2 Corridor Location and Layout

The Cane Island-Intercession City Transmission Line (Line) will exit the Cane Island switchyard and follow the east side of the Power Park access road (placed on the existing Clay Street Transmission Line structures) to a turning point near the Power Park entrance and CSX Railroad. Heavy-duty double circuit steel poles will be constructed from this turning

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.





point to the Intercession City Plant. The Line will be placed in the reserved utility corridor on the southern Power Park boundary, paralleling the north edge of CSX Railroad right-of-way to a point near the southeast corner of the Intercession City Plant. The Line will then parallel the ~~southeast~~ and ~~westnorth~~ boundary fences of the Intercession City Plant, turning ~~east~~~~south~~ into the Intercession City Plant switchyard. Existing 115 kV or larger transmission lines within 5 miles of the proposed corridor are shown on Figure 6.1-2.

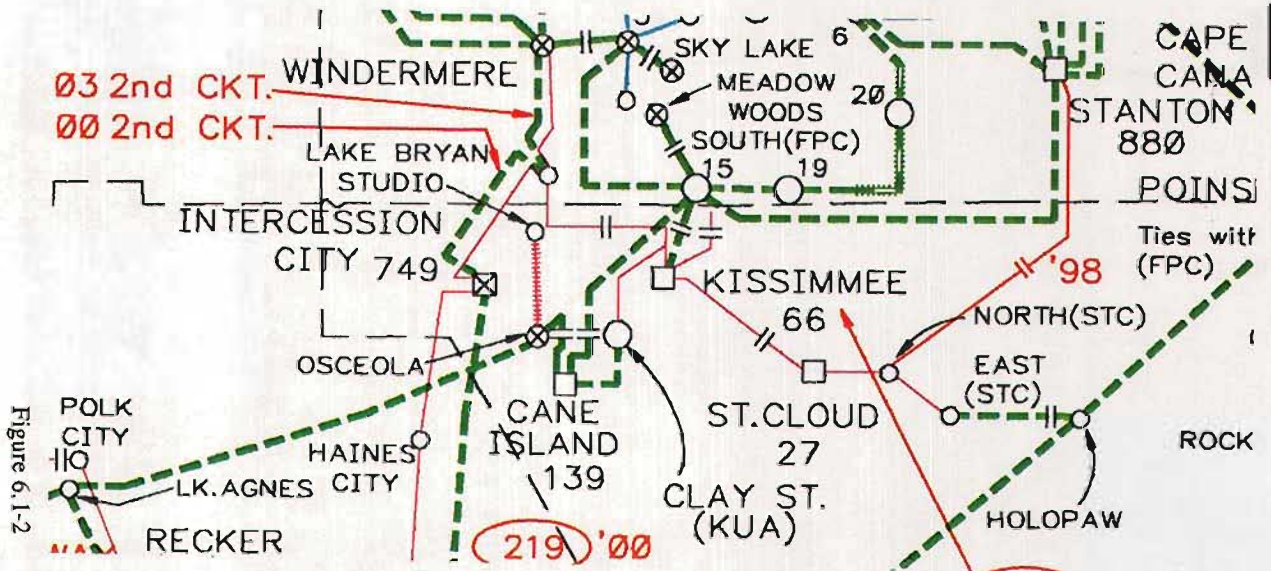
6.1.3 Transmission Line and Road Design Characteristics

The Cane Island-Intercession City 230 kV Transmission Line will be constructed using single-pole tubular steel structures as shown on Figure 6.1-3. The structures will be designed to support two 230 kV circuits; however, as shown on Figure 6.1-4, only one circuit will be installed. The structures will be spaced approximately 800 to 1,000 feet apart along the right-of-way. The transmission line conductors will be 954 kcmil 54/7 ACSR/AW conductors on the existing structures and 1,590 kcmil ACSR/AW conductors on the new structures designed for a maximum loading of 444 MVA. One fiber-optic shield wire will be installed on the structures for shielding, relaying, and communications.

The Line will be designed to meet the clearance requirements of the National Electrical Safety Code. A minimum ground clearance of 26 feet will be maintained to ground under the maximum design loading condition of the Line. Figure 6.1-5 shows the profile of a typical 800 foot span. The structures will vary in height along the route, depending on the span lengths and obstacles that must be crossed.

Access to the Line right-of-way will be from existing roads where practical. Construction of access roads will be necessary along the segments of the right-of-way which are not accessible. The access roads are necessary, not only for initial construction, but also for maintenance of the Line and right-of-way. Figure 6.1-6 shows a cross section of a typical access road segment. The 15 foot wide driving surface of the road will be composed of crushed aggregate or shell surfacing. Where access roads are necessary through wetlands, corrugated metal pipe culverts will be installed at regular intervals to maintain equal water level between the sides of the roads.

Figure 6.1-1 shows where the construction of new transmission line access road is anticipated along the route. Table 6.1-1 provides a summary cost estimate of the proposed and alternative alignments.



LEGEND

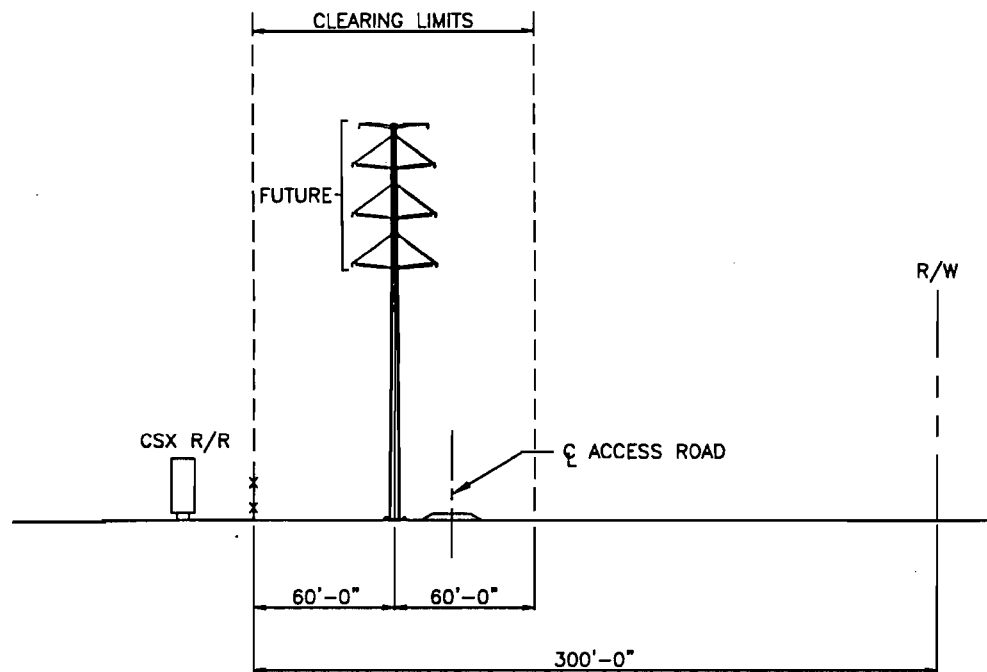
TRANSMISSION LINES

—	500kV
- - -	230kV
—	138kV
—	115kV
—	69kV
+++++	UNDERGROUND CABLE
—	INTERCONNECTION

FUTURE

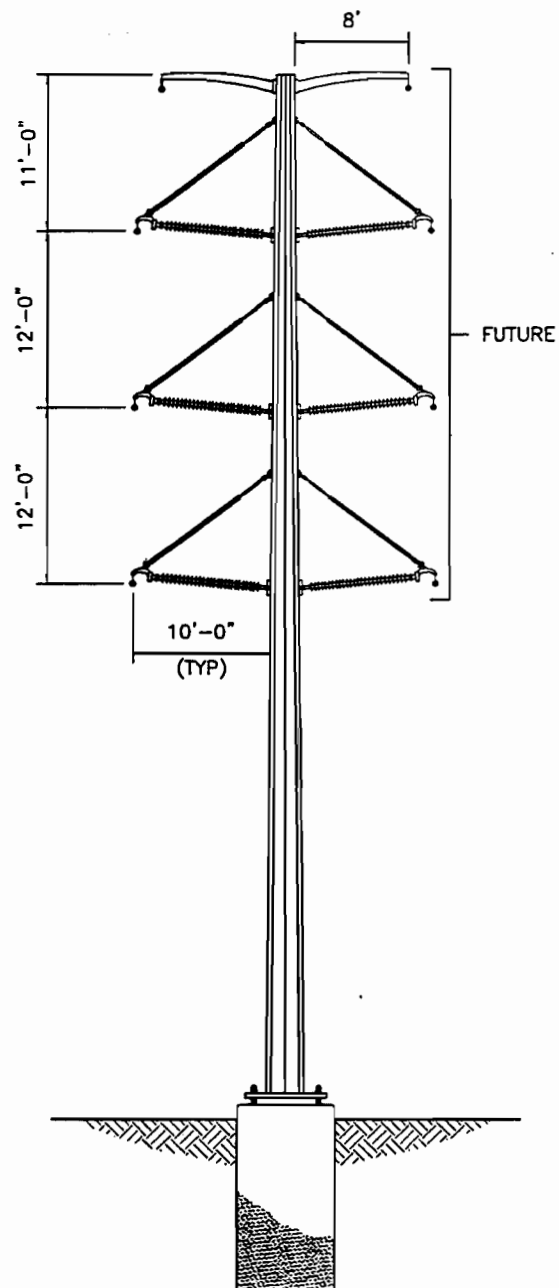
—	500kV
- - -	230kV
—	BELOW 230kV
'00	IN SERVICE YEAR
(000)	FUTURE TOTAL CAPACITY





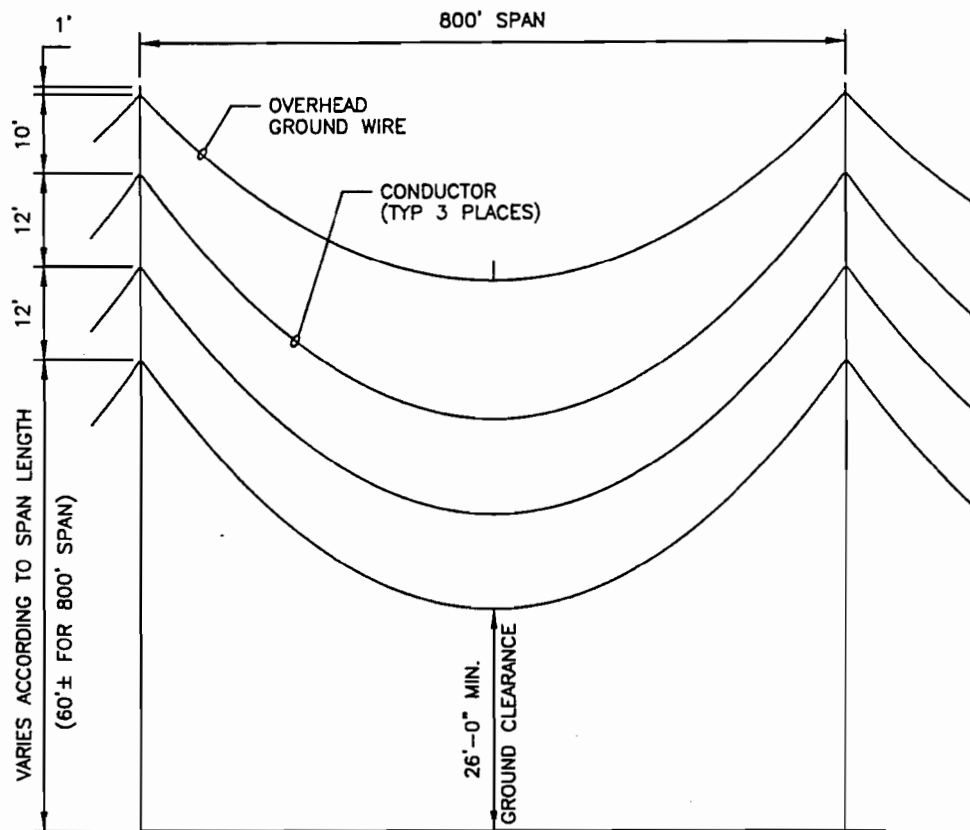
CANE ISLAND-INTERCESSION CITY 230kV
TRANSMISSION LINE ALONG RAIL ROAD
CANE ISLAND PLANT ACCESS ROAD
WEST TO EDGE OF KUA PROPERTY
LOOKING WEST

Figure 6.1-3



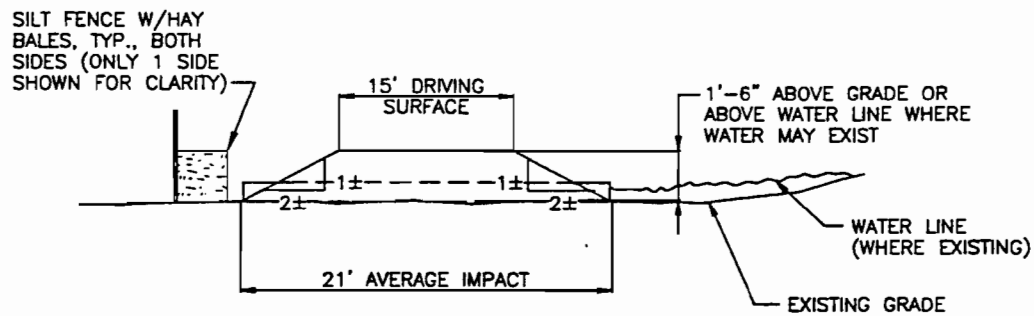
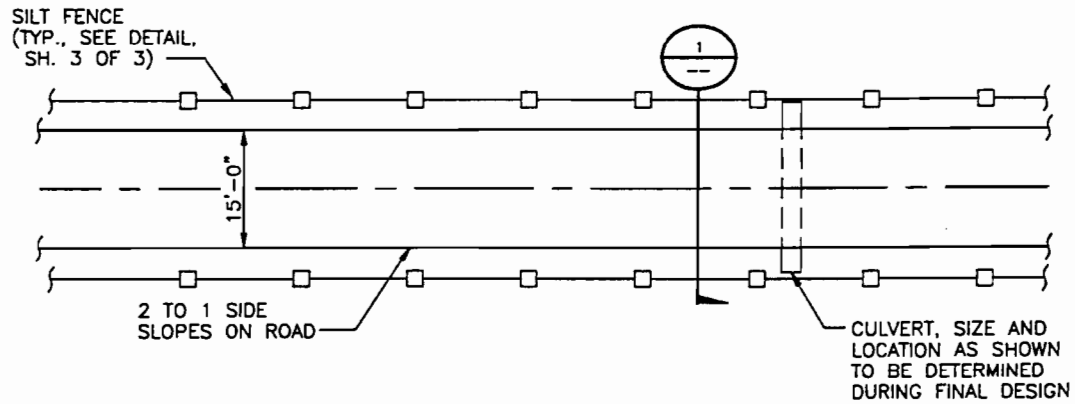
DOUBLE CIRCUIT TRANSMISSION LINE STRUCTURE

Figure 6.1-4



PROFILE OF TYPICAL 800 FOOT SPAN

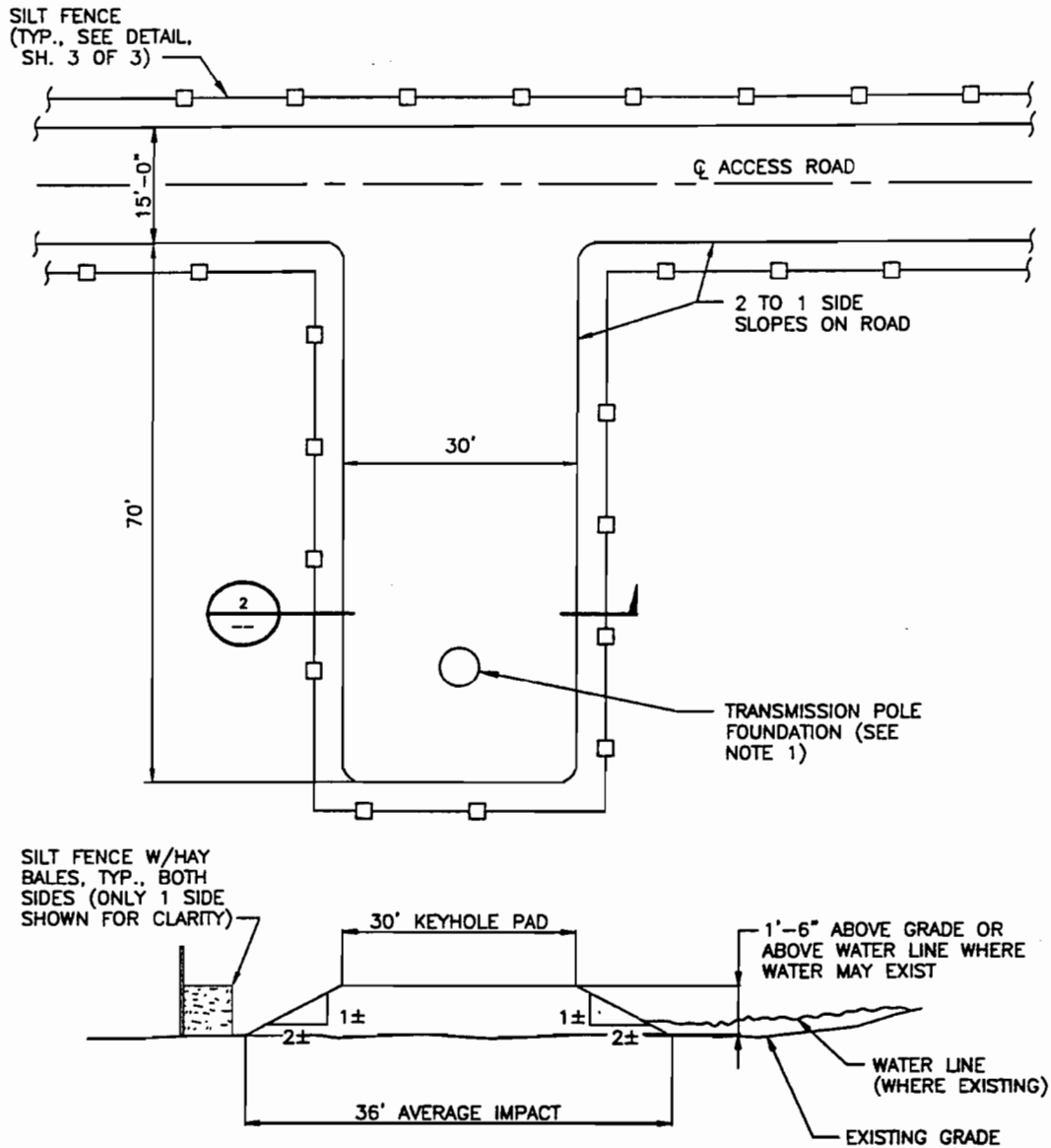
Figure 6.1-5



SECTION 1

CANE ISLAND-INTERCESSION CITY 230kV
TRANSMISSION LINE CROSS SECTION
OF TYPICAL TRANSMISSION LINE ACCESS ROAD

Figure 6.1-6



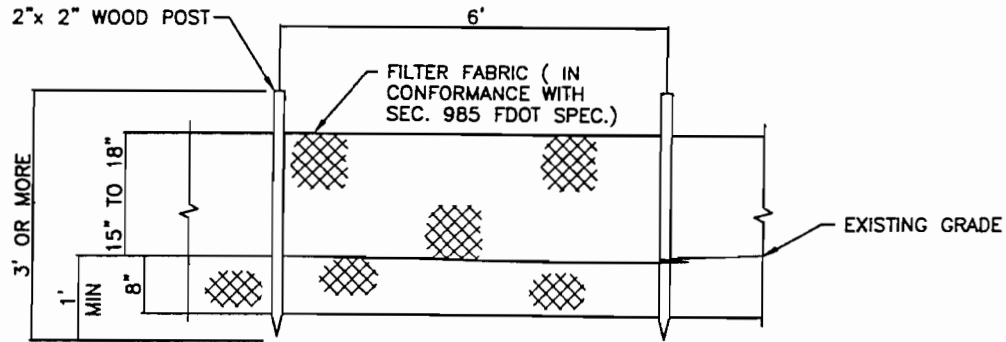
SECTION 2

NOTE:

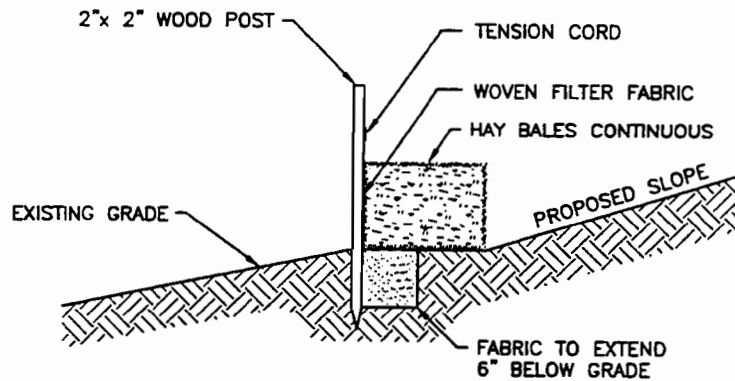
1. SPOILS FROM FOUNDATION EXCAVATION TO BE SPREAD IN UPLAND LOCATIONS ON KUA PROPERTY.

CANE ISLAND-INTERCESSION CITY 230kV
TRANSMISSION LINE CROSS SECTION
OF TYPICAL TRANSMISSION LINE ACCESS PAD

Figure 6.1-6 (Continued)



ELEVATION



SECTION

CANE ISLAND-INTERCESSION CITY 230kV
TRANSMISSION LINE CROSS SECTION
OF TYPICAL SILT FENCE DETAILS

Figure 6.1-6 (Continued)



Table 6.1-1. Kissimmee Utility Authority
Cane Island to Intercession City 230 kV Tie Line
Summary Table

Line Alternate	Line Length (Miles)	Materials (See Note 1)	Line Construction	Land Acquisition	Right of way Preparation	Road Construction & Pad Fill	Design, Soils, Survey, & CM	Contingency	Work By Others	Total Project Cost	Total Project Cost/Mile
1	2.63	\$740,100	\$1,591,540	\$0	\$216,720	\$91,720	\$415,600	\$305,600	\$600,000	\$3,961,280	\$1,506,190
2	2.71	\$854,550	\$1,799,780	\$0	\$228,240	\$94,475	\$447,100	\$342,400	\$600,000	\$4,366,545	\$1,611,271
3	2.66	\$730,925	\$1,575,160	\$0	\$186,720	\$92,100	\$412,300	\$299,700	\$1,400,000	\$4,696,905	\$1,765,754

Note 1: 7 percent sales tax is included in material cost.



6.1.4 Cost Projections

The estimated total cost of the Cane Island-Intercession City 230 kV transmission line is ~~\$2.48~~ \$3.96 million as summarized in Table 6.1-1.

6.1.5 Corridor Selection

Studies of KUA's electric transmission and distribution system showed that a connection from the Power Park switchyard to the Intercession City Plant switchyard integrated very well with the existing system and was preferable to other possible connections or system upgrades for the addition of Unit 3. In addition, the reserved utility corridors on Power Park property were established for such uses. Therefore, there will be minimal environmental impacts associated with the line installation using the reserved utility corridor.

Two other route options were evaluated; however, these routes would result in greater impacts because of potentially longer line lengths, and additional vegetation clearing and construction within wetland areas.

6.1.6 Socio-Political Environment of the Corridor Area

The sociopolitical environment of the transmission line right-of-way is essentially the same as that described for the Power Park in Section 2.2 of this application. This line will be approximately 3 miles in length from switchyard to switchyard, constructed entirely on either KUA or FPC property, and adjacent to an existing transportation/utility corridor. The Power Park and Intercession City plant sites do not support residential development.

There are currently no other utilities in the reserved utility corridor along the south Power Park boundary; however, there are several utilities, including a transmission line, in place south of the CSX tracks, between the tracks and Old Tampa Highway. The new transmission line is, therefore, not expected to have a significant visual impact on the few residents in the area, nor will the Line introduce a new land use into the area.

6.1.6.1 Governmental Jurisdictions. The Power Park, Intercession City Plant, and the proposed transmission line, all lie in an unincorporated area of Osceola County.

6.1.6.2 Zoning and Land Use Plans. Both the Power Park and the Intercession City Plant sites have been zoned for industrial use by the Osceola County. The installation of the electric transmission line therefore complies with the existing zoning and future planning of both sites.



6.1.6.3 Easements, Title, Agency Works. The proposed transmission line lies within a dedicated utility easement on the Power Park property. This utility easement was established to work in concert with the conservation easement which covers the majority of the Power Park site. An easement or agreement will be reached with FPC regarding the use of the Intercession City property.

The transmission line will cross Reedy Creek on Power Park property. No structures will be placed in the creek channel or below the safe uplands line.

An Environmental Resource Permit application has been prepared to facilitate the review of the proposed line. This application is included in Subsection 10.4.3, Volume 3, of this SCA.

6.1.6.4 Vicinity Scenic, Cultural and Natural Landmarks. There are no cultural or natural landmarks within the transmission line corridor. The scenic value of the area has been previously affected by raised train tracks, underground and above ground utilities, and the two existing power plants. Therefore, due to the existing facilities and lack of residents in the corridor area, the addition of the proposed transmission line will not significantly affect the scenic value of the area.

6.1.6.5 Archaeological and Historic Sites. There are several archaeological sites identified on the Power Park property; however, these sites have been determined ineligible for listing on the *National Register of Historic Places* by the Florida Division of Historic Resources. The FDHR has confirmed that no other recorded historic or archaeological resources exist within the proposed corridor.

6.1.7 Bio-Physical Environment of the Corridor Area

The following subsections describe the environment of the proposed 120 foot wide Cane Island-Intercession City Transmission Line corridor.

6.1.7.1 Land Use and Vegetation. Vegetation in the Clay Street Transmission Line corridor on Power Park property is maintained essentially as lawn (i.e., grass) for safety and operation of the transmission line. The new corridor passes through pine-mesic oak, mixed hardwood swamp, old field, cypress strand, and hydric hammock plant communities. Figure 2.3-4 in Section 2.3 of Volume 2 of this SCA is a map of the plant communities that occur at the Power Park.

Pine-mesic oak is an upland community on flat to sloping terrain with well-drained soils. It is a common plant community in the project area. This community is dominated



by slash pine (*Pinus elliottii*), laurel oak (*Quercus laurifolia*), and Virginia live oak (*Quercus virginiana*), which form a dense canopy often reaching 60 to 80 feet in height. The mid-story is usually open, but may approach closure. It includes sabal palm (*Sabal palmetto*), loblolly bay (*Gordonia lasianthus*), wax myrtle (*Myrica cerifera*), dahoon holly (*Ilex cassine*), sweet gum (*Liquidambar styraciflua*), and swamp honeysuckle (*Rhododendron viscosum*). The understory and ground cover tend to be sparse, but may be somewhat thick in transitional zones with other communities.

Mixed hardwood swamp is a bottomland community usually found on relatively flat land and flooded from six to nine months annually. Mixed hardwood swamps are associated with riverine systems, cypress strands, and ponds as well as the more xeric hydric hammock community. The dominant overstory includes red maple (*Acer rubrum*), laurel oak, and sweet gum and forms a closed canopy at a height of 80 to 100 feet. An occasional bald cypress (*Taxodium distichum*) may also be found. Understory ranges from somewhat open to nearly closed and includes: water oak (*Quercus nigra*), cabbage palm, loblolly bay, fetterbush (*Lyonia lucida*), and sweet bay (*Magnolia virginia*). Ground cover ranges from sparse to moderately open and includes a rich variety of herbaceous species and woody vines such as cinnamon fern (*Osmunda cinnamomea*), royal fern (*Osmunda regalis*), sedges (*Carex* spp.), grapes (*Vitis* sp.), beakrush (*Rhynchospora* sp.), cypress witchgrass (*Dichanthelium dichotomum*), giant cane (*Arundinaria gigantea*), Florida shield fern (*Dryopteris ludoviciana*), marsh fern (*Thelypteris palustris*), peppervine (*Ampelopsis arborea*), green briars (*Smilax* sp.), and poison ivy (*Toxicodendron radicans*).

Old field communities are communities that have been disturbed to the extent that little or none of the natural vegetation remains. This area apparently had been used for pasture, cropland, and a residence by the previous owner, but now is abandoned. These communities are upland in nature, on relatively flat terrain with moderately drained soils.

Cypress strand is a stillwater swamp community situated in a depression channel that is often flooded for most of the year. Cypress strands often intergrade with mixed hardwood and cypress pond swamps. The vegetation is dominated by an overstory of bald cypress, red maple, and sweet gum. The understory includes stiff dogwood (*Cornus foemina*), red bay (*Persea borbonia*), loblolly bay, and a ground cover of sedges, giant cane, pennywort (*Hydrocotyle umbellata*), cypress witchgrass, and jointed flatsedge (*Cyperus articulatus*).



Hydric hammock is a wetland community with a flat to slightly sloping topography, which may be inundated for up to 6 months per year. It is often situated between xeric upland communities and wetlands that are flooded for longer periods. The vegetation is characterized by a canopy of cabbage palm, Virginia live oak, laurel oak, slash pine, water oak, and red maple. The sparse understory and ground cover include wax myrtle, loblolly bay, greenbrier (*Smilax bona-nox*), grapevines (*Vitis* sp.), golden polypodium (*Polypodium aureum*), marsh fern, cinnamon fern, Florida shield fern, longleaf chasmanthium (*Chasmanthium sessilifolium*), and cypress witchgrass.

The proposed corridor will pass through old field, pine mesic oak, cypress strand, pine flatwoods, oak scrub, sand pine scrub, hydric hammock, and cypress strand/mixed hardwood swamp communities. Old field, pine-mesic oak, mixed hardwood swamp, cypress strand, and hydric hammock were described above and sand pine scrub was described in Section 2.0.

Pine flatwoods is an upland community with flat to slightly sloping topography and well to moderately drained soils. Canopy cover consists of primarily slash pine and may be dense or open. Mid-canopy, which often approaches closure, includes loblolly bay, wax myrtle, water oak, and cabbage palm. Typical understory species include inkberry (*Ilex glabra*), palmetto (*Serenoa repens*), fetterbush, and dahoon holly. Ground cover is more sparse than the understory and includes shiny blueberry (*Vaccinium myrsinites*), cinnamon fern, grapevines (*Vitis* sp.), and greenbrier.

Oak scrub is a natural community with flat topography and well-drained soils. Oak scrub is a xeromorphic community that is very similar in composition to the sand pine scrub community except that it lacks sand pine and it tends to have a denser and shorter canopy cover. The thick canopy is predominantly scrub oak (*Quercus inopina*), sand live oak (*Quercus geminata*), and Chapman's oak (*Quercus chapmanii*). The understory is fairly open and consists of palmetto, inkberry, rusty lyonia, fetterbush, and tar flower (*Befaria racemosa*). The ground cover is also sparse with indigo (*Indigoifera* sp.), shiny blueberry, catbrier (*Smilax laurifolia*), and golden aster (*Heterotheca graminifolia*).

Land use in the vicinity of the proposed transmission line includes native habitats and utility/industrial uses. Residences occur east and south of the Power Park. The Intercession City Plant property and the Power Park property share approximately 360 feet of common boundary; both properties are zoned industrial.



6.1.7.2 Affected Waters and Wetlands. This section describes the surface water bodies or wetlands which are crossed by the transmission line and the significant drainage features that may be affected by this project.

The surface water bodies which are crossed by the corridor are limited to Reedy Creek and its associated wetlands (swamp). These waters are classified as Class III water bodies as defined in FAC 62-302.400. Wetlands in the corridor include cypress strand and mixed hardwood swamp which are described in Section 6.1.7 and illustrated on Figure 2.3-4. The approximate area covered by waters or wetlands in the 120 foot corridor is ~~11.3~~ 14.7 acres. A breakdown of the estimated acreage of waters and wetlands in the corridor is presented in Table 6.1-2.

6.1.7.3 Ecology. Section 2.3.6 presents a general ecological overview of the sensitive species which occur or may potentially occur in the vicinity of the Power Park. The proposed transmission line corridor study area is located within the vicinity of the Power Park and ecological issues within one-quarter of a mile are addressed in Section 2.3.6.

Important Species

This section discusses the potential occurrence of important species in the vicinity of the proposed line. Important flora and fauna of the transmission line corridor are the same as discussed in Section 2.3.6. Identification of important species known to occur or that potentially may occur within the vicinity of the line corridor is based on agency consultations, available literature, and important species surveys conducted on July 6-10, 1998. The following information was obtained through agency consultations:

- A list of federally listed plants and animals potentially occurring in the corridor (letter included in Section 2.3.6 of this SCA).

Plant Species. Floristic elements considered "important" by federal and state agencies that may occur in the transmission corridor are the same floristic elements that were considered in Section 2.3.6.

Wildlife Species. Wildlife species considered "important" by federal and state agencies that may occur in the transmission corridor are the same species that were considered in Section 2.3.6. No bald eagles or wading bird colonies were located during the survey of



Table 6.1-2
Estimated Acreage of Waters and Wetlands in Transmission Line
Corridor

Affected Waters/Wetlands	Cleared (acres)	Fill (cubic yards)
Mixed hardwood swamp	9.5 <u>12.9</u>	3,250 <u>3,566</u>
Cypress strand	1.8	780
Total Wetland Impacts	11.3 <u>14.7</u>	4,030 <u>4,346</u> (1.8 acres)



the proposed transmission line. Gopher tortoise burrows were observed in the vicinity of the corridor, largely on Power Park property. Study methods were those specified in FGFWFC's (1988) *Wildlife Methodology Guidelines*.

Species Environmental Relationships. The habitat along the corridor is similar to the habitat found at the Power Park. The species environmental relationships discussed for the power generation units in Section 2.3.6 are applicable to the species environmental relationships within this transmission corridor. The principle difference is the free flowing stream habitat of Reedy Creek.

Reedy Creek is a permanent source of flowing water. The persistence of the water allows a different aquatic ecosystem to develop than what is found in stillwater swamps and ponds. Fish and invertebrate populations may be different and, although wildlife using the system will likely be similar, the abundance and use of the system will likely be greater for some species. Species most likely found in the corridor include great blue heron, little blue heron, green heron, great egret, snowy egret, cattle egret, purple gallinule, American bittern, and other species commonly found foraging and nesting along Florida canals.

Reedy Creek is a mixed hardwood swamp wetland system that can have significant flows during seasonal wet periods. Several developments occur in the vicinity of the proposed transmission line crossing. CSX Railroad and Old Tampa Highway cross Reedy Creek and Reedy Creek Swamp in the same general area. Therefore, the quality of the wildlife habitat in this area will not be significantly disturbed.

The important species in the vicinity which may potentially be affected by the transmission line are gopher tortoises (*Gopherus polyphemus*) and associated inhabitants of gopher tortoise burrows. Potential burrow inhabitants include the Florida mouse (*Peromyscus floridanus*), the eastern indigo snake (*Drymarchon corais couperi*), and the crawfish frog (*Rana aerolata*). The gopher tortoise and Florida mouse have been recorded on Power Park property. The eastern indigo snake and the crawfish frog are species that could potentially occur in this area but have not been observed.

Existing Stresses. Existing habitat stresses in the proposed corridor include railroad and automobile traffic. Trains frequently pass the property on the adjacent railroad tracks.



Old Tampa Highway, the Power Park access road, and the private access road are all well traveled roads.

The Power Park boundary and the private access road are bordered by barbed wire fences. However, the fence along the southern property boundary is incomplete. It is old and has fallen down in some areas. It is a 4-wire, barbed wire, wooden post fence. The access road fence is a steel post, 5-wire, barbed wire, galvanized fence installed by KUA. The private access road fence is gated on the east end where it connects with the Power Park access road and on the west end where it connects with the private portion of a previous residential road.

Other Environmental Features. No additional significant environmental features are known to occur in the transmission corridor.

6.1.8 Effects of Right-of-Way Preparation and Transmission Line Construction

6.1.8.1 Construction Techniques. Several distinct tasks will be required for construction of the proposed transmission line. These will include surveying, clearing, road construction, foundation construction, structure assembly and erection, conductor and shield wire installation, and cleanup. The tasks will occur in the following sequence and will be separated, in time, by several days to several months.

The right-of-way center line and edges, and structures sites, are established prior to construction. This task is usually performed by three- to five-person survey teams and requires minimum clearing for a "line of sight." Clearing and road construction usually run concurrently because of similar requirements for heavy equipment. Road construction is necessary where the structure site would otherwise be under water or the terrain will not support the heavy equipment to be used in subsequent phases of work.

In wetlands connected to waters-of-the-state, chain saws and/or light, tracked shear machines will be used for clearing. Fill material will be hauled in for the construction of access roads. Stumps and root mat will be left in place except at structure foundation locations. There will be no need to demuck.

In areas outside of wetlands, the right-of-way will be cleared by heavy tracked machines, usually bulldozers, and dressed to facilitate future maintenance using wheeled tractors with "bush-hog" mowers. Stumps and cuttings will be piled and burned. The



disposal method will depend on KUA preferences, requirements of the Division of Forestry, and other conditions at the time.

Fill material for access roads will be hauled in by truck and spread with bulldozers to obtain suitable compaction. Culverts, if required, are installed as the road construction progresses to maintain drainage and water flow.

Construction of concrete foundations occurs during the second phase of construction. Equipment required for foundation construction consists of an augering machine mounted on tracked or all-wheel-drive vehicles, "ready-mix" concrete trucks, water trucks, pile driving equipment, and medium-sized (25 to 75 ton) tracked cranes. Each work group will have a bulldozer available to assist in the installation. Tractors, trailers, and light vehicles are used to transport material and personnel.

The next series of tasks consists of hauling material, assembly of structures, erection of structures, and installation of the conductors. The structures and conductor hardware will probably be hauled to the site by tractors and trailers, then offloaded with medium-sized truck cranes or all-wheeled cranes. Medium-sized (1-1/2 to 2 ton) all-wheel-drive trucks are used to transport personnel and tools. Medium-sized truck or all-wheel-drive cranes are required to move structure components and place the structure for erection. The most common method of erecting the structure is with heavy tracked cranes. A work group will normally place the entire structure in one "pick." The boom "reach" will be sufficient to work the tallest structures. Insulators and roller blocks are installed during or immediately following this task. The location of the worksite for installation of conductors and shield wires is determined by the length of conductor on a reel or the line configuration. The basic equipment used for conductor installation is a matched set of machines (puller and tensioner) to pull the conductor and static wires through the rollers to the receiving end and, at the same time, to retard the conductor or maintain light tension at the sending end. The conductors and shield wires are hauled to the sending end on tractors and trailers. A variety of other equipment (radio-equipped pickups to medium-sized cranes and bulldozers) is required at both ends to complete the pull. The puller and tensioner then "leap-frog" as consecutive sections are completed. A bulldozer with a three- or four-drum winch is ordinarily used at the receiving ends to bring the conductors to final tension. The rollers are then removed and the conductors are permanently affixed ("clipped") to each structure. The time required to complete a "pull" averages less than a week.



Finally, at each "heavy-angle" or "dead-end" structure (where the wire has been stopped and/or started), it is necessary to install short pieces of conductor between the ends in order to electrically connect the conductors. Structures, fences, and gates are grounded during this phase of construction and before the line is energized.

Soil erosion is not a problem with proper design and maintenance. Consequently, each contractor will be required to have sufficient equipment and personnel to maintain roads and to keep the right-of-way clear of debris and waste materials. Roads will be constructed with slight crowns and slopes. In addition, culverts, if required, will be placed at necessary locations to allow for proper sheet flow and prevent road washouts. Turbidity screens will be used as required to maintain water quality. Access to private lands will be maintained throughout the construction period. If necessary, restoration, including grading the soil and replanting or reseeding disturbed areas of the construction site(s), will be accomplished prior to the end of the construction phase of the project.

6.1.8.2 Impact on Waterbodies and Uses. The anticipated impacts on the waterbodies and uses along the transmission line and access road from the Power Park to the Intercession City Plant were minimized to the extent practical.

The proposed transmission line will span Reedy Creek, thereby avoiding impacts to this resource. Access and keyhole roads for construction and maintenance will be required for some areas. These proposed linear facilities will, however, have some impact on wetland areas in the new utility corridor. Minor wetland dredge and fill will be necessary in a few locations to construct transmission pole foundations. The placement of fill will also be necessary in a number of locations associated with the construction of access and maintenance roads. The expected locations of fill placement are shown on Figure 6.1-1. In addition, cost estimates of dredging, fill, and clearing necessary for the transmission line and roads are included in Table 6.1-1. Cross-sections showing transmission line and road locations within the existing corridor are shown on Figure 6.1-3. Road sections are shown on Figure 6.1-6.

Section 6 of this SCA includes all currently available preliminary design information regarding the wetland impacts of the proposed transmission line and access roads. However, the Instruction Guide for Certification Applications allow the submittal of detailed wetland impact information either during the certification process or post-certification for later review. The additional information is being developed and is expected to be available by approximately mid-June 1999 during the certification process.



A pedestrian survey was conducted in July 1998 within the proposed corridor to determine the extent of wetlands and other "Waters of the United States." Approximately ~~11.3~~ 14.7 acres of jurisdictional wetlands will be impacted and would be, therefore, subject to Environmental Resource Permitting. Reedy Creek will be spanned to avoid impacts, but impacts to Reedy Creek Swamp wetlands are unavoidable. Best engineering practices will be used to minimize impacts. Unavoidable impacts would include the clearing of large woody wetland vegetation (cypress trees) in the right-of-way, and dredge and fill activities within Reedy Creek Swamp for transmission structures and access roads. An Environmental Resource Permit application for construction of the transmission line is included in Section 10.4 to facilitate project review.

6.1.8.3 Solid Wastes. Solid waste generated from right-of-way preparation and transmission line and access road construction generally consists of construction related debris and cleared vegetation. The quantity of cleared vegetation depends primarily upon the site-specific characteristics of the land being cleared. All cleared vegetation and combustible debris are typically burned onsite. Applicable local and state ordinances regarding open burning will be observed. Noncombustible material will be collected and disposal will occur at existing landfills. If burning is not allowed, material will be buried or removed for acceptable offsite disposal.

6.1.8.4 Changes to Vegetation, Wildlife, and Aquatic Life. Potential impacts to terrestrial and aquatic communities will vary according to the community in which construction takes place. The potential for impacts has already been minimized by placing new facilities in the reserved utility corridor. Additionally, by placing the transmission line route next to the existing railroad corridor, forested communities will not be fragmented. The potential impacts on vegetation, wildlife, and aquatic life within the study corridor are described below.

Vegetation. The entire 120 foot wide transmission line right-of-way will be cleared of trees and shrubs greater than 14 feet tall. Ground cover and soil structure will not be modified permanently for transmission line construction, with the exception of minimal disruption for structure placement. Keyhole roads for structure access may be required in some areas and would require vegetation removal and regrading around each of those structures. Access road construction will require regrading and will necessitate vegetation removal during subgrade preparation.



Forested plant communities dominate the entire corridor. Forested communities within the right-of-way will be cleared and maintained in a mowed or bush-logged condition. The sand pine scrub and oak scrub communities are an exception. Within these communities only trees greater than 14 feet tall will be removed or topped. In forested wetlands, appropriately sized drainage structures will be placed in the access road to maintain existing drainage patterns and to allow the movement of aquatic organisms. After trees are removed in densely forested areas, sun tolerant plant species will replace existing shade tolerant ground cover. In open forested areas such as pine flatwoods, existing ground cover is sun tolerant and will not be permanently affected by tree clearing.

Wildlife. Wildlife impacts from right-of-way preparation and line construction are species-specific and range from temporary displacement of individual animals to losses of individuals or their habitat due to soil compaction and vegetation clearing. According to an assessment of the status and potential occurrence of species listed as threatened, endangered, or of special concern in and adjacent to the corridor, no permanent or adverse changes are expected to occur in the populations of species listed in Table 2.3-1. This conclusion is based on each species' probability of occurrence within the corridor and on each species' mobility (the ability to avoid areas under construction).

The transmission line traverses predominantly mixed hardwood swamp habitat; therefore, right-of-way preparation has the greatest impact on species that inhabit these forests. Habitat will be altered by the clearing of canopy higher than 14 feet where the right-of-way traverses mixed hardwood swamp, pine flatwoods, or forested uplands. Mixed hardwood swamp and cypress stands are commonly used by wading birds for nesting sites.

Pedestrian surveys conducted in July 1998 did not identify any rookeries within the corridor. The forests along Reedy Creek are the most extensive woodlands in the area. The corridor was routed to cross in an area near the cleared railroad and highway rights-of-way, thereby reducing potential impacts to canopy dwelling species and minimizing the effects of fragmenting a large contiguous woodland.

Alligators may occur in Reedy Creek and Reedy Creek Swamp within the corridor. It is not expected that the presence of alligator populations will be in conflict with transmission line construction. If alligators become a nuisance for construction or maintenance personnel, FGFWFC will be contacted to deal with the problem individuals.



Individual small burrowing mammals or fossorial reptile and amphibian species may be lost during right-of-way preparation. The gopher tortoise and the Florida mouse occur in suitable habitat. Tortoises or species typically using burrows for refuge, such as rattlesnakes and indigo snakes, could be eliminated during construction of the access road or the structure pad. Appropriate mitigation, previously developed in consultation with FGFWFC, SFWMD, and USFWS was provided to minimize damages to gopher tortoise populations on Cane Island during development of Units 1 and 2. Because of the limited area to be disturbed, losses of individuals are not expected to significantly affect local or regional tortoise populations.

Aquatic Life. The USFWS did not identify any known threatened or endangered aquatic species occurring in wetlands within the corridor. None are expected to occur in the corridor.

The construction of the transmission line temporarily could impact the water quality of Reedy Creek Swamp, therefore affecting aquatic biota. During construction, surface runoff in the right-of-way may carry small amounts of sediment to the waterways. If unchecked, such runoff could cause increased turbidity in nearby streams. The increased sediments could interfere with the feeding and respiring mechanisms of invertebrates and fish, as well as with photosynthesis in algae and plants. However, the existing vegetation will filter and retain most sediment and residue from the construction area. In addition, soil erosion control practices (Figure 6.1-6) will also be implemented as necessary during construction to minimize adverse water quality impacts. Reedy Creek will be spanned to avoid impacts.

6.1.9 Post-Construction Impacts and Effects of Maintenance

Transmission lines (structures, conductors, etc.) normally require minimal maintenance; however, lines are inspected on a regular basis for any abnormalities caused by weather, vandalism, etc. After initial clearing, maintenance of the right-of-way will be annual or on the basis of need.

6.1.9.1 Maintenance. KUA will inspect and maintain the transmission line and line right-of-way by the following activities:

- Emergency patrol by vehicle and/or aerial in the event of damage to the line by severe weather, etc.



- Use of farm-type tractors with mowing and brush-cutting attachment to maintain the initial clearing of vegetation at intervals of one, two, or more years, as necessary.
- Application of herbicides, as required, in areas where the soil remains too wet for vegetation to be maintained by mechanical means.

Herbicides may be used throughout the right-of-way. Applications will include only those registered by the US Environmental Protection Agency and which have the required state approval. Application rates and concentrations will be in accordance with the label directions. In most cases, the frequency of application will be one treatment every three to five years. Only in a very unusual situation would treatment be required more frequently.

Burning is not normally required for maintenance of the transmission line right-of-way. When extensive reclearing of the right-of-way is necessary, as during construction, limited burning of cleared vegetation may occur. Since the cleared right-of-way itself acts as a fire lane, no fire lanes are anticipated to be necessary.

6.1.9.2 Multiple Use. There are no multiple uses planned for the proposed transmission line corridor.

6.1.9.3 Changes in Species Populations. Pedestrian surveys of the transmission corridor for "important" species were conducted in July 1998. The following paragraphs address changes in species composition and populations as a result of transmission line operation. Vegetation, wildlife, and aquatic resources are discussed.

Vegetation. Transmission line maintenance will require regular trimming of shrubby vegetation within the right-of-way. This maintenance is expected to reduce the number of fast growing woody species and increase the abundance of herbaceous and shrubby species that occur within the right-of-way.

Wildlife. Operation and maintenance of the transmission line will result in a net loss of canopy trees and the creation of new herbaceous and shrubby habitats in and adjacent to the right-of-way. However, the corridor selection process resulted in a corridor which minimized fragmenting forested lands, particularly forested wetlands, and crossed in areas adjacent to previous developments (railroad, highway). Therefore, impacts to wildlife species composition and population abundance will not be significant. However, the right-of-way will attract more ground, low, and mid-canopy foliage feeders and nesters into the once forested habitats.



As indicated in Subsection 6.1.8.2, the integrity of wetland hydrology will be maintained through drainage structure placement, allowing the wetlands to function and develop normally in response to seasonal wet and dry periods. Therefore, the integrity of the habitat and the composition and population levels of local wildlife within the wetlands will be maintained.

Maintenance of the right-of-way will require the use of mowing, manual cutting, or the application of EPA and state approved herbicides by a licensed contractor to keep down invasive woody species throughout the right-of-way and around anchor locations. The selective, site-specific use of agency approved herbicides will not adversely impact wildlife species within the right-of-way or in adjoining terrestrial and aquatic habitats.

The abundance and species diversity of small mammals and birds will decrease during the period immediately after brush mowing or herbicide application. However, abundance and diversity should recover after grasses and other herbaceous vegetation are reestablished. Because the number of small mammals and birds varies with season, species, and other environmental influences, specific decreases and increases are difficult to predict. However, in the long-term, no significant changes to abundance or diversity of wildlife are expected.

Brush mowing temporarily eliminates aboveground foraging and nesting habitat, but the effects are short-lived because the plants will resprout after cutting. Herbicide application, in contrast, will eliminate undesirable vegetation and prevent resprouting. Both techniques will result in a short-term reduction in available habitat and associated vertebrate diversity.

Installation of transmission lines has the potential to cause birds to collide with conductors, shield wires, guy wires, and occasionally even structures, and result in mortality (APLIC, 1994). Electrocution of the larger birds is also possible. However, mortality caused by collision and electrocution does not significantly affect many species (Krapu, 1981; Stout and Cornwell, 1976; Kroodsmas, 1978). Design of the proposed transmission line will provide adequate spacing between conductors to eliminate the potential for electrocution. Again, no wading bird rookeries were located within the corridor.

Transmission line maintenance and operation are not expected to significantly impact local or regional population levels of reptiles and amphibians. Individuals encountered during periodic maintenance activities will move to adjacent habitats or other



refuges (such as burrows) in response to ground vibrations, noise, and human presence. Some mortality of individuals may occur, but such losses will not affect entire populations. The presence of the transmission line and cleared right-of-way will not inhibit daily or seasonal movements of any reptile or amphibian species.

Aquatic Resources. Maintenance activity impacts on aquatic systems and species will be minor or insignificant. Although construction of the transmission line may involve installation of culverts, dredging, and filling, these actions will result only in temporary increases in turbidity and silt deposition which will not continue after vegetation is reestablished. No impacts to aquatic resources will occur due to transmission line operation or maintenance.

6.1.9.4 Effects of Public Access. Any new transmission line access roads will have controlled entry (locked gates); therefore, there will be no impacts on any existing wildlife from increased public exposure. Traffic on the access road will be controlled by gates at the fenced site boundary.

6.1.10 Other Post-Construction Effects

The *Report on Compliance with Electric and Magnetic Field (EMF) Standards* follows page 6-27.

6.2 Associated Linear Facilities

No other new offsite linear facilities will be required for construction or operation of the Power Park or Unit 3.

6.3 References

Avian Power Line Interaction Committee (APLIC), *Mitigation Bird Collisions With Power Lines: State of the Art in 1994*. Edison Electric Institute, Washington, DC, 1994.

Krapu, G.L., *The Platte River Ecology Study: Special Research Report*. U. S. Fish and Wildlife Service, Northern Prairie Wildlife Research Center, Jamestown, ND, 1981.



Kroodsma, R.L., *Evaluation of a Proposed Transmission Line's Impacts on Waterfowl and Eagles*. Pages 117-128 in M.L. Avery, editor, *Proceedings, Impacts of Transmission Lines on Birds in Flight*, U.S. Fish and Wildlife Service, Washington, DC, 1978.

Stout, I.J. and G.W. Cornwell, *Nonhunting Mortality of Fledged North American Waterfowl*. *Journal of Wildlife Management*, Volume 40, pages 681-693, 1976.

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.



Florida Department of Environmental Regulation

Twin Towers Office Bldg • 2000 Blair Stone Road • Tallahassee, Florida 32399-2400

DER Form # 17-814.900
Form Title: Report on Compliance with EMF Standards
Effective Date: January 7, 1993
DER Application No. _____ (Filed in by DER)

Report on Compliance with Electric and Magnetic Field (EMF) Standards

I. AGENT/FACILITY INFORMATION

A. Name of Transmission Line/Substation: Cane Island - Intercession City 230 kV Transmission Line

B. Name of Facility (Utility) Owner: Kissimmee Utility Authority

C. Facility Address: 1701 W. Carroll St., Kissimmee, FL 34741

D. Location of Transmission Line/Substation (County + nearby cities): Osceola County, Intercession City

E. Name of Person Submitting Notification: A. K. Sharma, KUA

F. Address of Person Submitting Notification: 1701 W. Carroll St., Kissimmee, FL 34741

G. Date of Proposed Construction: Sept. 1999

H. Signature of Authorized Agent: *Peter Polif* - BLACK & VEATCH

II. FIELD STRENGTH INFORMATION

A. Transmission Lines

1. Width of Right-of-Way (ROW): 120 feet

2. Maximum Calculated Electric Field within ROW: 3.03 kV/m (single circuit), 2.18 kV/m (double circuit)

3. Maximum Calculated Electric Field at edge of ROW: 126 kV/m (single circuit), .06 kV/m (double circuit)

4. Maximum Calculated Magnetic Field at edge of ROW: 40.7 mG (single circuit), 18.2 mG (double circuit)

B. Substations/Intersections with Transmission Lines

1. Dimensions of substation property: Substation & Line Route fall within property owned by KUA and/or FPC.

2. Intersection of Substation Boundary with Transmission Line ROW:

a. Maximum Calculated Electric Field: same as above

b. Maximum Calculated Magnetic Field: same as above

Note: Line crosses substation property with a tangent configuration.

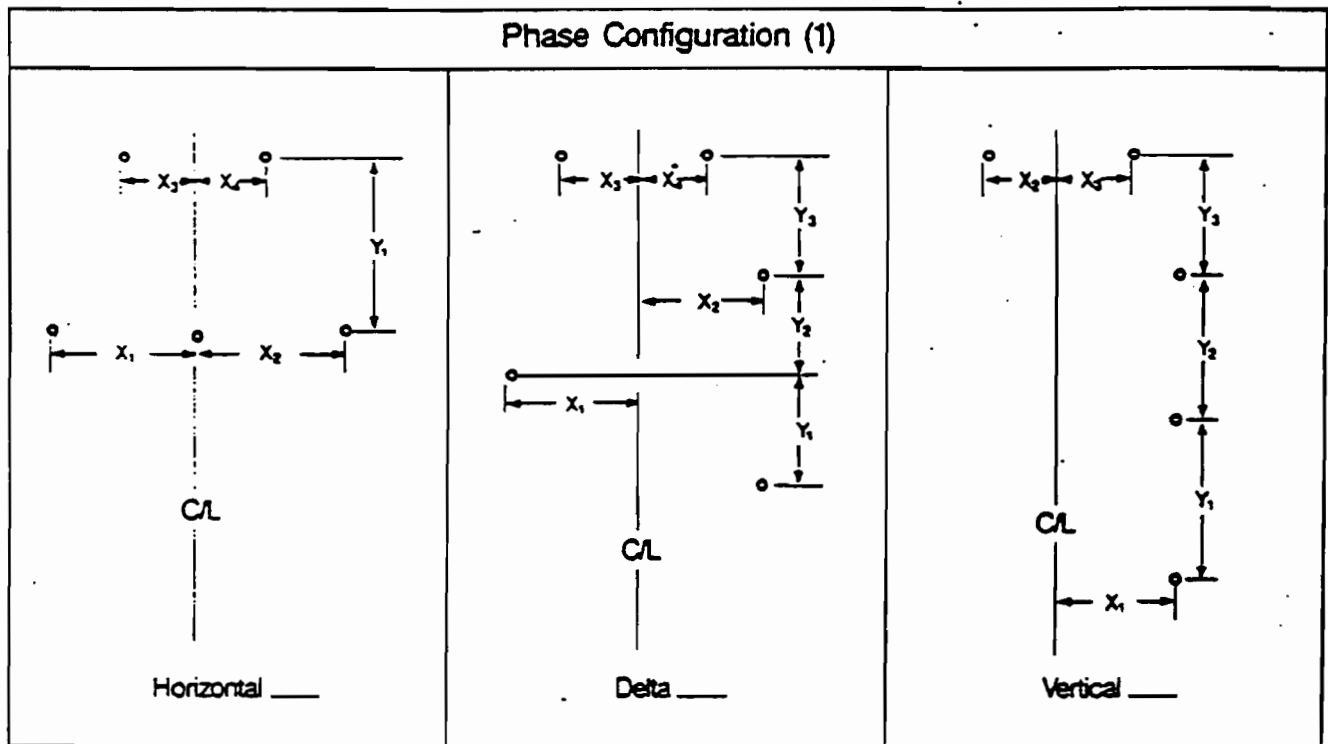
III. DATA FILE

Provide a copy of the (BPA) input data file used in calculation of the field levels provided in this form.

See attached printout.

IV. TRANSMISSION LINE DESIGN DATA

- Voltage Classification: 69 ___ kV 115 ___ kV 138 ___ kV 230 X kV 500 ___ kV
- MCR: 467.36 (MVA) Highest Operating Voltage: 242 kV (L-L)
- Conductor Temperature at MCR: 266 (°F)
- Mid-span minimum clearance from bottom conductor to ground elevation: 26 feet (as measured at MCR)
 Structure type: Single steel pole double circuit vertical
- Conductor diameter: 1.196 inches 954 kcmil ACSR type
- Subconductors per bundle: 1 X 2 ___ 3 ___
- Bundle configuration: vertical NA horizontal ___ delta ___ inverted delta ___ diamond ___ other ___
- Bundle spacing: NA inches
- Overhead ground wires: number 1 size .5 inches
- Centerline of structure to edge of right-of-way: right 60 feet left 60 feet (as seen with back to the power source)
- Attach ROW location map, and attach a scale drawing of structures on the ROW including all sub-conductors, underbuild, and ground wires.

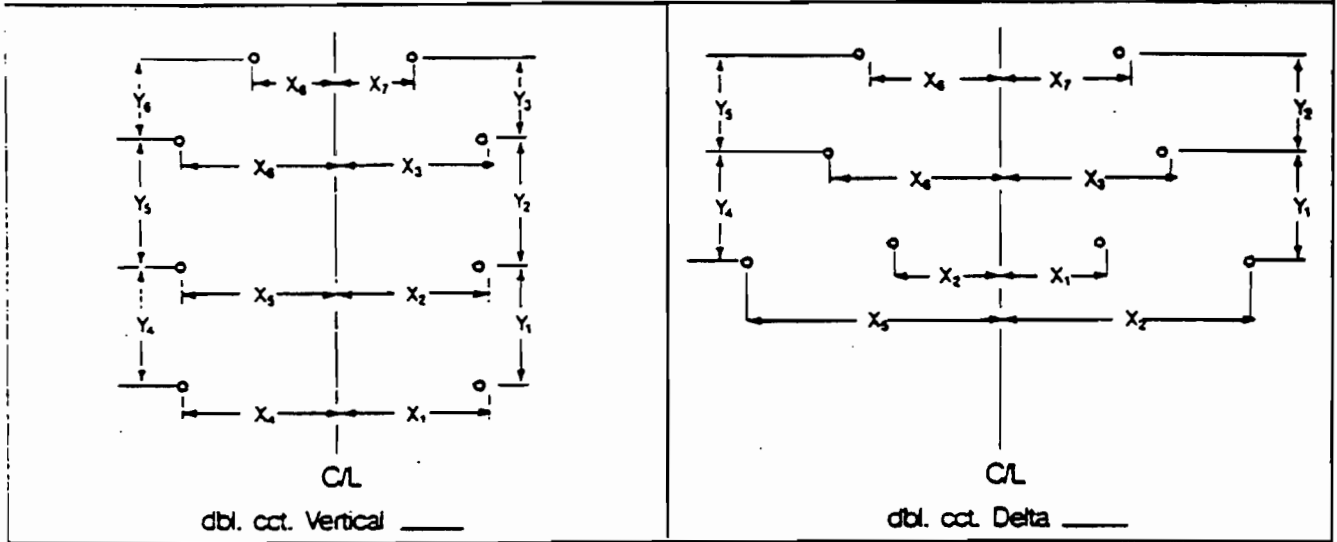


X₁ ___ : X₂ ___ : X₃ ___ : X₄ ___ (feet)

Y₁ ___ : Y₂ ___ : Y₃ ___ (feet)

(1) show X & Y to geometric center of bundled conductors. (See page 3 for dbl. ckt.)

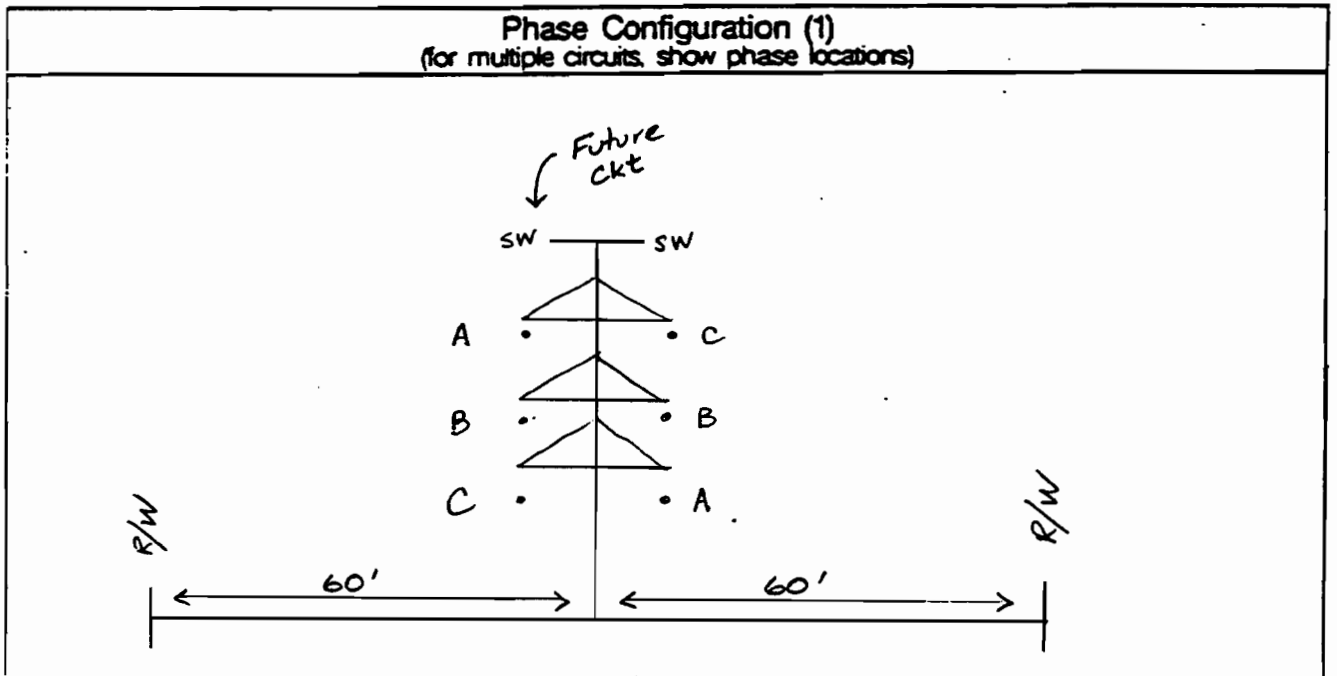
Phase Configuration (1)



X ₁ 10 φ A :	X ₂ 10 φ B :	X ₃ 10 φ C :	X ₄ 8.5 (feet)
X ₂ -10 φ C :	X ₃ -10 φ B :	X ₄ -10 φ A :	X ₅ -8.5 (feet)
Y ₁ 12 :	Y ₂ 12 :	Y ₃ 17.7 (feet)	
Y ₄ 12 :	Y ₅ 12 :	Y ₆ 17.7 (feet)	

(1) show X & Y to geometric center of bundled conductors.

Phase Configuration (1) (for multiple circuits, show phase locations)



X ₁ _____ :	X ₂ _____ :	X ₃ _____ :	X ₄ _____ (feet)
Y ₁ _____ :	Y ₂ _____ :	Y ₃ _____ (feet)	

(1) show X & Y to geometric center of bundled conductors.

CORONA AND FIELD
EFFECTS PROGRAM
Source: Bonneville Power Administration

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+ INPUT DATA LIST +

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+KUA Cane Island - Intercession City 230 kV Transmission Line
+Double Circuit Line
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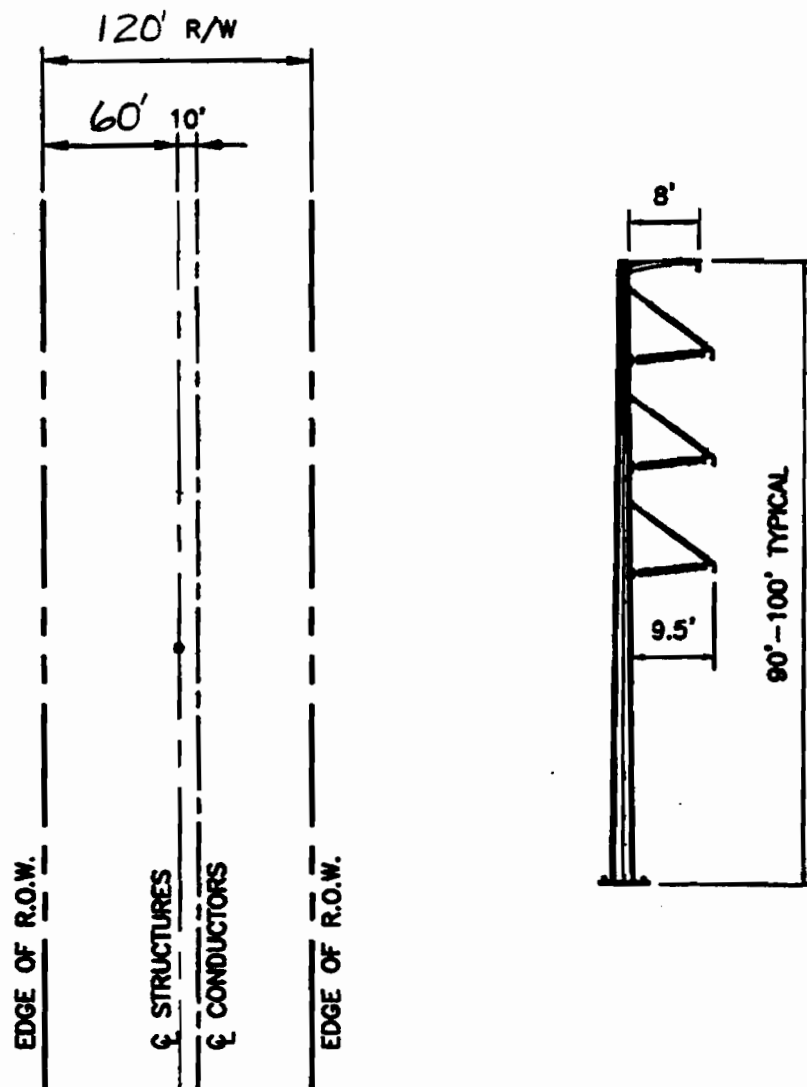
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(ENGLISH UNITS OPTION)

LINE GRADIENTS COMPUTED BY PROGRAM

PHYSICAL SYSTEM CONSISTS OF 8 CONDUCTORS, OF WHICH 6 ARE ENERGIZED PHASES

[illegible]



TYPICAL 230KV TRANSMISSION LINE PLAN

© 1998 Black & Veatch



BLACK & VEATCH LLP

ENGINEER	MGJ	DRAWN	DMH	0	INITIAL ISSUE	DH	MJ	JM
CHECKED	JEM	DATE	06/15/98	NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK APP

KISSIMMEE UTILITIES AUTHORITY
KISSIMMEE, FLORIDA

PROJECT
59140

DRAWING NUMBER
SK-0615

PROPOSED CANE ISLAND/INTERCESSION CITY

FILENAME

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7.0 Economic and Social Effects of Plant Construction and Operation

7.1 Socio-Economic Benefits

The Cane Island Power Park (Power Park) will provide benefits to Osceola County, the region, and the state of Florida primarily by providing jobs which will increase the buying power of individuals and also generate tax revenues. The Power Park also productively uses a site with limited development potential.

7.1.1 Creation of Temporary and Permanent Jobs

7.1.1.1 Temporary Jobs. The construction phase of Unit 3 is expected to create approximately 240 temporary jobs. As with all major construction projects, the labor force will change as the project progresses. Early in the project, laborers, carpenters, concrete workers and operating engineers will be needed. Later, electricians, pipe fitters, boilermakers and ironworkers will be hired. It is anticipated that the Unit 3 expansion project workforce will evolve similar to that experienced during the construction of Unit 2. The anticipated workforce evolution for Unit 3 is shown on Figure 7.1-1.

The construction workforce is expected to be primarily drawn from the impact area of Polk, Osceola, Orange, Lake, and Seminole counties. As discussed above, it is anticipated that most of the workforce will commute daily from permanent residences within the impact area. However, workers who commute weekly to similar construction jobs have been known to travel up to 200 miles (EPRI 1982).

The estimated payroll for the construction project is \$18 million. Distribution of this payroll would follow the workforce curve presented in Figure 7.1-1.

7.1.1.2 Permanent Jobs. It is estimated that KUA will retain only 2 full-time workers to help operate Unit 3. The current operational staff is 28 individuals with a total annual salary of \$1.46 million. Therefore, it is anticipated that beginning in June 2001 (the projected on-line date for Unit 3), the total operating workforce salary will increase to \$1.55 million per year. Over the lifetime of the three unit Power Park, this means an annual addition of \$46.5 million into the local economies. Studies indicate that operational staff tend to live within 30 miles of the work site (EPRI IV-2). Therefore, the benefits of these permanent positions will accrue in the impact area.

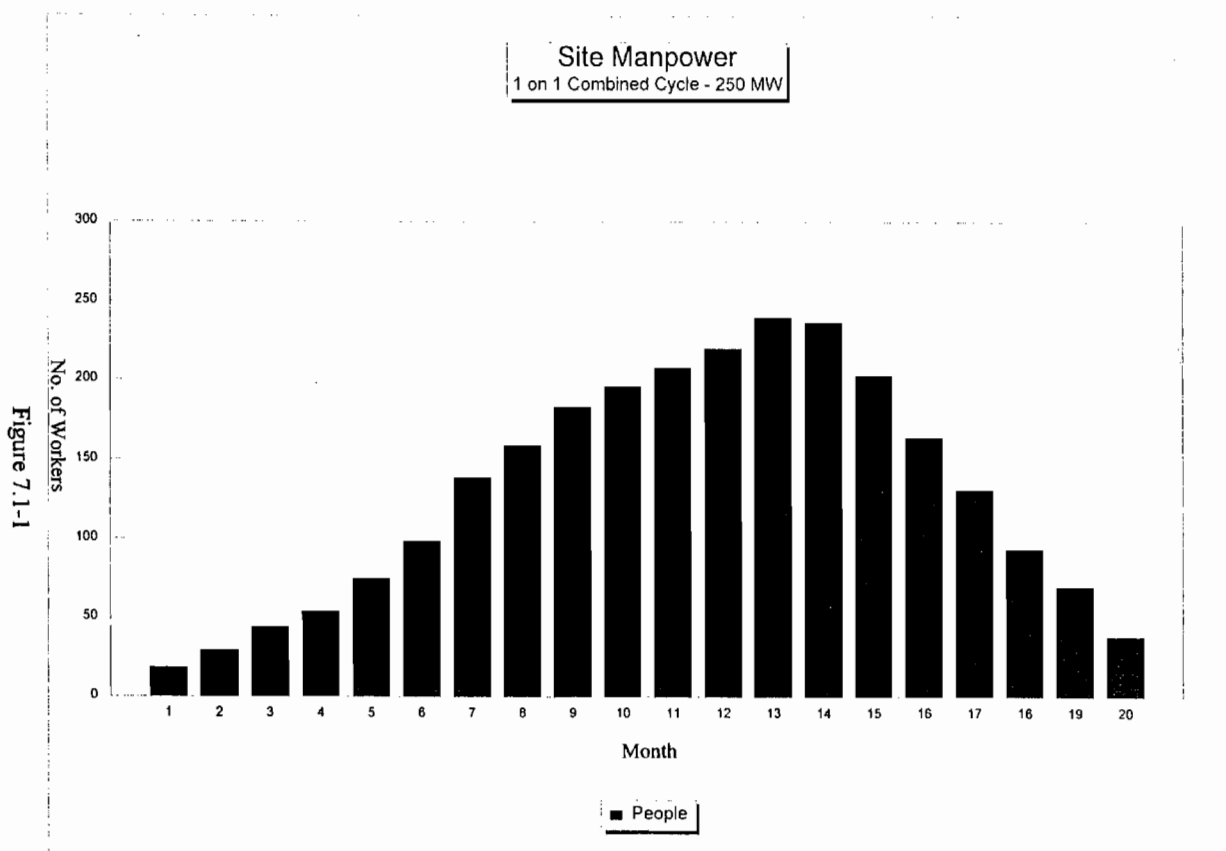


FIGURE 7.1-1

UNIT 3 CONSTRUCTION WORKFORCE



7.1.2 Additional Job Creation/Stimulation of Local Economies

While a great deal of local purchasing is not expected to be generated by the power plant construction (EPRI VI-5), the influx of workers into an area tends to stimulate job creation in the service industry. This indirect economic benefit has been studied in power plant construction situations by the Electric Power Research Institute (EPRI). EPRI concluded from case studies that 0.7 full-time local service jobs are created for every one power plant construction job (EPRI 1982). Therefore, the construction workforce during peak employment could be expected to stimulate the creation 168 service positions ($240 \times 0.7 = 168$).

For operational employees, the multiplier has been found to be 0.8 (EPRI, 1982). Therefore, it is anticipated that possibly 1 service position may be created as a result of the additional operational personnel ($2 \times 0.8 = 1.6$).

7.1.3 Revenue Generation for State and Local Governments

Each of the temporary and permanent jobs directly or indirectly created will contribute revenue to the State of Florida and local jurisdictions through sales and use taxes and, potentially, property taxes generated by purchases.

7.1.4 Creation or Improvement of Local Roads, Waterways or Other Local Transportation Facilities

Although no direct creation or improvement to local transportation systems are planned, the Power Park will nonetheless contribute to the general creation and improvement of local transportation through the increased tax revenue which can be used by local and state governments to improve transportation systems to the benefit of all residents. The local roadway improvements completed for the construction and installation of Units 1 and 2 at the Power Park remain more than adequate to handle the anticipated weight and traffic count loads for the new Unit 3 construction project.

7.1.5 Increased Knowledge of the Environment

Plant and wildlife surveys were completed prior to construction of Units 1 and 2; management and monitoring of the non-project habitats is on-going and in compliance with the *Cane Island Project Mitigation Plan*. The studies revealed no new information, but added to the general scientific knowledge of species type and distribution, the importance of habitat, and the ability of the wide variety of plant and animal species located at or near the



Power Park to co-exist with a human population. Species inventories, mapping and delineation of habitats were all conducted and have subsequently become part of the general body of scientific knowledge of area ecosystems and the overall environment.

7.1.6 Increased Land Use Efficiency

The Power Park increases the efficiency of land use in the area. Increased productivity from a given parcel of land is especially beneficial in areas of high economic growth, such as the impact area, since this allows other parcels to remain available for other beneficial uses.

7.2 Socioeconomic Costs

Major construction projects can potentially affect area residences and businesses, school and library systems, parks and recreation facilities, public infrastructure such as streets, bridges and highways, as well as police and fire departments, sewer and water service providers, and local government administration. However, the Power Park expansion and two additional operators will not have any significant negative long-term impacts on these resources and services.

7.2.1 Temporary External Costs

Temporary external costs may include shortages of housing; inflationary rentals or prices; congestion of local streets and highways; noise; temporary aesthetic disturbances; overloading of water supply and sewage treatment facilities; crowding of local schools, hospitals or other public facilities; burdening of community services; and, the disruption of people's lives or the local community caused by the acquisition of land for the proposed site. However, KUA has owned the Power Park site since 1990, with the intent of developing the property as an electrical power plant station. Other than temporary construction impacts, KUA and FMPPA believe that the Power Park is an environmentally and socially responsible development.

7.2.1.1 Traffic Congestion. Some form of construction-related transportation impact is unavoidable in a project of any significant size due to the movement of workers, machines and supplies to and from the work site. During Unit 3 construction, the most significant negative impact is expected to take the form of traffic congestion. However, this impact will only be temporary and will not have any significant adverse impact on the roadways and intersections in the vicinity of the Power Park.



Construction will occur during daylight hours, with the majority of workers on site between 7 a.m. and 4 p.m. A late shift is anticipated, but this shift will have fewer workers.

The access point for the construction workforce and deliveries is the Power Park entrance off of Old Tampa Highway. The entrance is gated and access will continue to be controlled. Designed and constructed during the initial construction of the Power Park, this entrance was designed with appropriate geometric improvements, deceleration, acceleration and turn lanes, all based on Florida Department of Transportation (FDOT) standards, so that the construction and operational traffic could be appropriately accommodated.

It is estimated that the peak construction workforce will be approximately 240. Traffic counts for US-17/92, which is also State Highway 600, in the Intercession City vicinity support the expectation that the additional traffic generated by the construction project will have an insignificant impact. FDOT traffic count Site 29 is on Highway 600, is 0.4 mile northeast of State Highway 532. This location is approximately 1 mile west of the Power Park entrance. In 1997, the annual average daily traffic count for Site 29 was 12,200 vehicles. Assuming that every worker arrives alone in a single vehicle, the additional traffic would mean a 2% increase in traffic. Given the multitude of connector and highway access points available to traffic proceeding either west or east bound on Old Tampa Highway or US-17/92, it is anticipated that any construction-related congestion will be alleviated by the close proximity of multiple ingress and egress routes.

To further lessen the impact of the influx of construction workers on existing traffic patterns, KUA will encourage transportation demand management techniques to reduce the number of temporary, construction-related vehicle trips on the road networks. These techniques will include placing a bulletin board onsite which may be used by construction contractors to place car-pooling advertisements. All construction contractors will be requested to inform their employees that this service is available.

During the early construction phase, vehicles such as road graders, bulldozers and dump trucks will also require access. However, the majority of these heavy construction vehicles are anticipated to remain onsite for the duration of the initial construction activities, entering at initiation and exiting upon completion. Since the majority of these vehicles will not be making daily trips to and from the work site, traffic impacts are expected to be minimal. Routine multiple trips by dump trucks and cement mixer vehicles are expected but volumes are not anticipated to be problematic. For example, a majority of the concrete pouring



activity will occur in a single day. While cement truck volume on that single day will be significant, the inconvenience will be of short duration.

7.2.1.2 Noise. As indicated in Section 2.3.8, the noise of operation from the current Power Park configuration does not have a significant negative impact on nearby residences. Furthermore, the additional noise generated by the operation of Unit 3 is expected to be imperceptible.

The construction noise associated with Unit 3 is not anticipated to be significant. The majority of construction will be located on the north end of Cane Island. The structures on the south side of the island, as well as the vegetative buffer and physical distance to the nearest residences (nearly 1 mile), will all mitigate the intermittent disturbance.

7.2.1.3 Housing Impacts. No negative housing impacts will occur due to Unit 3 construction. As mentioned previously, most of the construction workforce is expected to commute daily from established residences within the impact area. This expectation is based on studies of electric generator construction projects which found that in areas such as the Power Park impact area "where a trained labor force exists, there is likely to be less relocation of workers and more commuting from existing places of residence" (III-11, Socioeconomic Impacts of Power Plants, EPRI, Report EA-2228, February 1982). Since the impact area has been experiencing tremendous economic growth for an extended period of time, a seasoned labor force of construction tradesmen is well established in the impact area.

Construction workers relocating to the area temporarily will not affect the availability of short-term housing. If even half of the expected workforce seeks temporary housing, this is only an increased demand of 120 individuals. As mentioned in Section 2.2.7.1 under the heading Existing Housing Stock, the Orlando MSA alone had over 5,600 vacant rental units, over 86,500 hotel rooms and at least 43 camping and recreational vehicle sites. This large amount of available temporary housing will easily absorb the additional individuals.

Creation of single family housing or apartment complexes that will later stand vacant is not expected to be a result of the influx of migratory construction workers. Such workers will not be in the area long enough for it to make financial sense for them to make single family home purchases. Indeed, it is doubtful they would be able to obtain financing for such purchases if they already maintained residences elsewhere. These factors will also discourage the construction of new single or multi-family housing units.



KUA and FMPA are not planning on providing housing for construction workers nor offering incentives to local developers or subsidies to local housing suppliers, a fact that supports the conclusion that no significant problems with housing supply are anticipated.

7.2.1.4 General municipal or utility services impacts. As with potential housing impacts, construction related impacts to public services and facilities will not be significant. The majority of the construction workforce is anticipated to commute from current residences, with only minimal relocation. Since the current workforce is, therefore, already provided with services, no significant changes in the patterns of use or demands upon public services will occur.

Water Service Impacts

Additional cooling water will be required for the operation of Unit 3. However, Unit 3 will use the Kissimmee effluent pipeline for cooling water supply, as does Unit 2, with the cooling tower blowdown returned to the pipeline. Additional groundwater will also be withdrawn for service/potable uses.

The construction contractors will be required to provide potable water for the Unit 3 construction workers. It is anticipated that the contractors will be permitted to use groundwater from the onsite wells for service water requirements.

Solid Waste Collection and Disposal Impacts

Sufficient capacity exists at the Bass Road construction and demolition landfill to handle the solid waste disposal needs of Unit 3 construction. The Bass Road facility has approximately 6 years of capacity remaining, depending on the level of tipping. Other non-construction debris landfills in the area are scheduled to close fairly soon. The St. Cloud and Southport landfills (both Class 1 residential landfills) are scheduled to close in 2001 and 2003, respectively. After these facilities close, Osceola County may operate a system of transfer stations with the ultimate disposal site being a facility in Okeechobee which has a long-term operating permit and 100 years of landfill capacity. Nonetheless, the Bass Road facility has sufficient capacity to handle construction waste from Unit 3 construction project. Osceola County expects to have no problem arranging for the disposal of the solid waste generated during the subsequent operation of the Power Park.



Sewer Service Impacts

The Power Park currently uses and will continue to use a septic tank/tile field system for sanitary wastewater treatment and disposal. Construction contractors will be required to provide temporary sanitary services for their employees.

Police Protection Impacts

The Power Park will continue to be gated with keypad entry-restricted access. Therefore, police protection demand will not increase.

The combination of the size of the construction work force and the duration of the construction phase will not cause any deterioration in the ability of the Osceola County Sheriff's Department to provide routine patrol and protection services in the Power Park area.

7.2.2 Long-Term External Costs

There may be long term external costs resulting from operation of the Power Park as described in the following paragraphs. However, due to the remote location, self-reliant operation, relatively small staff, use of modern pollution control devices, and compliance with all applicable federal, state, and local regulatory requirements, the potential negative impacts will not be significant.

Negative Impacts on Water Service

The additional potable water usage required during the construction phase will not impact the provision of potable water for the surrounding communities. The wells for the Power Park tap a deeper aquifer than that utilized locally for potable water provision. In addition, the contractors will be required to supply potable water to their employees during construction.

The incremental use of potable water at the Power Park due to Unit 3 will not have significant impacts during the operational phase. The design of Unit 3 will minimize groundwater consumption by using treated wastewater effluent for cooling tower makeup, the highest volume of water utilized at this type of facility. The potential for significant temporary potable groundwater usage exists from use of the deep aquifer as the emergency supply system for the cooling tower makeup. However, the modeling results in Section 5.3.2



of this document indicate that this emergency withdrawal will not negatively impact the quantity or quality of well water for the residents in the surrounding area.

Negative Impacts on Potential Use of Contiguous Parcels

Since the Power Park is already developed as an electric generating facility, the addition of a third generating unit will not negatively affect any land usage for the balance of Power Park property or the surrounding area. The surrounding area consists of hardwood swamp, which makes commercial or residential development difficult, if not impossible. In addition, areas to the west, north, and northeast of the project site have been designated conservation areas. Since the Power Park already operates as an electric generating facility, the Unit 3 construction project at issue will not affect the utility of this area.

Negative Impacts on Local Recreational Activities

No access to local recreational activities is available through or near the Power Park site; therefore, the construction project described herein will not affect these activities.

Negative Impacts on Local Native Species

The Power Park site was studied because of the potential of the area as habitat for the Florida scrub jay. However, resource agency personnel, specifically the FGFWFC and USFWS, have agreed that the appropriate habitats were of marginal quality. No scrub jays have been reported or observed onsite.

Gopher tortoises have been documented onsite. The gopher tortoise is a species of Special Concern in Florida. Efforts to mitigate the impact of ultimate site development on the gopher tortoise have been approved and implemented. These measures include establishment of a conservation easement granted to the FGFWFC, and habitat management and monitoring activities. Any takings of gopher tortoises or their habitats onsite have been permitted by the FGFWFC.



Negative Impacts on Archaeological Sites

No significant archaeological sites existed on Power Park property prior to the development; and no eligible sites have been subsequently identified. Access to Cane Island was created specifically and exclusively for ingress and egress to the power block area so the project poses no threat to access of any other areas, whether of recreational, scenic, historic, cultural, natural, or archeological value.

Negative Impacts on Alternative Land Uses

No alternative uses for the Power Park have been proposed. The Power Park has been designated for industrial use such as electricity generation by the Osceola County Board of Commissioners.

Negative Impacts on Local Meteorological Conditions

Neither the construction of Unit 3 or operation of the Power Park will have significant meteorological impacts. Fogging due to operation of the cooling tower is projected to be minimal. Air pollutant emissions from the combustion units will be within acceptable, permitted limits.

Noise

The Power Park will not generate sufficient noise to negatively affect any local residents. There are currently no residential units within one-half mile of the power block, and none are currently planned. As described previously, the closest residence is separated from the Power Park by nearly 1 mile of hardwood swamp. The vegetation will act to absorb or deflect sounds that otherwise may travel to the populated area. Equipment traveling to and from the Power Park will unavoidably generate noise during transit through populated areas, but this noise will not be significant in either level of intensity or duration.

Displacement of Persons for Construction Purposes

Since the Power Park was uninhabited prior to the construction of Units 1 and 2, and has continued to be uninhabited, no displacement of persons will result from the expansion. No lost income will result from any reduction of regional products or productivity whether due to displacement of persons from the land proposed for the site or otherwise.



Negative Impacts on Neighboring Property Values

Since the site has been zoned and developed as a electric generating facility, the proposed expansion will not decrease the property values of the surrounding real estate. There are no current or proposed public recreation, tourist, or commercial fishing developments in the area immediately surrounding the site. Since the area is zoned for industrial use, it is not anticipated that such proposals will be forthcoming.

Negative Impacts on Local Municipal or Utility Services

As discussed above, the majority of workers hired during the construction phase of Unit 3 are expected to commute locally to the Power Park from established, permanent residences. The majority of the remaining workers are expected to travel alone into the impact area on a weekly basis, staying in temporary housing facilities such as hotels or recreational vehicle campgrounds. In either case, these workers will not generate any increased costs to local government for services. While such workers will benefit from police, fire, ambulance, sewer, water and recreational services provided by local governments, they will help defray the costs of providing such services through property taxes, sales taxes, or costs built into rent payments. In any event, the number of workers hired for peak construction activity is expected to be about 240, a figure considered too low to adversely affect the ability of local governments to adequately provide any necessary services. Furthermore, the number of permanently employed workers associated with Unit 3 is only expected to be 2, which again is too low to adversely impact the ability of a local government from providing services. It is also expected that these permanent employees will simply continue to commute from their current, existing, permanent residences which will therefore reduce further any negative impacts of service provisions by government.

Negative Impacts on Aesthetic or Scenic Values

Due to vegetative buffers and extensive setbacks, incremental Power Park development will not result in the deterioration of any local scenic or aesthetic values. Some tree removal will be required during the construction phase of the facility. However, these removals will not cause a deterioration of the local or regional aesthetics.



7.3 References

Cane Island Project Mitigation Plan, Black & Veatch, October 1993.

Socioeconomic Impacts of Power Plants, Electric Power Research Institute (EPRI), Report EA-2228, February, 1982.

Telephone conversation between Bill Grotts, B&V, and Roberta Martin, FDOT, (850) 488-4111 ext. 132 on 5/19/98.

Telephone conversation between Bill Grotts, B&V, and Lenny Marion, Osceola County Solid Waste Department, (407) 847-4481, on May 13, 1998.

Telephone conversation between Bill Grotts, B&V, and the Public Relations Office of the Osceola County Sheriff's Department, (407) 348-2222, on May 13, 1998.



8.0 Site and Design Alternatives

8.1 Alternative Sites

In 1988, KUA performed a siting study for a combustion turbine generation site through a three step procedure. Step 1 screened a predetermined study region to identify areas suitable for a combustion turbine power plant considering fuel, water, transportation, and transmission factors. Siting specialists visited the 34 potential sites to confirm resources, and eliminated 14 of these sites from further consideration. The remaining 20 candidate sites were evaluated using a weighted scoring system considering site-specific technical and environmental criteria during Step 2 of the study.

The top three sites from the scoring evaluation were subjected to a feasibility analysis during Step 3 of the study to determine development options, costs, and permitting requirements. KUA selected the Cane Island site as the preferred site. Preliminary field studies and consultations with the US Fish and Wildlife Service, Florida Game and Fresh Water Fish Commission, and the South Florida Water Management District confirmed the feasibility of development at the Cane Island site. Consequently, KUA purchased the Cane Island property in 1990.

The Cane Island site was arranged considering future development. Units 1 and 2 were located in the southern portion of the approved development area, with future units expanding north.

KUA also conducted a siting study for a substation location for transmission and distribution of the new generation capacity into Kissimmee. An east-west utility corridor exists from the Cane Island site into Kissimmee generally following the CSX Railroad track. This corridor was selected for installation of the new transmission line to minimize environmental impacts, clearing requirements, and land disruptions. Five potential substation locations were identified and evaluated near this corridor. The Clay Street site was selected due to location adjacent to the railroad, cost, and availability.

8.2 Proposed Site Design Alternatives

8.2.1 Alternative Heat Rejection Systems

No alternative heat rejection systems were evaluated due to the availability of treated sewage effluent from the City of Kissimmee.



8.2.2 Biological Fouling Control Alternatives

Periodic biocide treatment of recirculating cooling water is necessary to control biological fouling of condensers, associated piping, and related equipment. Potential biofouling control alternatives include the following:

- Chlorination
- Sodium bromination
- Ozonation
- Ultraviolet radiation
- Mechanical cleaning

8.2.2.1 Alternative Biofouling Control Methods. Non-chlorine biofouling control alternatives are considered less favorable than the chlorination method primarily due to cost and operational effectiveness. Sodium bromide and ozone as biocides were considered but involve significantly higher operational costs than chlorine, especially in the treatment of such large water volumes as recirculating cooling water for power plants. Ultraviolet radiation also involves much higher operational cost and has operation deficiencies since this alternative is relatively ineffective in treating water with suspended particles. Mechanical cleaning is ineffective in cleaning remote portions of the cooling system equipment and destroying microorganisms suspended in the water. Based on these considerations, these potential alternatives offer no environmental, operational, or cost-effectiveness advantages relative to the chlorination method for biofouling control.

8.2.2.2 Proposed Biofouling Control Method. Chlorination using liquid sodium hypochlorite is the method of biocide treatment currently used in the Unit 2 cooling tower and is proposed for the Unit 3 cooling tower. The sodium hypochlorite solution will be contained in a storage tank. Pumps will transfer the solution through diffusers at the cooling tower basin. Biological growth will be controlled by shock chlorination. Provisions will also be included for periodic feed of a nonoxidizing biocide should operation indicate the need.

8.2.3 Cooling Water Makeup/Process Water Source Alternatives

8.2.3.1 Potential Alternative Water Sources. Treated well water is the only source suitable to supply the Power Park potable water system as municipal supplies are not available in the area. The use of Kissimmee treated sewage effluent for potable water is not an acceptable alternative.



Treated effluent would be a potential alternative water source for the demineralization system. However, extensive additional treatment equipment would be required if the effluent was used instead of well water as a source. Pretreatment methods such as clarification, filtration, and reverse osmosis would be required to reduce the organics and dissolved and suspended solids of the effluent prior to demineralization. The consistency of the effluent is also a concern. A demineralization process requires a consistent quality of supply water or operational problems which can impact the reliability of the generating units may develop.

In conclusion, the use of treated effluent is not considered appropriate for plant use other than for cooling tower makeup. Extensive additional treatment would be needed to convert the effluent to service water quality, when well water is readily available at the quality and quantity needed.

8.2.3.2 Proposed Water Sources. The two proposed sources of water for the Power Park are well water and Kissimmee treated sewage effluent. Site wells will supply plant service water requirements. Reclaimed water from the effluent pipeline will be used as cooling tower makeup. Well water will also be used as an emergency source of cooling tower makeup should reclaimed water be temporarily unavailable. Additional wells will be required to meet this increased demand in well water.

8.2.4 Sanitary Waste System Alternatives

No sanitary waste system alternatives were considered due to the small amount of sanitary waste produced at the Power Park. The availability of septic tank/tile field systems and lack of City facilities limited the available options.

8.2.5 Plant Drainage System Alternatives

8.2.5.1 Potential Alternative Systems. Presently, oil/water separator effluent is routed to an onsite percolation pond. One potential alternative would be to discharge treated oil/water separator effluent to the Kissimmee effluent pipeline; however, this option was not considered acceptable in discussions with the FDEP. It is considered desirable to maintain the current concept which will continue to allow groundwater recharge in the site area.

8.2.5.2 Proposed Plant Drainage System. Site drainage from oil containment areas and other potentially oil contaminated areas will be routed through oil/water separators and



to an onsite percolation pond prior to groundwater discharge. The existing percolation pond will be expanded to accommodate the additional wastewaters from Unit 3.

As required by the South Florida Water Management District, the Power Park storm water management system directs all storm waters from developed areas to an onsite detention pond. A second collection system and detention pond will be constructed with Unit 3.

8.2.6 Process Wastewater Treatment Alternatives

8.2.6.1 Potential Alternative Systems. Presently, cooling tower blowdown and a small amount of other process wastewaters are routed to the Kissimmee effluent pipeline for reuse or disposal. One potential alternative would be a zero discharge treatment system which would treat cooling tower blowdown, neutralized chemical waste, and boiler blowdown for reuse at the Power Park. Solid wastes produced from this system would be hauled off site by a licensed contractor. The capital costs and operational costs for such a zero discharge treatment system would be very high.

The present concept of reuse of treated effluent for cooling with disposal of cooling tower blowdown back to the effluent pipeline with a small amount of treated process wastewater has been acceptable to the FDEP and has shown to not increase the loading of nutrients to the Imperial percolation ponds.

The zero discharge treatment system was not considered for use at the Power Park because of high costs and the availability of the Imperial Percolation Ponds to accept Power Park wastewaters without significant environmental impact.

8.2.6.2 Proposed Wastewater Treatment System. Cooling tower blowdown, neutralized chemical waste, and boiler blowdown will be returned to the Kissimmee effluent pipeline for reuse or ultimate disposal of this wastewater at the Imperial Percolation Ponds. Existing Units 1 and 2 dispose of these wastes in this manner.

8.2.7 Solid Waste Disposal System

There are no solid process wastes generated at the Power Park. Trash and other solid waste will be disposed of at an approved facility. No alternatives were evaluated.



9.0 Coordination

The following is a list of individuals within federal, state, regional, and local government agencies who were contacted to provide information for this project.

FEDERAL

- **US Army Corps of Engineers**
Jacksonville, FL, District
Mr. Stuart Santos, (904) 232-2018
- **US Fish and Wildlife Service**
Vero Beach, FL
Mr. Wes Shockley, (407) 562-3909
- **US Department of Energy**
Washington, DC
Mr. Tony Como, (202) 586-5935

STATE

- **Public Service Commission**
Tallahassee
Mr. Cochran Keating, (850) 413-6193
Mr. Robert Elias, (850) 413-6189
Mr. Kenneth Dudley, (850) 413-6662
Mr. Roland Floyd, (850) 413-6676



- **Department of Environmental Protection:**

- Power Plant Siting Coordination**

- Tallahassee

- Mr. Buck Oven, (850) 487-0472

- Air Resources Management Division, Bureau of Air Regulation**

- Tallahassee

- Mr. Al Linero, (850) 488-1944

- Mr. Cleave Holladay, (850) 921-9530

- Ms. Teresa Heron, (850) 921-9524

- Mr. Scott Sheplak, (850) 488-1344

- Environmental Resource Permitting Division**

- Central District

- Mr. Jim Carr, (407) 894-7555

- Water Facilities Division**

- Central District

- Mr. Ali Kazi, Program Manager-Industrial Wastewater Section, (407) 893-3317

- Mr. Eugene Elliott, Permitting Engineer-Industrial Wastewater Section, (407) 893-3317

- **Game and Fresh Water Fish Commission**

- Tallahassee

- Mr. Brad Hartman, Director, Office of Environmental Services, (904) 488-6661

- **South Florida Water Management District:**

- Site Certification Coordination**

- West Palm Beach

- Ms. Susan Coughanour, Senior Planner, (561) 687-6920

- Mr. Jeff Rosenfeld, Senior Hydrogeologist, (561) 687-6922



Environmental Resource Permitting

Orlando

Mr. Alan Leavens, Engineer, (407) 858-6100

Mr. George Ogden, Hydrogeologist, (407) 858-5992

Ms. Susan Elfers, Environmental Analyst, (407) 858-6112

Mr. Ed Edmundson, Enforcement, (407) 858-6107

LOCAL

- **Osceola County:**

Planning/Zoning/Engineering Departments

Lori McKosky, Zoning, (407) 847-1551

Earl Harris, Zoning, (407) 847-1405

Walt Krujaick, Zoning, (407) 847-1405

Rod Schultz, Zoning, (407) 847-1405

Tad Calkins, Planning, (407) 847-1380

Phil Whitney, Engineering, (407) 847-1260

Don Lepic, Engineering, (407) 847-1260

Miro Poss, Engineering, (407) 847-1260

- **City of Kissimmee:**

Water & Sewer Department

Mr. Brian Wheeler, Director, (407) 847-2821

Mr. Robert Pelham, Asst. Director, (407) 847-2821

**SITE CERTIFICATION
APPLICATION**

Volume 3

Kissimmee Utility Authority
Florida Municipal Power Agency
Cane Island – Units 1 - 3



BLACK & VEATCH^{LLP}

SITE CERTIFICATION APPLICATION

Volume 3

Kissimmee Utility Authority
Florida Municipal Power Agency



Cane Island
Units 1 - 3



BLACK & VEATCH_{LLP}

Cane Island Power Park

Site Certification Application

VOLUME 3

Manual Number KUA/FMPA- 33

Issued to _____

Location _____

SITE CERTIFICATION APPLICATION

**CANE ISLAND POWER PARK
UNITS 1-3**

VOLUME 3

Submitted by:

**Kissimmee Utility Authority
and the
Florida Municipal Power Agency**

August 1998



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10.0 Appendices

This section identifies the existing Cane Island Power Park Unit 1 and 2 permits and approvals, and includes the major permit applications and approvals required to construct and operate Unit 3.





10.1 Existing Federal Permits

10.1.1 NPDES Permit

KUA currently holds NPDES General Permit FLR00B641 for operational storm water discharges from the Power Park. This permit was issued by the EPA. A copy of the operational permit is included herein.

10.1.2 Oil Pollution Prevention

The amount of reserve fuel oil stored at the Power Park required KUA to comply with the EPA's oil pollution prevention regulations. The Power Park Response Plan, and the Spill Prevention, Control, and Countermeasures (SPCC) Plan were prepared for Units 1 and 2 in compliance with those regulations. Copies of the plans are available from KUA. These plans will be revised to incorporate Unit 3 facilities.

10.1.3 Certification of Compliance

The Power Plant and Industrial Fuel Use Act required KUA to certify that, with the installation of additional equipment, Units 1 and 2 would be capable of firing coal (including gasified coal) or another alternate fuel as the primary energy source. A copy of the Certification of Compliance documents submitted for Units 1 and 2 are included herein.

**National Pollutant Discharge Elimination System
Storm Water General Permit**



U.S. ENVIRONMENTAL PROTECTION AGENCY
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
STORM WATER GENERAL PERMIT COVERAGE NOTICE

July 31, 1995

RECEIVED EPA

AUG 11 1995

POWER SUPPLY DEPT.

Dear Operator:

Your Notice of Intent (NOI) for the facility noted below has been processed by the U.S. Environmental Protection Agency. This facility is authorized to discharge storm water associated with industrial or construction activity under the terms and conditions imposed by EPA's NPDES storm water general permit issued for use in the state of Florida. Your facility's NPDES Baseline Industrial storm water permit number is FLR00B641.

EPA's storm water general permit requires certain storm water pollution prevention and control measures, possible monitoring and reporting, and annual inspections. Among the conditions and requirements of this permit, you must prepare and implement a pollution prevention plan (PPP) that is tailored to your industrial or construction site. Enclosed is a summary guidance document designed to assist you in the development and implementation of your PPP. The summary is organized according to the phases of the pollution prevention planning process. A set of worksheets and an example of a pollution prevention plan are provided for your assistance. As a facility authorized to discharge under this storm water general permit, all terms and conditions must be complied with to maintain coverage and avoid possible penalties.

FACILITY:

Cane Island Power Park
6075 Old Tampa Hwy
Intercession City, FL 33848-
281650, 813200,
SW, 29, 025S 028E

OPERATOR:

Kissimmee Utility Authority
1701 West Carroll St
Kissimmee
FL 34742-3219

Poor Original

To obtain a copy of the general permit terms and conditions to which you are now held accountable, please call the EPA Office of Water Resource Center at (202)260-7786. If you have general questions concerning the storm water program, please call the EPA Region 04 contact: Roosevelt Childress, (404)347-3012 x 2980.

Certification of Compliance



BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

DRAFT LETTER

Director, Office of Coal and Electricity
Department of Energy
Office of Fuels Programs
Forrestall Building, Room 3H-087
1000 Independence Avenue, S.W.
Washington, D.C. 20586

Subject: Self-Certification Under the
Fuel Use Act

Attention: Director of the Office of Coal and Electricity

Gentlemen:

Pursuant to Section 201(d) of the Powerplant and Industrial Fuel Use Act of 1978, as amended, 42 U.S.C. 8311(d), the Kissimmee Utility Authority hereby submits its Certification of Compliance attesting to the coal capability of the proposed new Cane Island electric powerplant project to be located in Osceola County, Florida. The Cane Island Project will consist of a 40 MW (nominal) simple cycle combustion turbine unit and a 120 MW (nominal) combined cycle combustion turbine unit that will be constructed, owned, and operated by the Kissimmee Utility Authority in partnership with the Florida Municipal Power Agency. Further information can be obtained from the Kissimmee Utility Authority at 1701 West Carroll Street, P.O. Box 423219, Kissimmee, Florida, 34742-3219.

Very truly yours,

Kissimmee Utility Authority

James C. Welsh
President and General Manager

Enclosure
cc: John C. L'Engle, FMFA

IN THE MATTER OF:)
KISSIMMEE UTILITY AUTHORITY)

I, James C. Welsh, do hereby certify that I am President and General Manager of the Kissimmee Utility Authority, a municipal electric utility operating under the laws of the State of Florida. The Kissimmee Utility Authority, in partnership with the Florida Municipal Power Agency, is planning to construct, own, and operate the proposed new Cane Island electric powerplant which consists of a simple cycle combustion turbine unit and a combined cycle combustion turbine unit. The Cane Island Project will be located on land owned by the Kissimmee Utility Authority in Osceola County, Florida.

I do hereby further certify that, pursuant to Section 201(d) of the Powerplant and Industrial Fuel Use Act of 1978, as amended 42 U.S.C. 8311(d), the Cane Island Project as planned:

- (1) has sufficient inherent design characteristics to permit the addition of equipment (including all necessary pollution control devices) necessary to render it capable of using gasified coal or another alternate fuel as its primary energy source; and
- (2) is not physically, structurally, or technologically precluded from using gasified coal or another alternate fuel as its primary energy source.

A description of the Cane Island Project is attached to this Certification as Exhibit A.

IN WITNESS WHEREOF, I have hereupon set my hand this ____ day of December 1992.

James C. Welsh
President and General Manager
Kissimmee Utility Authority
1701 West Carroll Street
P. O. Box 423219
Kissimmee, FL 34742-3219

SWORN AND SUBSCRIBED to me this
____ day of December 1992.

Notary of Public

My Commission Expires:

(SEAL)

EXHIBIT A
CANE ISLAND PROJECT DESCRIPTION

The proposed new Cane Island Project (Project) to be built, owned and operated by the Kissimmee Utility Authority in partnership with the Florida Municipal Power Agency, will be a simple and combined cycle combustion turbine power plant. The Project will be located on an approximately 1,000 acre site owned by the Kissimmee Utility Authority near Intercession City, in Osceola County, Florida.

Phase 1 of the Project will consist of a 40 megawatt General Electric LM6000 combustion turbine operated in simple cycle (Unit 1), and a 120 megawatt combined cycle combustion turbine unit (manufacturer unknown at this date) operated with a heat recovery steam generator (Unit 2). The simple cycle unit will be capable of modification in the future to combined cycle operation.

The initial fuel supply for the Project will be natural gas. Number 2 fuel oil will be used as a back-up fuel supply. Net electricity will be supplied to the Kissimmee Utility Authority and Florida Municipal Power Agency systems. Both units could be converted to burn low Btu gas from a coal gasification facility.

Unit 1 is scheduled for commercial operation in March 1994. Unit 2 is scheduled for commercial operation in January 1995. Additional units may be added to the project as demand requires.



10.2 Federal Permit Applications or Approvals

10.2.1 NPDES Permit Applications

Construction of Unit 3 will require an NPDES General Permit for storm water discharges associated with construction activities. This permit is issued by the EPA. The Notice of Intent (NOI) for Storm Water Discharges Associated with Industrial Activity Under the NPDES General Permit will be completed and submitted at least 2 days prior to construction. A Storm Water Pollution Prevention Plan will also be prepared and implemented at the construction site. A copy of the construction NOI is included herein.

Operation of Unit 3 will require modification of existing NPDES General Permit FLR00B641 to incorporate Unit 3 facilities. However, the EPA has terminated the current General Permit program, and will begin issuing a modified Storm Water Multi-Sector General Permit in the near future, prior to Unit 3 operation. Coverage under FLR00B641 has been extended until the new Multi-Sector Permit is available. A Multi-Sector NOI will be submitted for the current operation (Units 1 and 2) when that permit becomes available, and revised when Unit 3 begins operation. The Multi-Sector NOI will be completed and submitted at least 2 days prior to operation. The existing Storm Water Pollution Prevention Plan prepared for Units 1 and 2 will be revised in accordance with the new Multi-Sector requirements to incorporate Unit 3 facilities. A copy of the operational Multi-Sector NOI application is included herein. A copy of the existing Storm Water Pollution Prevention Plan is available from KUA.

10.2.2 Environmental Resource Permit Application

The US Army Corps of Engineers and the US Fish and Wildlife Service will review the potential environmental impacts of the Cane Island-Intercession City Transmission Line. An Environmental Resource Permit application has been prepared to assist in this review, and is included in Section 10.4.

10.2.3 PSD Permit Application

The US EPA will review the PSD application in coordination with the Florida Department of Environmental Protection. This application is included under separate cover as Appendix 10.7.



10.2.4 Certification of Compliance Statement

The Power Plant and Industrial Fuel Use Act requires KUA to certify that, with the installation of additional equipment, Unit 3 would be capable of firing coal (including gasified coal) or another alternate fuel as the primary energy source. A copy of the Certification of Compliance documents to be submitted for Unit 3 prior to construction are included herein.

**National Pollutant Discharge Elimination System
Permit Application**

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.

NPDES
FORMUnited States Environmental Protection Agency
Washington, DC 20460Notice of Intent (NOI) for Storm Water Discharges Associated with Industrial
Activity Under a NPDES General Permit

Submission of this Notice of Intent constitutes notice that the party identified in Section II of this form intends to be authorized by a NPDES permit issued for storm water discharges associated with industrial activity in the State identified in Section III of this form. Becoming a permittee obligates such discharger to comply with the terms and conditions of the permit. ALL NECESSARY INFORMATION MUST BE PROVIDED ON THIS FORM.

I. Permit Selection: You must indicate the NPDES Storm Water general permit under which you are applying for coverage. Check one of these.

Baseline
Industrial☐Baseline
Construction☒Multi-Sector
(Group Permit)☐

II. Facility Operator Information

Name: K i s s i m m e e U t i l i t y A u t h o r i t y Phone: 4 0 7 9 3 3 7 7 7 7

Address: 1 7 0 1 W e s t C a r r o l l S t r e e t Status of Owner/Operator: M

City: K i s s i m m e e State: F L ZIP Code: 3 4 7 4 2 - 3 2 1 9

III. Facility/Site Location Information

Name: C a n e I s l a n d P o w e r P l a n t Is the facility located on Indian Lands? (Y or N) N

Address: 6 0 7 5 O l d T a m p a H i g h w a y

City: I n t e r c e s s i o n C i t y State: F L ZIP Code: 3 3 8 4 8 -

Latitude: 2 8 1 6 5 0 Longitude: 8 1 3 2 0 0 Quarter: S W Section: 2 9 Township: 2 5 S Range: 2 8 E

IV. Site Activity Information

MS4 Operator Name:

Receiving Water Body: R e e d y C r e e k S w a m p

If you are filing as a co-permittee,
enter storm water general permit number:SIC or Designated
Activity Code:

Primary:

4 9 1 1

2nd:

Is the facility required to submit monitoring data? (1, 2, 3, or 4)

1

If You Have Another Existing NPDES
Permit, Enter Permit Number:

F L R 0 0 3 6 4 1

Multi-Sector Permit Applicants Only:

Based on the instructions provided in Addendum H of the Multi-Sector permit, are species identified in Addendum H in proximity to the storm water discharges to be covered under this permit, or the areas of BMP construction to control those storm water discharges? (Y or N)

☐

Will construction (land disturbing activities) be conducted for storm water controls? (Y or N)

☐

Is applicant subject to and in compliance with a written historic preservation agreement? (Y or N)

☐

V. Additional Information Required for Construction Activities Only

Project Start Date:

Completion Date:

0 9 0 1 9 9

0 6 3 0 0 1

Estimated Area to be
Disturbed (in Acres):

0 0 0 0 0 8

Is the Storm Water Pollution Prevention Plan in compliance with State and/or Local sediment and erosion plans? (Y or N)

☒

VI. Certification:

The certification statement in Box 1 applies to all applicants.

The certification statement in Box 2 applies only to facilities applying for the Multi-Sector storm water general permit.

BOX 1

ALL APPLICANTS:

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

BOX 2

MULTI-SECTOR STORM WATER GENERAL PERMIT APPLICANTS ONLY:

I certify under penalty of law that I have read and understand the Part I.B. eligibility requirements for coverage under the Multi-Sector storm water general permit, including those requirements relating to the protection of species identified in Addendum H.

To the best of my knowledge, the discharges covered under this permit, and construction of BMPs to control storm water run-off, are not likely to and will not likely adversely affect any species identified in Addendum H of the Multi-Sector storm water general permit or are otherwise eligible for coverage due to previous authorization under the Endangered Species Act.

To the best of my knowledge, I further certify that such discharges, and construction of BMPs to control storm water run-off, do not have an effect on properties listed or eligible for listing on the National Register of Historic Places under the National Historic Preservation Act, or are otherwise eligible for coverage due to a previous agreement under the National Historic Preservation Act.

I understand that continued coverage under the Multi-Sector general permit is contingent upon maintaining eligibility as provided for in Part I.B.

Print Name: J a m e s C W e l s h

Date:

Signature:

NPDES
FORM



United States Environmental Protection Agency
Washington, DC 20460

Notice of Intent (NOI) for Storm Water Discharges Associated with Industrial
Activity Under a NPDES General Permit

Submission of this Notice of Intent constitutes notice that the party identified in Section II of this form intends to be authorized by a NPDES permit issued for storm water discharges associated with industrial activity in the State identified in Section III of this form. Becoming a permittee obligates such discharger to comply with the terms and conditions of the permit. ALL NECESSARY INFORMATION MUST BE PROVIDED ON THIS FORM.

I. Permit Selection: You must indicate the NPDES Storm Water general permit under which you are applying for coverage. Check one of these.

Baseline
Industrial

☐

Baseline
Construction

☐

Multi-Sector
(Group Permit)

☒

II. Facility Operator Information

Name: K i s s i m m e e U t i l i t y A u t h o r i t y Phone: 4 0 7 9 3 3 7 7 7 7

Address: 1 7 0 1 W e s t C a r r o l l S t r e e t Status of
Owner/Operator: M

City: K i s s i m m e e State: F L ZIP Code: 3 4 7 4 2 - 3 2 1 9

III. Facility/Site Location Information

Name: C a n e I s l a n d P o w e r P l a n t Is the facility located on
Indian Lands? (Y or N) N

Address: 6 0 7 5 0 1 d T a m p a H i g h w a y

City: I n t e r c e s s i o n C i t y State: F L ZIP Code: 3 3 8 4 8

Latitude: 2 8 1 6 5 0 Longitude: 8 1 3 2 0 0 Quarter: S W Section: 2 9 Township: 2 5 S Range: 2 8 E

IV. Site Activity Information

MS4 Operator Name: _____

Receiving Water Body: R e e d y C r e e k S w a m p

If you are filing as a co-permittee,
enter storm water general permit number: _____

SIC or Designated
Activity Code: Primary: 4 9 1 1 2nd: _____

Is the facility required to submit monitoring data? (1, 2, 3, or 4) 1

If You Have Another Existing NPDES
Permit, Enter Permit Number: F L R 0 0 3 6 4 1

Multi-Sector Permit Applicants Only:

Based on the instructions provided in Addendum H of the
Multi-Sector permit, are species identified in Addendum H
in proximity to the storm water discharges to be covered
under this permit, or the areas of BMP construction to
control those storm water discharges? (Y or N) N

Will construction (land disturbing activities) be conducted
for storm water controls? (Y or N) Y

Is applicant subject to and in compliance with a written
historic preservation agreement? (Y or N) N

V. Additional Information Required for Construction Activities Only

Project Start Date: _____ Completion Date: _____

Estimated Area to be
Disturbed (in Acres): _____

Is the Storm Water Pollution Prevention Plan
in compliance with State and/or Local
sediment and erosion plans? (Y or N)

VI. Certification: The certification statement in Box 1 applies to all applicants.
The certification statement in Box 2 applies only to facilities applying for the Multi-Sector storm water general permit.

BOX 1

ALL APPLICANTS:

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

BOX 2

MULTI-SECTOR STORM WATER GENERAL PERMIT APPLICANTS ONLY:

I certify under penalty of law that I have read and understand the Part I.B. eligibility requirements for coverage under the Multi-Sector storm water general permit, including those requirements relating to the protection of species identified in Addendum H.

To the best of my knowledge, the discharges covered under this permit, and construction of BMPs to control storm water run-off, are not likely to and will not likely adversely affect any species identified in Addendum H of the Multi-Sector storm water general permit or are otherwise eligible for coverage due to previous authorization under the Endangered Species Act.

To the best of my knowledge, I further certify that such discharges, and construction of BMPs to control storm water run-off, do not have an effect on properties listed or eligible for listing on the National Register of Historic Places under the National Historic Preservation Act, or are otherwise eligible for coverage due to a previous agreement under the National Historic Preservation Act.

I understand that continued coverage under the Multi-Sector general permit is contingent upon maintaining eligibility as provided for in Part I.B.

Print Name: J a m e s C W e l s h

Date: _____

Signature: _____

Certification of Compliance Statement

DRAFT LETTER

Date 1999

Director, Office of Coal and Electricity
US Department of Energy
Office of Fuels Programs
Forrestall Building, Room 3H-087
1000 Independence Avenue, S.W.
Washington, D.C. 20586

Subject: Self-Certification Under the Fuel Use Act

Attn: Director of the Office of Coal and Electricity

Gentlemen:

Pursuant to Section 201(d) of the Powerplant and Industrial Fuel Use Act of 1978, as amended (42 USC 8311(d)), the Kissimmee Utility Authority (KUA) hereby submits the attached Certification of Compliance attesting to the coal capability of the proposed Unit 3 at the Cane Island Power Park in Osceola County, Florida. Unit 3 will be a nominal 250 megawatt combined cycle combustion turbine unit constructed and owned in partnership with the Florida Municipal Power Agency, and operated by KUA. Additional information on the project can be obtained from KUA at 1701 West Carroll Street, Kissimmee, Florida, 34741.

Very truly yours,
Kissimmee Utility Authority

James C. Welsh
President and General Manager

Enclosure
cc: John C. L'Engle, FMPPA

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FUELS PROGRAMS

IN THE MATTER OF:
KISSIMMEE UTILITY AUTHORITY

COAL CAPABILITY OF NEW ELECTRIC POWERPLANT
CERTIFICATION OF COMPLIANCE
PURSUANT TO THE POWERPLANT AND INDUSTRIAL FUEL USE ACT, AS AMENDED

I, James C. Welsh, do hereby certify that I am President and General Manager of the Kissimmee Utility Authority, a municipal electric utility operating under the laws of the State of Florida. The Kissimmee Utility Authority, in partnership with the Florida Municipal Power Agency, is planning to construct, own, and operate the proposed new Unit 3 at the existing Cane Island Power Park, property owned by the Kissimmee Utility Authority, in Osceola County, Florida. Unit 3 will be a nominal 250 megawatt combined cycle combustion turbine unit. Units 1 and 2 were certified in 1992, and have been in operation since 1995.

I do hereby further certify that, pursuant to Section 201(d) of the Powerplant and Industrial Fuel Use Act of 1978, as amended (42 USC 8311(d)), Unit 3 as planned:

- (1) has sufficient inherent design characteristics to permit the addition of equipment (including all necessary pollution control devices) necessary to render it capable of using gasified coal or another alternate fuel as its primary energy source; and,
- (2) is not physically, structurally, or technologically precluded from using gasified coal or another alternate fuel as its primary energy source.

A description of Unit 3 is attached to this Certification as Exhibit A.

IN WITNESS WHEREOF, I have hereupon set my hand this ____ day of ____ 1999.

James C. Welsh
President and General Manager
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

SWORN AND SUBSCRIBED to me this ____ day of ___, 1999.

Notary of Public

My Commission Expires:

(Seal)

EXHIBIT A
CANE ISLAND POWER PARK UNIT 3 DESCRIPTION

The proposed Cane Island Power Park Unit 3 (Unit 3) will be constructed, owned, and operated by the Kissimmee Utility Authority in partnership with the Florida Municipal Power Agency. Unit 3 will be a nominal 250 megawatt combined cycle combustion turbine unit operated as a baseload facility. The Cane Island Power Park site, located near Intercession City, in Osceola County, Florida, is owned by the Kissimmee Utility Authority.

The Unit 3 combustion turbine generator will be rated at approximately 150 megawatts; the steam turbine generator will be rated at approximately 100 megawatts. The primary fuel will be natural gas, No.2 fuel oil will be stored onsite as backup fuel. Unit 3 will be installed with modern pollution control devices to meet environmental quality standards. Unit 3 could be converted to burn low Btu gas from a coal gasification facility.

Unit 3 is scheduled for commercial operation in June 2001. The net electricity generated will be supplied to the Kissimmee Utility Authority and the Florida Municipal Power Agency systems.



10.3 Existing State Permits

10.3.1 Prevention of Significant Deterioration

Units 1 and 2 operate under the FDEP issued Authority to Construct Permit AC49-205703/PSD Permit PSD-FL-182 until such time a Title V operating permit is issued. A copy of the current ATC/PSD permit is included herein.

10.3.2 Surface Water Management Permit

Surface Water Management Permit 49-00672-S was issued by the South Florida Water Management District to KUA for development of the Power Park grading/drainage and storm water control plans associated with Units 1 and 2. A copy of this permit is included herein.

10.3.3 Water Use Permit

Water Use Permit 49-00671-W was issued by the South Florida Water Management District to KUA for the withdrawal and use of deep aquifer ground water required for Units 1 and 2 operation. A copy of this permit is included herein.

10.3.4 Industrial Wastewater Treatment System Permit

The industrial wastewater treatment and disposal system associated with Units 1 and 2 was constructed under FDEP issued Permit IC49-212248. Operating Permit FLA010961 was subsequently issued to KUA for operation of the system. A copy of the operating permit is included herein.

10.3.5 Public Drinking Water System Permit

The FDEP issued KUA Permit 3494409 to operate the drinking water system associated with the development currently at the Power Park. A copy of this permit is available from KUA.

10.3.6 Gopher Tortoise "Take" Permit

KUA was issued Permit OSC-6 authorizing the "taking" of gopher tortoises and their burrows associated with development of the Power Park. The permit is still valid. A copy of this permit is included herein.

Prevention of Significant Deterioration Permit



Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

PERMITTEE:

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Permit Number: AC 49-205703

PSD-FL-182

Expiration Date: Dec. 30, 1994

County: Osceola

Latitude/Longitude: 28°16'40"N
81°30'42"W

Project: A 120 MW Combined
Cycle Turbine and a 40 MW Simple
Cycle Turbine

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Kissimmee Utility Authority proposes to operate a 40 MW simple cycle combustion turbine (SCCT) and a 120 MW combined cycle combustion turbine (CCCT) consisting of one combustion turbine, one steam turbine, one heat recovery steam generator and ancillary equipment. This facility is located near Intercession City, Osceola County, Florida. The UTM coordinates are Zone 17, 447.722 km East and 3127.685 km North.

The sources shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Kissimmee Utility Authority (KUA) applications received on November 15, 1991, and June 2, 1992.
2. Department's letter dated June 30, 1992.
3. KUA's letter received on July 30, 1992.
4. KUA's letters received on August 17 and October 8, 1992.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

- a. Have access to and copy any records that must be kept under the conditions of the permit;
- b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and
- c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

- a. a description of and cause of non-compliance; and
- b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

GENERAL CONDITIONS:

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

- (x) Determination of Best Available Control Technology (BACT)
- (x) Determination of Prevention of Significant Deterioration (PSD)
- (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

- a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
- b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
- c. Records of monitoring information shall include:
 - the date, exact place, and time of sampling or measurements;

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

GENERAL CONDITIONS:

- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

Emission Limits

1. The maximum allowable emissions from this source shall not exceed the emission rates listed in Tables 1 and 2.

2. Visible emissions during startup, shutdown, or period of part load operation shall not exceed 20% opacity during any 6-minute period. At full load operation, visible emissions shall not exceed 10% opacity.

Operating Rates

3. This source is allowed to operate continuously (8760 hours per year).

4. This source is allowed to use natural gas as the primary fuel and low sulfur No. 2 distillate oil as the secondary fuel up to 1,000 hours per year. Distillate fuel oil No. 2 (0.05% S) shall not be burned if natural gas is available.

5. The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:

40 MW Simple Cycle Turbine

- a) The maximum heat input of 371 MMBtu/hr (LHV) at ISO conditions (base load) for distillate fuel oil No. 2.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

SPECIFIC CONDITIONS:

- b) The maximum heat input of 367 MMBtu/hr (LHV) at ISO conditions (base load) for natural gas.

120 MW Combined Cycle Turbine

- a) The maximum heat input of 928 MMBtu/hr (LHV) at ISO conditions (base load) for distillate fuel oil No. 2.
- b) The maximum heat input of 869 MMBtu/hr (LHV) at ISO conditions (base load) for natural gas.

6. Any change in the method of operation, equipment or operating hours shall be submitted to DER's Bureau of Air Regulation.

7. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility may be included in the operating permit.

Compliance Determination

8. Compliance with the NO_x, SO₂, CO, PM, PM₁₀, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1991 version) and adopted by reference in F.A.C. Rule 17-2.700.

- Method 1 Sample and Velocity Traverses
- Method 2 Volumetric Flow Rate
- Method 3 Gas Analysis
- Method 5 Determination of Particulate Emissions from
or Stationary Sources
- Method 17
- Method 9 Visual Determination of the Opacity of Emissions
from Stationary Sources
- Method 8 Determination of Sulfuric Acid Mist from Stationary
Sources
- Method 10 Determination of Carbon Monoxide Emission from
Stationary Sources
- Method 20 Determination of Nitrogen Oxides, Sulfur Dioxide,
and Diluent Emissions from Stationary Gas Turbines
- Method 25A Determination of Total Gaseous Organic
Concentrations Using a Flame Ionization Analyzer

Other DER approved methods may be used for compliance testing after prior Departmental approval.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

SPECIFIC CONDITIONS:

9. Method 5 or Method 17 must be performed on each unit to determine the initial compliance status of particulate matter emissions of the unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

10. Compliance with the SO₂ emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuel.

11. Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

12. Mercury (Hg) shall be tested during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

13. During performance tests, to determine compliance with the proposed NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_x \text{ obs}) \left(\frac{P_{\text{ref}}}{P_{\text{obs}}} \right)^{0.5} e^{19 (H_{\text{obs}} - 0.00633)} \left(\frac{288^\circ K}{T_{\text{AMB}}} \right)^{1.53}$$

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

NO_x obs = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

SPECIFIC CONDITIONS:

14. Test results will be the average of 3 valid runs. The Central District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources shall operate between 95% and 100% of permitted capacity during the compliance test(s) as adjusted for ambient temperature. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

15. The permittee shall leave sufficient space for the combined cycle (CT) suitable for future installation of SCR equipment should the facility be unable to meet the NO_x standards, if required.

16. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in each stack to measure and record the nitrogen oxides emissions from each source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992).

17. A continuous monitoring system shall be installed to monitor and record the fuel consumption on each unit. While water injection is being utilized for NO_x control, the water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

18. Literature on equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NO_x emissions and water injection and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Central District office and the Bureau of Air Regulation.

19. Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be determined as specified in 40 CFR 60.334(b). The records of fuel oil usage shall be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight.

Rule Requirements

20. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-2 and 17-4, Florida Administrative Code and 40 CFR (July, 1991 version).

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

SPECIFIC CONDITIONS:

21. The sources shall comply with all requirements of 40 CFR 60, Subpart GG, and F.A.C. Rule 17-2.660(2)(a), Standards of Performance for Stationary Gas Turbines.

22. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-2.210(1)).

23. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-2.240: Circumvention; 17-2.250: Excess Emissions; 17-2.660: Standards of Performance for New Stationary Sources (NSPS); 17-2.700: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

24. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2)).

25. Quarterly excess emission reports, in accordance with the July 1, 1992 version of 40 CFR 60.7 and 60.334 shall be submitted to DER's Central District office.

26. Fugitive dust emissions, during the construction period, shall be minimized by covering or watering dust generation areas.

27. Pursuant to F.A.C. Rule 17-2.210(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur, nitrogen contents and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Central District office by March 1 of each calendar year.

28. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

29. An application for an operation permit must be submitted to the Central District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: December 30, 1994

SPECIFIC CONDITIONS:

operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this _____ day
of _____, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner
Secretary



Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

May 19, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. A. K. Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Re: Permit Modification AC49-205703 (PSD-FL-182)
DEP File Number: 0970043-004
Extension of NO_x Compliance Date on Simple Cycle Turbine at Cane Island Facility

Dear Mr. Sharma:

The Department has reviewed the request concerning the extension of the NO_x compliance date for Kissimmee Utility Authority's simple cycle gas turbine. This turbine is located at KUA's Cane Island facility near Intercession City in Osceola County. This request is acceptable and the permit is hereby modified as follows:

Specific Condition No. 15 b

FROM:

For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

TO:

The simple cycle unit (LM6000), shall achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/99.

Table 1, Note B

FROM:

The NO_x maximum emission limit will be lowered to 15 ppm by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

TO:

The simple cycle unit (LM6000), shall achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/99.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,



Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/ch/hh

Enclosures

273675
182

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT MODIFICATION

In the Matter of an
Application for Permit Modification

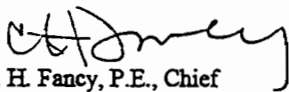
Mr. A. K. Sharma
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

DEF File No. 0970043-003C
AC49-205703, PSD-FL-182
Cane Island Facility
Osceola County

Enclosed is a letter that modifies Permit Number AC49-205703 (PSD-FL-182). The modification makes the following changes: 1) compliance with the nitrogen oxide emission limit will be demonstrated by using nitrogen oxide emission data collected during the annual Relative Accuracy Test Audit (RATA) testing; 2) removes the requirement for annual testing for particulate matter, sulfuric acid mist and VOC; 3) specifies that measured NO_x emissions shall not be ISO corrected for comparison with the BACT standard; 4) excess emissions will be reported semiannually using data collected by the continuous emissions monitors and 5) monitoring of water to fuel and fuel-bound nitrogen will be waived as long as KUA follows excess emissions reporting procedures which are at least as stringent or are more stringent than the New Source Performance Standards (NSPS). This permit modification is issued pursuant to Section 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 (fourteen) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.


C. H. Fancy, P.E., Chief
Bureau of Air Regulation

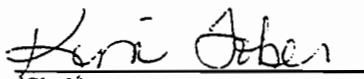
CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT MODIFICATION (including the FINAL permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8-15-97 to the person(s) listed:

Mr. A. K. Sharma, Kissimmee Utility Authority *
Mr. Jerome Guidry, P.E., Perigee
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, CD

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.


(Clerk)

8-15-97
(Date)

FINAL DETERMINATION

Kissimmee Utility Authority

Amendment of Permit No. AC-0970043-003, PSD-FL-182
Cane Island Facility

An Intent to Issue an air construction permit amendment for Kissimmee Utility Authority's (KUA) Cane Island Facility located near Intercession City, Osceola County was distributed on September 30, 1996. The Notice of Intent was published in the Orlando Sentinel on October 6, 1996. Comments were submitted by KUA in response to the public notice. KUA requested that annual compliance with the NO_x standard be demonstrated using data collected as part of the annual Relative Accuracy Test Audit (RATA) testing instead of using data recorded by the continuous emissions monitors. The department concludes this proposed procedure meets the intended NO_x compliance testing requirement. In addition, KUA requested that excess emissions be reported semiannually instead of quarterly using data collected by the continuous emissions monitors. KUA also requested that monitoring of water to fuel and fuel-bound nitrogen be waived since they will report excess emissions using the data collected by the continuous monitoring system. This procedure is more stringent than the applicable New Source Performance Standards (NSPS) requirement.

The final action of the Department will be to issue the permit amendment as proposed.



Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

August 12, 1997

CERTIFIED MAIL--RETURN RECEIPT REQUESTED

Mr. A. K. Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Dear Mr. Sharma:

Re: Permit Modification AC49-205703 (PSD-FL-182)
DEP File Number: 0970043-003
Modification of Compliance Testing Methods

The Department hereby modifies the following Specific Conditions related to compliance testing.

Specific Condition 8:

Initial Compliance with the NO_x, SO₂, sulfuric acid mist, CO, PM, PM₁₀, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter for SO₂, NO_x, and CO only, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1991 version) and adopted by reference in ~~F.A.C. Rule 17-2.700~~ Rule 62-297.401, F.A.C.

- | | |
|------------|---|
| Method 1 | Sample and Velocity Traverses |
| Method 2 | Volumetric Flow Rate |
| Method 3 | Gas Analysis |
| Method 5 | Determination of Particulate Emissions from Stationary Sources |
| or | |
| Method 17 | |
| Method 9 | Visual Determination of the Opacity of Emissions from Stationary Sources |
| Method 8 | Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources (for fuel oil firing only) |
| Method 10 | Determination of Carbon Monoxide Emissions from Stationary Sources |
| Method 20 | Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines |
| Method 25A | Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer |

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Other DEPR approved methods may be used for compliance testing after prior Departmental approval.

Annual compliance with the NO_x standard may be determined by using data collected as part of the annual Relative Accuracy Test Audit (RATA) testing as described in 40 CFR 60, Appendix B, Performance Specification 2, Section 7.1.2, instead of performing Methods 7E and 20 as separate tests. EPA Method 10 will be conducted simultaneously with the NO_x/O₂ RATA tests. The 20-30 minute tests conducted for the RATA testing will be strung together in a manner that fulfills additional requirements of EPA Methods 10 and 20 as to test run time (3 one hour runs) and O₂ stratification investigation. The collected data will be bias corrected to comply with the RATA test requirements, but will not be bias corrected for compliance with NSPS so as to meet the requirements of methods 10 and 20 (the NSPS test methods). No less than eight test points will be used for the RATA testing which will comply with both the RATA test requirements and the NSPS test requirements. The NO_x span for methods 20 and 7E should not exceed 50 ppm instead of a span of 300 ppm as required by Subpart GG. Mass emissions of NO_x and CO shall be determined pursuant to the procedures in 40 CFR 60, Appendix A, Method 19 or 40 CFR 75, Appendix F.

Specific Condition 10:

Compliance with the SO₂ and sulfuric acid mist emission limits can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuel.

Specific Condition 13:

During performance tests, to determine compliance with the allowable NSPS NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\text{ obs}}) \left(\frac{P_{\text{ref}}}{P_{\text{obs}}} \right)^{0.5} e^{19(H_{\text{obs}} - 0.00633)} \left(\frac{288^\circ K}{T_{\text{amb}}} \right)^{1.53}$$

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

NO_{x obs} = Measured NO_x emission at 15 percent oxygen, ppmvd.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{amb} = Temperature of ambient air at test ($^{\circ}K$).

Note: Measured NO_x emissions will not be ISO corrected for comparison with the BACT standard.

Specific Condition 14:

Test results will be the average of 3 valid runs, each to be of at least one hour in duration to comply with EPA Method 10. Each 60-minute test may be divided into segments that conform with RATA test run times (20-30 minutes: see Specific Condition 8). The Central District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources shall operate between 95% and 100% of permitted capacity during the compliance test(s) as adjusted for ambient temperature. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

Specific Condition 16:

The permittee shall comply with the following requirements:

- (a) Install, calibrate, maintain, and operate a continuous emission monitor in each stack to measure and record the nitrogen oxides emissions from each source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992);
- (b) A continuous monitoring system shall be installed to monitor and record the fuel consumption on each unit. ~~While water injection is being utilized for NO_x control, the water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored.~~ The system shall meet the requirements of 40 CFR Part 60.334, Subpart GG; except that the monitoring of water to fuel ratio and fuel bound nitrogen is waived as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:
 1. Each NO_x CEMs must be capable of calculating NO_x emissions concentrations corrected to 15% O_2 and ISO conditions.
 2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
 3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition (b)1. KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition (b)2. KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NO_x emissions (i.e., when firing natural gas, dry low NO_x burners are used).

- (c) In addition, literature on equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between ambient temperature and heat inputs to the CT shall be submitted to DEPR's Central District office and the Bureau of Air Regulation.

Specific Condition 23

Semi-annual Quarterly excess emission reports, in accordance with the July 1, 1992 version of 40 CFR 60.7 and 60.334 shall be submitted to DEPR's Central District office. Excess emissions for NO_x shall be reported using data collected by the continuous emissions monitors. Since CEM data will be used for the reporting of excess emissions for NO_x the monitoring of water/fuel ratio and fuel-bound nitrogen required by 40 CFR 60. Subpart GG is waived.

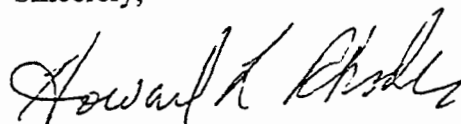
References to ISO conditions in footnote C) in Tables 1 and 2:

Emission rates are based on 100% load and at ISO conditions.

The department did not change the annual test requirement for SO₂ emissions in Specific Condition 8 because compliance with the SO₂ emission limit can also be determined by fuel analysis as stated in Specific Condition 10.

A copy of this letter shall be attached to the reference air construction permit and shall become a part of that permit.

Sincerely,



Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/ch

Enclosure



Department of Environmental Protection

POWER SUPPLY DEPT.

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

January 2, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. A. K. Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Re: DRAFT Permit Amendment No. 0970043-004AC (PSD-FL-182)]
Option to Burn Very Low Sulfur Fuel Oil at Cane Island Facility

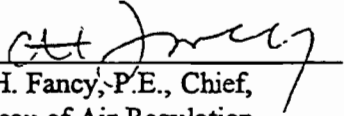
Dear Mr. Sharma:

Enclosed is one copy of the Draft Air Construction Permit Amendment for the option to burn very low sulfur fuel oil for up to 800 hours per year in the combustion turbines referenced in this permit. The turbines are located at the Cane Island facility near Intercession City, Osceola County. The Department's Intent to Issue Air Construction Permit Amendment and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit amendment.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Cleve Holladay or Mr. Linero at 904/488-1344.

Sincerely,


C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/ch

Enclosures

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

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IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF
IMAGES, PLEASE NOTE THAT THE ORIGINAL
DOCUMENTS WERE OF POOR QUALITY.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DRAFT Permit Amendment No.: 0970043-004-AC, PSD-FL-182
Low Sulfur Fuel Oil Usage at Cane Island Facility
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit amendment to Kissimmee Utility Authority, to allow additional use of very low (0.05%) sulfur distillate No.2 fuel oil in the combustion turbines located at its Cane Island Facility near Intercession City, Osceola County. A Best Available Control Technology (BACT) determination was not required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD). The amendment will result in small actual increases: nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), and particulate matter (PM/PM₁₀). These increases are less than the applicable PSD significant emission rates; therefore, PSD requirements do not apply. The amendment will not result in an increase in any allowable emissions from the facility, and will not cause a violation of any state or federal ambient air quality standards or increments. The applicant's name and address are: Kissimmee Utility Authority, (KUA), 1701 West Carroll Street, Kissimmee, Florida 34741.

Both units burn natural gas, an inherently clean fuel, and very low sulfur fuel oil when gas is not available. This amendment will allow the use of very low sulfur fuel oil for up to 800 hours even when natural gas is available. Fuel oil with a sulfur content this low is also clean. The option to burn fuel oil will give KUA greater flexibility in fuel use during the winter heating season.

The Department will issue the FINAL Permit Amendment, in accordance with the conditions of the DRAFT Permit Amendment unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed DRAFT Permit Amendment issuance action for a period of 14 (fourteen) days from the date of publication of this Notice. Any written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Amendment, the Department shall issue a Revised DRAFT Permit Amendment and require, if applicable, another Public Notice.

The Department will issue FINAL Permit Amendment with the conditions of the DRAFT Permit Amendment unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. or a party requests mediation as an alternative remedy under Section 120.573 before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9370, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the

petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed permitting decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information: (a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any; (b) A statement of the preliminary agency action; (c) A statement of the relief sought; and (d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following: (a) The names, addresses, and telephone numbers of any persons who may attend the mediation; (b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time; (c) The agreed allocation of the costs and fees associated with the mediation; (d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation; (e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen; (f) The name of each party's representative who shall have authority to settle or recommend settlement; and (g) The signatures of all parties or their authorized representatives.

As provided in Section 120.573 F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57 F.S. for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57 F.S. remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 904/488-1344
Fax: 904/922-6979

Department of Environmental Protection
Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407-894-7555
Fax: 407-897-2966

The complete project file includes the Draft Permit Amendment, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-1344, for additional information.

In the Matter of an
Application for Permit Amendment by:

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741/

DRAFT Permit Amendment No.:0970043-004-AC
[PSD-FL-182]
Cane Island Facility
Osceola

INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit amendment (copy of DRAFT Permit amendment attached) for the proposed project, as detailed in the application specified above, for the reasons stated below.

The applicant, Kissimmee Utility Authority, applied on December 12, 1996, to the Department for an air construction permit amendment for its Cane Island Facility located Intercession City, Osceola County. The amendment will allow the burning of very low sulfur (0.05%) content fuel oil when natural gas is available for up to 800 hours per year in its 40 MW and 120 MW combustion turbines.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit amendment is required to commence or continue operations at the described facility.

The Department intends to issue this air construction permit amendment based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT". The notice shall be published one time only within 30 (thirty) days in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 904/488-1344; Fax 904/922-6979) within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit amendment pursuant to Rule 62-103.150 (6), F.A.C.

The Department will issue the FINAL Permit Amendment, in accordance with the conditions of the enclosed DRAFT Permit Amendment unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed DRAFT Permit Amendment issuance action for a period of 14 (fourteen) days from the date of publication of "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT." Any written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Amendment, the Department shall issue a Revised DRAFT Permit Amendment and require, if applicable, another Public Notice.

The Department will issue the permit amendment with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., or a party requests mediation as an alternative remedy under Section 120.573 F.S. before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9730, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed permitting decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information: (a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any; (b) A statement of the preliminary agency action; (c) A statement of the relief sought; and (d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following: (a) The names, addresses, and telephone numbers of any persons who may attend the mediation; (b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time; (c) The agreed allocation of the costs

and fees associated with the mediation; (d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation; (e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen; (f) The name of each party's representative who shall have authority to settle or recommend settlement; and (g) The signatures of all parties or their authorized representatives.

As provided in Section 120.573 F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57 F.S. for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57 F.S. remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

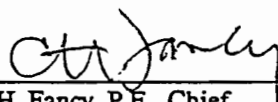
In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.


C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT AMENDMENT (including the PUBLIC NOTICE, and DRAFT permit amendment) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/3/97 to the person(s) listed:

Mr. A. K. Sharma, Kissimmee Utility Authority*
Mr. Jerome Guidry, P.E., Perigee
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, CD

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes
(Clerk)

1/3/97
(Date)

Surface Water Management Permit

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.



South Florida Water Management District
Certification For Stormwater Discharge

Form #0113
 Rev 7/91

SURFACE WATER MANAGEMENT PERMIT NO. 49-00672-S
 (NON-ASSIGNABLE)

DATE ISSUED: APRIL 15, 1993

AUTHORIZING: CONSTRUCTION AND OPERATION OF A SURFACE WATER MANAGEMENT SYSTEM TO SERVE A 1012.7 ACRE INDUSTRIAL PROJECT CONSISTING OF THE FIRST PHASE OF THE COMBUSTION TURBINE GENERATING FACILITY, THE ACCESS ROADWAY, THE NATURAL GAS PIPELINE, THE TRANSMISSION LINES, AND THE CLAY STREET SUBSTATION, DISCHARGING VIA EXISTING WETLANDS AND AN EXISTING DITCH TO THE REEDY CREEK SWAMP OR SHINGLE CREEK.

LOCATED IN: OSCEOLA COUNTY, SECTION 29, 32 TWP. 25S RGE 28, 29E

ISSUED TO: KISSIMMEE UTILITY AUTHORITY
 (CANE ISLAND COMBUSTION TURBINE)
 102 LAKESHORE DRIVE
 KISSIMMEE, FL 34741

This Permit is issued pursuant to Application for Permit No. 920325-3 dated Mar. 27, 1992. Permittee agrees to hold and save the South Florida Water Management District and its successors harmless from any and all damages, claims or liabilities which may arise by reason of the construction, operation, maintenance or use of any work or structure involved in the Permit. Said Application, including all plans and specifications attached thereto, as addressed by the Staff Report, is by reference made a part hereof.

This Permit may be revoked or modified at anytime pursuant to the appropriate provisions of Chapter 373, Florida Statutes.

This Permit does not convey to Permittee any property rights or privileges other than those specified herein, nor relieve the Permittee from complying with any law, regulation or requirement affecting the rights of other bodies or agencies. All structures and works installed by Permittee hereunder shall remain the property of the Permittee.

Within thirty (30) days after the completion of the construction of any work or structure relative to this Permit, the Permittee shall file with the District a written statement of completion on the appropriate form provided by the Board.

SPECIAL CONDITIONS ARE AS FOLLOWS:

SEE SHEETS 2, 3, 4 & 5 OF 7 - 22 SPECIAL CONDITIONS.
 SEE SHEETS 6 & 7 OF 7 - 12 LIMITING CONDITIONS.

FILED WITH THE CLERK OF THE SOUTH
 FLORIDA WATER MANAGEMENT DISTRICT

SOUTH FLORIDA WATER
 MANAGEMENT DISTRICT, BY ITS
 GOVERNING BOARD

ON 4-21-93
 BY [Signature]
 DEPUTY CLERK

By [Signature]
 Assistant Secretary

SPECIAL CONDITIONS

- 1 . MINIMUM BUILDING FLOOR ELEVATION: BASIN: COMBUSTION TURBINE - 81.50 FEET NGVD.
BASIN: SUBSTATION - 72.25 FEET NGVD.
- 2 . MINIMUM ROAD CROWN ELEVATION: BASIN: COMBUSTION TURBINE - 80.75 FEET NGVD.
BASIN: ACCESS ROAD - 71.00 FEET NGVD.
- 3 . DISCHARGE FACILITIES:
BASIN: COMBUSTION TURBINE:
1-10' WIDE BROAD CRESTED WEIR WITH CREST AT ELEV. 76.5' NGVD.
1-.33' DIA. CIRCULAR ORIFICE WITH INVERT AT ELEV. 74' NGVD.
RECEIVING BODY : EXISTING WETLANDS
CONTROL ELEV : 75 FEET NGVD.
BASIN: SUBSTATION:
1-.25' W X 3' H RECTANGULAR NOTCH WITH INVERT AT ELEV. 66' NGVD.
20 LF OF 1.25' DIA. RCP CULVERT.
1-3' W X 3' L DROP INLET WITH CREST AT ELEV. 69' NGVD.
RECEIVING BODY : EXISTING POND
CONTROL ELEV : 66 FEET NGVD.
- 4 . THE PERMITTEE SHALL BE RESPONSIBLE FOR THE CORRECTION OF ANY EROSION, SHOALING OR WATER QUALITY PROBLEMS THAT RESULT FROM THE CONSTRUCTION OR OPERATION OF THE SURFACE WATER MANAGEMENT SYSTEM.
- 5 . MEASURES SHALL BE TAKEN DURING CONSTRUCTION TO INSURE THAT SEDIMENTATION AND/OR TURBIDITY PROBLEMS ARE NOT CREATED IN THE RECEIVING WATER.
- 6 . THE DISTRICT RESERVES THE RIGHT TO REQUIRE THAT ADDITIONAL WATER QUALITY TREATMENT METHODS BE INCORPORATED INTO THE DRAINAGE SYSTEM IF SUCH MEASURES ARE SHOWN TO BE NECESSARY.
- 7 . FACILITIES OTHER THAN THOSE STATED HEREIN SHALL NOT BE CONSTRUCTED WITHOUT AN APPROVED MODIFICATION OF THIS PERMIT.
- 8 . A BENCHMARK SHALL BE PROVIDED IN THE VICINITY OF THE CONTROL STRUCTURE AND A DESCRIPTION PROVIDED TO THE DISTRICT WHEN AVAILABLE.

9. PRIOR TO MAY 15, 1993, THE SOUTH FLORIDA WATER MANAGEMENT DISTRICT SHALL BE NOTIFIED BY THE PERMITTEE OR AUTHORIZED AGENT (VIA THE SUPPLIED CONSTRUCTION COMMENCEMENT NOTICE OR EQUIVALENT) OF THE ACTUAL OR ANTICIPATED CONSTRUCTION START DATE AND THE EXPECTED COMPLETION DATE/DURATION.
10. WHEN THE DURATION OF CONSTRUCTION EXCEEDS ONE YEAR, CONSTRUCTION STATUS REPORTS SHALL BE SUBMITTED TO THE SOUTH FLORIDA WATER MANAGEMENT DISTRICT ON AN ANNUAL BASIS (VIA THE SUPPLIED ANNUAL STATUS REPORT OR EQUIVALENT) BEGINNING ONE YEAR AFTER THE INITIAL COMMENCEMENT OF CONSTRUCTION DATE.
11. WITHIN 30 DAYS AFTER COMPLETION OF CONSTRUCTION OF THE SURFACE WATER MANAGEMENT SYSTEM, THE PERMITTEE OR AUTHORIZED AGENT SHALL NOTIFY THE SOUTH FLORIDA WATER MANAGEMENT DISTRICT OF THAT COMPLETION DATE AND SUBMIT CERTIFICATION BY A FLORIDA REGISTERED PROFESSIONAL ENGINEER THAT ALL FACILITIES HAVE BEEN CONSTRUCTED IN ACCORDANCE WITH THE DESIGN APPROVED BY THE DISTRICT (VIA THE SUPPLIED CONSTRUCTION COMPLETION/CONSTRUCTION CERTIFICATION OR EQUIVALENT). SUCH CERTIFICATION MAY CONSIST OF WORDING IN PARAGRAPH 3.1.7 "CONSTRUCTION COMPLETION CERTIFICATION" OF THE CURRENT BASIS OF REVIEW FOR SURFACE WATER MANAGEMENT PERMIT APPLICATIONS WITHIN THE SOUTH FLORIDA WATER MANAGEMENT DISTRICT. IF THE CERTIFICATION LANGUAGE USED IS DIFFERENT FROM THE SUGGESTED LANGUAGE, A SET OF RECORD DRAWINGS CONSISTING OF ELEVATIONS, LOCATIONS AND DIMENSIONS OF COMPONENTS OF THE SURFACE WATER MANAGEMENT SYSTEM SHALL ALSO BE SUBMITTED.
12. OPERATION OF THE SURFACE WATER MANAGEMENT SYSTEM SHALL BE THE RESPONSIBILITY OF KISSIMMEE UTILITY AUTHORITY.
13. SILT SCREENS, HAY BALES OR OTHER SUCH SEDIMENT CONTROL MEASURES SHALL BE UTILIZED DURING CONSTRUCTION. THE SELECTED SEDIMENT CONTROL MEASURES SHALL BE INSTALLED LANDWARD OF THE UPLAND BUFFER ZONES AROUND ALL PROTECTED WETLANDS. ALL AREAS SHALL BE STABILIZED AND VEGETATED IMMEDIATELY AFTER CONSTRUCTION TO PREVENT EROSION INTO THE WETLANDS AND UPLAND BUFFER ZONES.
14. THE SFWMD RESERVES THE RIGHT TO REQUIRE REMEDIAL MEASURES TO BE TAKEN BY THE PERMITTEE IF WETLAND AND/OR UPLAND MONITORING OR OTHER INFORMATION DEMONSTRATES THAT ADVERSE IMPACTS TO PROTECTED, CONSERVED, INCORPORATED OR MITIGATED WETLANDS OR UPLANDS HAVE OCCURRED DUE TO PROJECT RELATED ACTIVITIES.
15. ANY FUTURE CHANGES IN LAND USE OR TREATMENT OF WETLANDS AND/OR UPLAND BUFFER/COMPENSATION AREAS MAY REQUIRE A SURFACE WATER MANAGEMENT PERMIT MODIFICATION AND ADDITIONAL ENVIRONMENTAL REVIEW BY DISTRICT STAFF. PRIOR TO THE PERMITTEE INSTITUTING ANY FUTURE CHANGES NOT AUTHORIZED BY THIS PERMIT, THE PERMITTEE SHALL NOTIFY THE SFWMD OF SUCH INTENTIONS FOR A DETERMINATION OF ANY NECESSARY PERMIT MODIFICATIONS.

16. THE WETLAND CONSERVATION AREAS AND UPLAND BUFFER ZONES AND/OR UPLAND PRESERVATION AREAS SHOWN ON EXHIBIT(S) 76 MAY IN NO WAY BE ALTERED FROM THEIR NATURAL STATE. ACTIVITIES PROHIBITED WITHIN THE CONSERVATION AREAS INCLUDE, BUT ARE NOT LIMITED TO: CONSTRUCTION OR PLACING OF BUILDINGS ON OR ABOVE THE GROUND; DUMPING OR PLACING SOIL OR OTHER SUBSTANCES SUCH AS TRASH; REMOVAL OR DESTRUCTION OF TREES, SHRUBS, OR OTHER VEGETATION - WITH THE EXCEPTION OF EXOTIC/NUISANCE VEGETATION REMOVAL; EXCAVATION, DREDGING OR REMOVAL OF SOIL MATERIAL; DIKING OR FENCING; AND ANY OTHER ACTIVITIES DETRIMENTAL TO DRAINAGE, FLOOD CONTROL, WATER CONSERVATION, EROSION CONTROL, OR FISH AND WILDLIFE HABITAT CONSERVATION OR PRESERVATION.
17. ACTIVITIES ASSOCIATED WITH IMPLEMENTATION OF THE WETLAND MITIGATION, MONITORING AND MAINTENANCE SHALL BE IN ACCORDANCE WITH THE FOLLOWING WORK SCHEDULE. ANY DEVIATION FROM THESE TIME FRAMES SHALL REQUIRE FORMAL SFWMC APPROVAL. SUCH REQUESTS MUST BE MADE IN WRITING AND SHALL INCLUDE (1) REASON FOR THE MODIFICATION; (2) PROPOSED START/FINISH DATES; AND (3) PROGRESS REPORT ON THE STATUS OF THE EXISTING MITIGATION EFFORTS.

MITIGATION PLAN ID: BONNET CREEK ROOKERY

COMPLETION DATE	ACTIVITY
FEBRUARY 12, 1994	ROOKERY MONITORING
MARCH 12, 1994	ROOKERY MONITORING
APRIL 9, 1994	ROOKERY MONITORING
MAY 14, 1994	ROOKERY MONITORING
JUNE 11, 1994	ROOKERY MONITORING
JULY 9, 1994	ROOKERY MONITORING
AUGUST 13, 1994	ROOKERY MONITORING
SEPTEMBER 10, 1994	ROOKERY MONITORING
FEBRUARY 11, 1995	ROOKERY MONITORING
MARCH 11, 1995	ROOKERY MONITORING
APRIL 8, 1995	ROOKERY MONITORING
MAY 6, 1995	ROOKERY MONITORING
MAY 20, 1995	ROOKERY MONITORING
JUNE 3, 1995	ROOKERY MONITORING
JUNE 17, 1995	ROOKERY MONITORING
JULY 1, 1995	ROOKERY MONITORING
JULY 15, 1995	ROOKERY MONITORING
AUGUST 12, 1995	ROOKERY MONITORING
SEPTEMBER 9, 1995	ROOKERY MONITORING

MITIGATION PLAN ID: COMPENSATION AREA

COMPLETION DATE	ACTIVITY
NOVEMBER 30, 1993	LEGAL DESCRIPTION PROVIDED TO DISTRICT
NOVEMBER 30, 1993	SURVEY PROVIDED TO DISTRICT
JANUARY 31, 1994	CONSERVATION EASEMENT RECORDED IN PUBLIC RECORDS
FEBRUARY 28, 1994	RECORDED COPY OF EASEMENT PROVIDED TO DISTRICT

18. (A) NO LATER THAN JANUARY 31, 1994, THE PERMITTEE SHALL RECORD CONSERVATION EASEMENTS ON THE REAL PROPERTY DESIGNATED AS A CONSERVATION AREA ON EXHIBIT 76, WHICH PURSUANT TO SECTION 704.06 FLORIDA STATUTES, PROHIBITS WITHIN THE CONSERVATION AREA ALL CONSTRUCTION, INCLUDING GRADING, DREDGING OR FILLING. THE CONSERVATION EASEMENT SHALL BE IN SUBSTANTIAL CONFORMANCE WITH THE DRAFT CONSERVATION EASEMENT ATTACHED AS EXHIBIT 75 AND SHALL CONTAIN PROVISIONS SET FORTH IN SUBSECTION (1) (a) THROUGH (h) OF SECTION 704.06, FLORIDA STATUTES, AS WELL AS PROVISIONS THAT THE PROHIBITIONS SET FORTH IN THE EASEMENT MAY BE ENFORCED BY THE DISTRICT AND MAY NOT BE AMENDED WITHOUT DISTRICT APPROVAL.

(B) AT LEAST 60 DAYS PRIOR TO RECORDING THE CONSERVATION EASEMENTS, THE PERMITTEE SHALL PROVIDE THE DISTRICT WITH 2 COPIES OF THE CONSERVATION EASEMENTS WITH A SURVEY FOR DISTRICT REVIEW AND APPROVAL. THE SURVEY MUST BE PERFORMED BY A REGISTERED PROFESSIONAL LAND SURVEYOR, WITHIN 30 DAYS OF RECORDING THE DISTRICT APPROVED CONSERVATION EASEMENTS. THE PERMITTEE SHALL PROVIDE THE DISTRICT WITH 2 CERTIFIED COPIES OF THE RECORDED EASEMENT.
19. CONSTRUCTION OF THE TRANSMISSION LINES WITHIN 300 METERS OF EITHER OF THE BIRD ROOKERIES SHALL NOT BE CONDUCTED DURING NESTING SEASON. IT SHALL BE THE PERMITTEE'S RESPONSIBILITY TO COORDINATE WITH THE FLORIDA GAME AND FRESH WATER FISH COMMISSION TO DETERMINE THE APPROPRIATE TIME PERIOD OF THE NESTING SEASON.
20. THE PERMITTEE SHALL SUBMIT ON AN ANNUAL BASIS TO THE DISTRICT'S REGULATION DEPARTMENT THE RESULTS OF ALL WETLAND, UPLAND AND WILDLIFE MONITORING PROGRAMS INCLUDED BY REFERENCE IN THE PERMIT FILE.
21. ENDANGERED SPECIES, THREATENED SPECIES, OR SPECIES OF SPECIAL CONCERN HAVE BEEN OBSERVED ONSITE AND/OR THE PROJECT CONTAINS SUITABLE HABITAT FOR THESE SPECIES. IT SHALL BE THE PERMITTEE'S RESPONSIBILITY TO COORDINATE WITH THE FLORIDA GAME AND FRESH WATER FISH COMMISSION AND/OR U.S. FISH AND WILDLIFE SERVICE FOR APPROPRIATE GUIDANCE, RECOMMENDATIONS, AND/OR NECESSARY PERMITS FOR ANY IMPACTS TO LISTED SPECIES.
22. THE PERMITTEE SHALL BE RESPONSIBLE FOR IMPLEMENTING THE PYRIC MANAGEMENT PLAN WHICH IS INCLUDED BY REFERENCE IN THE PERMIT FILE AND FOR PERFORMING ALL FOLLOWUP MONITORING ASSOCIATED WITH THE IMPLEMENTATION OF THAT PLAN.

LIMITING CONDITIONS

- 1 . THE PERMITTEE SHALL PROSECUTE THE WORK AUTHORIZED IN A MANNER SO AS TO MINIMIZE ANY ADVERSE IMPACT OF THE WORKS ON FISH, WILDLIFE, NATURAL ENVIRONMENTAL VALUES, AND WATER QUALITY. THE PERMITTEE SHALL INSTITUTE NECESSARY MEASURES DURING THE CONSTRUCTION PERIOD, INCLUDING FULL COMPACTION OF ANY FILL MATERIAL PLACED AROUND NEWLY INSTALLED STRUCTURES, TO REDUCE EROSION, TURBIDITY, NUTRIENT LOADING AND SEDIMENTATION IN THE RECEIVING WATERS.
- 2 . WATER QUALITY DATA FOR THE WATER DISCHARGED FROM THE PERMITTEE'S PROPERTY OR INTO SURFACE WATERS OF THE STATE SHALL BE SUBMITTED TO THE DISTRICT AS REQUIRED. PARAMETERS TO BE MONITORED MAY INCLUDE THOSE LISTED IN CHAPTER 17-302. IF WATER QUALITY DATA IS REQUIRED, THE PERMITTEE SHALL PROVIDE DATA AS REQUIRED, ON VOLUMES OF WATER DISCHARGED INCLUDING TOTAL VOLUME DISCHARGED, DURING THE DAYS OF SAMPLING AND TOTAL MONTHLY DISCHARGES FROM THE PROPERTY OR INTO SURFACE WATERS OF THE STATE.
- 3 . THE PERMITTEE SHALL COMPLY WITH ALL APPLICABLE LOCAL SUBDIVISION REGULATIONS AND OTHER LOCAL REQUIREMENTS. IN ADDITION, THE PERMITTEE SHALL OBTAIN ALL NECESSARY FEDERAL, STATE, LOCAL AND SPECIAL DISTRICT AUTHORIZATIONS PRIOR TO THE START OF ANY CONSTRUCTION OR ALTERATION OF WORKS AUTHORIZED BY THIS PERMIT.
- 4 . THE OPERATION PHASE OF THIS PERMIT SHALL NOT BECOME EFFECTIVE UNTIL A FLORIDA REGISTERED PROFESSIONAL ENGINEER CERTIFIES THAT ALL FACILITIES HAVE BEEN CONSTRUCTED IN ACCORDANCE WITH THE DESIGN APPROVED BY THE DISTRICT. WITHIN 30 DAYS AFTER COMPLETION OF CONSTRUCTION OF THE SURFACE WATER MANAGEMENT SYSTEM, THE PERMITTEE SHALL SUBMIT THE CERTIFICATION AND NOTIFY THE DISTRICT THAT THE FACILITIES ARE READY FOR INSPECTION AND APPROVAL. UPON APPROVAL OF THE COMPLETED SURFACE WATER MANAGEMENT SYSTEM, THE PERMITTEE SHALL REQUEST TRANSFER OF THE PERMIT TO THE RESPONSIBLE ENTITY APPROVED BY THE DISTRICT.
- 5 . ALL ROADS SHALL BE SET AT OR ABOVE ELEVATIONS REQUIRED BY THE APPLICABLE LOCAL GOVERNMENT FLOOD CRITERIA.
- 6 . ALL BUILDING FLOORS SHALL BE SET AT OR ABOVE ELEVATIONS ACCEPTABLE TO THE APPLICABLE LOCAL GOVERNMENT.
- 7 . OFF-SITE DISCHARGES DURING CONSTRUCTION AND DEVELOPMENT SHALL BE MADE ONLY THROUGH THE FACILITIES AUTHORIZED BY THIS PERMIT. NO ROADWAY OR BUILDING CONSTRUCTION SHALL COMMENCE ON-SITE UNTIL COMPLETION OF THE PERMITTED DISCHARGE STRUCTURE AND DETENTION AREAS. WATER DISCHARGED FROM THE PROJECT SHALL BE THROUGH STRUCTURES HAVING A MECHANISM SUITABLE FOR REGULATING UPSTREAM WATER STAGES. STAGES MAY BE SUBJECT TO OPERATING SCHEDULES SATISFACTORY TO THE DISTRICT.
- 8 . NO CONSTRUCTION AUTHORIZED HEREIN SHALL COMMENCE UNTIL A RESPONSIBLE ENTITY ACCEPTABLE TO THE DISTRICT HAS BEEN ESTABLISHED AND HAS AGREED TO

OPERATE AND MAINTAIN THE SYSTEM. THE ENTITY MUST BE PROVIDED WITH SUFFICIENT OWNERSHIP SO THAT IT HAS CONTROL OVER ALL WATER MANAGEMENT FACILITIES AUTHORIZED HEREIN. UPON RECEIPT OF WRITTEN EVIDENCE OF THE SATISFACTION OF THIS CONDITION, THE DISTRICT WILL ISSUE AN AUTHORIZATION TO COMMENCE CONSTRUCTION.

9. THE PERMIT DOES NOT CONVEY TO THE PERMITTEE ANY PROPERTY RIGHT NOR ANY RIGHTS OR PRIVILEGES OTHER THAN THOSE SPECIFIED IN THE PERMIT AND CHAPTER 40E-4, FAC.
10. THE PERMITTEE SHALL HOLD AND SAVE THE DISTRICT HARMLESS FROM ANY AND ALL DAMAGES, CLAIMS, OR LIABILITIES WHICH MAY ARISE BY REASON OF THE CONSTRUCTION, OPERATION, MAINTENANCE OR USE OF ANY FACILITY AUTHORIZED BY THE PERMIT.
11. THIS PERMIT IS ISSUED BASED ON THE APPLICANT'S SUBMITTED INFORMATION WHICH REASONABLY DEMONSTRATES THAT ADVERSE OFF-SITE WATER RESOURCE RELATED IMPACTS WILL NOT BE CAUSED BY THE COMPLETED PERMIT ACTIVITY. IT IS ALSO THE RESPONSIBILITY OF THE PERMITTEE TO INSURE THAT ADVERSE OFF-SITE WATER RESOURCE IMPACTS DO NOT OCCUR DURING CONSTRUCTION.
12. PRIOR TO DEWATERING, PLANS SHALL BE SUBMITTED TO THE DISTRICT FOR APPROVAL. INFORMATION SHALL INCLUDE AS A MINIMUM: PUMP SIZES, LOCATION AND HOURS OF OPERATION FOR EACH PUMP. IF OFF-SITE DISCHARGE IS PROPOSED OR OFF-SITE ADVERSE IMPACTS ARE EVIDENT, AN INDIVIDUAL WATER USE PERMIT MAY BE REQUIRED. THE PERMITTEE IS CAUTIONED THAT SEVERAL MONTHS MAY BE REQUIRED FOR CONSIDERATION OF THE WATER USE PERMIT APPLICATION.

Water Use Permit



Form #0299
Rev 1/90

**South Florida
Water Management District**
WATER USE PERMIT NO. 49-00671-W
(NON-ASSIGNABLE)

DATE ISSUED: APRIL 15, 1993

EXPIRATION DATE APRIL 15, 2003

AUTHORIZING: THE USE OF GROUNDWATER FROM THE FLORIDIAN AQUIFER SYSTEM
FOR INDUSTRIAL USE WITH AN ANNUAL ALLOCATION OF 75
MILLION GALLONS.

LOCATED IN: OSCEOLA COUNTY, SECTION 29, 32 TWP. 25S RGE. 28E

ISSUED TO:

KISSIMMEE UTILITY AUTHORITY
(CANE ISLAND COMBUSTION TURBINE PROJECT)
1701 WEST CARROLL STREET
KISSIMMEE, FL 34742

This Permit is issued pursuant to Application No. 920330-19 dated MARCH 27, 19 92 for the Use of Water as specified above and subject to the Special Conditions set forth below. Said application, including all plans and specifications attached thereto, is by reference made a part hereof.

Upon written notice to the permittee, this permit may be temporarily modified, or restricted under a Declaration of Water Shortage or a Declaration of Emergency due to Water Shortage in accordance with provisions of Ch. 373, Fla. Statutes, and applicable rules and regulations of the South Florida Water Management District.

This Permit may be permanently or temporarily revoked, in whole or in part, for the violation of the conditions of the permit or for the violation of any provision of the Water Resources Act and regulations thereunder.

This Permit does not convey to permittee any property rights nor any privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation, or requirement affecting the rights of other bodies or agencies.

SPECIAL CONDITIONS ARE AS FOLLOWS:

SEE SHEET 2 - 4 of 4 - 20 LIMITING CONDITIONS.

FILED WITH THE CLERK OF THE SOUTH
FLORIDA WATER MANAGEMENT DISTRICT

ON

BY

DEPUTY CLERK

SOUTH FLORIDA WATER MANAGEMENT
DISTRICT, BY ITS GOVERNING BOARD

By

Assistant Secretary

LIMITING CONDITIONS

- 1 . IN THE EVENT OF A DECLARED WATER SHORTAGE, WATER WITHDRAWAL REDUCTIONS WILL BE ORDERED BY THE DISTRICT IN ACCORDANCE WITH THE WATER SHORTAGE PLAN, CHAPTER 40E-21, FLORIDA ADMINISTRATIVE CODE. DURING A WATER SHORTAGE PUMPAGE REPORTS MAY BE NECESSARY ON A WEEKLY BASIS.
- 2 . SOURCE CLASSIFICATION IS:

GROUNDWATER FROM THE FLORIDAN AQUIFER SYSTEM
- 3 . PERMITTEE SHALL MITIGATE TO THE SATISFACTION OF THE DISTRICT ANY ADVERSE IMPACT ON EXISTING LEGAL USES CAUSED BY WITHDRAWALS. WHEN ADVERSE IMPACTS OCCUR, OR ARE IMMINENT, DISTRICT RESERVES THE RIGHT TO CURTAIL WITHDRAWAL RATES. ADVERSE IMPACTS ARE:
 - A) REDUCTION IN WELL WATER LEVELS THAT IMPAIRS THE ABILITY OF AN ADJACENT WELL TO PRODUCE WATER (AN ADJACENT WELL MAY BE A DOMESTIC WELL, LAWN IRRIGATION WELL, PUBLIC WATER SUPPLY WELL, ETC.),
 - B) SIGNIFICANT REDUCTION IN LEVELS IN AN ADJACENT WATER BODY SUCH AS A LAKE, POND, OR A CANAL SYSTEM,
 - C) SALINE WATER INTRUSION OR INDUCTION OF POLLUTANTS INTO THE WATER SUPPLY OF AN ADJACENT WATER USE, RESULTING IN A SIGNIFICANT REDUCTION IN WATER QUALITY, AND
 - D) CHANGE IN WATER QUALITY THAT CAUSES IMPAIRMENT OR LOSS OF USE OF A WELL OR WATER BODY.
- 4 . PERMITTEE SHALL MITIGATE TO THE SATISFACTION OF THE DISTRICT ANY ADVERSE IMPACT ON EXISTING OFF-SITE LAND USE AS A CONSEQUENCE OF WITHDRAWALS PERMITTED HEREIN. IF INCREASED WITHDRAWALS CAUSE AN ADVERSE IMPACT ON EXISTING LAND USE, THE DISTRICT RESERVES THE RIGHT TO CURTAIL FUTURE WITHDRAWAL RATES. ADVERSE IMPACTS ARE:
 - A) SIGNIFICANT REDUCTION IN WATER LEVELS IN AN ADJACENT WATER BODY (SUCH AS A LAKE, POND, WETLAND OR CANAL SYSTEM);
 - B) LAND COLLAPSE OR SUBSIDENCE CAUSED BY REDUCTION IN WATER LEVELS;
 - C) DAMAGE TO CROPS AND OTHER VEGETATION, CAUSING FINANCIAL HARM TO THE LANDOWNER; AND
 - D) DAMAGE TO HABITAT OF RARE, ENDANGERED SPECIES.
- 5 . AUTHORIZED REPRESENTATIVES OF THE DISTRICT SHALL BE PERMITTED TO ENTER, INSPECT, AND OBSERVE THE PERMITTED SYSTEM TO DETERMINE COMPLIANCE WITH SPECIAL CONDITIONS.
- 6 . IF ANY CONDITION OF THE PERMIT IS VIOLATED, THE PERMIT SHALL BE SUBJECT TO REVIEW AND POSSIBLE MODIFICATION, ENFORCEMENT ACTION, OR REVOCATION.
- 7 . APPLICATION FOR A PERMIT MODIFICATION MAY BE MADE AT ANY TIME.

8 . WITHDRAWAL FACILITIES ARE:

GROUNDWATER - PROPOSED:

2 - 6" X 400' X 200 GPM WELLS CASED TO 150 FEET

- 9 . THIS PERMIT SHALL EXPIRE ON APRIL 15, 2003.
10. ANNUAL ALLOCATION SHALL NOT EXCEED 75 MG.
MAXIMUM DAILY ALLOCATION SHALL NOT EXCEED .26 MG.
11. USE CLASSIFICATION IS INDUSTRIAL.
12. THE PERMITTEE SHALL OBTAIN ALL NECESSARY FEDERAL, STATE, LOCAL AND SPECIAL DISTRICT AUTHORIZATIONS PRIOR TO THE USE OR WITHDRAWAL OF WATER.
13. THE PERMIT DOES NOT CONVEY ANY PROPERTY RIGHT TO THE PERMITTEE, NOR ANY RIGHTS AND PRIVILEGES OTHER THAN THOSE SPECIFIED IN THE PERMIT AND CHAPTER 40E-2, FAC.
14. A PERMIT MODIFICATION WILL BE REQUIRED PRIOR TO ANY CHANGES INCLUDING, BUT NOT LIMITED TO, ALLOCATION (INCREASE OR DECREASE), CHANGES IN USE, OR CHANGE IN FACILITIES OR IN THE LOCATION OF FACILITIES. THE PERMITTEE IS ADVISED THAT AN APPLICATION FOR MODIFICATION SHALL BE EVALUATED BASED ON RULES AND PERMITTING CRITERIA IN EFFECT AT THE TIME OF APPLICATION SUBMITTAL.
15. WITHDRAWALS ON A DAILY BASIS SHALL BE REPORTED TO THE DISTRICT MONTHLY. DATA SUBMITTAL BEGINS EITHER IN THE MONTH FOLLOWING THE DATE OF PERMIT ISSUANCE OR IN THE MONTH THAT WATER USE IS INITIATED.
16. THE WATER CONSERVATION PLAN REQUIRED BY CRITERIA 3.1, OF APPENDIX 1 OF THE BASIS OF REVIEW FOR WATER USE PERMIT APPLICATIONS WITHIN THE SOUTH FLORIDA WATER MANAGEMENT DISTRICT - JANUARY, 1993, MUST BE IMPLEMENTED IN ACCORDANCE WITH THE IMPLEMENTATION SCHEDULE CONTAINED THEREIN.
17. IF AT ANY TIME THERE IS AN INDICATION THAT THE WELL CASING, VALVES, OR CONTROLS LEAK OR HAVE BECOME INOPERATIVE, REPAIRS OR REPLACEMENT SHALL BE MADE TO RESTORE THE SYSTEM TO AN OPERATING CONDITION ACCEPTABLE TO THE DISTRICT. FAILURE TO MAKE SUCH REPAIRS SHALL BE CAUSE FOR FILLING AND ABANDONING THE WELL, IN ACCORDANCE WITH PROCEDURES OUTLINED IN CHAPTERS 40E-3 AND 40E-30, F.A.C.
18. IF A PROPOSED WELL LOCATION IS DIFFERENT FROM A LOCATION SPECIFIED IN THE APPLICATION, THE PERMITTEE SHALL SUBMIT TO THE DISTRICT AN EVALUATION OF THE IMPACT OF PUMPAGE FROM THE PROPOSED WELL LOCATION ON ADJACENT EXISTING LEGAL USES, POLLUTION SOURCES, ENVIRONMENTAL FEATURES, THE SALINE WATER INTERFACE, AND WATER BODIES ONE MONTH PRIOR TO ALL NEW WELL CONSTRUCTION. THE PERMITTEE IS ADVISED THAT THE PROPOSAL MUST MEET ALL PERMITTING CRITERIA IN EFFECT AT THE TIME OF SUBMITTAL, AND THAT BASED ON STAFF

EVALUATION OF THE IMPACT, A FORMAL MODIFICATION OF THE PERMIT MAY BE REQUIRED.

19. PERMITTEE SHALL SECURE A WELL CONSTRUCTION PERMIT PRIOR TO CONSTRUCTION, REPAIR, OR ABANDONMENT OF ALL WELLS, AS DESCRIBED IN CHAPTERS 40E-3 AND 40E-30, F.A.C.
20. THE PERMITTEE SHALL SUBMIT TO THE DISTRICT AN UPDATED TABLE "A" (WELL DESCRIPTION TABLE) WITHIN ONE MONTH OF COMPLETION OF THE 2 PROPOSED WELLS IDENTIFYING THE ACTUAL TOTAL AND CASED DEPTHS, PUMP MANUFACTURER AND MODEL NUMBERS, PUMP TYPES, INTAKE DEPTHS AND TYPE OF METERS.

Industrial Wastewater Treatment System Permit



Department of Environmental Protection

Lawton Chiles
Governor

Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Virginia B. Wetherell
Secretary

INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:

Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, FL 34742
Attention: James C. Welsh, President

PERMIT NO.: FLA010961
FILE NO.: 49-283594
FACILITY I.D. NO.: 3049M06279
ISSUANCE DATE:
EXPIRATION DATE: August 15, 2001

FACILITY:

KUA/Cane Island Power Plant
6075 Old Tampa Highway
1.5 miles Northwest of Intercession City, Osceola County, Florida

Latitude: ^{26°}16' 29" N Longitude: 81° 31' 50" W
_{28"}

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.). The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Operation of an existing industrial wastewater treatment and disposal system to serve the referenced electric power generation facility. The facility receives a Monthly Average Flow (MAF) of 1.00 MGD from the City of Kissimmee/Bermuda Avenue wastewater treatment facility (POTW). This water supply is designated as INT-01. Well water is at the monthly average rate of 0.205 MGD to supplement the wastewater from the POTW. This supply is designated as INT-02 for well 2A and INT-03 for well 2B. The permittee may alter the flow volumes from INT-01, INT-02 and INT-03 as required for operational needs. The POTW effluent is used for cooling tower makeup water. The wells are used to supply the potable services and the demineralizer systems. This permit also authorizes the relocation of the percolation pond used for onsite discharge to ground water to another portion of the property. The various wastestreams from the operation of the facility are listed as follows:

- A. Cooling Tower Blowdown at an approximate daily flow of 0.20 MGD.
- B. Neutralization Basin Effluent at a monthly average flow of 0.021 MGD. This consists of :
 - 1. Ion Exchange Regeneration Wastes.
 - 2. Chemical/Metal Cleaning Rinses.
 - 3. Chemical Area Drains.
- C. Steam Cycle Blowdown at a MDF of 0.013 MGD.

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D. Drains from the Turbine Area, Plant and Equipment Areas.

E. Area Drains as follows:

1. Fuel Oil Storage Tank Bermed Containment Area.
2. Transformer Area Containment Bermed Area.
3. Fuel Oil Unloading Station.

F. Roof and Site Drains.

WASTEWATER TREATMENT:

Wastestream B is treated by pH neutralization and settling before mixing with Wastestreams A and C. These three wastestreams are discharged to the POTW effluent forcemain to the Imperial percolation ponds at a MDF of 0.20 MGD. The Imperial site disposal system operates under DEP Domestic Wastewater Permit Number FLA010959 and the South Bermuda Domestic Wastewater treatment facility is under Permit Number FL0041874.

Wastestreams D and E are treated in oil/water separators prior to discharge to Class G-II ground water via percolation in a 127 foot by 62 foot (top of berm) above ground impoundment. There shall be no discharge of these wastestreams to surface waters of the State.

Wastestream F shall be routed to an onsite stormwater management system permitted by the South Florida Water Management District.

There are maintenance manholes containing electrical conduits. These must be dewatered for access by maintenance personnel. The water removed from these manholes is not considered to be industrial wastewater and is not regulated under this permit.

There shall be no discharges from the treatment or disposal system to the surface waters of the State.

EFFLUENT DISPOSAL:

Land Application: A 0.009 MGD monthly average flow, from the treatment system for combined Wastestreams D and E, is land applied in a one cell, above grade percolation impoundment for discharges into Class GII ground water. This outfall is designated Outfall G001. The land application system is located approximately at the latitude and longitude listed above.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in attached Pages 3 through 14 of this permit.

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PERMIT NO.: FLA010961
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I. Effluent Limitations and Monitoring Requirements:

A. Land Application Systems:

1. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee is authorized to discharge, from Discharge Location G001, wastewater from the industrial wastewater treatment system (Wastestreams D & E) to an impoundment onsite. Samples shall be taken at the sampling port designated G001. Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (MGD)	0.009 (b)	Report	NA	Daily	Metered	G001
TDS (mg/l)	Report	Report	NA	Monthly	Grab	G001
Chlorides (mg/l)	Report	Report	NA	Monthly	Grab	G001
Total Nitrogen (mg/l)	Report	Report	NA	Monthly	Grab	G001
Sodium (mg/l)	Report	Report	NA	Monthly	Grab	G001
Sulfates (mg/l)	Report	Report	NA	Monthly	Grab	G001
TRPH (mg/l) (c)	Report	Report	NA	2/ Month	Grab	G001
pH (SU)	See Specific Condition I.A.5					

2. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee is authorized to discharge, from Discharge Location G002, wastewater from Wastestreams A, B and C to the City of Kissimmee forcemain to the Imperial land application site. Samples shall be taken at the sampling port designated G002. Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (MGD)	0.250	0.275	NA	Daily	Metered	G002
TDS (mg/l)	Report	Report	NA	2/Month	Grab	G002
Chlorides (mg/l)	Report	Report	NA	2/Month	Grab	G002
Nitrates as N (mg/l)	Report	Report	NA	Weekly	Grab	G002
Nitrates as N (#/ day)	Report	Report	NA	Weekly	Grab	G002
Total Nitrogen (mg/l)	Report	Report	NA	Weekly	Grab	G002
Total Nitrogen (#/ day)	Report	Report	NA	Weekly	Grab	G002
Sodium (mg/l)	Report	Report	NA	2/Month	Grab	G002
Sulfates (mg/l)	Report	Report	NA	2/Month	Grab	G002
TRPH (mg/l) (c)	Report	Report	NA	Monthly	Grab	G002
pH (SU)	See Specific Condition I.A.5					

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3. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee shall sample the treated domestic effluent from the City of Kissimmee POTW that is used in the power plant. There will be a sampling port established that will be designated location INT-01 to obtain representative samples of this wastewater. Samples shall be taken at Location INT-01 and tested by the permittee as specified below:

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	NA	Daily	Metered	INT-01
Nitrates as N (#/ day) (d)	Report	Report	NA	Weekly	Grab	INT-01
Nitrates as N (mg/l)	Report	Report	NA	Weekly	Grab	INT-01
Total Nitrogen (#/ day) (d)	Report	Report	NA	Weekly	Grab	INT-01
Total Nitrogen (mg/l)	Report	Report	NA	Weekly	Grab	INT-01

4. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee shall sample the raw water supply from the wells onsite that are used in the power plant. There will be sampling ports established that will be designated Locations INT-02 and INT-03 to obtain representative samples of this ground water. These ports shall be located on the lines from Well No. 2A and Well No. 2B respectively. Samples shall be taken at Locations INT-02 and INT-03 and tested by the permittee as specified below:

INT-02

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (gpd)	Report	Report	NA	Daily	Metered	INT-02
TDS (mg/l)	Report	Report	NA	Monthly	Grab	INT-02
TSS (mg/l)	Report	Report	NA	Monthly	Grab	INT-02
Surfactants (mg/l)	Report	Report	NA	Monthly	Grab	INT-02
Total Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-02
Total Nitrogen as N (mg/l)	Report	Report	NA	Weekly	Grab	INT-02
Nitrate Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-02
Nitrate Nitrogen (mg/l)	Report	Report	NA	Weekly	Grab	INT-02

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INT-03

Parameters (Units)	Discharge Limitations(a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (gpd)	Report	Report	NA	Daily	Metered	INT-03
TDS (mg/l)	Report	Report	NA	Monthly	Grab	INT-03
TSS (mg/l)	Report	Report	NA	Monthly	Grab	INT-03
Surfactants (mg/l)	Report	Report	NA	Monthly	Grab	INT-03
Total Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-03
Total Nitrogen as N mg/l	Report	Report	NA	Weekly	Grab	INT-03
Nitrate Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-03
Nitrate Nitrogen mg/l	Report	Report	NA	Weekly	Grab	INT-03

- (a) Daily Discharge: The "discharge of a pollutant" measured during a calendar day or any 24 hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the "daily discharge" is calculated as the total mass of the pollutants discharged over the day. For pollutants expressed in other units of measurements; e.g., concentration, "daily discharge" is calculated as the average measurement of the pollutant over the day.

Average Monthly Discharge Limitation : The highest allowable average of "daily discharges" over a calendar month calculated as the sum of all "daily discharges" measured during a calendar month divided by the number of "daily discharges" measured during that month.

Maximum Daily Discharge Limitation: The highest allowable daily discharge.

- (b) The flow limitation does not include the component of the flow that is introduced through the plant area drains.
- (c) Total Recoverable Petroleum Hydrocarbons
- (d) See Condition I.A.16.
5. The pH shall not be less than 6.0 standard units, nor greater than 8.5 standard units at any time at Sampling Locations G001 and G002. The pH shall be monitored twice monthly by grab sample at Locations G001 and G002.
6. Unless specified elsewhere in the permit, samples taken in compliance with the monitoring requirements specified in I.A.1. shall be taken at the nearest accessible point after final treatment but prior to the actual discharge to the land application system. The same sampling point shall be used in each sampling event.
7. There shall be no discharge of industrial wastewater from this facility to surface waters.
8. Monitoring results obtained for each calendar month shall be summarized for that period and reported on a Discharge Monitoring Report (DMR), Form 62-620.910(10), postmarked no later than the 28th day of the month following the completed calendar month. For example, data for January shall be submitted by February 28. Signed copies of the DMR shall be submitted to the address specified below:

Florida Department of Environmental Protection Central District Office
Industrial Wastewater Program
3319 Maguire Boulevard, Suite 232
Orlando, FL 32803

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If no discharge occurs during the reporting period, the above sampling requirements of this permit do not apply. The DMR shall be submitted with the statement "No discharge" written on the DMR form. If, during the term period of this permit, the facility ceases to discharge, the Department shall be notified immediately upon cessation of discharge. Such notification shall be in writing.

9. Unless specified otherwise in this permit, all other reports and notifications required by this permit, including twenty- four hour notifications, shall be submitted to or reported to, as appropriate, the Central District Office of the Department at the address specified above.
10. Grab samples shall be collected during periods of minimal treatment plant pollutant removal efficiencies or maximum hydraulic and/or pollutant loading.
11. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.
12. The permittee shall ensure that all laboratory analytical data submitted to the department as required by this permit is from a laboratory which has a currently valid and Department-approved Comprehensive Quality Assurance Plan (ComQAP) [or a ComQAP pending approval] for all parameters being reported as required by Chapter 62-160, Florida Administrative Code.
13. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.
14. Any bypass of the treatment facility which is not included in the monitoring specified in I.A.1. above is to be monitored for flow and all other required parameters. For parameters other than flow, at least one grab sample per day shall be monitored. Daily flow shall be monitored or estimated, as appropriate, to obtain reasonable data. All monitoring results shall be reported on the appropriate DMR.
15. Sampling shall commence in accordance with the requirements of this permit in the first month following the month in which the permit is issued.
16. There shall be no net increase of total Nitrogen and Total Nitrates as N in pounds per day, on an annual basis, introduced back into the City's forcemain to the Imperial disposal site than was recieved from the City in the domestic effluent water used for supply. Calculations shall be made on the following basis: Total weekly flow in Million Gallons x 8.34 x concentration in mg/l for each parameter.

II. Industrial Sludge Management Requirements

A. Basic Management Requirements:

1. There will be no residual solids generated in the treatment/ disposal process at this facility.
2. Waste oil removed from any treatment unit in this system shall be stored onsite in a separate waste oil tank. The stored waste oil shall be managed and ultimately disposed of by a licensed used oil recycler in accordance with the provisions of Chapter 62-710, F.A.C.
3. Mixing of any waste product generated from this system with septage or domestic residuals is prohibited.

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III. Groundwater Monitoring Requirements

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A. Groundwater Monitoring requirements:

1. During the period of operation authorized by this permit, the permittee shall sample ground water in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-522.600, F.A.C. [62-522.600, 4/14/94] - - - -
2. The following monitoring wells shall be sampled quarterly:

Well Name	Monitoring Location Site Number	WAFR Number	Depth (Feet)	Aquifer Monitored	Well Type	New or Existing
MW-1	3049A17007	6240	18	Shallow	Background	Existing
MW-5	3049A17008	6239	42	Shallow	Compliance	Existing
MW-6	3049A17009	6238	35	Shallow	Compliance	Existing

3. The following parameters shall be analyzed quarterly for each of the monitoring well(s) identified in Item III. 2.:
 - a. Water level (field measurement)
 - b. pH
 - c. Sodium
 - d. Chloride
 - e. TDS
 - f. Turbidity
 - g. TRPH
 - h. Nitrate Nitrogen
 - i. Sulfate

[62-522.600(11)(b), 4/1/94]

4. All sampling shall be conducted using standard DEP sampling procedures.[62-4.426]
5. In accordance with Part D of Form 62-620.910(10), water levels shall be recorded before evacuating the wells for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NVGD) at a precision of plus or minus 0.1 foot.
6. Ground water monitoring wells shall be evacuated or purged prior to sampling to obtain a representative sample.
7. Analyses shall be conducted on un-filtered samples, unless filtered samples have been approved by the Department as being more representative of ground water conditions.
8. If a monitoring well becomes damaged or cannot be sampled for some reason, the permittee shall notify the Department with a written report within seven days detailing the circumstances and remedial measures taken or proposed. Replacement of monitoring wells shall be approved in advance by the Department.
9. Ground water monitoring test results shall be submitted on Part D of Form 62-620.910(10). Results shall be submitted with the April, July, October and January DMR's for each year during the period of operation allowed by this permit. [62-522.600(10) and (11)(b), 4/14/94 [62-620.610(18), 11-29-94]

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IV. Other Land Application Requirements

- A. The permittee's discharge to ground water shall not cause a violation of water quality standards for Class G-II ground waters at the boundary of the zone of discharge in accordance with rules 62-520.400 and 62-520.420, F.A.C.
- B. The permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in rule 62-520.400, F.A.C., within the zone of discharge.
- C. The frequency and rate of effluent disposal shall be managed by the permittee to avoid secondary environmental impacts such as severe odors and other nuisance conditions.

V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities:

- 1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.
- 2. The operation of the pollution control facilities described in this permit shall be under the full time supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

B. Record keeping Requirements:

The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:

- 1. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;
- 2. Copies of all reports, other than those required in items 1. and 6. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;
- 3. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, unless otherwise specified by Department rule;
- 4. A copy of the current permit;
- 5. A copy of any required record drawings;
- 6. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Compliance Schedules and Self-imposed Improvement Schedules

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A. The permittee shall achieve compliance with the terms of this permit in accordance with the following schedule:

Operational compliance shall be attained within 15 days of issuance of this permit.

VII. Other Specific Conditions

A. Specific Conditions Applicable to all permits:

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Central District Office, are made a part hereof.
2. If significant historical or archaeological artifacts are discovered at any time within the project site, the permittee shall immediately notify the District Office and the Bureau of Historic Preservation, Division of Archives, History and Records Management, R.A. Gray Building, Tallahassee, Florida 32301.
3. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.
4. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Duty to Reapply:

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.
2. The permittee shall apply on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Rules 62-620.400 through 62-620.460, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.
3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.
4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

C. Specific Conditions Related to Best Management Practices Condition:

1. BMP Plan: For purposes of this part, the terms "pollutant" or "pollutants" refer to any substance listed as toxic under Section 307(a)(1) of the Clean Water Act (the "Act"), oil, as defined in Section 311(a)(1) of the Act, and any substance listed as hazardous under Section 311 of the act. The permittee shall develop and implement a Best Management Practices (BMP) plan which prevents, or minimizes the potential for, the release of pollutants from ancillary activities, including material storage areas; plant site runoff; in-plant transfer, process and material handling areas; loading and unloading operations; and sludge and waste disposal areas, to the waters of the State through plant site runoff; spillage or leaks; sludge or waste disposal; or drainage from raw material storage.

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2. Implementation: The plan shall be developed within six months after the issuance date of this permit and shall be implemented as soon as practicable but not later than 18 months after the issuance date of the permit. The permittee shall submit written notification of compliance or noncompliance with these requirements to the Department in accordance with part I.A.8. of this permit.
3. General Requirements: The BMP plan shall:
 - a. Be documented in narrative form, and shall include any necessary plot plans, drawings or maps.
 - b. Establish specific objectives for the control of pollutants.
 - (1) Each facility component or system shall be examined for its potential for causing a release of significant amounts of pollutants to waters of the State due to equipment failure, improper operation, natural phenomena such as rain or snowfall, etc.
 - (2) Where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural conditions (e.g., precipitation), or other circumstances to result in significant amounts of pollutants reaching surface waters, the plan should include a prediction of the direction, rate of flow, and total quantity of pollutants which could be discharged from the facility as a result of each condition or circumstance.
 - c. Establish specific best management practices to meet the objectives identified under paragraph b of this subsection, addressing each component or system capable of causing a release of significant amounts of pollutants to the waters of the State, and identifying specific preventative or remedial measures to be implemented.
 - d. Include any special conditions established in Section B of this part.
 - e. Be reviewed by plant engineering staff and plant manager.
4. Documentation: The permittee shall maintain the BMP plan at the facility and shall make the plan available to the Department upon request.
5. BMP Plan Modification: The permittee shall amend the BMP plan whenever there is a change in the facility or change in the operation of the facility which materially increases the potential for the ancillary activities to result in a discharge of significant amounts of pollutants.
6. Modification for Ineffectiveness: If the BMP plan proves to be ineffective in achieving the general objective of preventing the release of significant amounts of pollutants to surface waters and the specific objectives and requirements under paragraphs b and c of item 3., the permit shall be subject to modification pursuant to rule 62-620.325, F.A.C., to incorporate revised BMP requirements.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. [62-620.610(1)]

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2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. [62-620.610(2)]
3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. [62-620.610(3)]
4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. [62-620.610(4)]
5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. [62-620.610(5)]
6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. [62-620.610(6)]
7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. [62-620.610(7)]
8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [62-620.610(8)]
9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:
 - a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
 - b. Have access to and copy any records that shall be kept under the conditions of this permit;
 - c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
 - d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules. [62-620.610(9)]

REVISED

PERMITTEE:
Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, FL 34742
Attention: James C. Welsh, President

PERMIT NO.: FLA010961
FILE NO.: 49-283594
FACILITY I.D. NO.: 3049M06279
ISSUANCE DATE:
EXPIRATION DATE: August 15, 2001

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, Florida Administrative Code. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. [62-620.610(10)]
11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. [62-620.610(11)]
12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. [62-620.610(12)]
13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. [62-620.610(13)]
14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. [62-620.610(14)]
15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. [62-620.610(15)]
16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, 62-620.420 or 62-620.450, F.A.C., as applicable, at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.300 for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.330, F.A.C. [62-620.610(16)]
17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:
 - a. A description of the anticipated noncompliance;
 - b. The period of the anticipated noncompliance, including dates and times; and
 - c. Steps being taken to prevent future occurrence of the noncompliance. [62-620.610(17)]
18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapter 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.

REVISED

NOV 18 1996

PERMITTEE:
Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, FL 34742
Attention: James C. Welsh, President

PERMIT NO.: FLA010961
FILE NO.: 49-283594
FACILITY I.D. NO.: 3049M06279
ISSUANCE DATE:
EXPIRATION DATE: August 15, 2001

- a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).
 - b. If the permittee monitors any contaminate more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.
 - c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.
 - d. Any laboratory test required by this permit for domestic wastewater facilities shall be performed by a laboratory that has been certified by the Department of Health and Rehabilitative Services (DHRS) under Chapter 10D-41, F.A.C., to perform the test. In domestic wastewater facilities, on-site tests for dissolved oxygen, pH, and total chlorine residual shall be performed by a laboratory certified to test for those parameters or under the direction of an operator certified under Chapter 61E12-41, F.A.C.
 - e. Under Chapter 62-160, F.A.C., sample collection shall be performed by following the protocols outlined in "DER Standard Operating Procedures for Laboratory Operations and Sample Collection Activities" (DER-QA-001/92). Alternatively, sample collection may be performed by an organization who has an approved Comprehensive Quality Assurance Plan (CompQAP) on file with the Department. The CompQAP shall be approved for collection of samples from the required matrices and for the required tests. [62-620.610(18)]
19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. [62-620.610(19)]
20. The permittee shall report to the Department any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances.

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NOV 18 1996

PERMITTEE:
Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, FL 34742
Attention: James C. Welsh, President

PERMIT NO.: FLA010961
FILE NO.: 49-283594
FACILITY I.D. NO.: 3049M06279
ISSUANCE DATE:
EXPIRATION DATE: August 15, 2001

The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

- a. The following shall be included as information which must be reported within 24 hours under this condition:
 - (1) Any unanticipated bypass which causes any reclaimed water or the effluent to exceed any permit limitation or results in an unpermitted discharge,
 - (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
 - (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
 - (4) Any unauthorized discharge to surface or ground waters.
 - b. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department shall waive the written report. [62-620.610(20)]
21. The permittee shall report all instances of noncompliance not reported under Conditions VIII. 18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII. 20 of this permit. [62-620.610(21)]
22. Bypass Provisions.
- a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
 - (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
 - (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
 - (3) The permittee submitted notices as required under Condition VIII. 22.b of this permit.
 - b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII. 20 of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.
 - c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII. 22.a(1) through (3) of this permit.

REVISED

NOV 18 1996

PERMITTEE:
Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, FL 34742
Attention: James C. Welsh, President

PERMIT NO.: FLA010961
FILE NO.: 49-283594
FACILITY I.D. NO.: 3049M06279
ISSUANCE DATE:
EXPIRATION DATE: August 15, 2001

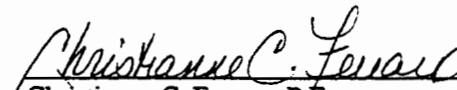
- d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII. 22.a through c of this permit. [62-620.610(22)]

23. Upset Provisions

- a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
- (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
 - (2) The permitted facility was at the time being properly operated;
 - (3) The permittee submitted notice of the upset as required in Condition VIII. 20. of this permit; and
 - (4) The permittee complied with any remedial measures required under Condition VIII. 5. of this permit.
- b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.
- c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review. [62-620.610(23)]

Executed in Orlando, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION


Christianne C. Ferraro, P.E.
Program Administrator
Water Facilities

DATE: Nov. 18, 1996

REVISED

NOV 18 1996

Gopher Tortoise “Take” Permit

FLORIDA GAME AND FRESH WATER FISH COMMISSION

QUINTON L. HEDGEPEETH, DDS
Miami

MRS. GILBERT W. HUMPHREY
Miccosukee

JOE MARLIN HILLIARD
Clewiston

J. BEN ROWE
Gainesville

JULIE K. MORRIS
Sarasota

ROBERT M. BRANTLY, Executive Director
ALLAN L. EGBERT, Ph.D., Assistant Executive Director



FARRIS BRYANT BUILDING
620 South Meridian Street
Tallahassee, Florida 32399-1600
(904) 488-1960

March 12, 1993

Mr. Ben Sharma
Kissimmee Utility Authority
1701 Carroll Street
Kissimmee, FL 34741

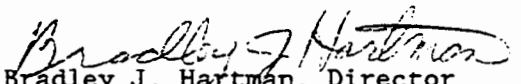
RE: Gopher Tortoise Incidental Take
Permit OSC-6, Osceola County

Dear Mr. Sharma:

Enclosed is permit OSC-6 for the incidental taking of gopher tortoises, their eggs and their burrows within the development boundaries specified. The application for this permit was complete as of March 9, 1993.

Please contact Mr. Steve Lau at 407-778-5094 if you have any questions regarding this permit.

Sincerely,


Bradley J. Hartman, Director
Office of Environmental Services

BJH/tgw
ENV 3-2/1
Enclosure
osc-6.1tr

cc: Osceola County Planning Department
Mr. David M. Lefebvre
Ms. Julie Hovis, Central Region, GFC
Major Starling, Central Region, GFC
Mr. Steve Lau, Office of Environmental Services, GFC
Mr. Don Wood, Division of Wildlife, GFC

Poor Original

PERMIT FOR TAKING OF GOPHER TORTOISES AND
THEIR BURROWS

Chapter 39-27.002(4) FAC

STATE OF FLORIDA GAME AND FRESH WATER FISH COMMISSION

Issuance Date: March 12, 1993

Permittee: Kissimmee Utility Authority
Attention: Mr. Ben Sharma

Permittee Address: 1701 Carroll Street
Kissimmee, Florida 34741

Authorized Agent: David M. Lefebvre
Black and Veatch
P. O. Box 8405
Kansas City, Missouri 64114

Permit Number: OSC-6

Location of Affected Site: Kissimmee Utility Authority's Cane Island Project consisting of approximately 1,003 acres located in Section 29 and the north 1/2 of Section 32, T25S, R28E, Osceola County, see Location Map (Figure 1). The project would impact approximately 49.4 acres of gopher tortoise habitat for construction of the power generating complex, access road/utility corridor and transmission line corridor and approximately 6 acres of tortoise habitat for wetland creation; see Site Plan Map (Figure 4-2).

Permitted Action: The permittee or its agents are authorized to take gopher tortoises, their eggs and their burrows within its development boundaries where such taking is incidental to development activities. The criteria of Rule 39-27.002(4), F.A.C., have been satisfied and the taking, as conditioned below, will not be detrimental to the survival potential of the species.

Provisions/Conditions:

1. The applicant shall protect 129.7 acres of gopher tortoise habitat consisting of four sites [Gopher Tortoise Site 1 (22.7), Site 2 (65.7 acres), Site 3 (21.8 acres) and Site 4 (19.5 acres)] shown on the Gopher Tortoise Management Area Map (Figure 5-1), and grant a perpetual conservation easement over these lands to the Florida Game and Fresh Water Fish Commission (GFC). The installation and maintenance of the proposed Bonnet Creek Canal Transmission Line (location shown in Figure 2) shall be allowed across Gopher Tortoise Site 2. The applicant shall submit a draft copy of the conservation easement to the GFC for review and approval prior to recording. A copy of the recorded conservation easement shall be

provided to the GFC at the Office of Environmental Services, 620 South Meridian street, Tallahassee, Florida 32399-1600.

2. The permit will not go into effect until latter effective date of either:
 - a) 21 days from date of the receipt of this notice, or if a petition for Administrative Hearing is timely filed, until the petition is resolved; or
 - b) the date that the applicant has obtained a letter of acknowledgement from the GFC that it has received a copy of the recorded, previously approved conservation easement for the areas described in condition #1 above.
3. The applicant shall have the obligation to manage and maintain the protected 129.7 acres for gopher tortoises in accordance with the proposed "Upland Habitat Management Plan" (Section 5.1 of the Kissimmee Utility Authority, Florida Municipal Power Agency, Cane Island Project Mitigation Plan) prepared by Black and Veatch, January 1993.
4. The permittee shall keep written records of the habitat management activities conducted and provide a copy of said activities upon request of the GFC.
5. This permit does not relieve the applicant from any other "taking" requirements by the U.S. Fish and Wildlife Service or GFC as to other listed species.
6. The permittee, or authorized agents of the permittee, are authorized to move tortoises, at their discretion, within the property boundaries to minimize taking. This permit does not authorize the permittee or its agents to possess or move tortoises off the contiguous ownership of the permittee or to move tortoises into areas previously authorized as a relocation site by GFC permit. A separate relocation permit from GFC shall be required for those activities.
7. This permit does not authorize any taking of gopher tortoises beyond that which is a direct result of development activities or the on-site movement of animals addressed in Condition #6. Any other form of taking or relocation will require a separate permit from the Executive Director.
8. This permit must be available for inspection at all times while engaged in the permitted activities.

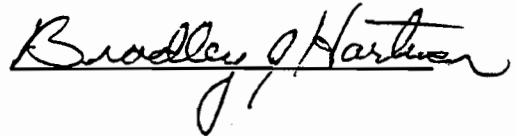
Kissimmee Utility Authority
Gopher Tortoise Take Permit OSC-6
March 12, 1993
Page 3

9. This permit is transferrable to subsequent owners of the property.

Notice of Rights Statement: In accordance with Rules 28-5.111 and 28.6.008, Florida Administrative Code, and Section 120.60, Florida Statutes, any party may request a hearing on this matter pursuant to Section 120.57, Florida Statutes by filing a completed Election of Rights form (copy attached) by certified mail, return receipt requested, with the undersigned within twenty-one (21) days of receipt of this permit and notice. If timely requested and a hearing is granted, the hearing will be conducted under the procedures established by Section 120.57, Florida Statutes. A party will be given the opportunity to be represented by counsel or other qualified representative, to take testimony, to call and cross-examine witnesses, and to have subpoenas issued on your behalf.

Colonel Robert M. Brantly
Executive Director

By:



ENV 3-2/1

Attachments:

1. Election of Rights
 2. Location Map (Figure 1)
 3. Project Impact Areas (Figure 4-2)
 4. Location of Gopher Tortoise Management Areas (Figure 5-1)
- utility.gt



10.4 State Permit Applications

10.4.1 Prevention of Significant Deterioration Application

The construction and operation of Unit 3 will require an ATC/PSD permit. The PSD Air Permit Application is attached to this Site Certification Application under separate cover as Appendix 10.7.

10.4.2 Title IV Acid Rain Permit Application

Modification of the existing Title IV Permit will be required with the addition of Unit 3. As a new unit, the Acid Rain Permit will be submitted 24 months prior to operation.

10.4.3 Environmental Resource Permit Application

Modification of the existing storm water management system is required for development of the grading/drainage and storm water control plans associated with Unit 3. These modifications will be accomplished through review of an Environmental Resource Permit Application. The application is included herein.

The construction, operation, and environmental impacts of the Cane Island-Intercession City Transmission Line will be reviewed as an associated facility. An Environmental Resource Permit Application has been prepared to assist in this review. The application is included herein.

10.4.4 Water Use Permit Application

Additional ground water withdrawals associated with the construction and operation of Unit 3 will be required. These additional withdrawals will be reviewed through completion and review of a SFWMD Application Form RC-1W. This application is included herein.

10.4.5 Industrial Wastewater Treatment System Permit Application

The existing industrial wastewater treatment and disposal system will require modification to incorporate the Unit 3 facilities. These additional treatment and disposal methods will be reviewed through completion and review of a FDEP Wastewater Application Form 2CG. The application is included herein.



10.4.6 Public Drinking Water System Permit Application

The existing drinking water system will require modification to incorporate the facilities associated with Unit 3. These modifications will be reviewed through completion and review of FDEP Form 62-555.900. The application is included herein.

10.4.7 Well Construction Permit Application

The emergency use of ground water as cooling tower makeup will require the installation of four new wells onsite. The selected well construction contractor must complete and submit the Well Construction Permit Applications.

10.4.8 Short Term Dewatering Permit Application

The general construction contractor will be required to complete and submit a short term dewatering permit for deep excavations (neutralization basin, oil/water separator, false start drain tank).

**Environmental Resource Permit Application for
Modification of an Existing Surface Water Management System**

ORG CODE: 3740-2010-0000
EO: G1
OBJ: 002256

FORM #: 62-343,900 (1)
FORM TITLE: JOINT ENVIRONMENTAL
RESOURCE PERMIT APPLICATION
DATE: October 3, 1995

SECTION A

FOR AGENCY USE ONLY

ACOE Application # _____	DEP/WMD Application # _____
Date Application Received _____	Date Application Received _____
Proposed Project Lat. _____	Fee Received \$ _____
Proposed Project Long. _____	Fee Receipt # _____

PART 1:

Are any of the activities described in this application proposed to occur in, on, or over wetlands or other surface waters? ☐ Yes ☒ No

Is this application being filed by or on behalf of a government entity or drainage district? ☐ Yes ☐ No

PART 2:

A. Type of Environmental Resource Permit Requested (check at least one). See Attachment 2 for thresholds and descriptions.

- ☐ Noticed General - include information requested in Section B.
- ☐ Standard General (Single Family Dwelling) - include information requested in Sections C and D.
- ☒ Standard General (all other Standard General projects) - include information requested in Sections C and E.
- ☐ Individual (Single Family Dwelling) - include information requested in Sections C and D.
- ☐ Individual (all other Individual projects) - include information requested in Sections C and E.
- ☐ Conceptual - include information requested in Sections C and E.
- ☐ Mitigation Bank Permit (construction) - include information requested in Section C and F.
(If the proposed mitigation bank involves the construction of a surface water management system requiring another permit defined above, check the appropriate box and submit the information requested by the applicable section.)
- ☐ Mitigation Bank (conceptual) - include information requested in Section C and F.

B. Type of activity for which you are applying (check at least one)

- ☐ Construction or operation of a new system, other than a solid waste facility, including dredging or filling in, on or over wetlands and other surface waters.
- ☐ Construction, expansion or modification of a solid waste facility.
- ☐ Alteration or operation of an existing system which was not previously permitted by a WMD or DEP.
- ☒ Modification of a system previously permitted by a WMD or DEP. Provide previous permit numbers. SFWMD Surface Water Management Permit 49-00672-S
 - ☐ Alteration of a system
 - ☐ Extension of permit duration
 - ☐ Abandonment of a system
 - ☐ Construction of additional phases of a system
 - ☐ Removal of a system

C. Are you requesting authorization to use Sovereign Submerged Lands. ☐ Yes ☒ No
(See Section G and Attachment 5 for more information before answering this question.)

D. For activities in, on or over wetlands or other surface waters, check type of federal dredge and fill permit requested:
☐ Individual ☐ Programmatic General ☐ General ☐ Nationwide ☒ Not Applicable

E. Are you claiming to qualify for an exemption? ☐ Yes ☒ No
If yes, provide rule number if known. _____

PART 3:

A. OWNER(S) OF LAND

NAME

Mr. A. K. Sharma

TITLE AND COMPANY

KUA

ADDRESS

1701 W. Carroll St.

CITY, STATE, ZIP

Kissimmee, FL 34741

TELEPHONE AND FAX

(407) 933-7777
 fax (407) 847-0787

B. ENTITY TO RECEIVE PERMIT (IF OTHER THAN OWNER)

NAME

KUA

ADDRESS

1701 S. Carroll St.

CITY, STATE, ZIP

Kissimmee, FL 34741

TELEPHONE AND FAX

(407) 933-7777

C. AGENT AUTHORIZED TO SECURE PERMIT

NAME

Myron Rollins

TITLE AND COMPANY

Black & Veatch

ADDRESS

11401 Lamar

CITY, STATE, ZIP

Overland Park, KS 66211

TELEPHONE AND FAX

(913) 458-7432
 fax (913) 458-2934

D. CONSULTANT (IF DIFFERENT FROM AGENT)

NAME

TITLE AND COMPANY

ADDRESS

CITY, STATE, ZIP

TELEPHONE AND FAX

PART 4 (Please provide metric equivalent for federally funded projects):

- A. Name of project, including phase if applicable: Cane Island Power Park - Unit 3
- B. Is this application for part of a multi-phase project? ☒ Yes ☐ No
- C. Total applicant-owned area contiguous to the project: 1,027 ac.; _____ ha.
- D. Total area served by the system: 26.2 ac.; _____ ha.
- E. Impervious area for which a permit is sought: 5.6 ac.; _____ ha.
- F. Volume of water that the system is capable of impounding: 11 ac. ft.; _____ m³
- G. What is the total area of work in, on, or over wetlands or other surface waters?
0 ac.; 0 ha. 0 sq. ft.; 0 sq. m.
- H. Total volume of material to be dredged: 0 yd³; 0 m³
- I. Number of new boat slips proposed: 0 wet slips; 0 dry slips

PART 5:

Project location (use additional sheets, if needed):

County(ies) Osceola

Section(s) 29 & 32 Township 25 South Range 28 East

Section(s) _____ Township _____ Range _____

Section(s) _____ Township _____ Range _____

Land Grant name, if applicable _____

Tax Parcel Identification Number _____

Street address, road, or other location 6075 Old Tampa Highway

City, Zip Code if applicable Intercession City, FL 33848

PART 6: Describe in general terms the proposed project, system, or activity.

KUA and FMPA are proposing to construct and operate a new electric
generating unit at the Cane Island Power Park. The new unit (Unit 3) will
be a combined cycle combustion turbine unit located in the previously
permitted area on the central portion of geographic feature known as Cane
Island, adjacent and north of Unit 2. A new storm water detention pond
and additional site drainage facilities are required. The proposed
facilities are further described in Section 3 of the SCA.

PART 7:

A. If there have been any pre-application meetings, including on-site meetings, with regulatory staff, please list the date(s), location(s), and names of key staff and project representatives.

5/13/98: Orlando Service Center; A. Leavens, G. Ogden, S. Elfers, E. Edmundson
6/9/98: W. Palm Beach; S. Coughanour, J. Rosenfeld, Orlando staff (above)
by conference phone, S. Palmer - FDEP by conference phone.

B. Please identify by number any MSSW/Wetland resource/ERP/ACOE Permits pending, issued or denied for projects at the location, and any related enforcement actions.

Agency ACOE	Date 4/93	No./Type of Application 199200600(IP-SL)	Action Taken None
FDEP	10/92	49-211129-4	None
SFWM	4/93	49-00671-S	None

C. Note: The following information is required for projects proposed to occur in, on or over wetlands that need a federal dredge and fill permit or an authorization to use state owned submerged lands.

Please provide the names, addresses and zip codes of property owners whose property directly adjoins the project (excluding applicant) and/or (for proprietary authorizations) is located within a 500 ft. radius of the applicant's land. Please attach a plan view showing the owner's names and adjoining property lines. Attach additional sheets if necessary.

None

- | | |
|----------|----------|
| 1. _____ | 2. _____ |
| _____ | _____ |
| _____ | _____ |
| 3. _____ | 4. _____ |
| _____ | _____ |
| _____ | _____ |
| 5. _____ | 6. _____ |
| _____ | _____ |
| _____ | _____ |
| 7. _____ | 8. _____ |
| _____ | _____ |
| _____ | _____ |

PART 8:

A. By signing this application form, I am applying, or I am applying on behalf of the applicant, for the permit and any proprietary authorizations identified above, according to the supporting data and other incidental information filed with this application. I am familiar with the information contained in this application and represent that such information is true, complete and accurate. I understand this is an application and not a permit, and that work prior to approval is a violation. I understand that this application and any permit issued or proprietary authorization issued pursuant thereto, does not relieve me of any obligation for obtaining any other required federal, state, water management district or local permit prior to commencement of construction. I agree, or I agree on behalf of the applicant, to operate and maintain the permitted system unless the permitting agency authorizes transfer of the permit to a responsible operation entity. I understand that knowingly making any false statement or representation in this application is a violation of Section 373.430, F.S. and 18 U.S.C. Section 1001.

Myron Rollins, Black & Veatch

Typed/Printed Name of Applicant (If no Agent is used) or Agent (If one is so authorized below)

Signature of Applicant/Agent

Date

Project Manager

(Corporate Title if applicable)

AN AGENT MAY SIGN ABOVE ONLY IF THE APPLICANT COMPLETES THE FOLLOWING:

B. I hereby designate and authorize the agent listed above to act on my behalf, or on behalf of my corporation, as the agent in the processing of this application for the permit and/or proprietary authorization indicated above; and to furnish, on request, supplemental information in support of the application. In addition, I authorize the above-listed agent to bind me, or my corporation, to perform any requirement which may be necessary to procure the permit or authorization indicated above. I understand that knowingly making any false statement or representation in this application is a violation of Section 373.430, F.S. and 18 U.S.C. Section 1001.

A. K. Sharma

Typed/Printed Name of Applicant

Signature of Applicant

Date

Director of Power Supply

(Corporate Title if applicable)

Please note: The applicant's original signature (not a copy) is required above.

PERSON AUTHORIZING ACCESS TO THE PROPERTY MUST COMPLETE THE FOLLOWING:

C. I either own the property described in this application or I have legal authority to allow access to the property, and I consent, after receiving prior notification, to any site visit on the property by agents or personnel from the Department of Environmental Protection, the Water Management District and the U.S. Army Corps of Engineers necessary for the review and inspection of the proposed project specified in this application. I authorize these agents or personnel to enter the property as many times as may be necessary to make such review and inspection. Further, I agree to provide entry to the project site for such agents or personnel to monitor permitted work if a permit is granted.

Jeff Ling

Typed/Printed Name

Signature

Date

Manager of Production

(Corporate Title if applicable)

SECTION C

Environmental Resource Permit Notice of Receipt of Application

Note: this form does not need to be submitted for noticed general permits.

This information is required in addition to that required in other sections of the application. Please submit five copies of this notice of receipt of application and all attachments with the other required information. Please submit all information on 8-1/2" x 11" paper.

Project Name: Cane Island Power Park - Unit 3
County: Osceola
Owner: KUA
Applicant: KUA
Applicant's Address: 1701 W. Carroll St.
Kissimmee, FL 34741

1. Indicate the project boundaries on a USGS quadrangle map. Attach a location map showing the boundary of the proposed activity. The map should also contain a north arrow and a graphic scale; show Section(s), Township(s), and Range(s); and must be of sufficient detail to allow a person unfamiliar with the site to find it. See Figures 2.1-1 and 2.1-2 in SCA.
2. Provide the names of all wetlands, or other surface waters that would be dredged, filled, impounded, diverted, drained, or would receive discharge (either directly or indirectly), or would otherwise be impacted by the proposed activity, and specify if they are in an Outstanding Florida Water or Aquatic Preserve:
Reedy Creek Swamp will receive storm water detention pond overflow.
3. Attach a depiction (plan and section views), which clearly shows the works or other facilities proposed to be constructed. Use multiple sheets, if necessary. Use a scale sufficient to show the location and type of works. This is provided in Figures 3.2-1 and 3.2-2 of the SCA.
4. Briefly describe the proposed project (such as "construct dock with boat shelter", "replace two existing culverts", "construct surface water management system to serve 150 acre residential development"):
Construct surface water management system to serve Unit 3, an industrial (power plant) development of 5 acres.
5. Specify the acreage of wetlands or other surface waters, if any, that are proposed to be filled, excavated, or otherwise disturbed or impacted by the proposed activity:
filled 0 ac.; excavated 0 ac.; other impacts 0 ac.
6. Provide a brief statement describing any proposed mitigation for impacts to wetlands and other surface waters (attach additional sheets if necessary):
No mitigation proposed; mitigation previously provided.

FOR AGENCY USE ONLY

Application Name: _____
Application Number: _____
Office where the application can be inspected: _____

Note to Notice recipient: The information in this notice has been submitted by the applicant, and has not been verified by the agency. It may be incorrect, incomplete or may be subject to change.

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.

SECTION E

INFORMATION REQUESTED FOR STANDARD GENERAL, INDIVIDUAL AND CONCEPTUAL ENVIRONMENTAL RESOURCE PERMIT APPLICATIONS NOT RELATED TO A SINGLE FAMILY DWELLING UNIT

Please provide the information requested below if the proposed project requires either a standard general, individual, or conceptual approval environmental resource permit and is not related to an individual, single family dwelling unit, duplex or quadraplex. The information listed below represents the level of information that is usually required to evaluate an application. The level of information required for a specific project will vary depending on the nature and location of the site and the activity proposed. Conceptual approvals generally do not require the same level of detail as a construction permit. However, providing a greater level of detail will reduce the need to submit additional information at a later date. If an item does not apply to your project, proceed to the next item. Please submit all information that is required by the Department on either 8 1/2 in. X 11 in. paper or 11 in. X 17 in. paper. Larger drawings may be submitted to supplement but not replace these smaller drawings.

I. Site Information

- A. Provide a map(s) of the project area and vicinity delineating USDA/SCS soil types.
See attached Figure E-1, SCS Soil Types.
- B. Provide recent aerials, legible for photointerpretation with a scale of 1" = 400 ft, or more detailed, with project boundaries delineated on the aerial.
See original application
- C. Identify the seasonal high water or mean high tide elevation and normal pool or mean low tide elevation for each on site wetland or surface water, including receiving waters into which runoff will be discharged. Include dates, datum, and methods used to determine these elevations. See attached additional information sheet.
- D. Identify the wet season high water tables at the locations representative of the entire project site. Include dates, datum, and methods used to determine these elevations.
Groundwater conditions at the site are presented in Section 2.3.2 of the SCA.

II. Environmental Considerations

- A. Provide results of any wildlife surveys that have been conducted on the site, and provide any comments pertaining to the project from the Florida Game and Fresh Water Fish Commission and the U.S. Fish and Wildlife Service.
See Section 2.3 of the SCA.

- B. Provide a description of how water quantity, quality, hydroperiod, and habitat will be maintained in on-site wetlands and other surface waters that will be preserved or will remain undisturbed. See attached additional information sheet
- C. Provide a narrative description of any proposed mitigation plans, including purpose, maintenance, monitoring, and construction sequence and techniques, and estimated costs. See original application.
- D. Describe how boundaries of wetlands or other surface waters were determined. If there has ever been a jurisdictional declaratory statement, a formal wetland determination, a formal determination, a validated informal determination, or a revalidated jurisdictional determination, provide the identifying number. Wetland delineations of the project impact areas were performed prior to Units 1 and 2 construction.
- E. **Impact Summary Tables:** There are no project impacts to wetlands or surface waters in the power block area.
 - 1. For all projects, complete Tables 1, 2 and 3 as applicable.
 - 2. For docking facilities or other structures constructed over wetlands or other surface waters, provide the information requested in Table 4.
 - 3. For shoreline stabilization projects, provide the information requested in Table 5.

III. Plans

Provide clear, detailed plans for the system including specifications, plan (overhead) views, cross sections (with the locations of the cross sections shown on the corresponding plan view), and profile (longitudinal) views of the proposed project. The plans must be signed and sealed by an appropriate registered professional as required by law. Plans must include a scale and a north arrow. These plans should show the following:

- A. Project area boundary and total land area, including distances and orientation from roads or other land marks; See Figure 2.1-2 in Section 2 of SCA.
- B. Existing land use and land cover (acreage and percentages), and on-site natural communities, including wetlands and other surface waters, aquatic communities, and uplands. Use the Florida Land Use Cover & Classification System (FLUCCS)(Level 3) for projects proposed in the South Florida Water Management District, the St. Johns River Water Management District, and the Suwannee River Water Management District and use the National Wetlands Inventory (NWI) for projects proposed in the Southwest Florida Water Management District. Also identify each community with a unique identification number which must be consistent in all exhibits. See Figures 2.3-3 and 2.3-4 in Section 2.3 of the SCA.

- C. The existing topography extending at least 100 feet off the project area, and including adjacent wetlands and other surface waters. All topography shall include the location and a description of known benchmarks, referenced to NGVD. For systems waterward of the mean high water (MHW) or seasonal high water lines, show water depths, referenced to mean low water (MLW) in tidal areas or seasonal low water in non-tidal areas, and list the range between MHW and MLW. For docking facilities, indicate the distance to, location of, and depths of the nearest navigational channel and access routes to the channel. Topographic information is included in Figure 3.8-1 of the SCA.
- D. If the project is in the known flood plain of a stream or other water course, identify the following: 1) the flood plain boundary and approximate flooding elevations; and 2) the 100-year flood elevation and floodplain boundary of any lake, stream or other watercourse located on or adjacent to the site; See attached additional information sheet
- E. The boundaries of wetlands and other surface waters within the project area. Distinguish those wetlands and other surface waters that have been delineated by any binding jurisdictional determination; See Figure 2.1-3 in Section 2 of SCA.
- F. Proposed land use, land cover and natural communities (acreage and percentages), including wetlands and other surface waters, undisturbed uplands, aquatic communities, impervious surfaces, and water management areas. Use the same classification system and community identification number used in III (B) above.
See Figures 2.3-4 and 2.3-5 in Section 2 of SCA.
- G. Proposed impacts to wetlands and other surface waters, and any proposed connections/outfalls to other surface waters or wetlands; This information is contained in Sections 3.8 and 5.3.1 of the SCA.
- H. Proposed buffer zones; See Figure 2.1-3 in Section 2 of SCA.
- I. Pre- and post-development drainage patterns and basin boundaries showing the direction of flows, including any off-site runoff being routed through or around the system; and connections between wetlands and other surface waters;
This information is contained in Section 3.8 and Figure 3.8-1 of the SCA.
- J. Location of all water management areas with details of size, side slopes, and designed water depths; This information is contained in Section 3.8 and in Figures 3.2-1, 3.8-1, 3.8-2 of the SCA.
- K. Location and details of all water control structures, control elevations, any seasonal water level regulation schedules; and the location and description of benchmarks (minimum of one benchmark per structure); This information is contained in Section 3.8 and in Figures 3.8-1 and 3.8-2 of the SCA.

- L. Location, dimensions and elevations of all proposed structures, including docks, seawalls, utility lines, roads, and buildings; This information is presented on Figure 3.2-1 of the SCA. Building floor elevations are set at 81'-9".
- M. Location, size, and design capacity of the internal water management facilities; This is discussed in Section 3 Item J, above.
- N. Rights-of-way and easements for the system, including all on-site and off-site areas to be reserved for water management purposes, and rights-of-way and easements for the existing drainage system, if any; None
- O. Receiving waters or surface water management systems into which runoff from the developed site will be discharged; Reedy Creek Swamp
- P. Location and details of the erosion, sediment and turbidity control measures to be implemented during each phase of construction and all permanent control measures to be implemented in post-development conditions; This is discussed in Section 3.8.5 and Figures 3.8-1 and 3.8-2 of the SCA.
- Q. Location, grading, design water levels, and planting details of all mitigation areas; None
- R. Site grading details, including perimeter site grading; This is presented in Figures 3.8-1 and 3.8-2 and in Section 3.8 of the SCA.
- S. Disposal site for any excavated material, including temporary and permanent disposal sites; Onsite or in Cane Island - Intercession City Transmission Line corridor.
- T. Dewatering plan details; A description of proposed dewatering activities during construction is presented in Section 4.3 of the SCA.
- U. For marina facilities, locations of any sewage pumpout facilities, fueling facilities, boat repair and maintenance facilities, and fish cleaning stations; N/A
- V. Location and description of any nearby existing offsite features which might be affected by the proposed construction or development such as stormwater management ponds, buildings or other structures, wetlands or other surface waters. None
- W. For phased projects, provide a master development plan. Figure 2.1-3 identified the ultimate development area.

IV. Construction Schedule and Techniques

Provide a construction schedule, and a description of construction techniques, sequencing and equipment. This information should specifically include the following: Construction scheduled to begin September 1999.

- A. Method for installing any pilings or seawall slabs; see Section 2.3 of SCA.

- B. Schedule of implementation of temporary or permanent erosion and turbidity control measures; See Section 4 of SCA.
- C. For projects that involve dredging or excavation in wetlands or other surface waters, describe the method of excavation, and the type of material to be excavated;
None
- D. For projects that involve fill in wetlands or other surface waters, describe the source and type of fill material to be used. For shoreline stabilization projects that involve the installation of riprap, state how these materials are to be placed, (i.e., individually or with heavy equipment) and whether the rocks will be underlain with filter cloth;
None
- E. If dewatering is required, detail the dewatering proposal including the methods that are proposed to contain the discharge, methods of isolating dewatering areas, and indicate the period dewatering structures will be in place (Note: a consumptive use or water use permit may be required); See Section 4.3 of SCA.
- F. Methods for transporting equipment and materials to and from the work site. If barges are required for access, provide the low water depths and draft of the fully loaded barge;
Trucks
- G. Demolition plan for any existing structures to be removed; and
N/A
- H. Identify the schedule and party responsible for completing monitoring, record drawings, and as-built certifications for the project when completed.

General Contractor

V. Drainage Information

- A. Provide pre-development and post-development drainage calculations, signed and sealed by an appropriate registered professional, as follows:
Except where noted otherwise, this information is included in Section 3.8.7 of SCA.
1. Runoff characteristics, including area, runoff curve number or runoff coefficient, and time of concentration for each drainage basin;
 2. Water table elevations (normal and seasonal high) including aerial extent and magnitude of any proposed water table drawdown;
 3. Receiving water elevations (normal, wet season, design storm); This is discussed in Section E, I. Site Information, item C.
 4. Design storms used including rainfall depth, duration, frequency, and distribution;

5. Runoff hydrograph(s) for each drainage basin, for all required design storm event(s);
 6. Stage-storage computations for any area such as a reservoir, close basin, detention area, or channel, used in storage routing;
 7. Stage-discharge computations for any storage areas at a selected control point, such as control structure or natural restriction;
 8. Flood routings through on-site conveyance and storage areas;
 9. Water surface profiles in the primary drainage system for each required design storm event(s);
 10. Runoff peak rates and volumes discharged from the system for each required design storm event(s);
 11. Tail water history and justification (time and elevation); and
See Item 3, above.
 12. Pump specifications and operating curves for range of possible operating conditions (if used in system). N/A
- B. Provide the results of any percolation tests, where appropriate, and soil borings that are representative of the actual site conditions; Subsurface conditions at the site are described in Section 2.3 and Appendix 10.8 of the SCA.
- C. Provide the acreage, and percentages of the total project, of the following:
1. Impervious surfaces, excluding wetlands; 5.6 acres (21.4%)
 2. Pervious surfaces (green areas, not including wetlands); 15.6 acres (59.5%)
 3. Lakes, canals, retention areas, other open water areas; and 3.0 acres (11.5%)
 4. Wetlands. 0.0 acres (0%)
 5. Containment Areas (no runoff generated) = 2.0 acres (7.6%).
- D. Provide an engineering analysis of floodplain storage and conveyance (if applicable), including: N/A
1. Hydraulic calculations for all proposed traversing works;
 2. Backwater water surface profiles showing upstream impact of traversing works;

3. Location and volume of encroachment within regulated floodplain(s); and
4. Plan for compensating floodplain storage, if necessary, and calculations required for determining minimum building and road flood elevations.

E. Provide an analysis of the water quality treatment system including:

The water quality treatment system is discussed in Sections 3.8 and 5.3 of the SCA.

1. A description of the proposed stormwater treatment methodology that addresses the type of treatment, pollution abatement volumes, and recovery analysis; and
2. Construction plans and calculations that address stage-storage and design elevations, which demonstrate compliance with the appropriate water quality treatment criteria.

F. Provide a description of the engineering methodology, assumptions and references for the parameters listed above, and a copy of all such computations, engineering plans, and specifications used to analyze the system. If a computer program is used for the analysis, provide the name of the program, a description of the program, input and output data, two diskette copies, if available, and justification for model selection.

See Section 3.10 in SCA for calculations.

VI. Operation and Maintenance and Legal Documentation

- A. Describe the overall maintenance and operation schedule for the proposed system.
The system will be checked on a regular basis to ensure proper operation.
- B. Identify the entity that will be responsible for operating and maintaining the system in perpetuity if different than the permittee, a draft document enumerating the enforceable affirmative obligations on the entity to properly operate and maintain the system for its expected life, and documentation of the entity's financial responsibility for long-term maintenance. If the proposed operation and maintenance entity is not a property owner's association, provide proof of the existence of an entity, or the future acceptance of the system by an entity which will operate and maintain the system. If a property owner's association is the proposed operation and maintenance entity, provide copies of the articles of incorporation for the association and copies of the declaration, restrictive covenants, deed restrictions, or other operational documents that assign responsibility for the operation and maintenance of the system. Provide information ensuring the continued adequate access to the system for maintenance purposes. Before transfer of the system to the operating entity will be approved, the permittee must document that the transferee will be bound by all terms and conditions of the permit.
KUA is permittee and operator.

- C. Provide copies of all proposed conservation easements, storm water management system easements, property owner's association documents, and plats for the property containing the proposed system. Conservation easement documents on file.
- D. Provide indication of how water and waste water service will be supplied. Letters of commitment from off-site suppliers must be included. Water supply and wastewater treatment are provided onsite.
- E. Provide a copy of the boundary survey and/or legal description and acreage of the total land area of contiguous property owned/controlled by the applicant. On file.

VII. Water Use

- A. Will the surface water system be used for water supply, including landscape irrigation, or recreation. No.
- B. If a Consumptive Use or Water Use permit has been issued for the project, state the permit number. 49-00671-W (modification requested)
- C. If no Consumptive Use or Water Use permit has been issued for the project, indicate if such a permit will be required and when the application for a permit will be submitted.
N/A
- D. Indicate how any existing wells located within the project site will be utilized or abandoned. 2 production wells onsite for service water supply.
4 new emergency cooling water supply wells proposed.

Item E.I.C. The receiving water is Reedy Creek Swamp adjacent to Cane Island. A water stage recorder is located at Reedy Creek Improvement District-Structure 40, approximately 3,500 feet west of the power block. For the period of record from October 1986 to September 1996, the maximum daily gage height was 71.23 feet msl on September 19, 1994. The minimum daily gage height was 66.76 feet msl on June 3, 1990.

Item E.II.B. There are no wetlands at the power block location; however, storm water runoff is discharged to Reedy Creek Swamp. The first ½ inch of runoff from the power block area is detained and percolated from the detentiopn ponds. Outlet structures at the ponds limit the post-development peak discharge to pre-development peak discharge rate.

Item E.III.D. The power block is not in the 100 year flood plain as shown on figure E-2. The 100 year recurrence interval flood elevation is Reedy Creek Swamp surrounding Cane Island is 70 feet msl.

TABLE 1
PROJECT IMPACT SUMMARY

WL & SW ID	WL & SW TYPE	WL & SW SIZE (AC.) ON SITE	WL & SW (AC.) NOT IMPACTED	PERMANENT WL & SW IMPACTS		TEMPORARY WL & SW IMPACTS		MITIGATION ID
				IMPACT SIZE	IMPACT	IMPACT	IMPACT	
PROJECT TOTALS:								

NL = Wetland; SW = Surface water; ID = Identification number, letter, etc.

Wetland Type: Use an established wetland classification system and, in the comments section below, indicate which classification system is being used.

Impact Code (Type): D = dredge; F = fill; H = change hydrology; S = shading; C = clearing; O = other. Indicate the final impact if more than one impact type is proposed in a given area. For example, show F only for an area that will first be demucked and then backfilled.

Note: Multiple entries per cell are not allowed, except in the "Mitigation ID" column. Any given acreage of wetland should be listed in one row only, such that the total of all rows equals the project total for a given category (column). For example, if Wetland No. 1 includes multiple wetland types and multiple impact codes are proposed in each type, then each proposed impact in each wetland type should be shown on a separate row, while the size of each wetland type found in Wetland No. 1 should be listed in only one row.

Comments: _____

TABLE 2
ON-SITE MITIGATION SUMMARY

MITIGATION ID	CREATION		RESTORATION		ENHANCEMENT		WETLAND PRESERVE		UPLAND PRESERVE		OTHER	
	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TYPE	AREA	TYPE	AREA	TARGET TYPE
PROJECT TOTALS												

DES (multiple entries per cell not allowed):

Target Type or Type = target or existing habitat type from an established wetland classification system or land use classification for non-wetland mitigation

REMARKS:

TABLE 3
OFF-SITE MITIGATION SUMMARY

MITIGATION ID	CREATION		RESTORATION		ENHANCEMENT		WETLAND PRESERVE		UPLAND PRESERVE		OTHER	
	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TYPE	AREA	TYPE	AREA	TARGET TYPE
PROJECT TOTALS												

DES (multiple entries per cell not allowed):
 Target Type=target or existing habitat type from an established wetland classification system or land use classification for non-wetland mitigation

REMARKS:

DOCKING FACILITY SUMMARY

*Dock, Pier, Finger Pier, Other Structure (specify type) **New, Replaced, Existing (unaltered), Removed, Altered/Modified	TOTALS:	Existing	Proposed
	# of Slips		
	Sq. Ft. Over		

Use of Structure _____

Will the docking facility provide: Livaboard Slips? If yes, Number: _____

Fueling Facilities: If yes, Number: _____

Sewage Pump-out Facilities? If yes, Number:_____

Other Supplies or Services Required for Boating (excluding refreshments, bait and tackle) _____ Yes _____ No

Type of Materials for Decking and Pilings (i.e., CCA, pressure treated wood, plastic, or concrete)

Pilings _____

Decking _____

Proposed Dock Plank Spacing (if applicable) _____

Proposed Size (length and draft), Type, and Number of Boats Expected to Use or Proposed to be Mooring at the facility)

Table 5: **SHORELINE STABILIZATION IF YOU ARE CONSTRUCTING A SHORELINE STABILIZATION PROJECT, PLEASE PROVIDE THE FOLLOWING:**

Stabilization	Linear Ft. New	Linear Ft. Replaced	Linear Ft. Repaired	Linear Ft. Removed	Slope H: V:	Toe Width (Ft.)
Vertical Seawall						
Seawall + Rip Rap						
Rip Rap						
Rip Rap + Vegetation						
Other Shoreline Stabilization Type _____						

Size of Rip Rap _____

Type of Rip Rap _____

SOIL TYPE LEGEND

Poor Original

NUMBER	DESCRIPTION
7	CANDLER SAND, 0 TO 5 PERCENT SLOPES
16	IMMOKALEE FINE SAND
24	NARCOOSSEE FINE SAND
37	POMPANO FINE SAND, DEPRESSIONAL
41	SATELLITE SAND

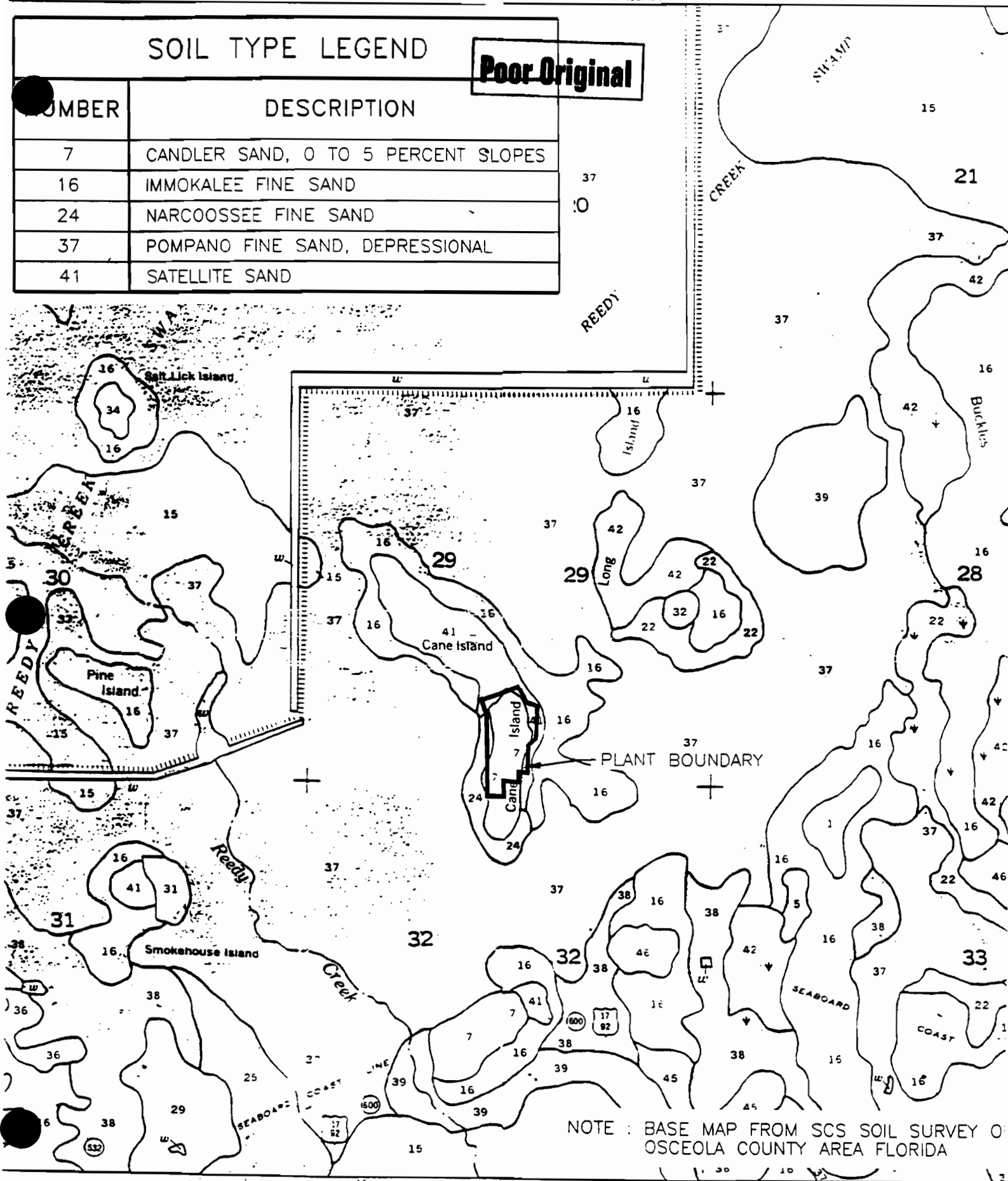


FIGURE E-1
SCS SOIL TYPES

Poor Original

Reedy Creek Improvement District
(AREA NOT INCLUDED)

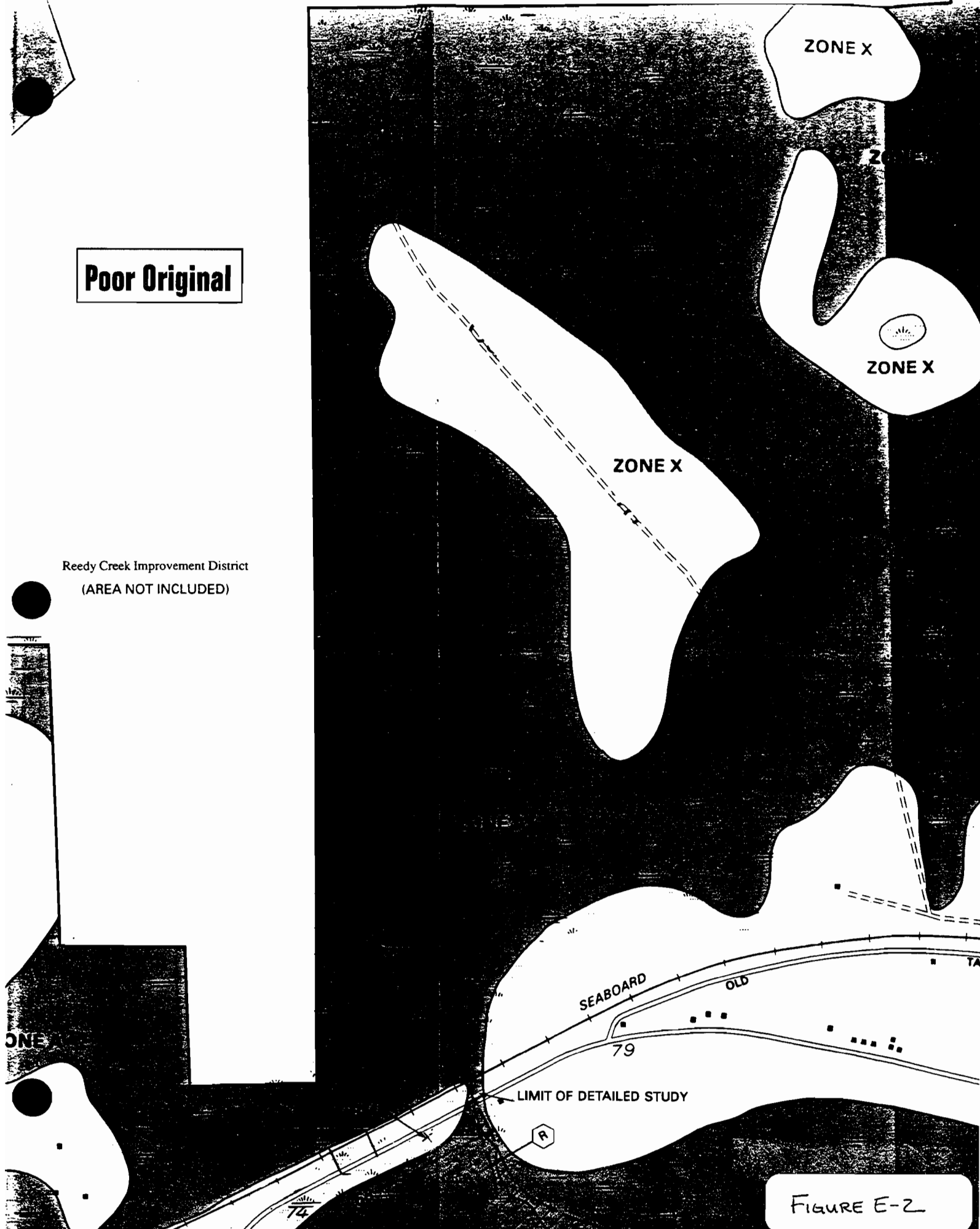


FIGURE E-2

**Environmental Resource Permit Application for The Proposed
Cane Island Power Plant to Intercession City
Power Plant Transmission Line**

Section C

Environmental Resource Permit Notice of Receipt of Application

Project Name: Cane Island to Intercession City Transmission Line

County: Osceola

Owner: Kissimmee Utility Authority (KUA)

Applicant: KUA

Applicant's Address: 1701 W. Carroll St.
Kissimmee, Florida
34741

1. Project map showing boundary and location of the proposed transmission line (See SCA Figure 6.1-1).
2. Reedy Creek and Reedy Creek Swamp will receive fill. They are not Outstanding Florida Waters or in Aquatic Preserves.
3. See Figures 6.1-3, 6.1-4, 6.1-5, and 6.1-6 in the Site Certification Application (SCA) for plan and section views of the proposed transmission line.
4. Construct transmission line from Cane Island Power Park to Intercession City Power Plant.
5. Cubic yards of fill to be added to Wetlands 4030.
Forested wetland to be cleared 11.3 ac.
6. Several routes have been investigated to avoid and minimize impacts to wetlands. Mitigation measures were established for ultimate site development of Cane Island. Proposed developments are part of the ultimate development.

Section E

I. Site Information

A. Figure E-1 is a map of the project area and vicinity delineating USDA/SCS soil types.

B. Map with project boundaries delineated (SCA Figure 6.1-1). Figure E-2 illustrates the safe upland line adjacent to Reedy Creek Swamp as determined for the existing gas pipeline.

C. The receiving water is Reedy Creek Swamp adjacent to the transmission line corridor. A water stage recorder is located at Reedy Creek Improvement District-Structure 40, approximately 3,500 west of the power block at Cane Island. For the period of record from October 1986 to September 1996, the maximum daily gage height was 71.23 feet msl on September 19, 1994. The minimum daily gage height was 66.76 feet msl on June 3, 1990.

D. Wetland and surface water boundaries are delineated in SCA Figure 6.1-1.

The wet season water table has been approximated to be 73.5 feet NGVD. A more exact SHWT will be determined by a qualified geotechnical engineer, in the final design of the project.

This preliminary estimation of the SHWT was made by reviewing stage data from gage #02266300 at Reedy Creek and Route 192, which is north of the proposed project. The seasonal highs between 1990 and 1996 were approximately 12 feet above the gage datum. The datum of the gage is 66.4 feet NGVD. Thus the seasonal high stage for this portion of Reedy Creek is at about 78.4 feet. The difference in land elevation between the gage station and the proposed project is about 4.9 feet, based in the Intercession City, FL Quad Map. Assuming that the slope of the creek bed approximates the water surface profile of Reedy Creek, the SHWT in the area of the project is 73.5 feet NGVD.

II. Environmental Considerations

A. U.S. Fish and Wildlife Service and the Florida Game and Fresh Water Fish Commission were involved in the mitigation for ultimate site development at Cane Island Power. No enforcement action has occurred. Results of wildlife monitoring are presented to the agencies in the annual mitigation reports.

B. The quantity, quality, hydroperiod, and habitat will be maintained in Reedy Creek swamp by allowing waters to flow through culverts under access roads. Access roads will not cross Reedy Creek and will not affect the quantity, quality, hydroperiod of Reedy Creek. Habitat will be maintained for clearance of the transmission lines.

C. Mitigation plans for the ultimate site development include conservation easements for the FGFWFC and South Florida Water Management District (SFWMD) in which the wildlife and vegetation is monitored and managed, and creation and monitoring of a forested wetland.

D. State (FAC 62-340) and Federal (1987 Corps Delineation Manual) wetland boundaries were delineated for the proposed transmission line in July 1998. Jurisdictional wetland determinations were conducted by a Black & Veatch wetland specialist.

E. Impact Summary Tables 1 and 2 are in the attachments.

III. Plans

A. The 30 acre project area for the new right-of-way is illustrated in SCA Figure 6.1-1.

B. Existing land use and land cover and on-site natural communities, including wetlands and other surface waters, aquatic communities, and uplands are illustrated in Figure E-3.

C. The existing topography extending at least 100 feet off of the project area including adjacent wetlands and other surface waters are illustrated in SCA Figure 6.1-1.

D. The transmission line is in the 100 year flood plain as shown in figure E-4. The 100 year recurrence interval flood elevation in Reedy Creek Swamp is 70 feet msl.

E. Boundaries of wetlands and other surface waters within the project area are illustrated in SCA Figure 6.1-1.

F. Proposed land use (Figure E-3), land cover and natural communities (Figure 2.3-4 in the SCA) including wetlands and other surface waters, undisturbed uplands, aquatic communities, impervious surfaces, and water management areas.

G. Proposed impacts to wetlands and other surface waters include 0.32 acres of aerial crossing, 11.3 acres of forested wetland clearing, and 4030 cubic yards of fill.

H. There are no proposed buffer zones.

I. The proposed Transmission line should not impact drainage patterns. Culverts, if required will be installed to maintain drainage and water flow.

J-K. Does not apply.

L. Location of structures is illustrated in SCA Figure 6.1-1. Elevations of the structures are illustrated in Figure 6.1-6 of the SCA.

M-N. Does not apply

O. There will be no discharge.

P. Refer to SCA section 6.1.8.1 and Figure 6.1-6.

Q. Does not apply.

R. Refer to Section 6.1.3 of the SCA.

S. Any excavated material will be disposed in uplands.

T. Does not apply.

U. Does not apply.

V. No offsite features will be affected by the proposed construction.

W. Development is described in Section 6 of the SCA.

IV. Construction Schedule and Techniques

(See Section 6.1.8 of the SCA)

V. Drainage Information

The Drainage Information section is not applicable for this project since the drainage and flood characteristics of the surrounding area will not be impacted. No water quality treatment is required for this type of project, therefore no impoundments are proposed. No significant impacts to the floodplain or floodway are proposed.

VI. Operation and Maintenance and Legal Documentation

(See Section 6.1.9 of the SCA)

VII. Water Use

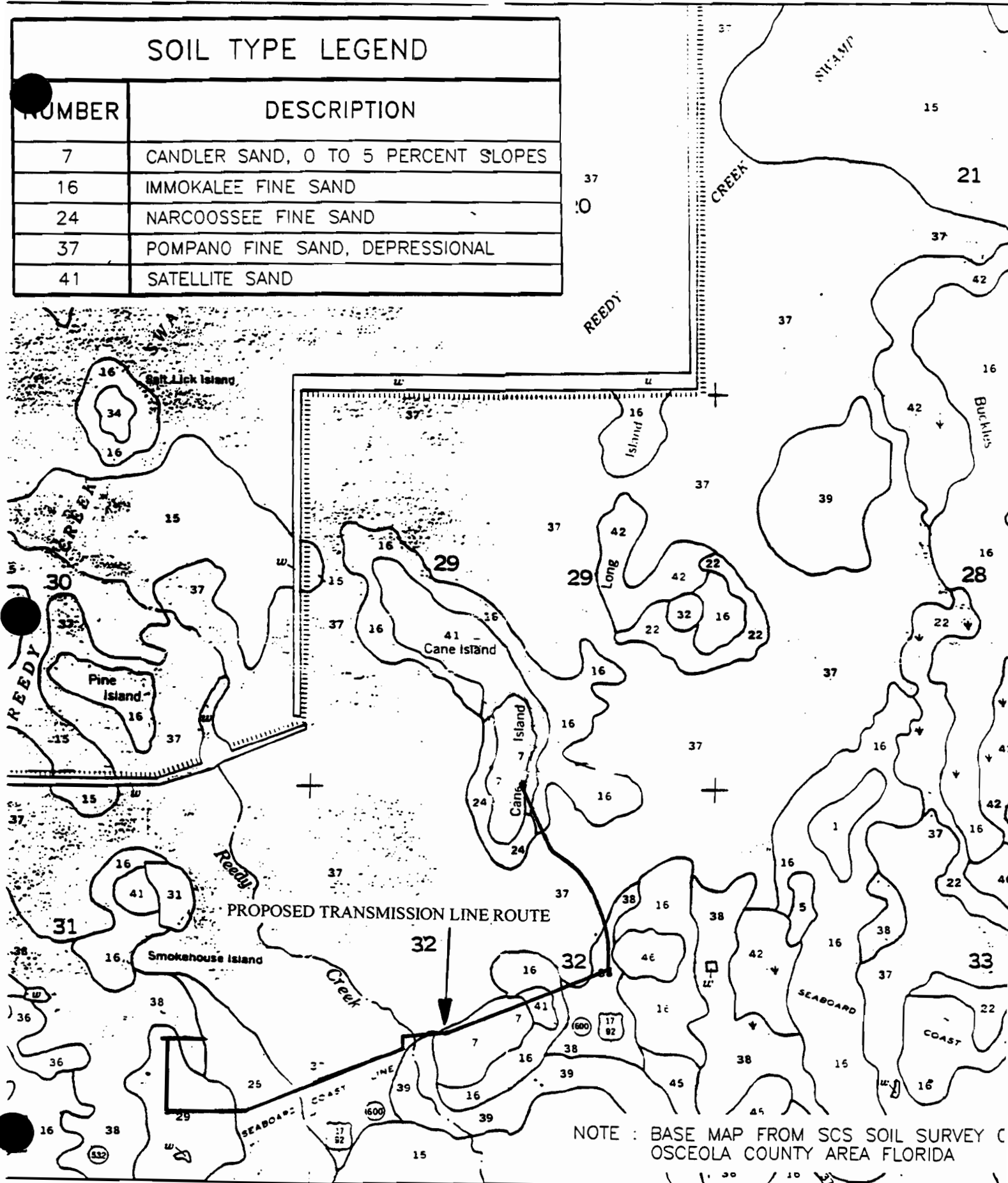
The Water Use information section is not applicable for this project since the will not be used in any manner.

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.

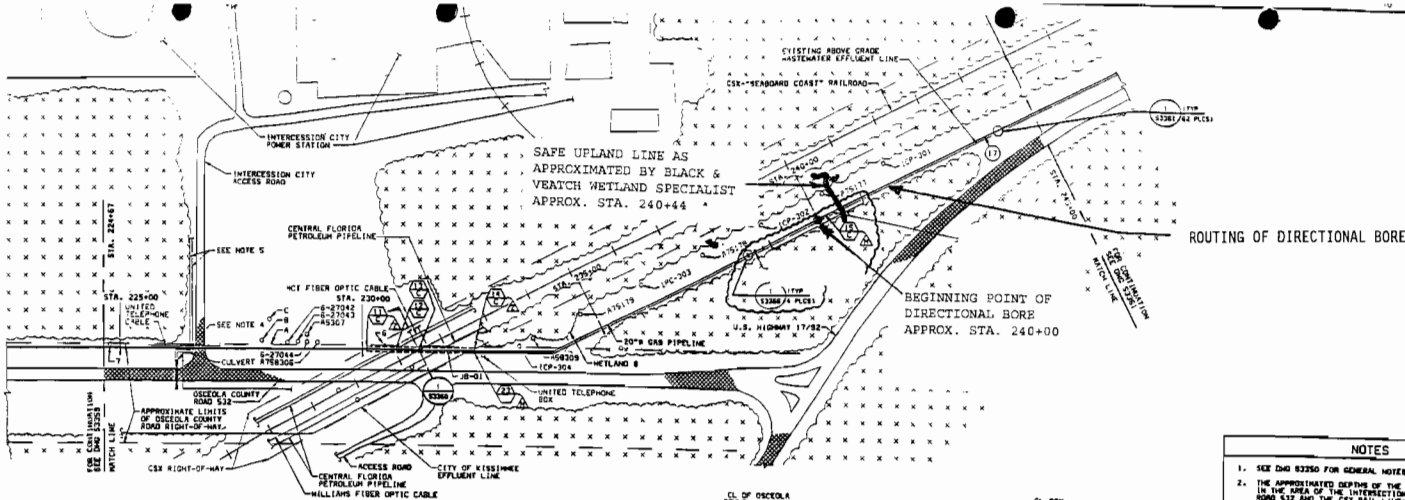
SOIL TYPE LEGEND

NUMBER	DESCRIPTION
7	CANDLER SAND, 0 TO 5 PERCENT SLOPES
16	IMMOKALEE FINE SAND
24	NARCOOSSEE FINE SAND
37	POMPANO FINE SAND, DEPRESSIONAL
41	SATELLITE SAND



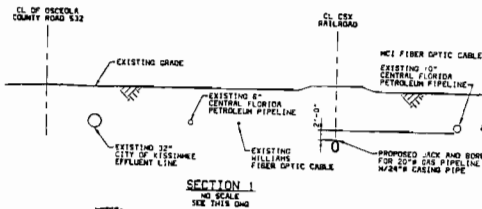
Poor Original

FIGURE E-1
SCS SOIL TYPES



UTILITY OFFSET LIST

PP I.D. NO.	CDP TO KUA GAS PIPELINE	CDP TO PP	CL OF PP TO KUA GAS PIPELINE	CDP TO EXISTING UTILITIES	CDP TO EASEMENT	TOTAL WIDTH OF EASEMENT	REMARKS
1	42"	48"	NA	34' 1 30' 05.6 116'	54"	200"	2 OUT WIRES, EAST SIDE OF POWER POLE
A158306	42"	55.2'	NA		54"	200"	3 OUT WIRES, SOUTH SIDE OF POWER POLE
S-27044	42"	55.6'	NA		54"	200"	2 OUT WIRES, SOUTH SIDE OF POWER POLE
S-27043	42"	55.8'	NA		54"	200"	4 OUT WIRES, EAST SIDE OF POWER POLE
S-27042	42"	55.2'	NA		54"	200"	2 OUT WIRES, SOUTH SIDE OF POWER POLE
4	42"	48.4'	NA		54"	200"	4 OUT WIRES, EAST SIDE OF POWER POLE
5	42"	58.3'	NA		54"	200"	2 OUT WIRES, EAST SIDE OF POWER POLE
A6303	42"	71.1'	NA	CL OF RR TO EXIST. UTILITY	54"	200"	2 OUT WIRES, WEST SIDE OF POWER POLE
6	42"	100.7'	NA	30' 25'	54"	200"	2 OUT WIRES, SOUTH SIDE OF POWER POLE
ICP-304	42"	50.0'	10' x		54"	200"	4-OFFSET IS SOUTH OF POWER POLE
A58309	NA	10'	27' x		NA	NA	4-OFFSET IS SOUTH OF POWER POLE
A78178	NA	120'	42' x		NA	NA	4-OFFSET IS SOUTHWEST OF POWER POLE
ICP-303	NA	180'	42' x		NA	NA	4-OFFSET IS SOUTHWEST OF POWER POLE
A78176	NA	240'	42' x		NA	NA	4-OFFSET IS SOUTHWEST OF POWER POLE
ICP-302	NA	290'	42' x		NA	NA	4-OFFSET IS SOUTHWEST OF POWER POLE
A78177	NA	318'	42' x		NA	NA	4-OFFSET IS SOUTHWEST OF POWER POLE
ICP-301	NA	218'	42' x		NA	NA	4-OFFSET IS SOUTHWEST OF POWER POLE



NOTES:

1. THE 24" DEPTH OF COVER BETWEEN EXISTING UNDERGROUND UTILITIES AND THE TOP OF THE PROPOSED CASING PIPE WILL BE BASED OFF OF THE LOWEST EXISTING UNDERGROUND UTILITIES.
2. REFER TO Dwg 83360 FOR TYPICAL STEEL PIPE CASING DETAIL.

NOTES

1. SEE Dwg 83360 FOR GENERAL NOTES AND LEGEND.
2. THE APPROXIMATE DEPTH OF THE EXISTING UTILITIES IN THE AREA OF THE INTERSECTION OF OSCEOLA COUNTY ROAD 532 AND THE CSX RAIL LINES:
* 12" FIBER OPTIC CABLE 25'
* CENTRAL FLORIDA PETROLEUM PIPELINE
* 12" FIBER OPTIC CABLE NOT AVAILABLE
* UNITED TELEPHONE INACTIVE LINE
3. SEE Dwg 83360 FOR JACK AND BORE DETAILS.
4. APPROXIMATE LOCATION OF EXISTING 24" STEEL CASING. APPROXIMATE ELEVATION AS SHOWN. CONTRACTOR TO FIELD VERIFY THE LOCATION AND ELEVATION BEFORE WORK CAN BEGIN IN THIS AREA.
5. APPROXIMATE LOCATION OF EXISTING 12" AND 6" LINES. APPROXIMATE ELEVATION AS SHOWN. CONTRACTOR TO FIELD VERIFY THE LOCATION AND ELEVATION BEFORE WORK CAN BEGIN IN THIS AREA.

RELEASED FOR
CONSTRUCTION

11-12-08-03 31-0000 CONSTRUCTION ISSUE

11-08-12-03 31-0000 BLDG ISSUE

NOT DATE: 11-08-12-03

SCALE:

VERTICALLY 1"=40'

HORIZONTALLY 1"=40'



I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A LICENSED PROFESSIONAL ENGINEER IN THE STATE OF FLORIDA.

DATE: 11-12-03, REV. NO.: 1, DRAWN: [signature]

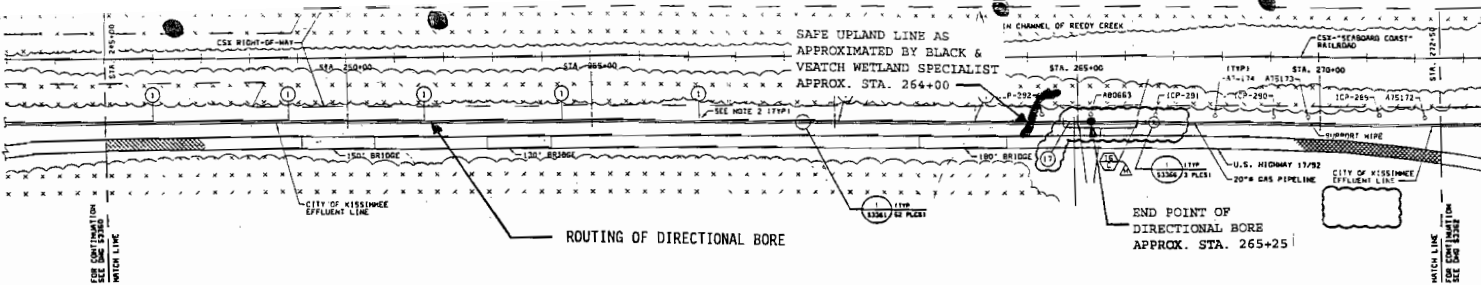
BLACK & VEATCH

KISSIMEE UTILITY AUTHORITY
CANE ISLAND NATURAL GAS PIPELINE

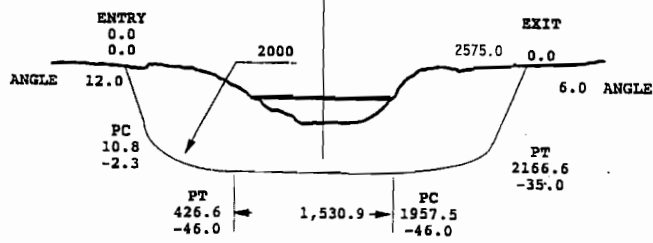
SITE - GAS PIPELINE
PLAN AND PROFILE - SHT 10

PROJECT: 17790-CFGA-S3360

FIGURE E-2



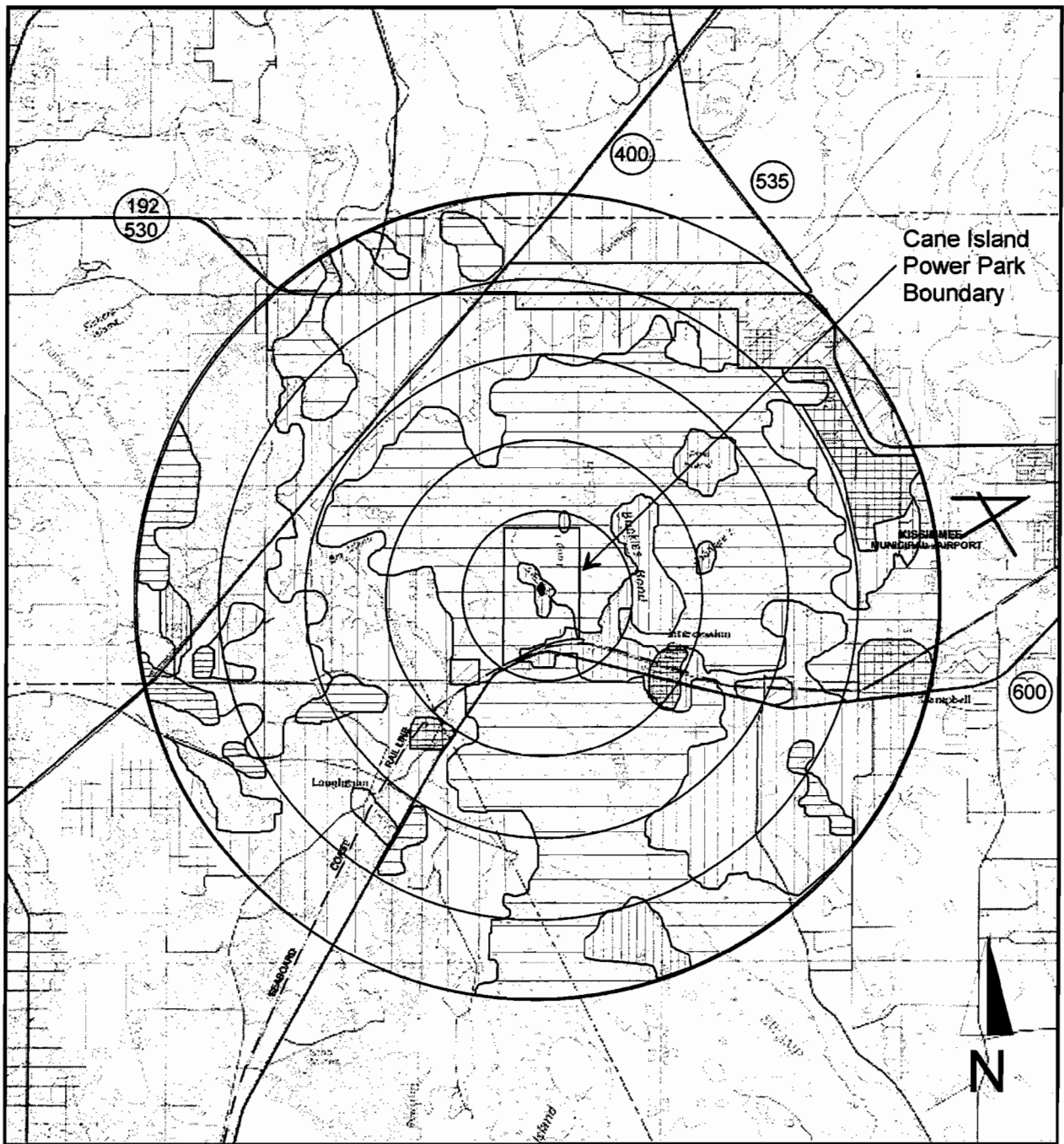
WEST END SEE DRAWING S3360
 EAST END SEE DRAWING S3361



ELEVATION VIEW OF THE DIRECTIONAL BORE
 (NOT TO SCALE)

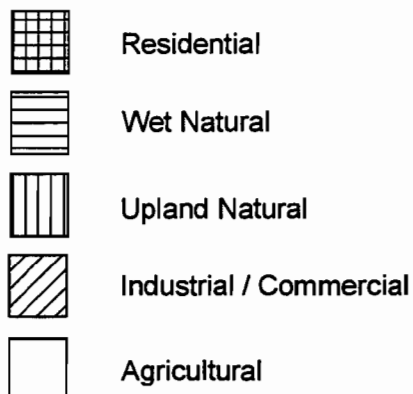
- NOTES
1. SEE DWG S3360 FOR GENERAL NOTES AND LEGEND.
 2. POWER POLE LOCATIONS ADJACENT TO ABOVE GRADE PORTION OF GAS PIPELINE ARE APPROXIMATE. SINGLE GROUND ROD INSTALLATIONS ARE LOCATED MIDWAY BETWEEN POWER POLES.

1. I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A duly LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA. ENGINEER STEPHEN R. LYNN DATE 09-13-92, REG. NO. 15581		BLACK & VEATCH ENGINEER DATE 7-9-92		KISSIMMEE UTILITY AUTHORITY CANE ISLAND NATURAL GAS PIPELINE PROJECT 17790-CFGA-S3361 SITE - GAS PIPELINE PLAN AND PROFILE - SHT 11		FIGURE E-2 Continued
---	--	--	--	--	--	-------------------------



Vegetation and Land Use within 5 miles of the Site Location

Figure E-3



Land2.srf



Poor Original

Reedy Creek Improvement District
(AREA NOT INCLUDED)

ZONE A

ZONE X

ZONE X

ZONE X

ZONE X

SEABOARD

OLD

79

LIMIT OF DETAILED STUDY

R

74

FIGURE E-4

TABLE 1
PROJECT IMPACT SUMMARY

WL & SW ID	WL & SW TYPE	WL & SW SIZE (AC.) ON SITE	WL & SW (AC.) NOT IMPACTED	PERMANENT WL & SW IMPACTS		TEMPORARY WL & SW IMPACTS		MITIGATION ID
				IMPACT SIZE	IMPACT	IMPACT	IMPACT	
SW Reedy Creek	Riverine, Lower Perennial, Unconsolidated Bottom	0.32 AC		0.32 AC	O			
WL Reedy Creek	Palustrine, Forested Wetland	11.3 AC		11.3 AC	C			
				4030 cy	F			
PROJECT TOTALS:								

WL = Wetland; SW = Surface water; ID = Identification number, letter, etc.

Wetland Type: Use an established wetland classification system and, in the comments section below, indicate which classification system is being used.

Impact Code (Type): D = dredge; F = fill; H = change hydrology; S = shading; C = clearing; O = other. Indicate the final impact if more than one impact type is proposed in a given area. For example, show F only for an area that will first be demucked and then backfilled.

Note: Multiple entries per cell are not allowed, except in the "Mitigation ID" column. Any given acreage of wetland should be listed in one row only, such that the total of all rows equals the project total for a given category (column). For example, if Wetland No. 1 includes multiple wetland types and multiple impact codes are proposed in each type, then each proposed impact in each wetland type should be shown on a separate row, while the size of each wetland type found in Wetland No. 1 should be listed in only one row.

Comments: Classification is based on Cowardin (1979) "Classification of Wetlands and Drywater Habitats of the United States."

TABLE 2
ON-SITE MITIGATION SUMMARY

To Be Determined

MITIGATION ID	CREATION		RESTORATION		ENHANCEMENT		WETLAND PRESERVE		UPLAND PRESERVE		OTHER	
	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TYPE	AREA	TYPE	AREA	TARGET TYPE
PROJECT TOTALS												

CODES (multiple entries per cell not allowed):

Target Type or Type = target or existing habitat type from an established wetland classification system or land use classification for non-wetland mitigation

COMMENTS: _____

Water Use Permit Application



Form 0845-A01

08/85

**SOUTH FLORIDA WATER MANAGEMENT DISTRICT
RC-1A ADMINISTRATIVE INFORMATION FOR
WATER USE PERMIT APPLICATIONS****GENERAL INFORMATION**

OWNER KUA	APPLICANT (IF DIFFERENT FROM OWNER)
NAME	NAME
ADDRESS	ADDRESS
CITY, STATE, ZIP	CITY, STATE, ZIP
TELEPHONE ()	TELEPHONE ()
PROJECT ENGINEER, CONSULTANT OR AGENT	PRE-APPLICATION MEETING
NAME OF FIRM Black & Veatch	HAVE ANY PRE-APPLICATION MEETINGS BEEN HELD WITH DISTRICT STAFF? YES ☒ NO ☐
NAME OF CONTACT PERSON Myron Rollins	DATE(S) 6/9/98
ADDRESS 11401 Lamar	LOCATION(S) W. Palm Beach
CITY, STATE, ZIP Overland Park, KS 66211	NAME(S) OF KEY DISTRICT STAFF S. Coughanour, J. Rosenfeld
TELEPHONE (913) 458-7432	NAME(S) OF PROJECT REPRESENTATIVE(S) B. Sharma, M. Rollins, M. Soltys

PROJECT INFORMATION

NAME (INCLUDING THE PHASES COVERED BY THIS APPLICATION) Cane Island Power Park - Units 1, 2, 3	
TOTAL PROJECT ACREAGE, INCLUDING ALL PHASES 1,027	PHASE AREAS (IF APPLICABLE):
6075 Old Tampa Highway	
CITY, TOWN, OR VILLAGE (IF APPLICABLE) Intercession City 33848	COUNTY Osceola
SECTION(S) OR GOVERNMENT LOT(S) 29 & 32	TOWNSHIP 25 S RANGE 28 E
SECTION(S) OR GOVERNMENT LOT(S)	TOWNSHIP S RANGE E
SECTION(S) OR GOVERNMENT LOT(S)	TOWNSHIP S RANGE E



FORM OF PERMIT (PLEASE CHECK ONLY ONE BOX):

☐ A NEW INDIVIDUAL PERMIT PURSUANT TO RULE
40E-2.101, FLORIDA ADMINISTRATIVE CODE (F.A.C.)

☐ A NEW GENERAL PERMIT PURSUANT TO RULE 40E-20, F.A.C.

☒ A MODIFICATION OF EXISTING
PERMIT NO. 49-00671-W
(for certification under Power Plant Siting Act)

☐ RENEWAL OF EXISTING PERMIT NO. _____

THE PURPOSE OF THIS REQUEST:

Additional allocation of groundwater from Floridan Aquifer for industrial use (Unit 3 at Cane Island Power Park).

TYPE OF PERMIT (PLEASE CHECK AT LEAST ONE BOX):

☐ AGRICULTURAL IRRIGATION

☐ LANDSCAPING IRRIGATION

☐ GOLF COURSE IRRIGATION

☐ PUBLIC WATER SUPPLY

☐ MINING/DEWATERING

☒ INDUSTRIAL/COMMERCIAL

☐ RECREATIONAL

☐ AQUACULTURE

☐ OTHER (PLEASE DESCRIBE) _____

SOURCE OF WATER (PLEASE CHECK AT LEAST ONE BOX):

SURFACE WATER FROM THE FOLLOWING WATER BODY(IES)

☐ ON-SITE RETENTION POND(S) OR LAKE(S) ☐ ADJACENT LAKE, CANAL, RIVER OR CREEK _____ (NAME)

GROUND WATER FROM THE FOLLOWING NAMED AQUIFER(S) (PLEASE INDICATE, FOR EACH AQUIFER, WHETHER IT IS SHALLOW OR DEEP).
Floridan Aquifer (deep)

CERTIFICATION

I hereby certify that, to the best of my knowledge, the total project acreage listed above is owned or controlled by me and encompasses the project referenced in this permit application. In addition, I agree to provide entry to the project site for South Florida Water Management District inspectors with proper identification or documents as required by law for the purpose of making analyses of the site. Further, I agree to provide entry to the project site for such inspectors to monitor permitted work if a permit is granted.

Printed/typed name (and agent's or principal's title, if not owner)

Signature (if acting as agent, please attach owner's signed document appointing you to apply for SPWMD permits for the property described in the application.)

DATE

FOR DISTRICT USE ONLY

APPLICATION NUMBER _____

FEE REQUIRED _____

FEE PAID _____

RECEIPT NUMBER _____



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Rev. 08/95

RC-1W APPLICATION FOR A WATER USE PERMIT

FOR SFWMD USE ONLY

APPLICATION NO. _____

ALL PERMITS: SECTION I - SITE INFORMATION

SFWMD ONLY

N A I M

☒	A	LOCATION SKETCH IS SUBMITTED AS ITEM I-1. See Figures 2.1-1 and 2.1-2 in SCA	☐	☐	☐	☐
☒	B	AERIAL PHOTOGRAPH IS SUBMITTED AS ITEM I-2. on file with original application	☐	☐	☐	☐
☒	C	WETLANDS				
☒		EXISTING COVER IS SUBMITTED AS ITEM I-3.	☐	☐	☐	☐
		PROPOSED PRESERVATION TECHNIQUES ARE SUBMITTED AS ITEM I-4. See original application	☐	☐	☐	☐
		WETLAND CONTROL ELEVATION TABLE IS SUBMITTED AS ITEM I-5.	☐	☐	☐	☐

ALL PERMITS: SECTION II - PROJECT INFORMATION

☒	A	GENERAL INFORMATION				
☒		MAP OF PROJECT IS SUBMITTED AS ITEM II-1. Site Arrangement as Figure 2.1-3 in SCA	☐	☐	☐	☐
		START DATE OF WATER USE IS: September 1999	☐	☐	☐	☐
☒	B	ENVIRONMENTAL RESOURCE				
☒		THE PROJECT IS PERMITTED. PERMIT NUMBER 49-006/1-W	☐	☐	☐	☐
		THE PROJECT IS EXISTING BUT UNPERMITTED. ☐	☐	☐	☐	☐
		AN ER PERMIT IS APPLIED FOR, APPLICATION NUMBER _____	☐	☐	☐	☐
		AN ER PERMIT IS NOT REQUIRED. ☒	☐	☐	☐	☐
☒	C	RIGHT OF WAY OCCUPANCY				
☒		PROJECT IS PERMITTED FOR RIGHT OF WAY, PERMIT NO. _____	☐	☐	☐	☐
		RIGHT OF WAY PERMIT IS APPLIED FOR, APPLICATION NO. _____	☐	☐	☐	☐
		RIGHT OF WAY PERMIT IS NOT REQUIRED ☒	☐	☐	☐	☐
☒	D	FACILITIES				
☒		TABLE OF EXISTING AND PROPOSED WELLS IS SUBMITTED AS ITEM II-2A. See existing permit	☐	☐	☐	☐
		TABLE OF EXISTING AND PROPOSED SURFACE WATER WITHDRAWAL PUMPS	☐	☐	☐	☐
		IS SUBMITTED AS ITEM II-2B. N/A				
		TABLE OF EXISTING AND PROPOSED WITHDRAWAL CULVERTS IS SUBMITTED AS ITEM II-2C. N/A	☐	☐	☐	☐
☒	E	WATER PROBLEMS				
☒		EVALUATION OF EXISTING WATER USE PROBLEMS IS SUBMITTED AS ITEM II-3. ☐	☐	☐	☐	☐
		NO EXISTING PROBLEMS. ☒	☐	☐	☐	☐
☒		EVALUATION OF POTENTIAL IMPACTS ASSOCIATED WITH THE PROPOSED WATER	☐	☐	☐	☐
		WITHDRAWALS IS SUBMITTED AS ITEM II-4. See Section 5.3 of SCA	☐	☐	☐	☐
		PROPOSED MITIGATION IS SUBMITTED AS ITEM II-5.	☐	☐	☐	☐
		NO WATER PROBLEMS OR IMPACTS ARE ANTICIPATED. ☒	☐	☐	☐	☐
☒	F	LOCATION OF POLLUTION SOURCES				
		A MAP SHOWING POLLUTION SOURCES IS SUBMITTED AS ITEM II-6	☐	☐	☐	☐
		See original application and Figure 2.1-3 in SCA	☐	☐	☐	☐



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SECTION II - PROJECT INFORMATION (CONTINUED)

SEWMD ONLY

N A I M

G TYPE OF WATER USE

IN ADDITION, PLEASE COMPLETE AT LEAST ONE:

- ☐ SECTION III FOR IRRIGATION WATER USE
- ☐ SECTION IV FOR PUBLIC WATER SUPPLY WATER USE
- ☐ SECTION V FOR MINING/DEWATERING WATER USE
- ☒ SECTION VI FOR INDUSTRIAL WATER USE
- ☐ SECTION VII FOR GENERAL WATER USE PERMITS

☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐

INDIVIDUAL PERMITS: SECTION III - IRRIGATION WATER USE

A OWNERSHIP AND LAND USE

PROOF OF OWNERSHIP IS SUBMITTED AS ITEM III-1.

PREVIOUSLY PERMITTED, NO CHANGE IN OWNERSHIP OR PROJECT ACREAGE: ☐ YES

LAND USE DOCUMENT IS SUBMITTED AS ITEM III-2.

PREVIOUSLY PERMITTED, NO CHANGE IN LAND USE ☐ YES

☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐

B CROP TYPE AND IRRIGATION SYSTEM

TOTAL IRRIGATED (PLANTED) ACREAGE: _____ ACRES.

IRRIGATION FOR PHASED PROJECTS IS SUBMITTED AS ITEM III-3.

TABLE OF CROP REQUIREMENTS IS SUBMITTED AS ITEM III-4.

☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐

C WATER USAGE

QUANTITY OF WATER NEEDED FOR ALL CROPS: _____

BASIS FOR THE WATER REQUESTED IS SUBMITTED AS ITEM III-4A _____

WATER USE ACCOUNTING SYSTEM IS SUBMITTED AS ITEM III-4B _____

☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐

D WATER CONSERVATION PLAN SUBMITTED AS ITEM III-5.

RECLAIMED WATER USE FEASIBILITY IS SUBMITTED AS ITEM III-6.

☐	☐	☐	☐
☐	☐	☐	☐

E FREEZE PROTECTION

NO FREEZE PROTECTION REQUESTED ☐

FREEZE PROTECTION IS SUBMITTED AS ITEM III-7.

☐	☐	☐	☐
☐	☐	☐	☐

F GOLF COURSE IRRIGATED ACREAGE MAP IS SUBMITTED AS ITEM III-8.

☐	☐	☐	☐
--------------------------	--------------------------	--------------------------	--------------------------

INDIVIDUAL PERMITS: SECTION IV - PUBLIC WATER SUPPLY WATER USE

A POPULATION AND WATER DEMAND ANALYSIS

WATER USE FOR 12 MONTH PERIOD IS SUBMITTED AS ITEM IV-1.

PAST WATER USE IS SUBMITTED AS ITEM IV-2.

PROJECTED WATER USE IS SUBMITTED AS ITEM IV-3.

PROJECTED WATER DEMAND (PER CAPITA USE GREATER THAN 200 GPD) IS SUBMITTED AS ITEM IV-4.

☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐
☐	☐	☐	☐

B SERVICE AREA

SERVICE AREA MAP IS SUBMITTED AS ITEM IV-5.

☐	☐	☐	☐
--------------------------	--------------------------	--------------------------	--------------------------



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SECTION IV - PUBLIC WATER SUPPLY WATER USE (CONTINUED)

SFWMD ONLY

N A I M

X

INTERCONNECTIONS WITH OTHER SUPPLIERS ARE SUBMITTED AS ITEM IV-6.

☐ ☐ ☐ ☐

SERVICE AREA DOCUMENTATION IS SUBMITTED AS ITEM IV-7.

☐ ☐ ☐ ☐

C FACILITIES

DESCRIPTION OF FACILITIES IS SUBMITTED AS ITEM IV-8.

☐ ☐ ☐ ☐

AVERAGE DAILY EFFLUENT PRODUCTION: _____

☐ ☐ ☐ ☐

DISPOSAL POINT OF EFFLUENT: _____

☐ ☐ ☐ ☐

D INFORMATION ABOUT RAW WATER QUALITY IS SUBMITTED AS ITEM IV-9.

☐ ☐ ☐ ☐

E REVERSE OSMOSIS TREATMENT

NO REVERSE OSMOSIS ☐

☐ ☐ ☐ ☐

REVERSE OSMOSIS OPERATION DESCRIPTION IS SUBMITTED AS ITEM IV-10.

☐ ☐ ☐ ☐

LETTER OF APPROVAL TO DISCHARGE REJECT WATER IS SUBMITTED AS ITEM IV-11.

☐ ☐ ☐ ☐

F WATER CONSERVATION

WATER CONSERVATION PLAN IS SUBMITTED AS ITEM IV-12.

☐ ☐ ☐ ☐

LETTER OF COMPLIANCE WITH THE MANDATORY WATER CONSERVATION ELEMENTS
IS SUBMITTED AS ITEM IV-13.

☐ ☐ ☐ ☐

G WELLFIELD PROTECTION

WELLFIELD WILL BE COVERED BY A WELLFIELD PROTECTION ORDINANCE ☐

☐ ☐ ☐ ☐

DOCUMENTATION OF APPROVAL FROM APPROPRIATE AGENCY IS SUBMITTED AS ITEM IV-14.

☐ ☐ ☐ ☐

WELLFIELD WILL NOT BE COVERED BY A WELLFIELD PROTECTION ORDINANCE ☐

☐ ☐ ☐ ☐

PLAN FOR PROTECTION OF THE WELLFIELD IS SUBMITTED AS ITEM IV-15.

☐ ☐ ☐ ☐

INDIVIDUAL PERMITS: SECTION V - MINING/DEWATERING WATER USE

A OWNERSHIP AND LAND USE

PROOF OF OWNERSHIP DOCUMENTATION IS SUBMITTED AS ITEM V-1.

☐ ☐ ☐ ☐

PREVIOUSLY PERMITTED, NO CHANGE IN OWNERSHIP OR PROJECT ACREAGE ☐ YES

☐ ☐ ☐ ☐

LAND USE DOCUMENT IS SUBMITTED AS ITEM V-2.

☐ ☐ ☐ ☐

PREVIOUSLY PERMITTED, NO CHANGE IN LAND USE ☐ YES

☐ ☐ ☐ ☐

B PROJECT DESCRIPTION

METHOD OF EXCAVATION: _____

☐ ☐ ☐ ☐

EXCAVATION AREA DATA ARE SUBMITTED AS ITEM V-3.

☐ ☐ ☐ ☐

GROUND WATER WILL BE DRAWN DOWN TO: _____ (FT, NGVD)

☐ ☐ ☐ ☐

MAXIMUM DEPTH OF PIT WILL BE EXCAVATED TO: _____ FT

☐ ☐ ☐ ☐

OPERATION SCHEDULE: _____ HOURS/DAY, _____ DAYS/WEEK, _____ WEEKS/YEAR

☐ ☐ ☐ ☐

REQUESTED ANNUAL ALLOCATION: _____ GALLONS

☐ ☐ ☐ ☐

MAXIMUM DAY PUMPAGE: _____ GALLONS

☐ ☐ ☐ ☐

BASIS FOR THE REQUESTED AMOUNTS: _____

☐ ☐ ☐ ☐

DURATION OF THE USE OF WATER: _____

☐ ☐ ☐ ☐

DURATION OF THE USE OF WATER: _____

☐ ☐ ☐ ☐



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SECTION V - MINING/DEWATERING WATER USE (CONTINUED)

SFWMD ONLY

N A I I

CONTRACTOR NAME: _____ PHONE: _____

ADDRESS: _____

NO CONTRACTOR ☐

C LOCATION

SITE MAP IS SUBMITTED AS ITEM V-4. ☐

NOT PHASED PROJECT ☐

SITE MAP FOR PHASED PROJECT IS SUBMITTED AS ITEM V-5. ☐

A TOPOGRAPHIC MAP IS SUBMITTED AS ITEM V-6. ☐

D INFORMATION ON WATER QUALITY IS SUBMITTED AS ITEM V-7. ☐

E HISTORICAL WATER USE

NOT APPLICABLE ☐ YES ☐

PUMPAGE RECORDS ARE SUBMITTED AS ITEM V-8. ☐

F WATER TABLE AND GEOLOGIC DATA

WATER TABLE ELEVATIONS

☐ WET SEASON: _____ FT (NGVD)

☐ DRY SEASON: _____ FT (NGVD)

LITHOLOGIC LOGS ARE SUBMITTED AS ITEM V-9. ☐

GEOPHYSICAL LOGS ARE SUBMITTED AS ITEM V-10. ☐

LITHOLOGIC LOGS ARE NOT AVAILABLE ☐

G DRAINAGE SYSTEM AND STRUCTURAL STABILITY

PLAN FOR ROUTING OF STORMWATER IS SUBMITTED AS ITEM V-11. ☐

PLAN FOR ON-SITE WATER RETENTION SYSTEM FACILITIES IS SUBMITTED AS ITEM V-12. ☐

STRUCTURAL STABILITY INFORMATION IS SUBMITTED AS ITEM V-13. ☐

H DEWATERING IN CONJUNCTION WITH LANDFILL OPERATIONS

LANDFILL DEWATERING NOT APPLICABLE ☐

LANDFILL INFORMATION IS SUBMITTED AS ITEM V-14. ☐

INDIVIDUAL PERMITS: SECTION VI - INDUSTRIAL WATER USE

A OWNERSHIP AND LAND USE

PROOF OF OWNERSHIP DOCUMENTATION IS SUBMITTED AS ITEM VI-1. ☐

PREVIOUSLY PERMITTED, NO CHANGE IN OWNERSHIP OR PROJECT ACREAGE ☐ YES ☐

LAND USE DOCUMENT IS SUBMITTED AS ITEM VI-2. ☐

PREVIOUSLY PERMITTED, NO CHANGE IN LAND USE ☐ YES ☐

B WATER DEMAND ANALYSIS

REQUESTED ANNUAL ALLOCATION: _____ GALLONS ☐

MAXIMUM DAY PUMPAGE: _____ GALLONS ☐

MAXIMUM DAY TO AVERAGE DAY DEMAND RATIO: _____ ☐

EXPLAIN BRIEFLY THE BASIS FOR USING THIS NUMBER: _____ ☐

FUTURE YEAR FOR WHICH WATER USE IS PROJECTED: _____ ☐

EXISTING WATER USE, WATER USE FOR 12 MONTH PERIOD IS SUBMITTED AS ITEM VI-3. ☐

WATER USE IS NOT NOW EXISTING, SO ITEM VI-3 NOT APPLICABLE ☐

APPROVED REMEDIAL ACTION PLAN IS SUBMITTED AS ITEM VI-4. ☐



SECTION VI - INDUSTRIAL WATER USE (CONTINUED)

SEWMD ONLY

N A I M

X

C FACILITIES

WATER TREATMENT PLANT CAPACITY: _____ GALLONS.

☐ ☐ ☐ ☐

TREATED WATER STORAGE CAPACITY: _____ GALLONS.

☐ ☐ ☐ ☐

IN-PLANT LOSSES: _____

☐ ☐ ☐ ☐

FIRE-FLOW CAPABILITY: _____

☐ ☐ ☐ ☐

STAND-BY CAPACITY: _____

☐ ☐ ☐ ☐

PUMP/WELLFIELD OPERATION SCHEDULE IS SUBMITTED AS ITEM VI-5.

☐ ☐ ☐ ☐

D DESCRIPTION OF THE INDUSTRIAL PROCESS, WATER CHANGES DUE TO THE PROCESS, AND DISPOSAL OF WASTEWATER, IS SUBMITTED AS ITEM VI-6.

☐ ☐ ☐ ☐

E WATER CONSERVATION PLAN IS SUBMITTED AS ITEM VI-7.

☐ ☐ ☐ ☐

RECLAIMED WATER USE FEASIBILITY IS SUBMITTED AS ITEM VI-8.

☐ ☐ ☐ ☐

SECTION VII - GENERAL WATER USE PERMITS

A OWNERSHIP AND LAND USE

PROOF OF OWNERSHIP DOCUMENTATION IS SUBMITTED AS ITEM VII-1.

☐ ☐ ☐ ☐

PREVIOUSLY PERMITTED, NO CHANGE IN OWNERSHIP OR PROJECT ACREAGE ☐ YES

☐ ☐ ☐ ☐

B GENERAL INFORMATION

☐ PROPOSED PROJECT ☐ EXISTING, HOW LONG: _____

☐ ☐ ☐ ☐

ESTIMATED AVERAGE DAILY WATER USE: _____ GALLONS.

☐ ☐ ☐ ☐

ESTIMATED MAXIMUM DAY WATER USE: _____ GALLONS.

☐ ☐ ☐ ☐

NAME OF WELL DRILLER (IF APPLICABLE): _____

☐ ☐ ☐ ☐

C TYPE OF WATER USE

IRRIGATION

CROP TYPE: _____

☐ ☐ ☐ ☐

IRRIGATED ACREAGE: _____

☐ ☐ ☐ ☐

IRRIGATION FOR PHASED PROJECTS IS SUBMITTED AS ITEM VII-2.

☐ ☐ ☐ ☐

PUBLIC WATER SUPPLY

TREATMENT PLANT CAPACITY: _____ GALLONS.

☐ ☐ ☐ ☐

POPULATION SERVED: _____

☐ ☐ ☐ ☐

NUMBER OF UNITS SERVED: _____

☐ ☐ ☐ ☐

SHORT-TERM DEWATERING APPLICATION IS SUBMITTED AS ITEM VII-3.

☐ ☐ ☐ ☐

AQUIFER REHABILITATION REMEDIAL ACTION PLAN IS SUBMITTED AS ITEM VII-4.

☐ ☐ ☐ ☐

ESTIMATED DATE OF COMPLETION: _____

☐ ☐ ☐ ☐

SECTION VIII - WORKS OF THE DISTRICT SURFACE WATER IMPROVEMENT AND MANAGEMENT (SWIM)

A PROJECT IS PERMITTED FOR WORKS OF THE DISTRICT (SWIM), PERMIT NO: _____

☐ ☐ ☐ ☐

B WORKS OF THE DISTRICT (SWIM) PERMIT IS APPLIED FOR, APPLICATION NO: _____

☐ ☐ ☐ ☐

C WORKS OF THE DISTRICT (SWIM) PERMIT IS NOT REQUIRED ☐

☐ ☐ ☐ ☐



Form 0845-W04
08/85

SECTION V - MINING/DEWATERING WATER USE (CONTINUED)

SFWMD ONLY

N A I

CONTRACTOR NAME: _____ PHONE: _____

ADDRESS: _____

NO CONTRACTOR ☐

C LOCATION

SITE MAP IS SUBMITTED AS ITEM V-4. ☐

NOT PHASED PROJECT ☐

SITE MAP FOR PHASED PROJECT IS SUBMITTED AS ITEM V-5. ☐

A TOPOGRAPHIC MAP IS SUBMITTED AS ITEM V-6. ☐

D INFORMATION ON WATER QUALITY IS SUBMITTED AS ITEM V-7. ☐

E HISTORICAL WATER USE

NOT APPLICABLE ☐ YES ☐

PUMPAGE RECORDS ARE SUBMITTED AS ITEM V-8. ☐

F WATER TABLE AND GEOLOGIC DATA

WATER TABLE ELEVATIONS

☐ WET SEASON: _____ FT (NGVD)

☐ DRY SEASON: _____ FT (NGVD)

LITHOLOGIC LOGS ARE SUBMITTED AS ITEM V-9. ☐

GEOPHYSICAL LOGS ARE SUBMITTED AS ITEM V-10. ☐

LITHOLOGIC LOGS ARE NOT AVAILABLE ☐

G DRAINAGE SYSTEM AND STRUCTURAL STABILITY

PLAN FOR ROUTING OF STORMWATER IS SUBMITTED AS ITEM V-11. ☐

PLAN FOR ON-SITE WATER RETENTION SYSTEM FACILITIES IS SUBMITTED AS ITEM V-12. ☐

STRUCTURAL STABILITY INFORMATION IS SUBMITTED AS ITEM V-13. ☐

H DEWATERING IN CONJUNCTION WITH LANDFILL OPERATIONS

LANDFILL DEWATERING NOT APPLICABLE ☐

LANDFILL INFORMATION IS SUBMITTED AS ITEM V-14. ☐

INDIVIDUAL PERMITS: SECTION VI - INDUSTRIAL WATER USE

A OWNERSHIP AND LAND USE

PROOF OF OWNERSHIP DOCUMENTATION IS SUBMITTED AS ITEM VI-1. ☐

PREVIOUSLY PERMITTED, NO CHANGE IN OWNERSHIP OR PROJECT ACREAGE ☒ YES ☐

LAND USE DOCUMENT IS SUBMITTED AS ITEM VI-2. ☐

PREVIOUSLY PERMITTED, NO CHANGE IN LAND USE ☒ YES ☐

B WATER DEMAND ANALYSIS

REQUESTED ANNUAL ALLOCATION: 283 million GALLONS (normal operations) ☐

MAXIMUM DAY PUMPAGE: 776,000 GALLONS " ☐

MAXIMUM DAY TO AVERAGE DAY DEMAND RATIO: 3.5-1 ☐

EXPLAIN BRIEFLY THE BASIS FOR USING THIS NUMBER: max day pumpage vs average summer ☐

Note: An additional 3 million gpd requested on an emergency conditions basis ☐

FUTURE YEAR FOR WHICH WATER USE IS PROJECTED: 2001 ☐

EXISTING WATER USE, WATER USE FOR 12 MONTH PERIOD IS SUBMITTED AS ITEM VI-3. See usage ☐

WATER USE IS NOT NOW EXISTING, SO ITEM VI-3 NOT APPLICABLE ☐ reports on file ☐

APPROVED REMEDIAL ACTION PLAN IS SUBMITTED AS ITEM VI-4. ☐



SECTION VI - INDUSTRIAL WATER USE (CONTINUED)

SEWMD ONLY

N A I M

X	C	FACILITIES				
		WATER TREATMENT PLANT CAPACITY: <u>776,000</u> GALLONS/day	☐	☐	☐	☐
		TREATED WATER STORAGE CAPACITY: <u>560,000</u> GALLONS.	☐	☐	☐	☐
		IN-PLANT LOSSES: <u>50% w/gas firing / 78% w/oil firing</u>	☐	☐	☐	☐
		FIRE-FLOW CAPABILITY: <u>360,000 gallons reserved storage</u>	☐	☐	☐	☐
		STAND-BY CAPACITY: <u>555,000 gpd; based on (max-summer average)</u>	☐	☐	☐	☐
		PUMP/WELLFIELD OPERATION SCHEDULE IS SUBMITTED AS ITEM VI-5.	☐	☐	☐	☐
	D	DESCRIPTION OF THE INDUSTRIAL PROCESS, WATER CHANGES DUE TO THE PROCESS, AND DISPOSAL OF WASTEWATER, IS SUBMITTED AS ITEM VI-6. See various sections of SCA	☐	☐	☐	☐
X	E	WATER CONSERVATION PLAN IS SUBMITTED AS ITEM VI-7. Water Conservation Plan on file	☐	☐	☐	☐
		RECLAIMED WATER USE FEASIBILITY IS SUBMITTED AS ITEM VI-8.	☐	☐	☐	☐

SECTION VII - GENERAL WATER USE PERMITS

A	OWNERSHIP AND LAND USE				
	PROOF OF OWNERSHIP DOCUMENTATION IS SUBMITTED AS ITEM VII-1.	☐	☐	☐	☐
	PREVIOUSLY PERMITTED, NO CHANGE IN OWNERSHIP OR PROJECT ACREAGE ☐ YES	☐	☐	☐	☐
B	GENERAL INFORMATION				
	☐ PROPOSED PROJECT ☐ EXISTING. HOW LONG: _____	☐	☐	☐	☐
	ESTIMATED AVERAGE DAILY WATER USE: _____ GALLONS.	☐	☐	☐	☐
	ESTIMATED MAXIMUM DAY WATER USE: _____ GALLONS.	☐	☐	☐	☐
	NAME OF WELL DRILLER (IF APPLICABLE): _____	☐	☐	☐	☐
C	TYPE OF WATER USE				
	IRRIGATION				
	CROP TYPE: _____	☐	☐	☐	☐
	IRRIGATED ACREAGE: _____	☐	☐	☐	☐
	IRRIGATION FOR PHASED PROJECTS IS SUBMITTED AS ITEM VII-2.	☐	☐	☐	☐
	PUBLIC WATER SUPPLY				
	TREATMENT PLANT CAPACITY: _____ GALLONS.	☐	☐	☐	☐
	POPULATION SERVED: _____	☐	☐	☐	☐
	NUMBER OF UNITS SERVED: _____	☐	☐	☐	☐
	SHORT-TERM DEWATERING APPLICATION IS SUBMITTED AS ITEM VII-3.	☐	☐	☐	☐
	AQUIFER REHABILITATION REMEDIAL ACTION PLAN IS SUBMITTED AS ITEM VII-4.	☐	☐	☐	☐
	ESTIMATED DATE OF COMPLETION: _____	☐	☐	☐	☐

SECTION VIII - WORKS OF THE DISTRICT SURFACE WATER IMPROVEMENT AND MANAGEMENT (SWIM)

A	PROJECT IS PERMITTED FOR WORKS OF THE DISTRICT (SWIM), PERMIT NO: _____	☐	☐	☐	☐
B	WORKS OF THE DISTRICT (SWIM) PERMIT IS APPLIED FOR, APPLICATION NO: _____	☐	☐	☐	☐
C	WORKS OF THE DISTRICT (SWIM) PERMIT IS NOT REQUIRED ☐	☐	☐	☐	☐

Industrial Wastewater Treatment System Permit Application



WASTEWATER PERMIT APPLICATION FORM 1 GENERAL INFORMATION

I IDENTIFICATION NUMBER:

Facility ID 3049M06279

II CHARACTERISTICS:

INSTRUCTIONS: Complete the questions below to determine whether you need to submit any permit application forms to the Department of Environmental Protection. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the blank in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if you activity is excluded from permit requirements. See Section B of the instructions. See also, Section C of the instructions for definitions of the terms used here.

SPECIFIC QUESTIONS	YES	NO	FORM ATTACHED
A. Is this facility a domestic wastewater facility which results in a discharge to surface or ground waters?		X	
B. Does or will this facility (either existing or proposed) include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters?		X	
C. Does or will this facility (other than those describe in A. or B.) discharge process wastewater, or non-process wastewater regulated by effluent guidelines or new source performance standards, to surface waters?		X	
D. Does or will this facility (other than those described in A. or B.) discharge process wastewater to ground waters?	X		X
E. Does or will this facility discharge non-process wastewater, not regulated by effluent guidelines or new source performance standards, to surface waters?		X	
F. Does or will this facility discharge non-process wastewater to ground waters?		X	
G. Does or will this facility discharge stormwater to surface waters?		X	
H. Is this facility a non-discharging/closed loop recycle system?		X	

III NAME OF FACILITY: (40 characters and spaces)

Cane Island Power Park

IV FACILITY CONTACT: (A. 30 characters and spaces)

A. Name and Title (Last, first, & title)	B. Phone (area code & no.)
Ling, Jeff - Mgr. of Production	(407) 846-7070

V FACILITY MAILING ADDRESS: (A. 30 characters and spaces; B. 25 characters and spaces)

A. Street or P.O. Box: 6075 Old Tampa Highway		
B. City or Town: Intercession City	State: FL	Zip Code: 33848

VI FACILITY LOCATION: (A. 30 characters and spaces; B. 24 characters and spaces; C. 3 spaces (if known); D. 25 characters and spaces; E. 2 spaces; F. 9 spaces)

A. Street, Route or Other Specific Identifier: 6075 Old Tampa Highway		
B. County Name: Osceola	C. County Code (if known):	
D. City or Town: Intercession City	E. State: FL	F. Zip Code: 33848

VII SIC CODES: (4-digit, in order of priority)

NAICS CODE: 221112, Fossil Fuel Electric Power Generation

1. Code #: 4911	(Specify) Electrical Services	2. Code #:	(Specify)
3. Code #:	(Specify)	4. Code #:	(Specify)

VIII OPERATOR INFORMATION: (A. 40 characters and spaces; B. 1 character; C. 1 character (if other, specify); D. 12 characters; E. 30 characters and spaces; F. 25 characters and spaces; G. 2 characters; H. 9 characters)

A. Name: Kissimmee Utility Authority		B. Is the name in VIII A. the owner? Yes: ☒ No: ☐	
C. Status of Operator: F = Federal; S = State; P = Private; O = Other; M = Public (other than F or S)	(code) M	(specify) Municipality	D. Phone No.: (407) 933-7777
E. Street or P. O. Box: 1701 W. Carroll St.			
F. City or Town: Kissimmee		G. State: FL H. Zip Code: 34741	

IX INDIAN LAND: Is the facility located on Indian lands? Yes: ☐ No: ☒

VIII CONNECTION TO REGIONAL POTW

A. Indicate the relationship between this project and area regional planning for wastewater treatment. List steps to be taken for this industrial wastewater facility to become part of an area-wide wastewater treatment system.

The Cane Island Power Park combines neutralization basin effluent, steam cycle blowdown, and cooling tower blowdown for return to Kissimmee's effluent pipeline and ultimate disposal at the Imperial Treatment Site (percolation ponds). The Power Park contributes to the regional wastewater treatment plan by consuming significant quantities of effluent, thereby reducing the amount of wastewater requiring disposal.

IX-A CERTIFICATIONS FOR NEW OR MODIFIED FACILITIES

This is to certify the engineering features of this pollution control project have been designed by me and found to be in conformity with sound engineering principles, applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules of the Department. It is also agreed that the undersigned, if authorized by the owner, will furnish the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Kenneth R. Weiss
 Signature
 Kenneth R. Weiss
 Name (please type)
 No. 30272
 STATE OF
 FLORIDA
 REGISTERED ENGINEER

Black & Veatch
 Company Name

Address 11401 Lamar

Overland Park

Kansas 66211

Florida Registration No.: 30272

Telephone No.: (913) 458-2662 Date 07/31/98

Poor Original

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

James C. Welsh, P.E.

Name (type or print)
President & General Manager, KUA

Title

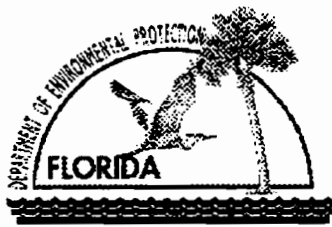
(407) 933-7777

Telephone No. (area code & No.)

Signature

Date Signed

FORM 2CG



WASTEWATER APPLICATION FOR PERMIT TO DISCHARGE PROCESS WASTEWATER FROM NEW OR EXISTING INDUSTRIAL WASTEWATER FACILITIES TO GROUND WATER

Facility I.D. Number: 3049M06279

Please print or type information in the appropriate areas.

I DISCHARGE LOCATION For each location, list the X,Y coordinates and, where applicable, the name of the land application site.

(latitude/longitude to the nearest 15 seconds)

A. Discharge Location No. (list)	B. Latitude			C. Longitude			D. Name of Land Application
	Deg.	Min.	Sec.	Deg.	Min.	Sec.	
G001	28	16	29	81	31	50	Percolation Pond (onsite)

II LAND APPLICATION DESIGN

A. Discharge No.	B. Design Configuration and Construction Materials	C. Cover Crop	D. Application Rate	E. Land Application Area ²	F. Ground Water
G001	Single cell, above-grade, earthen pond	Grass	20,000 gpd	4370 ft ²	G-II

III FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and discharge points. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures. See Figures 3.5-1 through 3.5-4 in SCA

B. For each discharge location, provide a description of: See sheet 2CG-16a

1. All operations contributing wastewater to the effluent; including process wastewater, sanitary wastewater, cooling water, and storm water runoff;
2. The average flow contributed by each operation; and
3. The treatment received by the wastewater.

Use the space below. Continue on additional sheets, if necessary.

(1) Discharge Location No.	(2) Operation(s) Contributing Flow		(3) Treatment		
	(a) Operation (list)	(b) Avg. Flow & Units	(a) Description	(b) List Code from Table 2CG-1	
G001	Misc. Plant & Eqpmt			xx	1-Y
	Drains	20,000 gpd	o/w Sep & Perc Pond *		
	Oil Containment Areas	Precip		xx	1-Y
	Fuel Oil Unloading Area	Precip		xx	1-Y

* o/w Sep & perc Pond=Oil/Water Separation & Percolation Pond

III Contd.

C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?

☒ Yes (complete the following table)

☐ No (go to D. below)

(1) Outfall # (List)	(2) Operations(s) Contributing Flow (List)	(3) Frequency		(4) Flow				(c) Duration (in days)
		(a) Days per Week (specify avg.)	(b) Months per Yr. (specify avg.)	(a) Flow Rate (in mgd)		(b) Total Volume (specify with units)		
				Long Term Avg	Max. Daily	Long Term Avg.	Max. Daily	
G001	Misc Plant & Eqmnt	7	12	0.02	0.072	20,000 g	72,000 g	0.5
	Drains							

For land application systems, also include the Rest Period.

D. Describe practices to be followed to ensure adequate wastewater treatment during emergencies such as power loss and equipment failures causing shutdown of pollution abatement equipment of the proposed/permitted facilities.

E. List the method(s) and location(s) of flow measurement.

IV IMPROVEMENTS

A. Are you now required by any Federal, State or local authority to meet any implementation schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

☐ Yes (complete the following table)

☒ No (go to Item VI-B)

1. Identification of Condition, Agreement, Etc.	2. Affected Discharge Locations		3. Brief Description of Project	4. Final Compliance Date	
	a. No.	b. Source of Discharge		a. Required	b. Projected

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs (or other environmental projects which may affect your discharges) you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction.

☐ Mark "X" if description of additional control programs is attached.

Form 2CG Additional Information

Item III.B. As indicated on the water mass balance, the percolation pond receives effluent only from the oil/water separators. The separators receive potentially contaminated (oily) waters from secondary containment areas, plant equipment and non-chemical floor drains, and the fuel oil unloading area. Oil collected in the separators is removed by a licensed hauler to a licensed facility for disposal.

A "valved" system controls the release of secondary containment area waters to the separators. An "unvalved" system directs waters from plant equipment drains, non-chemical area floor drains, and the fuel oil unloading area to the separators. Each separator was sized to contain the oil capacity of the largest piece of equipment discharging to the separator. Highland Tank separators were selected for use in this treatment system. Separator effluent is guaranteed to 10 ppm or less of oil or grease.

The existing percolation pond will be resized to contain the average daily flow (20,000 gpd) from the plant equipment and floor drains and a 10 year-24 hour rainfall. Total storage capacity of the percolation pond, with a 12 inch design freeboard, is 298,000 gallons. Percolation time for the average daily flow is approximately 5 hours. In the event of a 10 year-24 hour rainfall, the total flow into the pond would be 128,500 gallons (excluding the valved areas volume), which would require approximately 32 hours to percolate. The maximum daily flow from the plant is approximately 72,000 gpd which would require about 24 hours to percolate. Runoff collected in the secondary containment areas will be detained and released gradually to the separators. It will take about 5.5 days to percolate these waters.

The percolation pond is cleaned as required to maintain operating efficiency. The removed materials are disposed of by a licensed hauler.

Item III.D. In the event of a total power failure at the Power Park, the units will go off-line and would not produce wastewater. Should a particular wastewater lift station lose power or fail, a "High Level Alarm" will activate when the water level in the sump reaches the alarm elevation. Upon activation, a signal is transmitted to the Control Room which is manned 24 hours a day.

The power source associated with the alarm is independent of the pump, and originates from the Control Room. In the event that the pump and Control Room lose power simultaneously, battery back-up exists at the Control Room.

Item III.E. The oily waste system is monitored for flow on the downstream side of the oil/water separators. Oil/water separator flow is discharged to the wastewater lift station(s) which pump the wastewater to the percolation pond. The flow meter(s) are located in the discharge line associated with the lift station(s). The flow meters are turbine type instruments which are connected to the control panel in the Control Room.

V INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding--Complete one set of tables for each discharge location -- Annotate the location number in the space provided. NOTE: Tables V-A, V-B, and V-C are included on separate sheets number V-1 through V-10.

D. Use the space below to list any of the pollutants listed in Table 2CG-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1. Pollutant	2. Source	1. Pollutant	2. Source
N/A			

VI POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

Is any pollutant listed in Item V-C a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or by-product?

☐ YES (list all such pollutants below) ☒ NO (go to VII)

VII CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in Item V performed by a contract laboratory or consulting firm?

☐ YES (list the name, address, telephone number, and certification number of, and pollutants analyzed by each such laboratory or firm below)
☒ NO (go to Section VIII)

A. Name	B. Address	C. Telephone (area code & no.)	D. Pollutants Analyzed (list)

X EXISTING ENVIRONMENTAL PERMITS:

A. NPDES Permit No.	B. UIC Permit No.	C. Other (specify)	D. Other (specify)
Storm Water: FLR00B641	--	SFWMMD: 49-00672-S	

XI MAP: Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements. Location map and a Site Arrangement included in SCA as Figures 2.2-2 and 2.1-3

XII NATURE OF BUSINESS (provide a brief description)

The Cane Island Power Park is a combustion turbine power plant jointly owned by KUA and FMPA, and operated by KUA. Bulk electricity is generated and sold to KUA and FMPA customers. Unit 3 at the Power Park is proposed and will use similar, and in some instances common, wastewater treatment and disposal methods as previously permitted for Units 1 & 2.

XIII CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

Jeff Ling

A. Name (type or print)

B. SignatureManager of Production

Official Title (type or print)

C. Date Signed

Facility I.D. Number: _____

IX-B CERTIFICATIONS FOR PERMIT RENEWALS N/A

This is to certify the engineering features of this pollution control project have been examined by me and found to be in conformity with sound engineering principles, applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules of the Department.

_____ Signature	_____ Company Name
_____ Name (please type)	_____ Address
_____ (Affix Seal)	_____ Florida Registration No.:
	_____ Telephone No.: Date

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

_____ Name (type or print)	_____ Signature
_____ Title	_____ Date Signed
_____ Telephone No. (area code & No.)	

PLEASE PRINT OR TYPE ONLY: You may report some or all of this information on separate sheets instead of completing these pages. Use the same format. SEE INSTRUCTIONS.

V. INTAKE AND EFFLUENT CHARACTERISTICS

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. Pollutant	2. Effluent						3. Units		4. Intake (optional)			
	a. Max. Daily Value		b. Max. 30-day Value		c. Annual Avg. Value		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
a. BOD, Carbonaceous , 5-day, 20 Deg. C.	10	6						ppm	lbs			
b. Chemical Oxygen Demand (COD)	20	12						ppm	lbs			
c. Total Organic Carbon (TOC)	20	12						ppm	lbs			
d. Total Suspended Solids (TSS)	100	60						ppm	lbs			
e. Total Nitrogen (as N)	0.01	0.006						ppm	lbs			
f. Total Phosphorus (as P)	0.02	0.012						ppm	lbs			
g. Ammonia (as N)	0.01	0.006						ppm	lbs			
h. Flow - actual or projected	Value 72,000 gpd		Value		Value 20,000 gpd			gpd		Value		
i. Flow - design	Value 72,000 gpd		Value		Value			gpd		Value		
j. Specific Conductivity	Value 160 μ mhos/cm		Value		Value			μ mhos/cm		Value		
k. Temperature (winter)	Value 10		Value		Value			°C		Value		
l. Temperature (summer)	Value 32		Value		Value			°C		Value		
m. pH	Min. 6	Max. 8.5	Min.	Max.				STANDARD UNITS				

*Conc. = Concentration

PART B - Mark "X" in column 2a for each pollutant you know or have reason to believe is present. Mark "X" in column 2b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

I. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent				d. No. of Analyses	4. Units		5. Intake (optional)		
	a. believed present	b. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
			(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
a. Bromide (24949-67-9)		X										
b. Chlorine, Total Residual	X		0.2	0.3				ppm	lbs			
c. Color	X		< 5	-								
d. Fecal Coliform		X										
e. Fluoride (16984-48-8)	X		0.2	0.3				ppm	lbs			
f. Nitrate-Nitrite (as N)		X										

Item V-B Contd

Facility ID. Number: 3049M06279 Outfall No. G001

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent						d. No. of Analyses	4. Units		5. Intake (optional)		
	a. believed present	b. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)			a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
			(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
g. Nitrogen, Total Organic (as N)														
h. Oil and grease	x		10	1.7						ppm	lbs			
i. Phosphorus, Total (as P) (7723-14-0)	x		0.03	0.005						ppm	lbs			
j. Radioactivity														
(1) Alpha, Total	x		3.2	-						pCi/l	-			
(2) Beta, Total		x												
(3) Radium, Total		x												
(4) Radium 226, Total		x												
k. Sulfate (as SO ₄) (14808-79-8)	x		19	3.2						ppm	lbs			
l. Sulfide (as S)		x												
m. Sulfite (as SO ₃) (14265-45-3)		x												
n. Surfactants		x												
o. Aluminum, Total (7429-90-5)		x												
p. Barium, Total (7440-39-3)	x		0.02	0.003						ppm	lbs			
q. Boron, Total (7440-42-8)		x												
r. Cobalt, Total (7440-48-4)		x												
s. Iron, Total (7439-89-6)	x		0.1	0.02						ppm	lbs			
t. Magnesium, Total (7439-95-4)	x		7	1.2						ppm	lbs			
u. Molybdenum, Total (7439-98-7)		x												
v. Manganese, Total (7439-96-5)		x												
w. Tin, Total (7440-31-5)		x												
x. Titanium, Total (7440-32-6)		x												

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2a for all GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2a (secondary industries, non-process wastewater outfalls, and non-required GC/MS fractions), mark "X" in column 2b for each pollutant you know or have reason to believe is present. Mark "X" in column 2c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4-dinitrophenol, or 2-methyl-4,6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing routine	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)			X												
2M. Arsenic, Total (7723-14-0)			X												
3M. Beryllium, Total (7440-41-7)			X												
4M. Cadmium, Total (7440-43-9)			X												
5M. Chromium, Total (7440-47-3)			X												
6M. Copper, Total (7440-50-8)			X												
7M. Lead, Total (7439-92-1)			X												
8M. Mercury, Total (7439-97-6)			X												
9M. Nickel, Total (7440-02-0)			X												
10M. Selenium, Total (7782-49-2)			X												
11M. Silver, Total (7440-22-4)			X												
12M. Thallium, Total (7440-28-0)			X												
13M. Zinc, Total (7440-66-6)			X												
14M. Cyanide, Total (57-12-5)			X												
15M. Phenols, Total			X												
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X												
1V. Acrolein (107-02-8)			X												
2V. Acrylonitrile (107-13-1)			X												

Facility ID. Number:

Outfall No.

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION VOLATILE COMPOUNDS (continued)															
3V. Benzene (71-43-2)			X												
4V. Bis (Chloromethyl) Ether (542-88-1)			X												
5V. Bromoform (75-25-2)			X												
6V. Carbon Tetrachloride (56-23-5)			X												
7V. Chlorobenzene (108-90-7)			X												
8V. Chlorodibromomethane (124-8-1)			X												
9V. Chloroethane (74-00-3)			X												
10V. 2-Chloro-ethylvinyl Ether (110-75-8)			X												
11V. Chloroform (67-86-3)			X												
12V. Dichlorobromomethane (75-24-4)			X												
13V. Dichlorodibromomethane (75-71-8)			X												
14V. 1,1-Dichloroethane (75-34-3)			X												
15V. 1,2-Dichloroethane (107-06-2)			X												
16V. 1,1-Dichloroethylene (75-35-4)			X												
17V. 1,2-Dichloropropane (78-87-5)			X												
18V. 1,3-Dichloropropylene (542-75-6)			X												
19V. Ethylbenzene (100-41-4)			X												
20V. Methyl Bromide (74-83-9)			X												
21V. Methyl Chloride (74-87-3)			X												
22V. Methylene Chloride (74-98-2)			X												
23V. 1,1,2,2-Tetrachloroethane (79-34-5)			X												
24V. Tetrachloroethylene (127-18-4)			X												

Facility ID. Number:

Outfall No.

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)							
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value	b. No. of Analyses					
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass										
GC/MS DETECTION LIMITS FOR COMPOUNDS (continued)																			
25V. Toluene (108-88-3)			X																
26V. 1,2-Trans-Dichloroethylene (156-60-5)			X																
27V. 1,1,2-Trichloroethane (71-55-6)			X																
28V. 1,1,2-Trichloroethane (79-00-5)			X																
29V. Trichloroethylene (79-01-6)			X																
30V. Trichlorofluoromethane (75-69-4)			X																
31V. Vinyl Chloride (75-01-4)			X																
GC/MS DETECTION LIMITS FOR COMPOUNDS																			
1A. 2-Chlorophenol (95-57-8)			X																
2A. 2,4-Dichlorophenol (120-83-2)			X																
3A. 2,4-Dimethylphenol (105-67-9)			X																
4A. 4,6-Dinitro-Cresol (534-53-1)			X																
5A. 2,4-Dinitrophenol (51-28-5)			X																
6A. 2-Nitrophenol (88-75-5)			X																
7A. 4-Nitrophenol (100-02-7)			X																
8A. P-Chloro-M-Cresol (59-50-7)			X																
9A. Pentachlorophenol (87-86-5)			X																
10A. Phenol (108-95-2)			X																
11A. 2,4,5-Trichlorophenol (88-06-2)			X																
GC/MS DETECTION LIMITS FOR COMPOUNDS																			
11B. Acenaphthene (63-32-9)			X																
21B. Acenaphthylene (208-96-8)			X																
31B. Anthracene (120-12-7)			X																
41B. Benzidine (92-87-5)			X																

Facility ID. Number:

Outfall No.

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
5B. Benzo (a) Anthracene (56-55-3)			X												
6B. Benzo (a) Pyrene (50-32-8)			X												
7B. 3,4-Benzofluoranthene (205-99-2)			X												
8B. Benzo (ghi) Perylene (191-24-2)			X												
9B. Benzo (k) Fluoranthene (207-08-9)			X												
10B. Bis (2-Chloromethoxy) Methane (111-91-1)			X												
11B. Bis (2-chloroethyl) Ether (111-44-4)			X												
12B. Bis (2-Chloroisopropyl) Ether (102-60-1)			X												
13B. Bis (2-Ethylhexyl) Phthalate (117-81-7)			X												
14B. 4-Bromophenyl Phenyl Ether (101-55-3)			X												
15B. Butyl Benzyl Phthalate (84-68-7)			X												
16B. 2-Chlorophthalene (91-58-7)			X												
17B. 4-Chlorophenyl Phenyl Ether (7005-72-3)			X												
18B. Chrysene (218-01-9)			X												
19B. Dibenzo (a,h) Anthracene (53-70-3)			X												
20B. 1,2-Dichlorobenzene (95-50-1)			X												
21B. 1,3-Dichlorobenzene (54-73-1)			X												
22B. 1,4-Dichlorobenzene (106-46-7)			X												
23B. 3,3-Dichlorobenzidine (92-94-1)			X												
24B. Diethyl Phthalate (84-66-2)			X												
25B. Dimethyl Phthalate (131-11-3)			X												
26B. Di-N-Butyl Phthalate (84-74-2)			X												
27B. 2,4-Dinitrotoluene (121-14-2)			X												
28B. 2,6-Dinitrotoluene (606-20-2)			X												

Facility ID. Number:

Outfall No.

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
29B. Di-N-Octyl Phthalate (117-84-0)			X												
30B. 1,2-Diphenylhydrazine (as Azobenzene) (122-66-7)			X												
31B. Fluoranthene (206-44-0)			X												
32B. Fluorene (86-73-7)			X												
33B. Hexachlorobenzene (118-74-1)			X												
34B. Hexachlorobutadiene (87-68-3)			X												
35B. Hexachlorocyclopentadiene (77-47-4)			X												
36B. Hexachloroethane (67-72-1)			X												
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)			X												
38B. Isophorone (78-59-1)			X												
39B. Naphthalene (91-20-3)			X												
40B. Nitrobenzene (98-95-9)			X												
41B. N-Nitrosodiphenylamine (62-75-9)			X												
42B. N-Nitrosodi-N-Propylamine (621-64-7)			X												
43B. N-Nitrosodiphenylamine (86-30-6)			X												
44B. Phenanthrene (85-01-8)			X												
45B. Pyrene (129-00-0)			X												
46B. 1,2,4-Trichlorobenzene (120-82-1)			X												
1P. Aldrin (309-00-2)			X												
2P. -BHC (319-84-6)			X												
3P. -BHC (319-85-7)			X												
4P. -BHC (58-89-9)			X												
5P. -BHC (319-86-8)			X												

Facility ID. Number:														Outfall No.	
1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDE (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. Endosulfan (115-29-7)			X												
12P. Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-92-4)			X												
16P. Heptachlor (76-44-8)			X												
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)			X												
19P. PCB-1254 (11097-69-1)			X												
20P. PCB-1221 (11104-28-2)			X												
21P. PCB-1232 (11141-16-5)			X												
22P. PCB-1248 (12672-29-6)			X												
23P. PCB-1260 (11096-82-5)			X												
24P. PCB-1016 (12674-11-2)			X												
25P. Toxaphene (8001-35-2)			X												

Public Drinking Water System Permit Application



Department of Environmental Protection

Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

INSTRUCTIONS: This form shall be completed and submitted by persons proposing to construct projects permitted under the "General Permit for Construction of an Extension to a Public Drinking Water Distribution System" pursuant to Rule 62-555.540, Florida Administrative Code (F.A.C.). AT LEAST 30 DAYS BEFORE BEGINNING THE PROPOSED CONSTRUCTION, complete this form and submit it in quadruplicate to the appropriate district office of the Department or the appropriate Approved County Public Health Unit (ACPHU) along with a check for the proper permit processing fee and the following supporting documents: signed and sealed engineering design data, plans, and specifications and a certificate that the project has been approved by the governing body of the permittee (city commissioners, corporation, board, etc.). All supporting documents, as well as this form, shall be submitted in quadruplicate. All information provided on this form shall be typed or printed in ink. A signature page or cover letter for engineering design data, each sheet of engineering plans, and a cover or index sheet for engineering specifications shall be signed, dated, and sealed with an impression-type metal seal by the professional engineer(s) in responsible charge of the documents. Also, engineering plans and specifications shall be those intended for construction and shall not be stamped otherwise (e.g., "For Permitting Only," "For Review Only," etc.). Permit processing fees are listed in Rule 62-4.050, F.A.C. Checks for permit processing fees shall be made payable to the Department of Environmental Protection or the appropriate ACPHU. NOTE THAT A SEPARATE NOTIFICATION AND A SEPARATE PERMIT PROCESSING FEE ARE REQUIRED FOR EACH NON-CONTIGUOUS PROJECT.

I. NAME, DESCRIPTION, AND LOCATION OF PROJECT; PERMITTEE; ETC.

- Project Name: Cane Island Power Park - Unit 3
- Project Description: The Cane Island Power Park is a combustion turbine power plant jointly owned by KUA and FMFA, and operated by KUA. Bulk electricity is generated and sold to KUA and FMFA customers. Unit 3 at the Power Park is proposed. Unit 3 will be provided potable water by an extension of the existing Unit 1 & 2 non-community public drinking water system.
- Project Location
County: Osceola Section: 29 & 32 Township: 25 South Range: 23 East
- Permittee
Utility/Company Name: Kissimmee Utility Authority (KUA) Telephone No.: (407) 933-7777
Address: 1701 W. Carroll St.
City: Kissimmee State: FL Zip Code: 34741
- Public Water System Supplying Water for Project
System Name: Cane Island Power Park PWS Identification No.: 3494409
System Owner: KUA Telephone No.: (407) 933-7777
Address: 6075 Old Tampa Highway
City: Intercession City State: FL Zip Code: 33848
- Owner/Operator of Project After It Is Placed into Service
Utility/Company Name: KUA Telephone No.: (407) 933-7777
Address: Cane Island Power Park, 6075 Old Tampa Highway
City: Intercession City State: FL Zip Code: 33848
- Professional Engineer in Responsible Charge of Designing Project
Name of Engineer: Kenneth R. Weiss
Firm Name: Black & Veatch Telephone No.: (913) 458-2662
Address: 11401 Lamar
City: Overland Park State: KS Zip Code: 66211

Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

Project Name: Cane Island Power Park - Unit 3

Permittee: Kissimmee Utility Authority

II. STATEMENT BY PERMITTEE

I, the undersigned owner or authorized representative* of KUA, certify that all water main pipe, fittings, valves, fire hydrants, and related products that will be installed under this project and that will come into contact with drinking water conform, or will conform, with American National Standards Institute/NSF International Standard 61.

I agree that we will require the contractor to furnish us with record drawings for this project. Also, I agree that we will retain a professional engineer registered in Florida to inspect construction of this project for the purpose of determining if work proceeds in accordance with the construction permit and approved engineering plans and specifications.

I am fully aware that we must obtain a letter of clearance from the Department before we place this project into service for any purpose other than disinfection or testing for leaks. Also, I am fully aware that, if we sell or legally transfer ownership of this project before obtaining a letter of clearance from the Department, we must submit to the Department an "Application for Transfer of a Public Water System Construction Permit" within 30 days after such sale or legal transfer of ownership.

Signature and Date

Jeff Ling, Manager of Production

Name and Title (please type or print)

* Attach a letter of authorization.

III. STATEMENT BY PUBLIC WATER SYSTEM SUPPLYING WATER FOR PROJECT

I, the undersigned owner or authorized representative* of KUA, certify that we will provide the potable water supply required by this project. As indicated below, the water treatment plant to which this project will be connected has the capacity to provide the potable water supply required by this project, and I certify that said plant is in compliance with the standards and criteria set forth in Chapters 62-550, 62-555, and 62-560, F.A.C. Also, said plant was constructed under one or more valid Department construction permits as indicated below, and I certify that connection of this project to said plant will not be a violation of any condition of this(these) construction permit(s).

• Name of Water Treatment Plant to Which this Project Will Be Connected: Cane Island Power Park

• Construction Permit Number(s) for Plant and Date(s) Permit(s) Issued: _____

• Permitted Maximum Day Capacity of Plant: _____

• Maximum Day Flow at Plant as Recorded on Monthly Operating Reports During Past 12 Months: _____

Signature and Date

Jeff Ling, Manager of Production

Name and Title (please type or print)

* Attach a letter of authorization.

IV. STATEMENT BY OWNER/OPERATOR OF PROJECT AFTER IT IS PLACED INTO SERVICE

I, the undersigned owner or authorized representative* of KUA, certify that we will be the owner/operator of this project after it is placed into service. I agree that we will operate and maintain this project in a manner that will comply with Chapters 62-550, 62-555, 62-560, and 62-699, F.A.C. Also, I agree that we will promptly notify the Department if we sell or legally transfer ownership of this project.

Signature and Date

Jeff Ling, Manager of Production

Name and Title (please type or print)

* Attach a letter of authorization.

V. STATEMENT BY PROFESSIONAL ENGINEER IN RESPONSIBLE CHARGE OF DESIGNING PROJECT

I, the undersigned professional engineer registered in Florida, certify that I am in responsible charge of the preparation and production of engineering documents for this project; that I have expertise in the design of water distribution systems;

Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

Project Name: Cane Island Power Park

Permittee: Kissimmee Utility Authority

and that, to the best of my knowledge and belief, the engineering design for this project complies with Chapter 62-555, F.A.C.

The plans and specifications for this project require that all new and relocated water main pipe, fittings, valves, fire hydrants, and related products that will come into contact with drinking water be in conformance with American National Standards Institute/NSF International Standard 61. Also, the plans and specifications for this project comply with the following requirements preceded by a "✓," and the following requirements preceded by an "NA" are not applicable to this project.

- X (1) The location and size of existing water mains, reclaimed water lines, force mains, sanitary sewers, storm sewers, and other utilities, as well as the location and size of new and relocated water mains, are shown on the plans.
- X (2) The plans or specifications include procedures for keeping existing water mains in service or for minimizing interruption of existing water service during construction.
- X (3) It is required that all new and relocated water main pipe, fittings, valves, and fire hydrants be in conformance with applicable American Water Works Association (AWWA) standards, that all new and relocated water main pipe and fittings contain no more than eight percent lead, and that all packing and jointing materials used in the joints of new or relocated water main pipe be in conformance with applicable AWWA standards.
- X (4) To the best of the professional engineer's knowledge, this project does not include installation of any new or relocated water mains in areas of ground water for which there is existing publicly accessible documentation of the presence of low-molecular-weight petroleum products or organic solvents at concentrations exceeding ground water standards. (A specific construction permit is required for installation of water mains in areas of ground water that are known to be contaminated by low-molecular-weight petroleum products or organic solvents.)
- X (5) Based upon current and expected water system operating conditions, all new and relocated water mains are sized to maintain a minimum pressure of 20 psig at ground level under all design flow conditions listed in Part VI of this form.
- X (6) If there are any new or relocated water mains that serve fire hydrants, such water mains and all hydrant leads are no smaller than six inches in diameter, and auxiliary valves are provided in all hydrant leads.
- X (7) Dead-ends in new and relocated water mains are minimized by making appropriate tie-ins where practical, and if dead-ends do occur in new or relocated water mains, fire hydrants, flushing hydrants, or blow-offs are provided for flushing purposes.
- X (8) Sufficient valves are provided in new and relocated water mains so that inconvenience and sanitary hazards will be minimized during repairs. (It is recommended that valves be placed at not more than 500-foot intervals in commercial districts and at not more than one-block or 800-foot intervals in other districts.)
- X (9) If there are high points where air can accumulate in new or relocated water mains during design operating conditions, hydrants or air release valves are provided at such high points to remove the air.
- NA (10) If there are any automatic air release valves on new or relocated water mains, such valves are not located where the valve manhole or chamber could be flooded by surface runoff or by the 100-year flood or the highest recorded flood, whichever is higher, and the open end of the air release pipe from such valves is extended to at least one foot above grade and is provided with a screened downward-facing elbow.
- X (11) If there are any hydrant drains, flushing devices, air release valves, or chambers or manholes containing valves, blow-offs, meters, or other such appurtenances provided in conjunction with new or relocated water mains, they are not connected directly to any sanitary or storm sewers.
- X (12) It is required that new and relocated water mains and appurtenances be installed in accordance with applicable AWWA standards and/or the manufacturer's recommended procedures.

Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

Project Name: Cane Island Power Park

Permittee: Kissimmee Utility Authority

- X (13) It is required that rock and unsuitably sized stones (as described in applicable AWWA standards and/or the pipe manufacturer's recommended installation procedures) found in trenches for new and relocated water main pipe be removed to a depth of at least six inches below the bottom of the pipe, that continuous and uniform bedding be provided in trenches for new and relocated water main pipe, and that backfill material be tamped in layers around new and relocated water main pipe and to a sufficient height above such pipe to adequately support and protect the pipe.
- X (14) All tees, bends, plugs, and hydrants in new and relocated water mains are provided with reaction blocking or restrained joints to prevent movement.
- X (15) It is required that all new and relocated water mains be pressure tested and leakage tested in accordance with AWWA Standard C600.
- X (16) It is required that all new and relocated water mains be disinfected in accordance with AWWA Standard C651 and Rule 62-555.345, F.A.C.
- X (17) All new and relocated water mains are located at least ten feet horizontally from all sanitary sewers, storm sewers, force mains, and reclaimed water lines carrying reclaimed water for restricted public access areas and at least three feet horizontally from all reclaimed water lines carrying reclaimed water for public access areas; or data justifying an exception to these separation requirements are attached in accordance with Rule 62-555.314(1) or (4), F.A.C. (All distances are measured from outside pipe edge to outside pipe edge.)
- X (18) If there are any new or relocated water mains that cross any sanitary sewers, storm sewers, force mains, or reclaimed water mains, a profile view of each such crossing or the functional equivalent of a profile view of each crossing is provided.
- X (19) If there are any new or relocated water mains that cross any sanitary sewers, storm sewers, force mains, or reclaimed water lines, the water mains cross above such pipelines with a minimum vertical distance of 18 inches between the outside of the water mains and the outside of such pipelines, or such crossings are arranged so that all pipe joints are equidistant from the point of crossing with no less than ten feet between any two joints (or, alternatively, the sanitary sewers, storm sewers, force mains, and reclaimed water lines at such crossings are placed in sleeves or encased in concrete to obtain the equivalent of the ten-foot separation between joints); or data justifying an exception to these separation requirements is attached in accordance with Rule 62-555.314(4), F.A.C.
- NA (20) If there are any new or relocated water mains that cross over or under surface water, a profile view of each surface water crossing showing the elevation of the bottom of the surface water and the normal and extreme high and low water levels is provided.
- NA (21) If there are any new or relocated water mains that cross over any surface water, the water main pipe at each such surface water crossing is adequately supported and anchored, protected from damage and freezing, and accessible for repair and replacement.
- NA (22) If there are any new or relocated water mains that cross under any surface water, a minimum cover of two feet is provided over the water main pipe at each such surface water crossing, and if the surface water is greater than 15 feet in width, the following features are provided: (a) flexible watertight joints for the water main pipe at the crossing, (b) easily accessible valves located at both ends of the crossing with neither valve subject to flooding by surface runoff or by the 100-year flood or the highest recorded flood, whichever is higher, and with the valve closest to the supply source located in a manhole, and (c) permanent taps on each side of the valve within the manhole to allow for sampling and insertion of a small meter to determine leakage.
- X (23) Proper backflow-prevention assemblies/devices are provided in accordance with Rule 62-555.360, F.A.C., and the AWWA's Manual M14, *Recommended Practice for Backflow Prevention and Cross-Connection Control*.
- X (24) This project does not include any interconnection between previously separate public water systems that have separate water supply sources. (A specific construction permit is required for such an interconnection.)

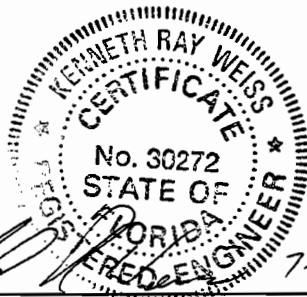
Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

Project Name: Cane Island Power Park

Permittee: Kissimmee Utility Authority

- X (25) It is required that all new and relocated water services be in conformance with the State plumbing code, that all pipe and pipe fittings for new and relocated water services contain no more than eight percent lead, and that all solders and flux for new and relocated water services contain no more than 0.2 percent lead.

Poor Original



Signature, Date, and Seal

Ken Weiss, FL 30272

Name and License Number (please type or print)

VI. SUMMARY OF DESIGN DATA FOR PROJECT

1. Design/Projected Annual Average and Maximum Day Water Demands for Proposed Altered/New Distribution Facilities (i.e., water mains) Under this Project:

A = Type of Unit	B = Number of Units	C = Population per Unit	D = Total Population (Columns B x C)	E = Per Capita Average Day Water Demand	F = Total Average Day Water Demand (Columns D x E)	G = Total Maximum Day Water Demand ¹
Single-Family Home	0				0	0
Mobile Home	0				0	0
Apartment	0				0	0
Commercial, Institutional, or Industrial Facility*	1				221,000 gal	776,000
Total	1				221,000 gal	776,000

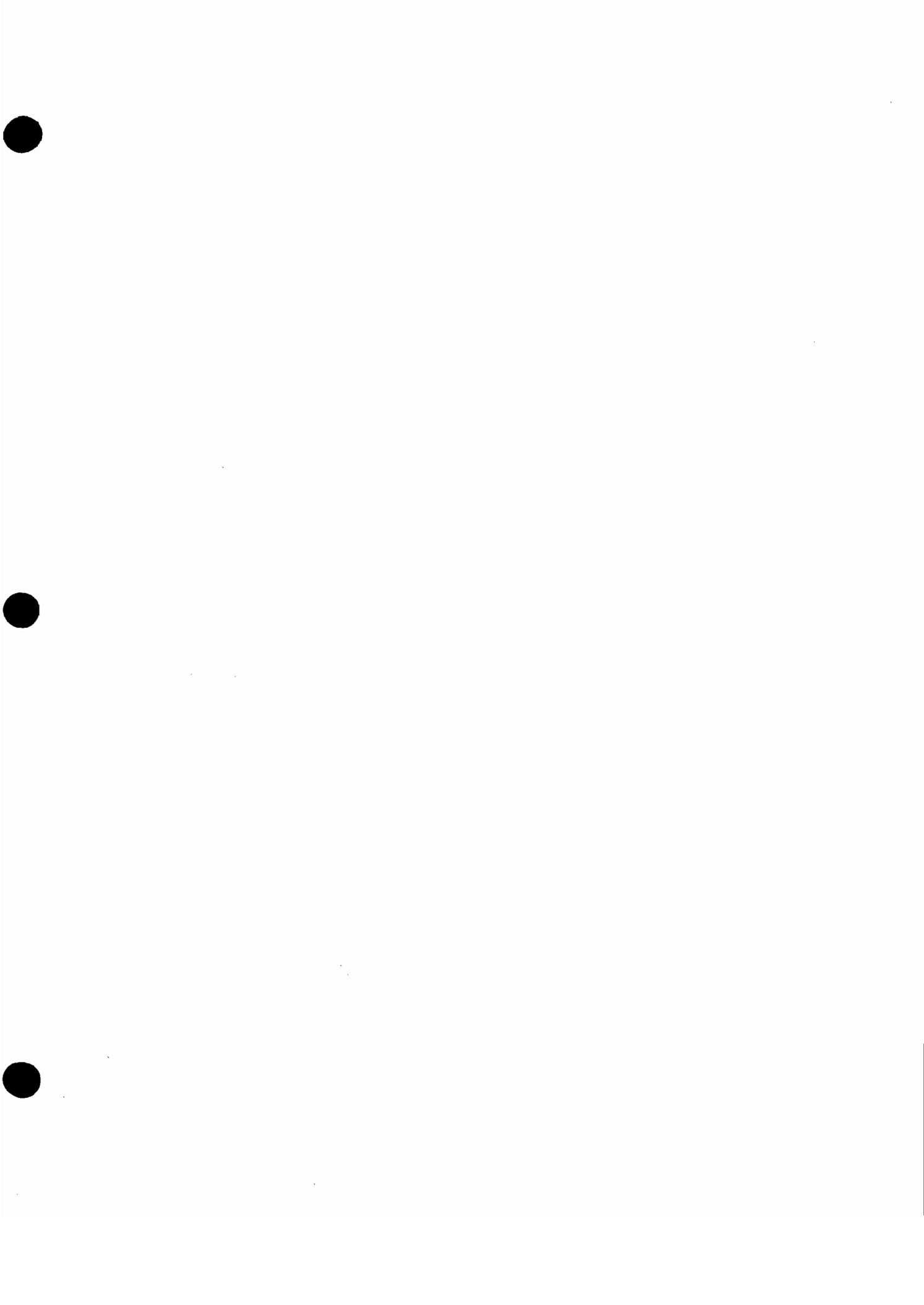
* Description of Commercial, Institutional, and Industrial Facilities and Explanation of Method Used to Estimate Average Day Water Demand for These Facilities: Facility is a power plant consisting of three operating units. Potable uses were estimated at 3,240 gpd based on 27 employees for 3 operating shifts with 40 gpd/person. The remaining flow is estimated for service water and process uses at 100% plant load.

¹ Explanation of Method Used to Estimate Maximum Day Water Demand: Same as above, but with service water quantities based on providing water for NO_x injection to the combustion turbines when firing oil.

2. Design/Projected Maximum Hour Water Demand for Proposed Altered/New Distribution Facilities Under this Project and Basis of Design/Projection: 65,000 gal based on anticipated capacity of well pumps to provide raw water to the service water system.

Design/Projected Fire Demand Plus Coincident Draft (usually maximum day water demand) for Proposed Altered/New Distribution Facilities Under this Project and Basis of Design/Projection: 1,136,000 gal based on maximum day water demand plus 360,000 gal of reserved fire water storage.

3. Operating Pressure Range for Proposed Altered/New Distribution Facilities Under this Project: 40 to 85 psig for the service water and potable water distribution systems.
4. Will the proposed altered/new distribution facilities under this project be part of a community water system or a public water system that has a service area also served by a reclaimed water system? Yes If yes, document that the system has a routine cross-connection control plan, including a written plan, in accordance with Rule 62-555.360, F.A.C.: Not applicable. Reclaim water used for cooling tower makeup only. Cross-ties not feasible.





10.5 Existing Local Permits

10.5.1 Conditional Use/Site Development Plan

Conditional Use/Site Development Plan Permit CU/SDP 92-86 was issued to KUA by the Osceola Board of County Commissioners for development of the property as a power generating station. A copy of this permit is included herein.

10.5.2 Tree Removal Permit

A Tree Removal Permit was issued to KUA by Osceola County in 1993 to remove trees for site development and demonstrate compliance with the County Ordinance 87-15.

10.5.3 Sanitary System Permit

A permit to construct and operate an onsite sewage disposal system was issued to KUA by Osceola County in 1993 to install the septic tank/tile field system at the Power Park.

10.5.4 Building Permit

A permit to construct the onsite generating facilities was issued to KUA by Osceola County in 1993.

10.5.5 Effluent Agreement

An agreement between KUA and the City of Kissimmee Water and Sewer Department was executed in 1993 for the delivery and use of treated sewage effluent. A copy of the agreement is included herein.

Conditional Use/Site Development Plan

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.



O S C E O L A C O U N T Y
BOARD OF COUNTY COMMISSIONERS

Bm
44

PHONE: 407 / 847-1200

17 SOUTH VERNON AVENUE, ROOM 155

KISSIMMEE, FLORIDA 34741-5488

January 25, 1993

Mr. Ben Sharma
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, FL 34741

REF: CU/SDP 92-86 -- Kissimmee Utility Authority (Combustion
Turbine Power Plant)

Dear Mr. Sharma:

Your referenced request for a Conditional Use/Site Development Plan approval was granted by the Osceola Board of County Commissioners at their meeting of January 11, 1993, subject to compliance with the following conditions:

A. STANDARD CONDITIONS:

1. Drainage and Stormwater Management Plans and Calculations to be approved by County Engineer prior to submitting plans for building permits. A benchmark will be required at a location to be noted on the approved drainage plans. The project engineer shall pick up a brass disk for the BM at the County Engineer's Office. All paving and drainage to be constructed per approved plans prior to receiving a Certificate of Occupancy.
3. South Florida Water Management District permit is required for surface water system evaluation.
20. Stop signs and stop bars required at project entrance and exit to Old Tampa Highway.
23. Applicant must maintain tree canopy based on tree-point requirement of County Tree Ordinance.
26. Applicant will need to obtain a tree removal permit prior to removing any trees (4 inches DBH) from the site.
28. Applicant shall provide 1/2" dry pre-treatment retention.
32. Applicant will need to submit a tree planting plan showing all trees to be removed, retained, and/or replanted, noting their size (in DBH), type and location on the site plan, to meet the tree point requirement.
33. Applicant will need to submit a copy of the tree removal permit to the County Engineering Department prior to final engineering/construction plans approval.

Charles Owen / Jim Swan / John Pate / Larry Whaley / Reidy Williams

COUNTY ATTORNEY NEAL D. BOWEN - CLERK MEL WALLS, JR.

Mr. Ben Sharma
Page Two
January 25, 1993

B. SPECIAL AND VOLUNTARY AGREEMENT CONDITIONS:

1. Approved copies of any required dredge and fill permits to be filed with the County Engineer.
2. Approved copies of any required DER permits for above ground storage tanks to be filed with the County Engineer.
3. Applicant shall pave the entrance road approach to Old Tampa Highway with 24' width pavement and required radii.
4. Approval of this Conditional Use shall void CU/SDP 91-90 as approved by the Board of County Commissioners on February 17, 1992.
5. Provide for compensating storage within the 100 year flood plain.
6. Access road 24' pavement and minimum 50' curb radius shall be a private easement.
7. Applicant to address KUA's intention to meander transmission lines within the 300 ft. corridor to avoid clear cutting.
8. Applicant shall submit SFWMD, DER and ACOE jurisdictional line determinations. Jurisdictional line approvals or acceptance will need to be indicated on all plans.
9. Any proposed alterations of State or federal jurisdictional areas will need to be approved by those agencies. The applicant shall submit letters of conceptual approval or approved permits and approvals from the applicable agencies to the Zoning Division prior to construction plan or building permit approval.
10. The Conditional Use/Site Development Plan requirement of submittal of a building permit will be satisfied if one of the following is submitted within the time frame allowed: dredge and fill permit from DER or a storm water management permit from SFWMD.
11. Within 30 days of commencement of operation of each phase of the combustion turbine power plant (the Facility), applicant shall monitor and model the noise impacts from the Facility at the boundaries of KUA site to ensure that the noise impact generated by the Facility complies with EPA, State and County regulations. The applicant shall forward the results of the monitoring and modelling to the County Zoning Division. If the noise impacts exceed the respective standards of the EPA, State or County regulations, the applicant shall immediately take corrective action to bring operation of the Facility into compliance with the respective regulations.
12. Draft conservation easement agreement language shall be amended to include the submittal of copies of the monitoring reports to the Zoning Division (Item 3.e.).

Mr. Ben Sharma
Page Three
January 25, 1993

13. No construction will be allowed until the conservation easement agreement is finalized and executed.
14. KUA agrees to increase the height of the utility lines ten feet (10') higher than the State requirements.
15. KUA agrees not to exceed the sound level of 55 (db) at the property line in the residential areas.
16. If Osceola County can negotiate the establishment of a site for a future park with the South Florida Water Management District, KUA will not object.
17. KUA agrees to comply with any future changes which relate to the magnetic field which would cause the regulatory agencies to change the regulations.
18. KUA agrees that replacement plants will include evergreen trees around the facility and along the easement for an additional buffer and would not clear cut the right-of-way.
19. KUA agrees to work with residents concerning the spacing of utility poles along the easement.

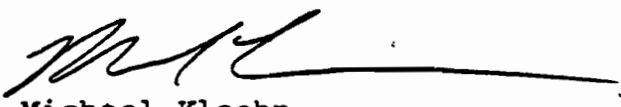
Note: Staff recommends that the applicant recognize the existence of an easement for adjacent property owner to existing crossing of Seaboard Coastline Railroad.

The Conditional Use/Site Development Plan requirement of submittal of a building permit will be satisfied if one of the following is submitted within the time frame allowed: dredge and fill permit from DER or a storm water management permit from SFWMD. The dredge and fill permit or the storm water management permit must be submitted within one year of the approval date by the Board of County Commissioners or the approval will become void.

If we can be of further assistance, please contact the Planning Department at 847-1380.

Respectfully,

PLANNING DEPARTMENT



Michael Kloehn
Planning Director

vj

c: Mr. David M. Lefebvre

Effluent Agreement



May 4, 1992/5

Mr. Brian Wheeler
Director of Water & Sewer Department
City of Kissimmee
101 North Church Street
Kissimmee, FL 34741

RE: Executed Agreement and Easement Concerning Delivery and Use
of Treated Sewage Effluent

Dear Brian:

I am returning herewith an original of the fully executed agreement between the City of Kissimmee and KUA for the utilization of the City's effluent at KUA's Cane Island site.

We very much appreciated the time and effort you and Don Smallwood put in to develop this agreement and get it approved.

Sincerely,

A. K. (Ben) Sharma, P.E.
Director of Power Supply

AKS/css

Enclosure

cc: Mr. Mike Soltys, B&V
Mr. Myron Rollins, B&V

Agreement and Easement Concerning Delivery and Use of Treated Sewage Effluent

This Agreement and Easement is made and entered into this 28th day of April, 1993, by and between the CITY OF KISSIMMEE, a municipal corporation, organized and existing under the laws of the State of Florida (hereinafter referred to as City); and KISSIMMEE UTILITY AUTHORITY, a body politic (hereinafter referred to as KUA).

Witnesseth:

WHEREAS, KUA is a body politic, organized under the laws of the State of Florida, empowered among other things to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, or extend electric generation, transmission, and distribution projects; and

WHEREAS, the City is a municipal corporation empowered among other things to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, or extend wastewater treatment and disposal facilities; and

WHEREAS, KUA and the City both serve residents of the City and the surrounding area providing the essential services of electricity and wastewater disposal; and

WHEREAS, KUA has purchased an electrical generating unit site, the Cane Island Site, adjacent to the City's treated wastewater effluent pipeline (Effluent Pipeline); and

WHEREAS, KUA has entered a joint participation agreement with the Florida Municipal Power Agency (FMPA) to construct two electrical generating units at the Cane Island Site; and

WHEREAS, FMPA has designated KUA as its agent; and

WHEREAS, KUA must obtain water for cooling tower makeup for the second unit to be constructed at the Cane Island Site; and

WHEREAS, KUA must dispose of wastewater from the Cane Island Site; and

WHEREAS, KUA anticipates building additional generating units at the Cane Island Site in the future which will require water for cooling tower makeup and wastewater discharge; and

WHEREAS, it is to the mutual benefit of KUA, the City, and their customers for KUA at the Cane Island Site to use the City's treated sewage effluent for cooling tower makeup and to discharge plant wastewater into the Effluent Pipeline;

NOW, THEREFORE, in consideration of the premises and other valuable consideration given one party to the other, the City and KUA hereby agree as follows:

I. Terms; Volume and Delivery Schedule.

A. The City shall deliver and KUA shall accept, use, and return treated sewage effluent, in quantities and under the quality provisions set forth herein. This Agreement shall be effective for a term of thirty (30) years. This Agreement shall be extended for additional terms of five (5) years unless written notification is given at least 18 months prior to the expiration of the initial thirty year term. KUA agrees to notify the City at least 30 days prior to the date it expects to actually accept the treated sewage effluent. Notwithstanding this provision, in the event changes in state or federal law subsequently prohibit the use of treated sewage effluent in the manner contemplated by this Agreement, the Agreement shall be terminated as a matter of law.

B. The City shall deliver treated sewage effluent to KUA for use at the Cane Island Site via the Effluent Pipeline. The City shall deliver up to 800,000 gallons per day at a flow rate of up to 600 gallons per minute for Cane Island Unit 2 through the term of the Agreement. The average annual withdrawal rate for this initial increment is estimated to be up to 220,000,000 gallons per year.

C. Throughout the term of the Agreement the parties acknowledge that the withdrawal and delivery of the treated sewage effluent will be on an as needed basis. KUA agrees to give reasonable notice (i.e., by telephone or written communications) of the expected treated sewage effluent quantities and the anticipated dates and times of withdrawal. The City must give KUA prior written notice of its inability to supply the treated sewage effluent to KUA as soon as practicable under the circumstances upon the initial discovery by the City. KUA acknowledges that from time to time there may be an interruption of flow or significant diminution of flow due to failure of mechanical equipment at the treatment plants, failure of the

pipeline, and/or failure due to substandard effluent quality. The City agrees to notify KUA at least 60 days in advance of scheduled outages of the Effluent Pipeline and any associated treatment plant and to cooperate with KUA during the scheduled outages. The City agrees to repair mechanical, pipeline, or effluent quality failures within seventy-two hours of the initial discovery by the City. If the City is not able to deliver the average daily allocation of treated sewage effluent to KUA because of mechanical, pipeline or effluent quality failures, KUA has the right to obtain water from an alternate source during such period of the City's inability to supply. During the periods of the City's inability to supply, wastewater discharges resulting from water obtained from other sources shall be excluded from any computation of ratios of annual withdrawals. No penalties shall be assessed against KUA for the amount of alternate wastewater discharged to the City.

D. The City agrees to notify KUA of any proposed agreements with third parties, negotiated for delivery and use of treated sewage effluent from the Effluent Pipeline prior to approval and execution by the City. The City will, upon request, demonstrate that the proposed additional agreement will not prevent the City from fulfilling the terms and obligations contained herein, materially affect the quality of the treated sewage effluent provided to KUA, or otherwise affect KUA in a detrimental manner. The City agrees to favor KUA with copies of any and all agreements between the City and third parties relating to the subject matter of this Agreement.

II. Option.

A. The City shall maintain subject to availability of sufficient quantity the capability to deliver to the KUA Cane Island Site additional treated sewage effluent in the following sequential increments.

Table of Increments of Treated Sewage Allocation

<u>Increment</u>	Gallons per Day <u>(1,000)</u>	Gallons per Minute <u>GPM</u>
A	2,900	2,200
B	1,000	800
C	900	700

D	900	700
E	2,900	2,200
F		
Upset Maximum Limit	8,600	6,600

The term of this availability of additional treated sewage effluent shall be twenty (20) years, however, the term of availability may be extended for additional terms of five (5) years based upon written request of KUA at least twelve (12) months prior to expiration of the initial twenty year term.

B. KUA shall notify the City in writing of its intent to exercise its option to utilize the next increment of allocation of treated sewage effluent in the sequence a minimum of two (2) years in advance of the projected date for the Cane Island Site to actually need the increased allocation. Within thirty (30) days of receipt of the KUA notice of intent to utilize the next increment of allocation of treated sewage effluent, the City shall provide KUA written notice of its availability to provide the increment of allocation with the schedule provided in the KUA notice. If the City does not have or project to have sufficient quantity of treated sewage effluent to fully provide the increment of allocation requested in the KUA notice, the City shall provide KUA in writing the estimated date of availability of the total quantity of treated sewage effluent.

C. KUA may substitute one increment for another increment subject to availability of sufficient quantity of treated sewage effluent and with the consent of the City by amendment to this Agreement. KUA may also establish an additional increment F by modifying one or more of the increments A-E above, however, the total upset limit of all increments A-F shall not exceed 8.6 million gallons per day and/or 6,600 gallons per minute of treated sewage effluent as established in the table contained herein. Additional amendments or modification to the Table of Increments of Treated Sewage Allocation not outlined herein may be requested by KUA, but will be subject to maintaining the Upset Maximum Limits contained in the table, the availability of sufficient quantity of treated sewage effluent and the consent of the City.

D. KUA shall not exercise its option for the next increment of allocation of treated sewage effluent in the sequence until the two (2) year period has expired from the last KUA written notification of intent to utilize an increment of allocation, e.g., if KUA notifies the City in writing on January 1, 1994, of its intent to utilize Increment A no earlier than January 1, 1996; then KUA cannot file written notification of its intent to utilize Increment B until January 1, 1996.

E. KUA may request in writing that the minimum two (2) year period between notification of intent to utilize the next increment of allocation of treated sewage effluent be waived. The City may grant a request for waiver of the minimum two (2) year period based on the City's ability to provide the requested increased allocation within the reduced schedule.

F. The schedule of sequential increment of treated sewage effluent allocation may be modified by the mutual consent of both parties.

G. KUA may request increased withdrawal rates in excess of the schedule contained in Paragraph II A by filing a request which indicates with specificity the increased withdrawal rate, date of proposed increase, the proposed increase in wastewater discharge and characteristics, and all other information which may be necessary for the City to evaluate the request. Such additional request must be filed a minimum of six months in advance of desired increased withdrawal. Within thirty (30) days of receipt of said request the city shall in writing either approve, reject, or approve with conditions the additional withdrawal.

H. Notwithstanding the above, throughout the term of this Agreement specified in Paragraph I A., the City will not modify or enter into any agreements that would limit the City's ability to supply KUA at the Cane Island Site the amounts of treated sewage effluent specified in Paragraph II A without providing KUA a first right of refusal. The first right of refusal shall be exercised by the City providing KUA a proposed agreement executed by the third party seeking the use of treated sewage effluent as well as the City's best effort projections of the availability of treated sewage effluent with and without the proposed agreement. At the same time, the City shall provide KUA the City's costs associated with foregoing the proposed agreement. KUA shall have 90 days to notify the City of KUA's decision as to whether KUA will exercise KUA's first right of refusal. If KUA exercises the first right of refusal, KUA will pay the City's costs associated with foregoing the proposed agreement and the City will maintain the capability to provide KUA with the amounts of treated sewage effluent specified in Paragraph II A. If KUA does not

give notice to the City that KUA will exercise KUA's first right of refusal within 90 days, the City may reduce the schedule of treated sewage effluent reserved for KUA by the amount of the third party agreement. The City agrees to make its best effort (subject to the conditions contained in this Agreement) to maintain the amounts of treated sewage effluent specified by the schedule in Paragraph II A available to KUA even though KUA does not exercise its first right of refusal. KUA and the City agree to cooperate and upon request provide the other party their best effort projections of availability and use of treated sewage effluent.

I. The City agrees to project the availability of treated sewage effluent and the consumption of reuse water. In the event the installation of a new reuse system in a new development is projected to result in the City's inability to provide KUA with the treated sewage effluent in accordance with the schedule in Paragraph II A, the City shall notify KUA of the proposed installation of the reuse system together with estimated costs of installation, costs of operation and maintenance and/or costs to perform (including but not limited to loss of revenue, cost of retrofitting reuse facilities, etc.). KUA shall have a 90 day period in which to exercise a first right of refusal for the proposed reuse system. If KUA gives notice to the City that KUA is exercising the first right of refusal, KUA shall reimburse the City for the City's cost associated with the installation of the reuse system; however, the users of the reuse system will only be provided with treated sewage effluent when it is not needed by KUA. KUA will also reimburse the City for the City's additional disposal costs until the effective date of the KUA's additional treated sewage effluent withdrawal. KUA will also reimburse the City for any ongoing costs including loss of revenue after KUA's additional treated sewage effluent withdrawal begins that are the result of KUA exercising this first right of refusal. Interest on KUA's costs to reimburse the City for the installation of the reuse water system will accrue monthly based on the rate per annum reported in Muniweek on the last publication of the calendar month as the Current Bond Buyer Revenue Bond Index. Revenues collected by the City from the sale of reuse water in the systems paid for by KUA will be paid to KUA by the City until the cost of the system including interest as calculated above has been repaid at such time and for thereafter the City will retain the revenues from the sale of the reuse water.

III. Effluent Quality.

A. All wastewater effluent delivered to KUA under this Agreement shall be treated by advanced treatment methods to control the levels of bacteria and any other constituents which would constitute a damage to human health and in accordance with the requirements of permits issued by state and federal regulatory agencies. The quality of the wastewater effluent shall be treated to meet the public access levels of treatment standards as defined in Florida Department of Environmental Regulation (FDER) Rule 17.610 Florida Administrative Code (F.A.C.) (the primary and secondary drinking water standards). The City agrees to provide to KUA copies of its monthly monitoring reports which are required to be filed with the FDER.

B. The City agrees to provide to KUA an annual chemical analysis of the treated sewage effluent from each wastewater treatment facility discharging to the Effluent Pipeline. This effluent will be analyzed for primary and secondary drinking water standards as established by the FDER. The City will not modify or enter into any agreements that would substantially reduce the quality or characteristics of the treated sewage effluent delivered to KUA without KUA concurrence. KUA agrees to provide the City with a copy of all reports as required by the FDER for KUA's wastewater returned to the Effluent Pipeline. KUA and the City will comply with the water quality standards set forth by the applicable permits issued by FDER.

C. Upon discovery by the City of any effluent discharged to the pipeline which does not meet the standards or requirements of the FDER permit, the City will immediately notify KUA. Notification will be made by telephone to the Cane Island Site followed by written notification to KUA at:

Kissimmee Utility Authority
Director of Power Supply
P. O. Box 423219
Kissimmee, Florida 34742-3219

D. The City and KUA each agree to indemnify and hold the other harmless for damages resulting from its actions causing wastewaters to be discharged into the Imperial Effluent Disposal Site which exceeds the FDER permit limits. The City also agrees to indemnify KUA for damages resulting from the actions of third parties with whom the city contracts, which cause wastewater to be discharged into the Imperial Effluent Disposal Site exceeding the FDER permit limits.

E. Should a dispute arise as to a determination of compliance or noncompliance with the FDER primary and secondary drinking water standards, hydraulic balance and mass balance analyses shall be conducted. If KUA and City Engineers' conclusions conflict, a mutually agreed upon independent Certified Engineer will be hired as a consultant to conduct an analysis.

F. Both parties agree to initially share equally the cost of such independent Certified Engineer. The opinion of the independent consultant shall be binding on the parties. If the results of the analysis determine that the discharge from the Cane Island Site is responsible for the effluent within the pipeline to be out of compliance with standards or requirements of the FDER permit or any other applicable permit, KUA shall immediately take all necessary and reasonable remedial actions at its cost and expense, and shall insure that any discharge from its facility does not result in non-compliance by the City of the standards and requirement of its permits. KUA shall be the party liable for all corrective action, fines and damages, including the initial analysis if the Cane Island Site is determined to be the cause of the non-compliance incident. If the cause of the non-compliance incident is determined to have been the City, then KUA shall not be liable for any required corrective action, fines and damages, including the initial analysis.

IV. Use of Treated Effluent.

A. It is contemplated by the parties hereto that KUA will use the treated sewage effluent as make-up supply for cooling towers for its facility. However, the parties agree that KUA may use the treated sewage effluent made available by the City for any on site purposes and in any manner determined by KUA; provided, however, that (i) KUA's use of treated sewage effluent shall at all times be consistent with all local, state, and federal guidelines and requirements; (ii) KUA shall not discharge the treated sewage effluent directly into any surface waters of the State of Florida without the express, written authorization of FDER, EPA, or any other jurisdictional agency, (iii) KUA shall comply with all local, state, and federal regulations and guidelines, and advise potential users of the limitations on the use of the treated sewage effluent. The City recognizes that the treated sewage effluent quality in the Effluent Pipeline at point of KUA's withdrawal must be of a quality that is better than required by F.A.C. 17.610 in order for KUA to meet the discharge permit quality requirements. The City will use reasonable efforts to provide KUA with treated sewage effluent which is of a quality that is better than that required by

F.A.C. 17.610 and which will meet KUA's requirements; however, the City is under no obligation to expend capital funds or increase the City's operating cost to provide treated sewage effluent which is of better quality than that required by F.A.C. 17.610 unless requested to do so by KUA. If KUA requests the City to take action to provide KUA with treated sewage effluent which is of better quality than that required by F.A.C. 17.610 which requires the City to expend capital funds and/or increases the City's operation costs the KUA shall fully reimburse the City for the additional costs the City incurs.

V. Return/Discharge.

A. KUA shall discharge and the City agrees to accept wastewater from the KUA Cane Island Site. The wastewater from the Cane Island Site will be injected into the City's Effluent Pipeline for disposal. The composition of the wastewater includes pretreatment equipment wastewater, neutralized demineralized wastes, and cooling tower blowdown. The City shall begin accepting return wastewater from KUA on or about November 1, 1993.

B. The KUA facility shall not discharge a chemical constituent in a concentration which, when combined with the effluent from the City's wastewater treatment facility at the end of the Effluent Pipeline, will result in a concentration of that constituent which will violate applicable permits or would prohibit Florida Power Corporation from exercising its rights under its contract with the City for delivery and use of Treated Sewage Effluent dated January 5, 1993.

C. KUA will sample the treated sewage effluent from the City of Kissimmee at the point of KUA withdrawal from the Effluent Pipeline and analyze for the following parameters:

<u>Parameter</u>	<u>Units</u>	<u>Daily Average</u>	<u>Daily Maximum</u>	<u>Sample Type</u>	<u>Freq.</u>
Nitrates (Total)	mg/l	Report	Report	Composite	weekly
Nitrates (Total)	lb/day	Report	Report	Composite	weekly

Total Nitrogen	mg/l	Report	Report	Composite	weekly
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Total Nitrogen	lb/day	Report	Report	Composite	weekly
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D. Samples shall be taken prior to the point of discharge from the Cane Island Site into the Effluent Pipeline and analyzed as follows:

<u>Parameter</u>	<u>Units</u>	<u>Daily Average</u>	<u>Daily Maximum</u>	<u>Sample Type</u>	<u>Freq.</u>
Flow	MGD	0.110	report	metered	daily
pH	SU	6.0 min.	8.5 max.	composite	2/mo.
TDS	mg/l	report	report	composite	2/mo.
Chlorides (total)	mg/l	report	report	composite	2/mo.
Sodium	mg/l	report	report	composite	2/mo.
Sulfates (total)	mg/l	report	report	composite	2/mo.
TRPH*	mg/l	BDL**	5.0	composite	weekly
Nitrates (total)	lbs/day	***	***	composite	weekly
Nitrogen (total)	lbs/day	***	***	composite	weekly
Nitrates (total)	mg/l	report	report	composite	weekly
Nitrogen (total)	mg/l	report	report	composite	weekly

*Total Recoverable Petroleum Hydrocarbon.

**Below detectable limits.

***There shall be no net increase in nitrates compared with the nitrates already present in the effluent line and the ground water used at the Cane Island Site.

E. There shall be no net increase in nitrates compared to the water sources. Parameters may be amended, from time to time, by agencies having jurisdiction over

the permit requirements of this Agreement. KUA agrees to modify sampling parameters in accordance with any future permit modifications.

F. If the City's treated sewage effluent does not exceed its permit limits at the point where KUA accepts the treated sewage effluent yet the discharge from the Cane Island facility contains any constituent in a concentration resulting in the City's violation of its disposal site permits or any federal, state or local regulation, the City shall immediately notify KUA of the problem. Notification will be made as indicated in Section III C, above. Upon receiving said notification, KUA will terminate the discharge of wastewater and review its data in an effort to determine the source of the problem. KUA acknowledges the contractual rights of Florida Power Corporation and the foreseeability that such permit violation may result in damages suffered by the City and Florida Power Corporation.

G. If the City notifies KUA that the quality of treated sewage effluent is such that the treated sewage effluent cannot be utilized as set forth in Agreement and Easement Concerning Delivery and Use of Treated Effluent between the City and Florida Power Corporation (FPC) dated January 5, 1993, KUA will review operations at the Cane Island Site and coordinate with FPC to attempt to provide treated sewage effluent of a quality adequate for FPC's use, although, KUA has no obligation to modify discharges to the Effluent Pipeline to provide treated sewage effluent of a quality better than that required for the combined effluent of the City's wastewater treatment facilities and the KUA Cane Island Site effluent to meet the requirements of the governing permit requirements and F.A.C. 17.610 as may be amended from time to time.

H. Should a dispute arise as to a determination of the cause of the noncompliance resolution shall be by the procedure outlined in Paragraphs III E and F.

I. KUA shall provide the City with copies of permits associated with the use of the treated sewage effluent and discharge of wastewater as well as reports summarizing sampling results and immediately notify the City of any violation or failure to meet the requirements of such permits.

VI. Rates.

A. This section governs the rates and compensation associated with the use of the treated sewage effluent at the Cane Island Site. For purposes of determining

charges, year will be defined as KUA's fiscal year which runs from October 1 through September 30. Payments for partial years will be prorated.

B. The ratio of annual gallons withdrawn to annual gallons returned will be 2.2/1. KUA and the City shall use this ratio as the basis for establishing compensation for the use of treated sewage effluent and administrative costs associated with the monitoring of effluent quality and quantity as required by the FDER and this Agreement.

C. On or about October 1 of each year, KUA will pay the City the Annual Base Rate (ABR). The first day of each month or as soon thereafter as practical, the City will read the meter recording the treated sewage effluent withdrawal and the wastewater discharge. Each month the City will bill KUA for the treated sewage effluent withdrawal in accordance with the charge outlined herein. The ABR shall be applied as a credit against the monthly treated sewage effluent charge for the contract year (October 1 through September 30). KUA shall receive a bill each month indicating the monthly and cumulative amounts for the contract year of treated sewage effluent withdrawn and wastewater discharged, the amount of credit, if any, remaining from the ABR and the amount, if any, due to the City. Payment shall be made to the City within twenty (20) days of receipt of the bill for any amounts due. A penalty of five percent (5%) shall be applied to any delinquent payments. The initial payment for the ABR shall not be made until KUA withdraws treated sewage effluent or discharges wastewater. The initial payment for the ABR shall be prorated based on the amount of the contract year remaining.

D. Compensation to the City shall be defined by the formula: annual payment = $ABR \text{ (new year)} + [(cumulative \text{ sum of MGW for the current operating year}) * RWC - ABR \text{ (current year)}]$ where: ABR = (Annual Base Rate), equals the incremental expenses incurred by the City for lab fees, monitoring, meter reading, and administrative costs. The ABR will escalate at a rate equal to the annual increase in the Consumer Price Index for the previous calendar year as published in the January issue of the *Survey of Current Business*. The first adjustment will be made for the ABR in October 1994.

RWC = (Reuse Water Charge) is the lowest commercial rate available for the suburban service area by City ordinance for reuse water charges.

MGW = (Monthly Gallon Withdrawals) is the KUA monthly gallon withdrawals from the Effluent Pipeline as read locally by the City using the KUA installed meters.

E. For the 1993-94 contract year, the City has established the following rates: ABR = \$12,000 and RWC = \$0.25/1,000 gallons. Should the annual ratio of 2.2/1 minus 0.05 not be achieved by KUA in any given year, then a rate penalty may be assessed at the end of that year according to Section VII (Penalties) of this contract.

VII. Penalties.

A. Beginning in October 1994, and each successive October thereafter, the ratio of the annual withdrawal of the treated sewage effluent to the discharge of wastewater shall be calculated. The calculation of the ratio will be based upon the meter readings of the treated sewage effluent withdrawal and the wastewater discharge for the previous contract year. If the minimum annual ratio of 2.2/1 with an allowance of minus 0.05 is not achieved, KUA shall pay a penalty surcharge on the incremental amount of wastewater discharged which is in excess of the amount allowed to maintain the 2.2/1 ratio. The surcharge shall be equal to three times the RWC. KUA shall be billed for the surcharge, if any, in November.

B. The amount of wastewater against which the surcharge shall be applied will be calculated as follows:

$$\text{SCF} = \text{TWW} - (\text{RW}/2.2)$$

SCF = Incremental amount of wastewater to be assessed penalty surcharge.

TWW = Wastewater discharged by KUA into the Effluent Pipeline.

RW = Treated sewage effluent withdrawn by KUA from the Effluent Pipeline.

VIII. Connection and Metering.

A. KUA shall be responsible for connecting to the City's Effluent Pipeline to receive the treated sewage effluent from the City and to discharge its wastewater from its facility to the Effluent Pipeline. KUA shall be responsible for the connection, all costs of installation, and agrees that it will be responsible for all damages associated with the loss of use, or damage to or destruction of the Effluent Pipeline resulting from the KUA connection.

B. KUA agrees to retain a professional engineer licensed/registered in Florida and a contractor, likewise licensed in Florida, both of whom are experienced in handling concrete pipe under pressure (PCP). KUA shall submit plans and procedures for connecting to the Effluent Pipeline for review and approval by the City. The City shall review and approve or disapprove the engineer, contractor, and connection plans within 30 days of receipt from KUA.

C. Within 30 days of execution of this agreement, the City agrees to make application to FDER to obtain and/or modify all necessary permits as required by FDER to allow KUA to connect to the Effluent Pipeline. The City will use due diligence to obtain permit approval as soon as possible thereafter. KUA agrees to obtain all permits required to connect to the Effluent Pipeline and to notify the City at least 30 days prior to the start of construction.

D. KUA shall provide metering of the treated sewage effluent taken from the City's Effluent Pipeline and of the discharge of wastewater from the KUA Cane Island Site to the Effluent Pipeline. The two meters and their location shall be subject to approval by the City, and will be easily accessible for reading, testing, and maintenance. The City shall retain the responsibility for testing and maintaining the meters. Unless an emergency arises, the City shall give KUA a 24-hour notice should service be interrupted to KUA operations due to maintenance or testing activity.

IX. Excuse from Performance by Governmental Act.

A. If for any reason during the term of this Agreement any local, state or federal governments or agencies shall fail to issue necessary permits, grant necessary approvals, or require any change in the operation of the treatment, transmission and distribution systems or the application and use of the treated sewage effluent by KUA, then, to the extent that such requirements shall affect the ability of any party to perform any of the terms of this Agreement, the affected party shall be excused from the performance thereof. The parties hereto shall immediately undertake to renegotiate that portion (and only that portion) of this Agreement affected by such requirements so that this Agreement, as renegotiated, will be in conformity with such permits, approvals or requirements.

X. Assignment and Damages.

A. The City shall have the right to transfer all or any part of the treatment, transmission or distribution facilities to another entity, and to assign all or any part of its rights and obligations under this Agreement to an alternate entity, who shall be bound by, accept, and be exclusively responsible for all applicable terms and conditions of this Agreement.

B. If KUA improperly refuses to accept the treated sewage effluent specified in this Agreement for any reason, and the City has otherwise complied with the terms

of this Agreement and the FDER permit, KUA shall be liable to the City for the City's reasonable, verifiable costs to dispose of the improperly refused treated sewage effluent, not to exceed three times the RWC. If exercised by the City, these costs shall be invoiced to KUA within one year of the refusal to accept the treated sewage effluent. Failure to invoice these costs within one year of the refusal to accept the treated sewage effluent shall constitute a waiver by the City for reimbursement of those costs, but failure to exercise this right by the City shall not constitute a waiver by the City for reimbursement upon subsequent breaches of this Agreement. For the purposes of this paragraph, "improperly refused" is defined as: KUA using water from another ultimate source for cooling tower makeup when the volume and flow rate of treated sewage effluent necessary for KUA's needs was available from the Effluent Pipeline and the quality of the treated sewage effluent at the point of KUA's withdrawal from the Effluent Pipeline meets the City's discharge permit requirements and is of sufficient quality to enable KUA to meet its discharge permit requirements after treatment and discharge.

C. If the City improperly refuses to supply the agreed upon annual allocation of treated sewage effluent for any reason and KUA has otherwise complied with the terms of this Agreement and the FDER permit, the City shall be liable to KUA for its reasonable costs to acquire placement water. If exercised by KUA, these costs shall be invoiced to the City within one year of the refusal to supply the treated sewage effluent. Failure to invoice these costs within one year of the refusal to supply the treated sewage effluent shall constitute a waiver by KUA for reimbursement of these costs, but failure to exercise this right by KUA shall not constitute a waiver by KUA for reimbursement upon subsequent breaches of this Agreement. For the purposes of this paragraph "improperly refused" is defined as: the City having the treated sewage effluent available from treatment facilities, making all reasonable efforts to treat the treated sewage effluent to an acceptable quality level, and not be subject to a force majeure event relative to delivery.

XI. Decisions by the City.

A. In those circumstances set forth herein in which a decision must or can be made by the City, the City shall not exercise such discretion in an unreasonable or arbitrary manner, nor will the City unreasonably or arbitrarily withhold or delay a decision or approval. For purposes of this agreement, decisions on behalf of the City shall be made by the City Manager or designee. In the case that such position does

not exist, a comparable administrative office of the City shall make decisions on behalf of the City.

XII. Administrative Review, Arbitration.

A. All determinations, approvals, etc. made by the City respecting the rights and duties of the Parties, and all demands made by the City to KUA respecting the performance of its obligations to the City consistent with the provisions herein, shall be binding upon KUA; provided, however, that such determinations and demands shall be subject to administrative review and arbitration as provided below.

B. In the event the City alleges that KUA is in breach of its obligations herein or determines course of action to be taken by the KUA; the KUA may within fourteen (14) business days following receipt of written notice from the City containing a determination or demand, send a written notice with any objections to the City Manager and request that the City Manager review such determination or demand. Such notice shall set forth KUA's position on the matter to the extent possible. KUA shall have the right to meet with the City Manager to explain more fully its position.

C. The City Manager shall review the matter after receiving information from KUA, and make a determination on the matter. For purposes hereof, the failure of the City Manager to make a determination within seven (7) business days following the receipt of KUA's request shall be deemed to constitute a determination supporting the position of the City. KUA shall also have the right to an administrative review of the City Manager's determination by the City Commission (Commission) of the City of Kissimmee. In order to exercise this right, KUA shall, within thirty (30) days following KUA's receipt of the written notice from the City Manager containing the review determination, or within twenty-one (21) business days following the City's receipt of the KUA written objection(s), send a written notice (by certified mail return receipt requested) to the Commission and request that the Commission review this determination.

D. The Commission shall schedule a hearing thereon at the next regularly scheduled Commission meeting at which the hearing can reasonably become part of the agenda, but no later than thirty (30) days following the Commission's receipt of such notice. KUA shall be notified of the date, time, and location of the hearing and be permitted to present evidence and argument at the hearing. The Commission

shall make a determination on the matter, which determination shall constitute the final and binding determination.

E. So long as KUA shall comply in a timely fashion with the foregoing administrative review procedures, its good faith failure to comply with a determination or demand of the City Manager or the Commission shall not constitute a breach of this Agreement. However, if any damages to the City shall accrue as a result of KUA's failure or delay in complying with any such determinations or demands, KUA shall be fully liable for all reasonably foreseeable damages unless the determinations of demands are found by the Commission, to be invalid.

F. In the event that KUA alleges that the City is in breach of its obligations herein, it shall request in writing that the City Manager make a determination as to whether the City is complying with its obligations. Such request shall set forth KUA's position on the matter and KUA shall have the right to meet with the City Manager to explain more fully its position. If the City Manager determines that the City is in breach hereof, he shall immediately initiate action directed at curing the breach, and the City shall be fully liable to KUA for any reasonably foreseeable damages suffered by KUA during the period for which the breach occurred and remains uncured.

G. If the City Manager determines that the City is not in breach of such obligations, KUA may utilize the administrative review procedures outlined above with respect to such determination. For purposes hereof the failure of the City Manager to make a determination within seven (7) business days following KUA's request shall be deemed to constitute a determination that the City is not in breach of such obligations, and KUA shall be entitled to request an administrative review by the Commission as outlined above.

H. If the City Manager determines that the City is not in breach of this Agreement, or if the City Manager fails to make any determination within fourteen (14) business days after receipt of such request by KUA, and KUA shall fail to timely utilize the administrative review procedure described above, then KUA shall be deemed to have agreed that the subject matter of such request does not constitute a breach hereunder.

I. The parties agree that no legal action related to this Agreement shall be brought in any court of competent jurisdiction except for an action arising from the contractual obligations contained in the Florida Power Corporation agreement dated January 5, 1993.

XIII. Notices.

All notices required or authorized under this Agreement shall be given in writing, and shall be served by United States Mail to the parties at the addresses listed below (or as such addresses may be changed from time to time in the same manner):

CITY: City Manager
 City of Kissimmee
 101 North Church Street
 Kissimmee, FL 34741

WITH COPY TO: Director of Water & Sewer
 City of Kissimmee
 101 North Church Street
 Kissimmee, FL 34741

KUA: Kissimmee Utility Authority
 James Welsh
 President and General Manager
 P. O. Box 423219
 Kissimmee, FL 34742-3219

XIV. Inspection.

The City shall have the right to enter upon the Cane Island Site to review and inspect KUA's operating practices as they relate to this Agreement.

XV. Joinder.

This Agreement is being executed by KUA as acknowledgement on their parts that this Agreement impacts them and further acknowledges their acceptance of the terms.

XVI. Severability.

If any part of this Agreement is found invalid or unenforceable by any court of competent jurisdiction, such invalidity or unenforceability shall not affect the other parts of this Agreement if the right and obligations of the parties contained therein

are not materially prejudiced, and if the intentions of the parties can continue to be effectuated. To that end, this Agreement is declared severable.

XVII. Land Use Approvals.

This Agreement shall not be construed as granting, or assuring, or indicating any future grant of any land use or zoning approvals, permissions, variances, special exceptions or rights thereof with respect to the land.

XVIII. Entire Agreement.

This Agreement as executed by both the parties supersedes all previous agreements or representations, either verbal or written, heretofore in effect between the City and KUA that may have concerned the matters covered herein. No additions, alterations, or variations to the terms of this Agreement shall be valid, nor can the provisions of this Agreement be waived by either party unless such additions, alterations or waivers are expressly set forth in writing in a document of import equal to this Agreement and duly executed by the parties hereto.

XIX. Time is of the essence.

XX. Execution of Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this AGREEMENT to be executed by their duly authorized officers, and copies delivered to each Party, as of the day and year first above stated.

Witnesses to

Kissimmee Utility Authority

Rosemary E. Klinge

Alga A. Rendon

KISSIMMEE UTILITY AUTHORITY

BY Richard L. Hall 4/28/12
Chairman Date

ATTEST
Secretary

B. B. B. B. B.

(Seal)

Poor Original

Witnesses to
City of Kissimmee

Cindy Frazer
CINDY FRAZER

Gwendolyn A. Davis Wiggins
Gwendolyn A. Davis Wiggins

CITY OF KISSIMMEE

BY Joe B. Pollet

Mayor-Commissioner

Date 4-20-93

ATTEST Sandra L. Yeager
Secretary City Clerk

(Seal)

APPROVED AS TO FORM AND
LEGALITY

By [Signature] 4-20-93
City Attorney Date



10.6 Local Permit Applications

10.6.1 Conditional Use/Site Development Plan Permit Application

A Conditional Use/Site Development Plan Permit Application for construction of Unit 3 at the Power Park is required. A completed CU/SDP Permit Application is included herein.

10.6.2 Tree Removal Permit

The Tree Removal Permit will require modification to incorporate Unit 3 and the Cane Island-Intercession City Transmission Line impacts. A completed Tree Removal Permit Application is included herein.

10.6.3 Sanitary System Permit

The onsite sewage disposal system will require modification to extend the system to include the Unit 3 facilities. The general construction contractor will be required to complete and submit an Onsite Sewage Disposal System Permit Application.

10.6.4 Building Permit

A Building Permit will be required to construct the Unit 3 facilities. The Building Permit is issued following approval of the CU/SDP Permit Application and the project construction plans.

Conditional Use/Site Development Plan Permit Application



PLANNING DEPARTMENT

Michael Kloehn, AICP
Division Director

Dori DeBord, AICP
Planning Manager

Aaron Mercer
Senior Planner

Jay Evans
Planner

Tad Calkins
Planner

Anna Pinellas
*Grants & Housing
Administrator*

July 16, 1998

Mr. J. Michael Soltys
Black & Veatch
8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Re: Cane Island Power Park

Dear Mr. Soltys:

As per your request, I am providing the section of the Osceola County 1990 Comprehensive Plan that regulates public utility developments. Osceola County 1990 Comprehensive Plan's sanctions public utility facilities through Policy 2.1.7.1:

Public utilities which provide essential service to existing and future land uses authorized by this plan shall be permitted in all future land use categories provided the performance standards in the Power Plant Siting Act, Transmission Line Siting Act, Osceola County Future Land Use Element, Osceola County Zoning Regulations, and any other applicable land development regulations are met.

Therefore, if the proposed expansion to the Cane Island Power Park site qualifies with the performance standards of the previously mention public utility developments, then the proposed use will comply the Rural/Agricultural Future Land Use designation.

If I can be of further assistants, please call.

Sincerely,

Tad Calkins
Planner

**Osceola
County**

17 S. Vernon Ave., Room 246
Kissimmee, Florida 34741
Planning: (407) 847-1380
Grants: (407) 847-1297
FAX: (407) 847-1286

OSCEOLA COUNTY BOARD OF COUNTY COMMISSIONERS
KISSIMMEE, FLORIDA 34741
PHONE (407) 847-1236

DATE RECEIVED _____
TRC MEETING _____
OCPC MEETING _____
BCC MEETING _____

NO. _____

GENERAL INSTRUCTIONS: This application must be completed and submitted to the Development Department along with the required fee and additional information necessary for hearings by the Technical Review Committee, Planning Commission, and the Board of County Commissioners.

I APPLICANT

NAME OF	Mr. A. K. Sharma, (same as Kissimmee Utility Authority applicant)	Myron Rollins Black & Veatch
	APPLICANT	OWNER
ADDRESS	1701 W. Carroll St. Kissimmee, FL 34741	11401 Lamar Overland Park, KS 66211
PHONE	(407) 933-7777	(913) 458-7432
FAX	(407) 847-0787	(913) 458-2934

II PROPERTY

LEGAL DESCRIPTION: Provide a complete legal description below. Include Section, Township, and Range and Plat Book and Page (if applicable) or attach a copy of your legal description to this application.

A copy of Kissimmee Utility Authority's deed to the Cane Island site was included in the original CU/SDP application.

III APPLICANT'S REQUEST

(X) CU/SDP () ZONING _____ to _____
() CDP () EXTENSION OF TIME REQUESTED _____

IV GENERAL INFORMATION

LAND USE CLASSIFICATION Industrial
ZONING CLASSIFICATION Industrial
NUMBER OF ACRES 1027

WATER SUPPLY WELL X UTILITY _____ (NAME) _____
SEWAGE DISPOSAL SEPTIC X UTILITY X (NAME) City of Kissimmee

DISTANCE TO NEAREST CITY approximately 1 mile northwest of Intercession City
FRONTAGE ON A COUNTY MAINTAINED ROAD YES X NO _____
PAVED YES X NO _____

CONDITIONAL USE/SITE DEVELOPMENT PLANS & COMPREHENSIVE DEVELOPMENT PLANS

CU/SDP: The applicant requests that the development plan (which is a part of this application) be approved and that a conditional use be authorized on this property for the following use or uses.

A 250 megawatt combustion turbine power plant unit (Unit 3)

CDP: The applicant requests that the development plan (which is part of this application) be approved for this property. The plan is consistent with the preliminary or concept plan (reference number _____) previously approved for this property on (date _____). The specific use is for _____

APPLICANTS FOR CU/SDP AND CDP SHALL COMPLY WITH THE FOLLOWING:

SITE/DEVELOPMENT PLAN: The applicant is required to submit a plan which satisfies the following specifications. This data shall be accurately drawn and clearly reproduced. This development plan shall include the data listed in the check list section and required by the land use regulations.

TREE SURVEY: (Ordinance #86-8 & 87-15) A tree survey shall be overlaid on the site development plan locating all trees four (4) inches in diameter at breast height (DBH) or greater. A tree point summary shall also be shown on the plan. Where there are not enough trees on the site, then a replanting plan shall accompany the plans. In lieu of a survey, an aerial photograph at scale no smaller than 1":100' is acceptable.

SHEET SIZE: 8 1/2 X 11, however plans may be on larger sheets if they are folded to the required size.

NUMBER OF COPIES: Twenty-five (25) copies of the site/development plan are required.

EXPIRATION: One (1) year from the date of final approval this application will become null and void unless a building permit or extension has been granted.

Note: Please be advised that all public hearing applications submitted and heard by the Planning Commission are subject to a time limit of a maximum of 90 days on the Planning Commission's Consent Agenda. At that time, unless the applicant is able to present to the Planning Commission good cause why the application(s) should be continued any further, the Planning Commission will take final action.

V CERTIFICATION

I CERTIFY THAT, to the best of my knowledge and belief, all information supplied with this application is true and accurate, and that I am:

- (☒) Owner of the property described herein.
(☐) Party to an agreement for purchase of this property (agreement attached).
(☐) An agent for the owner or purchaser of this property (authorization letter attached).

Note: Current owner of the property must sign the application or a written authorization for applicant/agent to apply on the owner's behalf must accompany this request.

DATE: _____ SIGNATURE: _____

CHECK LIST FOR CU/SDP AND CDP APPLICATIONS

TO BE COMPLETED BY APPLICANT AND SUBMITTED WITH APPLICATION:

DOES THE SITE PLAN CONTAIN?			See enclosed site arrangement drawing and original CU/SDP application.
YES	NO	N/A	
<u> </u>	<u> </u>	<u> X </u>	PROPERTY LINES WITH DIMENSIONS. See original application
<u> </u>	<u> </u>	<u> X </u>	RIGHTS-OF-WAY, EASEMENTS AND SETBACK LINES See original application
<u> </u>	<u> </u>	<u> X </u>	PARKING AND LOADING CALCULATIONS
<u> </u>	<u> </u>	<u> X </u>	POINTS OF INGRESS AND EGRESS (MINIMUM WIDTH 30 FT. - MAXIMUM WIDTH 50 FT.) See original application
<u> X </u>	<u> </u>	<u> </u>	BUILDINGS, STRUCTURES, AND OTHER FACILITIES WITH DIMENSIONS see Site Arrangement, figure 2.1-3 in SCA
<u> </u>	<u> </u>	<u> X </u>	SIGNS: TYPE, SIZE, AND LOCATION
<u> X </u>	<u> </u>	<u> </u>	WELL LOCATION AND DISTANCE FROM ANY SOURCE OF POLLUTION see Site Arrangement
<u> X </u>	<u> </u>	<u> </u>	SEWAGE TREATMENT LOCATION AND PERCOLATION RATE AT SITE OF POLISHING PONDS see Site Arrangement
<u> </u>	<u> </u>	<u> X </u>	RECREATION AREAS AND OPEN SPACE CALCULATIONS WITH NET AREA OF EACH
<u> X </u>	<u> </u>	<u> </u>	WALLS AND FENCES, TYPE AND HEIGHT See Site Arrangement
<u> X </u>	<u> </u>	<u> </u>	TREE SURVEY See Section 10.6 of SCA
<u> X </u>	<u> </u>	<u> </u>	VICINITY MAP See Figure 2.1-1 and 2.1-2 in SCA
<u> X </u>	<u> </u>	<u> </u>	NAME OF PERSON OR FIRM PREPARING PLAN AND DATE Black & Veatch
<u> X </u>	<u> </u>	<u> </u>	NORTH ARROW AND SCALE

SPECIAL USE REQUIREMENTS N/A

<u> </u>	<u> </u>	<u> </u>	NUMBER OF RECREATIONAL VEHICLE AND TENT SITES
<u> </u>	<u> </u>	<u> </u>	NUMBER OF MANUFACTURED HOME SPACES
<u> </u>	<u> </u>	<u> </u>	NUMBER OF HOTEL/MOTEL ROOMS
<u> </u>	<u> </u>	<u> </u>	NUMBER OF DWELLING UNITS
<u> </u>	<u> </u>	<u> </u>	NUMBER OF SEATS AND SQUARE FOOTAGE OF RESTAURANTS AND LOUNGES

THERE MAY BE OTHER INFORMATION THAT YOUR SITE PLAN WILL NEED TO CONTAIN. PLEASE REFER TO THE STANDARDS FOR LAND UTILIZATION (ZONING REGULATIONS) AND OTHER APPLICABLE COUNTY ORDINANCES.

Tree Removal Permit Application

OSCEOLA COUNTY
Zoning Division
17 S. Vernon Avenue
Kissimmee, FL 34741
(407) 847-1405

**TREE REMOVAL
APPLICATION & PERMIT**

PERMIT # _____
ISSUED DATE _____

PROJECT NAME & ADDRESS: Cane Island Unit 3 and Transmission Line

FILE REFERENCE # _____ # OF ACRES TO BE INSPECTED 50

Kissimmee Utility Authority
Property Owner Name _____ Contractor Name _____

1701 W. Carroll Street
Street Address _____ Street Address _____

Kissimmee, FL 34741
City/State/Zip _____ City/State/Zip _____

(407) 933-7777
Telephone # _____ Telephone # _____

LOCATION OF TREE(S): Trees in Unit 3 power block and laydown area; and trees in

Cane Island to Intercession City transmission line corridor.

JUSTIFICATION FOR REMOVAL: Construction of Cane Island Power Plant Unit 3 and

Transmission Line (public utility use).

TREES TO BE REMOVED

SPECIES	Oaks	Pines	Cabbage Palm	Other
SIZE (dbh)	<u>6" - 13"</u>	<u>6" - 12"</u>	<u>8" - 15"</u>	<u>6" - 26"</u>
# OF TREES	<u>58/acre</u>	<u>11/acre</u>	<u>27/acre</u>	<u>31/acre</u>
				see attached

I hereby make application for a permit to remove the tree(s) described above.
I agree to assume full responsibility for the removal of said tree(s) for
compliance with all applicable County laws.

Please check appropriate category: ☐ Contractor ☐ Qualifier ☒ Owner

Signature
Print Name: _____

Inspector Remarks: ☐ Approved ☐ Disapproved

Conditions for approval or disapproval: _____

of Acres Inspected _____

Fee \$ _____

Receipt # _____

Date _____

Signature of Inspector

Applicant — White
Zoning — Yellow
File — Pink

OSCEOLA COUNTY
Zoning Division
17 S. Vernon Avenue
Kissimmee, FL 34741
(407) 847-1405

**TREE REMOVAL
APPLICATION & PERMIT**

PERMIT # _____
ISSUED DATE _____

PROJECT NAME & ADDRESS: _____

FILE REFERENCE # _____ # OF ACRES TO BE INSPECTED _____

Property Owner Name _____ Contractor Name _____

Street Address _____ Street Address _____

City/State/Zip _____ City/State/Zip _____

Telephone # _____ Telephone # _____

LOCATION OF TREE(S): _____

JUSTIFICATION FOR REMOVAL: _____

TREES TO BE REMOVED

SPECIES	Red Maple	Loblolly	Bald Cypress	Hickories
SIZE	8" - 40"	6" - 23"	7" - 23"	6" - 25"
# OF TREES	24/acre	34/acre	11/acre	33/acre

I hereby make application for a permit to remove the tree(s) described above.
I agree to assume full responsibility for the removal of said tree(s) for
compliance with all applicable County laws.

Please check appropriate category: ☐ Contractor ☐ Qualifier ☐ Owner

Signature _____
Print Name: _____

Inspector Remarks: ☐ Approved ☐ Disapproved

Conditions for approval or disapproval: _____

of Acres Inspected _____

Fee \$ _____

Receipt # _____

Date _____

Signature of Inspector _____

Applicant — White
Zoning — Yellow
File — Pink



10.7 PSD Permit Application

The construction and operation of Unit 3 will require an ATC/PSD permit. The PSD Air Permit Application is attached to this Site Certification Application under separate cover as Appendix 10.7.





10.8 Site Subsurface Data

Three separate reports were prepared prior to construction of Units 1 and 2 describing the subsurface conditions at the Power Park. These reports are included herein.

**Kissimmee Utility Authority
Cane Island Combustion Turbine Project**

**Subsurface Investigation Data Report
Units 1 and 2**

November 2, 1992

**Revised
March 9, 1993**

**Black & Veatch
Kansas City, Missouri**

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Appendix B	Boring Logs
Appendix C	Test Pit Logs
Appendix D	Piezometer Logs
Appendix E	Laboratory Test Results
Appendix F	Cone Penetrometer Soundings
Appendix G	Soil Resistivity Test Results
Appendix F	Double Ring Infiltrometer Test Results

1.0 Introduction

This report provides a summary of subsurface site conditions for the proposed combustion turbine project at the Kissimmee Utility Authority (KUA) Cane Island site. The project consists of one combustion turbine with associated structures and a second combustion turbine and associated heat recovery steam generator and steam turbine with associated structures.

The report provides the following information.

- The site location.
- The subsurface investigation program.
- The subsurface conditions.
- The laboratory test results.
- Recommendations for further investigations.

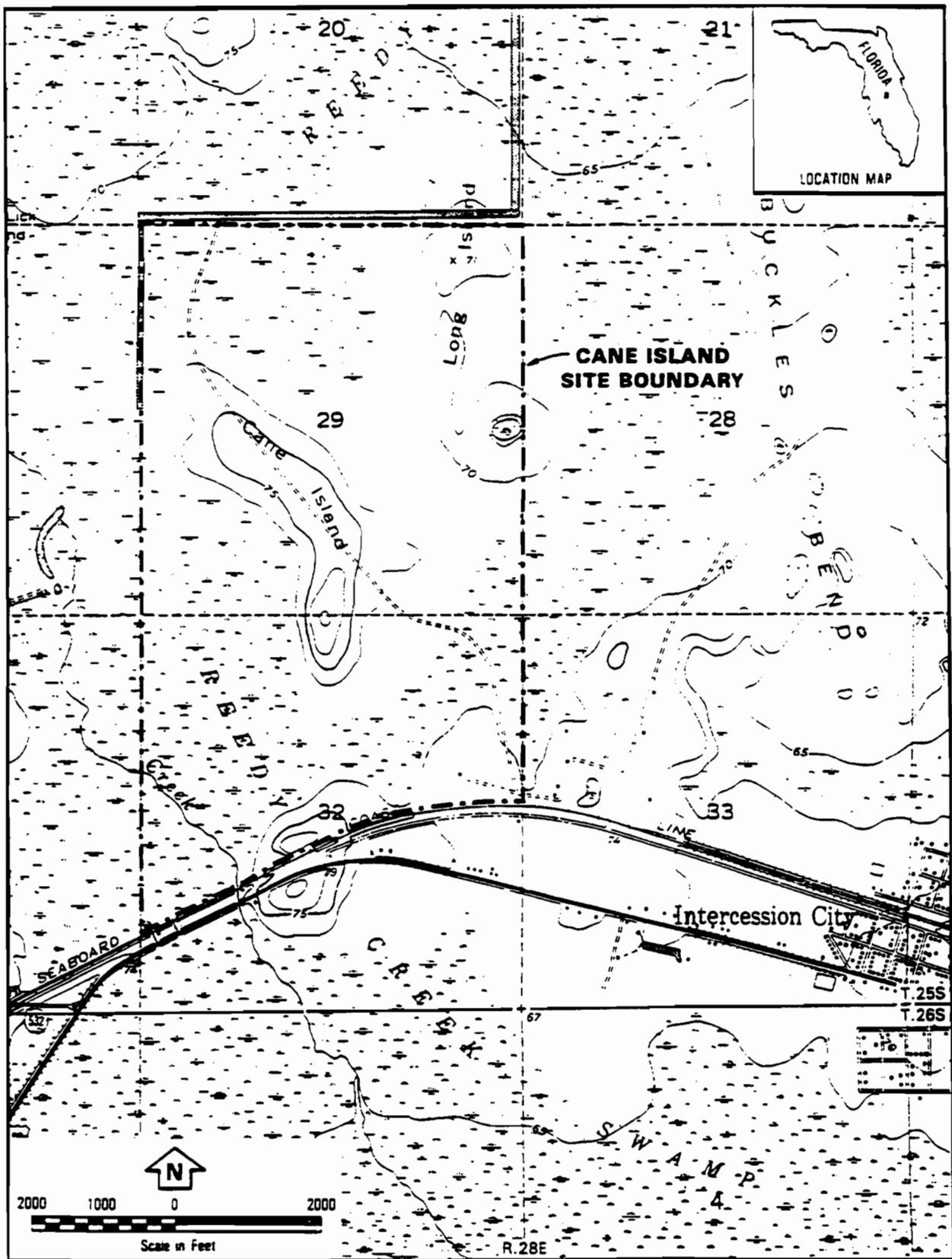
Data contained in this report will be utilized for geotechnical design work activities. A foundation report will be issued subsequent to geotechnical design.

2.0 Site Location

2.1 Site Location

The Cane Island site consists of a 1,000-acre tract near Intercession City, Osceola County, Florida. The site is about 1.5 miles northwest of Intercession City and about 20 miles southwest of Orlando, Florida. Figure 1 presents the site location.

Poor Original



Base Map Source: USGS,
Intercession City, FL quad.

Figure 1.
PROJECT LOCATION

3.0 Subsurface Investigation

The subsurface investigation was performed to determine the site stratigraphy and pertinent geotechnical engineering properties of the soil which underlie the proposed locations of the combustion turbines, steam turbines, and associated facilities.

The subsurface investigation was performed by Advanced Testing Laboratories (ATL) of Orlando, Florida under the direction of Black & Veatch. Field work began July 28, 1992 and was completed September 15, 1992. Survey locations for the planned field testing were located and staked by Sears Surveying Company of Orlando, Florida. Field test locations adjusted due to inaccessibility were noted and recorded by the Black & Veatch representative onsite. Test locations are presented in Appendix A of this report.

The subsurface investigation consisted of the following activities.

- 11 soil borings
- 5 test pits
- 13 cone penetrometer soundings
- 4 piezometers
- 11 soil resistivity tests
- 3 infiltrometer tests
- Laboratory tests on selected samples

The soil borings were advanced with a CME 45 truck-mount drill rig using the rotary wash method to depths ranging from 50 feet to 122 feet below ground surface (bgs) for a total of 868.5 lineal feet. Total footage included 31 feet of rock coring performed in three separate borings. Drilling fluid containing bentonite was used to maintain hydrostatic pressure and prevent caving of uncased holes. Temporary casing was used in some borings to prevent loss of drilling fluid and assist with rock coring.

Sampling while drilling consisted of continuous Standard Penetration Test (SPT) samples from 0 feet to 10 feet, with subsequent SPT samples obtained at 5 feet intervals. Cohesive soil, where encountered, was sampled using a combination of SPT's and Shelby tubes. Borehole logging and field classification of samples were performed in the field by Black & Veatch. The boring logs are presented in Appendix B of this report.

A total of five test pits were excavated by backhoe at the site during the subsurface investigation. Two test pits were excavated on Cane Island, two pits were excavated adjacent to the proposed entrance corridor from the Old Tampa Highway and one pit was excavated in the proposed borrow area. The test pits ranged in depth from approximately 5 feet to 8 feet bgs. Maximum depth was limited by free water in the pit or caving and sloughing of pit sides. The pits were logged by Black & Veatch and samples were obtained for laboratory testing. Test pit logs are presented in Appendix C of this report. Laboratory tests completed on samples obtained from the test pits are presented in Appendix E of this report.

Four piezometers were installed on the island using a 6-inch diameter hollow stem auger. The riser pipe was a 2 inch O.D. Schedule 40 PVC pipe, with a 10 feet length of 0.01 inch slotted screen attached. The piezometers were installed to an approximate depth of 25 feet. A medium-grained sand was used as a filter material in the annular space surrounding the screen. Native sand was used to backfill around the riser pipe and a two feet thick cement grout plug was used at ground surface. A lockable steel protective casing was placed to protect the PVC riser above the ground surface. The piezometer logs are presented in Appendix D of this report. Slug tests were performed in two piezometers to determine the horizontal coefficient of permeability.

A series of laboratory tests were performed on samples obtained during the subsurface investigation. The tests included natural moisture content, density, Atterberg limits, organic content, specific gravity, sieve and hydrometer analysis, triaxial and unconfined compression strength, consolidation, CBR bearing ratio, and modified proctor compaction. All tests were performed in accordance with ASTM test procedures, if applicable. Laboratory test results are presented in Appendix E of this report.

Cone penetrometer soundings were performed at twelve locations on the island at proposed structure locations. A truck-mounted electric cone penetrometer rig was used to advance the soundings. Total depths ranged from 60 feet to 114 feet. Cone penetrometer soundings are presented in Appendix F of this report.

Soil resistivity tests were completed at ten locations on the island. The tests were performed using the Wenner Four-Pin Method. Soil resistivity test results are presented in Appendix G of this report.

A total of three infiltrometer tests were completed during the subsurface investigation. A double-ring infiltrometer was used to perform the tests, one on the island at the proposed location of the surface water detention pond and two tests along the proposed entrance corridor. Infiltrometer test results are presented in Appendix H of this report.

4.0 Subsurface Conditions

4.1 Regional Geology

The Cane Island site is located in northwest Osceola County approximately 1.5 miles northwest of Intercession City, Florida. The following discussion of regional geology has been condensed from the references cited in this report, but principally from South Florida Water Management District (SFWMD) Technical Publication 84-1.

The site lies within the transitional physiographic boundary between the Lake Wales Ridge and the Osceola Plain. Regional geology for this area consists of Pleistocene age undifferentiated surficial deposits underlain by the Miocene age Hawthorne Formation underlain by Eocene age limestone deposits.

The surficial deposits consist of sand, clay, and shell. The upper horizon is composed of fine to medium grained quartz sand with organic material and iron staining. Below this are shell beds intermixed with clay layers.

The Hawthorne Formation is made up of sandy phosphatic limestones and sandy calcareous clays. The calcareous clays are light greenish-gray to dark green with black to brown phosphoritic sand. The limestone is white to yellow and becomes harder and more phosphatic towards the base. The top of the Hawthorne Formation in the region is generally about elevation 50 feet NGVD, approximately 30 feet below ground surface. Thickness varies considerably but is about 50 feet in the northwest corner of the county.

Limestone found below the Hawthorne Formation consists of the Ocala Group and Avon Park Limestone. The Ocala Group is composed of a white to cream, chalky, soft coquina of foraminifera. The top of the Ocala Group is an eroded surface which underlies the Hawthorne Formation. The deposition of the Ocala Group is believed to have occurred in an open, shallow, marine environment. The Ocala Group is easily recognizable by the abundance of flat and saddle shaped foraminifera.

Underlying the Ocala Group is the Avon Park Limestone. The limestone is dark brown to cream, very hard to soft, finely crystalline to chalky, fossiliferous dolomite and limestone. It is believed that the Avon Park Limestone was a shallow marine deposit which received little clastic material. The formation is distinguished from overlying formations by the abundance of sand-sized, cone-shaped forams.

4.2 Site Specific Geology

Site specific geology has been determined from the results of the subsurface investigation completed for the site. The surface stratum consists of a topsoil layer generally less than 1 foot thick consisting of sand with numerous roots and organic material. Underlying the topsoil is a 30 to 50 feet zone of loose to medium dense sand with intermittent layers of clayey and silty sands. Color was predominately orange to tan with varying lighter shades. Groundwater recorded while drilling was generally 8 to 14 feet below ground surface.

The test pits excavated in the surface stratum away from the actual island, TP-3, TP-4, and TP-5, encountered a "hardpan" layer approximately 3 feet bgs that was not found on the island. This layer consisted of a hard, slightly cemented dark brown to black fine sand with a strong sulfur odor. This layer would perch water during periods of heavy rainfall.

Underlying the surficial deposits is the Hawthorne Formation consisting of olive green clayey silt, silty clay, and clayey sand. The formation was identified by color and the presence of phosphate particles. The zone varied from firm to very stiff and contained varying amounts of shell. Thickness varied from 30 to 50 feet at the site. A dense to very dense layer of highly weathered limestone, logged as calcareous sand, was encountered from 68 to 102 feet bgs in 7 of the borings. This layer was located immediately above the limestone in Boring B-10.

Limestone was encountered in four borings at depths ranging from 62 to 109 feet bgs. The limestone was white to cream, moderately weathered with some solutioning and some fossils.

Subsurface soil density and layer continuity encountered in borings B-8, B-9, and B-10 varied considerably from conditions found in the other borings. SPT samples in these borings revealed a very loose, highly variable zone of sands and silts. The olive green material designated as the Hawthorne Formation was not found at expected depths. These three borings revealed a random collection of highly variable, loose sands and silts located from approximately 50 feet bgs down to the limestone. Depth to limestone in these three borings was significantly greater than the other borings. Limestone cored below this layer in Boring B-10 revealed the presence of voids and evidence of clay and silt filled cavities.

The absence of the Hawthorne Formation and significantly greater depth to limestone indicates that anomalies in the subsurface profile exist. It is postulated that these areas indicate the presence of paleokarst sinkholes. These areas are

ancient sinkholes that have caused the soil above to ravel into the voids created in the limestone. These areas might or might not be active. Since sinkhole activity is not evident on the ground surface, this could mean that the raveling zones have not reached ground surface, but that the sinkhole is still active, or that the sinkhole is not active and no further raveling is occurring.

4.3 Groundwater Conditions

A total of four piezometers were installed during the subsurface investigation to monitor groundwater levels for use in design and construction. These piezometers were installed in the proposed general plant area located on the island. Groundwater levels measured are as follows.

DATE	Groundwater Elevation, ft			
	Piezometer Number			
	P1	P2	P3	P4
05-AUG-92	69.0	69.8	69.3	69.1
06-AUG-92	69.2	69.2	69.3	69.1
12-AUG-92	69.8	69.7	69.4	69.5
23-SEP-92	69.3	70.9	70.7	70.4
05-OCT-92	70.6	71.2	71.0	70.9
14-OCT-92	71.3	71.4	71.7	71.4
17-NOV-92	70.3	70.4	70.5	70.3
16-DEC-92	70.5	70.4	70.4	70.3
15-JAN-93	70.5	70.2	70.4	69.9
28-FEB-93	71.1	71.1	72.0	70.8

Maximum high groundwater levels were investigated during the test pit excavations. Coloration, iron staining, and visual observation were used to estimate the historic high groundwater levels for Cane Island, the entrance corridor, and the proposed borrow pit area. Test pits TP-1 and TP-2 were excavated on Cane Island. Test pit depths in this area were limited by caving and sloughing of pit walls and free groundwater was not encountered. Maximum high groundwater was determined to be at approximately elevation 74 feet in TP-1.

TP-3, TP-4, and TP-5 were excavated along the entrance corridor and at the proposed borrow area. These test pits indicated similar profiles regardless of surface elevation. A hardpan layer was encountered at approximately 3 feet below ground surface. Perched groundwater was encountered above the hardpan layer. The true groundwater level was estimated to be approximately 6 feet below ground surface. The pits were backfilled before the groundwater was able to stabilize in the open pit. Maximum high groundwater in these areas is estimated to be 0 to 12 inches below ground surface and is directly related to the hardpan layer.

Maximum groundwater levels encountered during this investigation are consistent with the Osceola County Soil Survey published by the United States Department of Agriculture Soil Conservation Service in 1979.

Slug tests were performed in piezometers P-3 and P-4 to determine the horizontal coefficient of permeability in the upper zone of the surficial aquifer. Falling and rising head tests were completed by raising and lowering a water displacement device into the piezometers and recording the change in total head using a transducer and recording device. Data was analyzed using the Bouwer and Rice Method as well as the Hvorslev Method. The horizontal coefficient of permeability was determined to be 30 feet/day.

4.4 Surface Infiltration

Surface water infiltration was determined using double ring infiltrometer tests. Infiltrometer test I-1 was performed on Cane Island at the location of the surface water detention pond. I-2 and I-3 were performed along the proposed entrance corridor. Test results are as follows.

<u>Test No.</u>	<u>Steady State Infiltration Rate (in/hr)</u>
I-1	21.5
I-2	10.2
I-3	7.3

5.0 Recommendations for Further Investigations

The subsurface soil investigation conducted at the Cane Island site has revealed subsurface anomalies at the northern end of the proposed site. These anomalies indicate the possibility that limestone solutioning and raveling of soil above these zones might exist at the site. It is recommended that further studies be conducted to confirm whether or not these solution cavities and ravel zones exist and if so, determine the extent of property effected. In addition, a determination can be made whether these zones are active or inactive. The results of the additional study will be used to formulate a remedial action plan for deactivating the sinkhole, if required, in addition to supplementing the geotechnical foundation design for the project.

It is recommended that the additional investigation be performed by a knowledgeable firm experienced with evaluating sinkhole potential. The investigation should include the following.

- o An evaluation of regional geological and hydrogeological conditions.
- o Regional sinkhole history.
- o Site specific geology.
- o Appropriate geophysical investigations and evaluation of results.
- o Description of indicators of level of sinkhole potential.
- o Evaluation of the potential for sinkhole development at the site.
- o Provide a professional opinion of the suitability of locating the power plant facilities on the site.
- o Provide a general opinion on the likelihood and characteristics of sinkhole developments within the general plant vicinity but outside the study area.

In addition to the proposed study area for Units 1 and 2, the entire area planned for future expansion should be evaluated for the presence of existing sinkholes and potential for future sinkhole development. This would include the northern portions of Cane Island planned for future expansion.

6.0 References

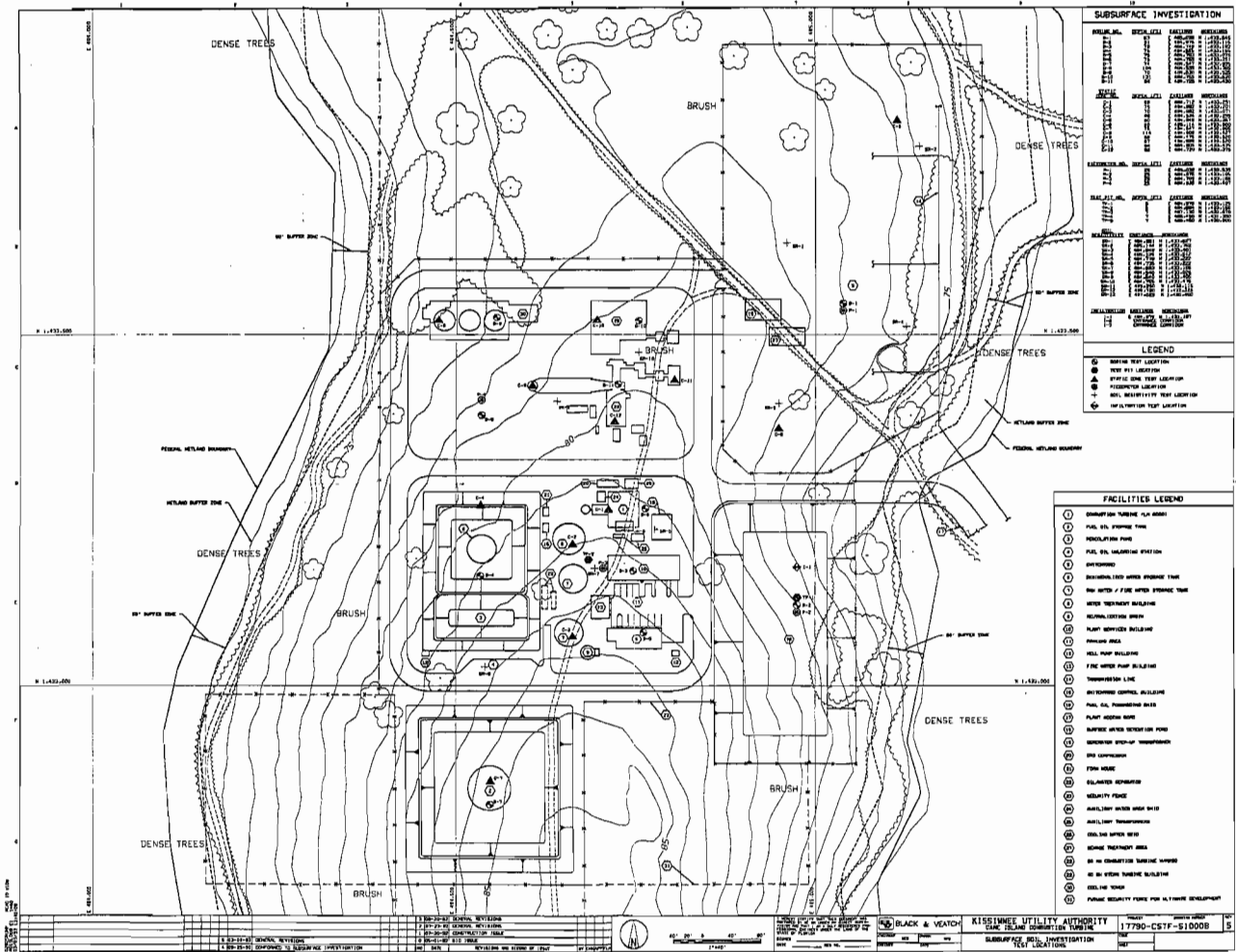
1. G.R. Schriver and E. C. Hayes, "Potentiometric Surface of the Floridan Aquifer in the St. Johns River Water Management District and Vicinity," United States Geological Survey, Open File Report 83-30, 1982. September 1982.
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4. W. F. Lichter et al., "Water Resources of Orange County, Florida," U. S. Geological Survey, Report of Investigation No. 50, 1968.
5. Herbert G. Stewart, Jr., "Ground-Water Resources of Polk County," Florida Geological Survey, Report of Investigation No. 44, 1966.
6. "Hydrogeology of the Kissimmee Planning Area, South Florida Water Management District," Technical Publication 84-1, Part 1 and Part 2, January 1984.
7. William C. Sinclair and J. W. Stewart, "Sinkhole Type, Development, and Distribution in Florida," U.S. Geological Survey, Map series No. 110, 1985.
8. Ed Lane, "Karst in Florida," Florida Geological Survey, Special Publication No. 29, 1986.

Appendix A

Subsurface Soil Investigation-Test Locations

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.



Appendix B

Boring Logs

EXPLANATION

BORING LOG TERMINOLOGY

GENERAL

PP	- Compressive strength as determined by penetrometer
TV	- Compressive strength as determined by torvane
Gravel	- From 1/4 inch to 3 inches in diameter
Cobble	- From 3 to 12 inches in diameter
Boulder	- Greater than 12 inches in diameter
60°	- Represents 60 degrees measured from a plane perpendicular to the longitudinal axis of the core
Trace	- Represents 0 to 10 per cent by volume
Some	- Represents 10 to 25 per cent by volume
N Value	- Indicates the number of blows required to drive a standard split spoon sampler 12 inches with a 140-pound weight falling 30 inches
REC	- Recovery indicates total amount of core recovered for each run. Expressed as a percentage of the total length of the core run
RQD	- A modified core recovery in which all pieces of sound core over 4 inches in length are counted as recovery. The modified sum of core recovered is then expressed as a percentage of the total length of the core run
---	- Dashed line in classification column indicates approximate or gradational change

WEATHERING

Fresh	- The rock shows no discoloration, loss of strength, or any other effect due to weathering (unweathered rock)
Slightly Weathered	- Rock is slightly discolored with a slightly lower strength than unweathered rock
Moderately Weathered	- Rock is considerably discolored with a significantly lower strength than unweathered rock
Highly Weathered	- Rock is discolored and weakened so intensely that 2-inch diameter rock cores can be broken readily by hand. Wet strength is usually much lower than dry strength

BEDDING

Laminated	- Less than 0.001 foot to 0.01 foot (.1 inch)
Thin Bedded	- 0.01 foot to 0.1 foot (.1 to 1.2 inches)
Medium Bedded	- 0.1 foot to 1.0 foot (1.2 to 12 inches)
Thick Bedded	- Greater than 1.0 foot
Massive	- Denotes no discernible internal bedding structure

SAMPLE SYMBOLS

Bag or Grab Sample	California	Piston	Pitcher	Split Barrel	Thin Wall
					



BLACK & VEATCH

LOG OF BORING

BORING NO. B-1
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790			
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433545 E 485038				ELEVATION (DATUM) 78.3 (MSL)		TOTAL DEPTH 63.0 FEET	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES			
								DATE FINISH 7/28/92			

SAMPLING								CHECKED BY M.C. SCHLUTER			APPROVED BY G.J. VAN RIESSEN		
SAMPLE TYPE	SAMPLE NUMBER	SET Ø INCHES	2ND Ø INCHES	3RD Ø INCHES	N VALUE	SAMPLE RECOVERY		DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING													
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD							
SPT	1	1	2	2	4	1.5		1			SAND; brown; loose; poorly graded; fine grained; rounded; dry; trace roots grading tan/orange grading moist; some iron oxide staining grading wet	Boring advanced w/3" diameter spade bit. Bentonite/water used as drilling fluid. Water encountered @ 8.5 ft.	
SPT	2	2	2	1	3	1.2		2					
SPT	3	2	2	4	6	1.7		3					
SPT	4	4	3	4	7	1.8		4					
SPT	5	2	2	1	3	1.7		5					
								6					
								7					
								8					
								9					
								10					
								11					
								12					
								13					
SPT	6	6	8	10	18	1.5		14			Silty SAND; tan/orange; medium dense; fine grained; slightly plastic; moist		
								15					
								16					
								17					
								18					
SPT	7	4	6	6	12	1.1		19			Silty SAND; white; medium dense; fine grained; rounded; wet		
								20					
								21					
								22					
								23					
SPT	8	4	5	6	11	1.0		24					
								25					
								26					
								27					
								28			SAND; white; very loose; fine grained; rounded; wet; some clay; trace phosphate particles		
SPT	9	1	1	1	2	1.6		29					



BLACK & VEATCH

LOG OF BORING

BORING NO. B-1
SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE										PROJECT NO. 17790																													
PROJECT LOCATION INTERCESSION CITY, FLORIDA										COORDINATES N 1433545 E 485038										ELEVATION (DATUM) 78.3 (MSL)										TOTAL DEPTH 93.0 FEET										DATE START 7/28/92									
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS										LOGGED BY W.C. JONES										DATE FINISH 7/28/92																													
SAMPLING										CHECKED BY M.C. SCHLUTER										APPROVED BY G.J. VAN RIESSEN																													
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL										REMARKS																													
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RUN RECOVERY	PERCENT RECOVERY	RUN																																											
SPT	10	1	2	1	3	2.0	31			grading tan																																							
							32																																										
							33																																										
							34			grading white																																							
							35																																										
							36																																										
							37																																										
							38																																										
SPT	11	1	1	1	2	2.0	39			grading tan																																							
							40																																										
							41																																										
							42																																										
							43																																										
SPT	12	2	1	2	3	1.7	44			grading white; no phosphate; trace iron oxide staining																																							
							45																																										
							46																																										
							47																																										
							48																																										
SPT	13	1	2	1	3	2.0	49			Silty SAND; brown; very loose; poorly graded; fine grained; wet; 0.01' thick interlayered seams of silt and medium grained sand																																							
							50																																										
							51																																										
							52																																										
							53																																										
SPT	14	2	1	2	3	2.0	54			Clayey SAND; blue/gray; loose; poorly graded; fine grained; wet																																							
							55																																										
							56																																										
							57																																										
							58																																										
SPT	15	1	1	1	2	2.0	59																																										



CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE										PROJECT NO. 17790									
PROJECT LOCATION INTERCESSION CITY, FLORIDA					COORDINATES N 1433545 E 485038					ELEVATION (DATUM) 78.3 (MSL)					TOTAL DEPTH 83.0 FEET					DATE START 7/28/92									
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS										LOGGED BY W.C. JONES										DATE FINISH 7/28/92									
SAMPLING										CHECKED BY M.C. SCHLUTER										APPROVED BY G.J. VAN RIESSEN									
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL										REMARKS									
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RUN RECOVERY	PERCENT RECOVERY	RUN																							
SPT	16	50/5"	-	-	50+	0.2	61			Limestone; fossiliferous; hard; white; microcrystalline										Lost circulation at 62.5 ft; caved to 10 ft depth. Set casing to 35 ft depth.									
							62																			Bottom of boring at 63.0 ft.			
							63													Backfilled w/cement grout from 35 ft to surface.									
							64													Water level not recorded.									
							65																						
							66																						
							67																						
							68																						
							69																						
							70																						
							71																						
							72																						
							73																						
							74																						
							75																						
							76																						
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							88																						
							89																						



BLACK & VEATCH

LOG OF BORING

BORING NO. B-2
SHEET 1 OF 2

CLIENT KISSIMMEE UTILITY AUTHORITY						PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17780		
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433115 E 484875				ELEVATION (DATUM) 77.4 (MSL)		TOTAL DEPTH 50.5 FEET		
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES		DATE FINISH 7/31/92		
SAMPLING							CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 6 INCHES	2ND 6 INCHES	3RD 6 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	R2D RECOVERY	PERCENT RECOVERY	R2D						
SPT	1	1	2	1	3	1.3	1			SAND; tan/orange; very loose; poorly graded; fine grained; roots; moist; trace phosphate particles	Boring advanced w/3" diameter spade bit. Bentonite/water used as drilling fluid. Water encountered @ 9.0 ft.	
SPT	2	2	2	2	4	1.7	2			grading loose		
SPT	3	3	6	4	10	1.7	3			grading tan/white		
SPT	4	4	4	4	8	1.6	4			grading loose		
SPT	5	3	4	4	8	2.0	5			grading wet; iron oxide staining		
							6					
							7					
							8					
							9					
							10					
							11					
							12					
							13					
SPT	6	3	4	5	9	1.0	14			SAND; dark brown; loose; poorly graded; fine grained; rounded; wet; slight organic odor		
							15					
							16					
							17					
SPT	7	3	5	6	11	1.0	18			grading dark gray/brown; medium dense		
							19					
							20					
							21					
							22					
							23					
SPT	8	4	6	7	13	1.2	24			grading trace iron oxide staining		
							25					
							26					
							27					
							28					
SPT	9	4	7	7	14	1.1	29			grading blue/gray		



BLACK & VEATCH

LOG OF BORING

BORING NO. B-2
SHEET 2 OF 2

CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE										PROJECT NO. 17790																													
PROJECT LOCATION INTERCESSION CITY, FLORIDA										COORDINATES N 1433115 E 484975										ELEVATION (DATUM) 77.4 (MSL)										TOTAL DEPTH 50.5 FEET										DATE START 7/31/92									
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS										LOGGED BY W.C. JONES										APPROVED BY G.J. VAN RIESSEN										DATE FINISH 7/31/92																			
SAMPLING										CHECKED BY M.C. SCHLUTER										APPROVED BY G.J. VAN RIESSEN																													
SAMPLE TYPE	SAMPLE NUMBER	SET 6 INCHES	2ND 6 INCHES	3RD 6 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL										REMARKS																													
CORING																																																	
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RUN RECOVERY	PERCENT RECOVERY	RUN																																											
SPT	10	1	1	1	2	2.0	31																																										
							32																																										
							33																																										
							34																																										
							35																																										
							36																																										
							37																																										
							38																																										
SPT	11	WR	1	WR	1	2.0	39																																										
							40																																										
							41																																										
TW	12					0.0	42																																										
							43																																										
SPT	13	1	1	2	3	2.0	44																																										
							45																																										
							46																																										
							47																																										
							48																																										
TW	14					0.0	49																																										
							50																																										
							51																																										
							52																																										
							53																																										
							54																																										
							55																																										
							56																																										
							57																																										
							58																																										
							59																																										

Bottom of boring at
50.5 ft.
Backfilled w/cement
grout to surface.
Water level not
recorded.



BLACK & VEATCH

LOG OF BORING

BORING NO. B-3
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY							PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433162 E 484748			ELEVATION (DATUM) 83.2 (MSL)		TOTAL DEPTH 72.5 FEET		DATE START 7/29/92	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS							LOGGED BY W.C. JONES				DATE FINISH 7/30/92	
SAMPLING							CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD						
SPT	1	1	1	1	2	1.3	1			SAND: brown; very loose; poorly graded; fine grained; rounded; moist; roots; trace phosphate particles grading tan/orange	Boring advance w/4" diameter spade bit. Bentonite/water used as drilling fluid.	
SPT	2	1	1	1	2	1.5	2					
SPT	3	1	2	1	3	1.7	3					
SPT	4	2	2	2	4	1.7	4					
SPT	5	2	3	3	6	1.7	5					
							6					
							7					
							8					
							9					
							10					
							11					
							12					
							13					
SPT	6	6	9	11	20	1.8	14			grading mottled tan/white to orange; medium dense; wet; some iron oxide staining	Water encountered @ 13.5ft.	
							15					
							16					
							17					
							18					
							19					
							20					
							21					
							22					
							23					
SPT	7	5	9	7	16	1.1	24			SAND: white; medium dense; poorly graded; fine grained; rounded; wet; trace silt; trace phosphate particles; iron oxide staining		
							25					
							26					
							27					
							28					
							29					
							30					
							31					
							32					
							33					
SPT	8	6	5	6	11	0.9	34			grading loose		
							35					
							36					
							37					
							38					
							39					
							40					
							41					
							42					
							43					
SPT	9	3	3	3	6	1.8	44					



BLACK & VEATCH

LOG OF BORING

BORING NO. B-3
SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790																								
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433182 E 484748				ELEVATION (DATUM) 83.2 (MSL)		TOTAL DEPTH 78.5 FEET		DATE START 7/29/92																				
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES				DATE FINISH 7/30/92																				
<table border="1"> <tr> <th colspan="8">SAMPLING</th> </tr> <tr> <th>SAMPLE TYPE</th> <th>SAMPLE NUMBER</th> <th>SET</th> <th>0 INCHES</th> <th>2ND 0 INCHES</th> <th>3RD 0 INCHES</th> <th>N</th> <th>VALUE</th> <th>SAMPLE RECOVERY</th> </tr> </table>								SAMPLING								SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N	VALUE	SAMPLE RECOVERY	CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLING																																
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N	VALUE	SAMPLE RECOVERY																								
CORING								DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS																				
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	NO	RECOVERY	PERCENT RECOVERY	NO																									
SPT	10	1	WR	1	1	1.5			31																							
									32																							
									33																							
									34																							
									35																							
									36																							
									37																							
									38																							
SPT	11	1	1	1	2	1.8			39																							
									40																							
									41																							
									42																							
									43																							
SPT	12	3	4	6	10	2.0			44																							
									45																							
									46																							
									47																							
									48																							
SPT	13	3	5	7	12	2.0			49																							
									50																							
									51																							
TW	14					2.0			52																							
									53																							
SPT	15	2	3	4	7	2.0			54																							
									55																							
									56																							
									57																							
									58																							
									59																							
SPT	16	4	6	9	15	2.0																										

CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433162 E 484748				ELEVATION (DATUM) 83.2 (MSL)		TOTAL DEPTH 73.5 FEET		DATE START 7/29/92			
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES				DATE FINISH 7/30/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS			
CORING															
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD									
SPT	17	5	7	13	20	2.0		61			grading some shells				
								62							
								63							
								64							
SPT	18	50+			50+	0.0		65			LIMESTONE; fossiliferous; white; moderately weathered; zones of horizontal jointing; some solutioning w/0.25 in. diameter voids				
			68.5					66							
NX	1	5.0	3.0	1.8	60	36		67							
								68							
								69							
								70							
								71							
								72							
								73							
								74							
NX	2	5.0	5.0	4.0	100	80		75			Bottom of boring at 78.5 ft. Backfilled w/cement grout to surface. Water level not recorded.				
			73.5					76							
								77							
								78							
								79							
								80							
								81							
								82							
								83							
								84							
								85							
								86							
								87							
								88							
								89							



BLACK & VEATCH

LOG OF BORING

BORING NO. B-4
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790							
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433155 E 484535				ELEVATION (DATUM) 81.7 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 8/3/92			
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES				DATE FINISH 8/3/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET 6 INCHES	2ND 6 INCHES	3RD 6 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS				
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RWD RECOVERY	PERCENT RECOVERY	RWD									
SPT	1	2	2	2	4	1.4	1			SAND: brown; loose; poorly graded; fine grained; rounded; roots grading tan/orange grading very loose grading loose	Boring advanced w/4" diameter spade bit. Bentonite/water used as drilling fluid.				
SPT	2	2	2	2	4	1.5	2								
SPT	3	1	WH	1	1	1.2	3								
SPT	4	2	2	2	4	1.5	4								
SPT	5	3	3	4	7	1.6	5								
							6								
							7								
							8								
							9								
							10								
SPT	6	3	4	6	10	0.9	11			grading medium dense; wet	Water encountered @ 13 ft.				
							12								
							13								
							14								
							15								
							16								
							17								
							18								
SPT	7	6	6	8	14	1.5	19								
							20								
							21			SAND: white; medium dense; poorly graded; fine grained; rounded; wet; trace silt; trace phosphate particles					
							22								
							23								
							24								
SPT	8	4	4	9	13	1.0	25								
							26								
							27								
							28								
							29								
SPT	9	1	WH	1	1	1.8									



BLACK & VEATCH

LOG OF BORING

BORING NO. B-4
SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433155 E 484535		ELEVATION (DATUM) 81.7 (MSL)		TOTAL DEPTH 75.0 FEET	DATE START 8/3/92
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS						LOGGED BY W.C. JONES			DATE FINISH 8/3/92

SAMPLING							CHECKED BY M.C. SCHLUTER			APPROVED BY G.J. VAN RIESSEN		
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD						
SPT	10	1	WH	1	1	2.0	31			<u>SAND</u> ; white; very loose; poorly graded; fine grained; slight plasticity; wet; some clay; trace phosphate particles		
SPT	11	1	WH	2	2	1.8	32			<u>Clayey SAND</u> ; mottled tan/orange to white (white clayey sand occurs as thin layers, 0.01' thick); very loose; poorly graded; slight plasticity; wet		
							33					
							34					
SPT	12	3	3	9	12	2.0	35			<u>SAND</u> ; olive green; medium dense; poorly graded; fine grained; rounded; moist; some silt; trace clay; trace phosphate particles; trace shells		
							36					
							37					
SPT	13	4	6	12	18	1.8	38					
							39					
							40					
TW	14					0.8	41			grading very shelly zones, 1" thick		
							42					
							43					
SPT	15	5	7	14	21	2.0	44			grading trace shells		
							45					
							46					
SPT	16	5	7	10	17	2.0	47					
							48					
							49					
							50					
							51					
							52					
							53					
							54					
							55					
							56					
							57					
							58					
							59					

Shelby tube pushed
12 inches to
refusal.



BLACK & VEATCH

LOG OF BORING

BORING NO. B-4
SHEET 3 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790							
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433155 E 484535				ELEVATION (DATUM) 81.7 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 8/3/92			
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES				DATE FINISH 8/3/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS			
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RUN RECOVERY	PERCENT RECOVERY	RUN	RUN	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS			
SPT	17	5	7	15	22	1.8		61							
								62							
								63							
								64							
								65							
								66							
								67							
								68							
SPT	18	20+	30	50+	50+	0.8		69			grading very shelly @ 69 ft				
								70			Calcareous Shelly SAND; white; very dense; wet (highly weathered limestone)	Hole advanced from 70 to 73.5 ft w/3" roller bit.			
								71							
								72							
								73							
SPT	19	31	50	50+	50+	1.0		74							
								75							
								76				Bottom of boring at 75.0 ft.			
								77				Backfilled w/cement to surface.			
								78				Water level not recorded.			
								79							
								80							
								81							
								82							
								83							
								84							
								85							
								86							
								87							
								88							
								89							



BLACK & VEATCH

LOG OF BORING

BORING NO. B-5
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY							PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433076 E 484763			ELEVATION (DATUM) 84.0 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 7/30/92	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS							LOGGED BY W.C. JONES				DATE FINISH 7/30/92	
SAMPLING							CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD						
CORING												
SPT	1	1	1	2	3	1.4	1			SAND; brown; very loose; poorly graded; fine grained; rounded; moist; roots; trace phosphate particles grading tan/orange	Boring advanced w/3" diameter spade bit. Bentonite/water used as drilling fluid.	
SPT	2	2	1	2	3	1.4	2					
SPT	3	2	1	2	3	1.6	3					
SPT	4	2	2	2	4	1.4	4					
SPT	5	2	3	3	6	1.9	5					
							6					
							7					
							8					
							9					
							10					
							11					
							12					
							13					
SPT	6	3	5	7	12	1.4	14					Silty SAND; tan/white; medium dense; poorly graded; fine grained; wet; trace clay; iron oxide staining grading mottled tan/orange to orange grading white; loose; trace phosphate
							15					
							16					
							17					
							18					
SPT	7	6	9	9	18	1.3	19					
							20					
							21					
							22					
							23					
SPT	8	3	3	4	7	1.4	24					
							25					
							26					
							27					
							28					
SPT	9	5	4	4	8	1.3	29					



BLACK & VEATCH

LOG OF BORING

BORING NO. B-5

SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790							
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433076 E 484763				ELEVATION (DATUM) 84.0 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 7/30/92			
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES				DATE FINISH 7/30/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL			REMARKS		
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD									
SPT	10	3	3	3	6	1.8	31			grading blue/grey					
SPT	11	1	1	2	3	2.0	32								
SPT	12	3	5	6	11	1.9	33								
SPT	13	5	6	11	17	2.0	34								
SPT	14	2	4	6	10	2.0	35								
SPT	15	4	6	12	18	2.0	36								
							37								
							38								
							39								
							40								
							41								
							42								
							43								
							44								
							45								
							46								
							47								
							48								
							49								
							50								
							51								
							52								
							53								
							54								
							55								
							56								
							57								
							58								
							59								

CLIENT KISSIMMEE UTILITY AUTHORITY					PROJECT CANE ISLAND COMBUSTION TURBINE					PROJECT NO. 17790		
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433076 E 484763			ELEVATION (DATUM) 84.0 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 7/30/92	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS							LOGGED BY W.C. JONES			DATE FINISH 7/30/92		
SAMPLING							CHECKED BY M.C. SCHLUTER			APPROVED BY G.J. VAN RIESSEN		
SAMPLE TYPE	SAMPLE NUMBER	SET Ø INCHES	2ND Ø INCHES	3RD Ø INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD						
TW	16					1.8	61					
SPT	17	4	8	10	18	0.0	62			Clayey <u>SILT</u> ; olive green; medium dense; moist; trace shells	Hole reamed out w/4" diameter spade bit.	
SPT	18	4	8	20	28	2.0	63			grading some shells		
							64					
							65				Hole continued w/3" diameter spade bit.	
							66					
							67					
							68					
							69					
SPT	19	3	37/2"	-	50+	1.3	70					
							71				Hole continued w/3" diameter roller bit.	
							72			Calcareous <u>SAND</u> ; white; dense; slightly cemented; wet; (highly weathered limestone)		
							73					
SPT	20	11	18	26	44	1.3	74					
							75				Bottom of boring at 75 ft.	
							76					
							77				Backfilled hole w/cement grout to surface.	
							78					
							79					
							80				Water level not recorded.	
							81					
							82					
							83					
							84					
							85					
							86					
							87					
							88					
							89					



BLACK & VEATCH

LOG OF BORING

BORING NO. B-6
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790			
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433251 E 484785				ELEVATION (DATUM) 81.9 (MSL)		TOTAL DEPTH 75.0 FEET	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES		DATE FINISH 7/29/82	

SAMPLING								CHECKED BY M.C. SCHLUTER		APPROVED BY G. J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 6 INCHES	2ND 6 INCHES	3RD 6 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORING											
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	R2D RECOVERY	PERCENT RECOVERY	R2D					
SPT	1	1	2	2	4	1.8	1			SAND: dark brown; loose; poorly graded; fine grained; rounded; moist; roots; trace phosphate particles; trace roots grading tan/orange grading orange	Boring advanced w/4" diameter spade bit. Bentonite/water used as drilling fluid.
SPT	2	2	2	2	4	1.8	2				
SPT	3	2	2	2	4	2.0	3				
SPT	4	2	2	3	5	2.0	4				
SPT	5	4	4	4	8	2.0	5				
							6				
							7				
							8				
							9				
							10				
							11				
							12				
							13				
SPT	6	3	7	14	21	1.1	14			SAND: tan/orange; medium dense; poorly graded; medium grained; wet; trace clay; iron oxide staining	Water encountered @ 13.5 ft.
							15				
							16				
							17				
							18				
							19				
SPT	7	5	6	7	13	1.3	20				
							21				
							22				
							23				
SPT	8	3	4	5	9	1.0	24			grading loose; no clay	
							25				
							26				
							27				
							28				
							29				
SPT	9	2	1	2	3	1.5				grading very loose	



BLACK & VEATCH

LOG OF BORING

BORING NO. B-6
SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY						PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433251 E 484765		ELEVATION (DATUM) 81.9 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 7/29/92	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS						LOGGED BY W.C. JONES				DATE FINISH 7/29/92	
SAMPLING						CHECKED BY M.C. SCHLUTER				APPROVED BY G. J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORE SIZE	R/N NUMBER	R/N LENGTH	R/N RECOVERY	R/D RECOVERY	PERCENT RECOVERY	R/D					
SPT	10	1	WR	1	1	2.0	31				
							32				
							33				
							34				
							35				
							36				
							37			SAND: tan/orange; very loose; fine grained; wet; some clay; iron oxide staining	
							38				
SPT	11	1	WR	1	1	1.8	39				
							40				
							41				
							42				
SPT	12	2	3	4	7	1.8	43				
							44			grading dark gray; grading loose	
							45				
							46				
							47				
SPT	13	3	6	7	13	2.0	48				
							49			Sandy SILT: olive green; stiff to very stiff; low plasticity; wet; some clay; some shells; wet	Set 3" diameter casing to 50 ft.
TW	14					1.5	50				
							51				
							52				
							53				
SPT	15	5	6	6	12	2.0	54			grading mottled dark gray & olive green; 2" very shelly seam at 54 ft	Hole continued w/3" spade bit from 55 ft.
							55				
							56				
							57				
							58				
SPT	16	4	6	11	17	1.9	59			grading olive green; trace clay	



BLACK & VEATCH

LOG OF BORING

BORING NO. B-6
SHEET 3 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY							PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790																			
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433251 E 484765			ELEVATION (DATUM) 81.9 (MSL)		TOTAL DEPTH 75.0 FEET		DATE START 7/29/92																			
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS							LOGGED BY W.C. JONES				DATE FINISH 7/29/92																			
<table border="1"> <tr> <th colspan="7">SAMPLING</th> </tr> <tr> <th>SAMPLE TYPE</th> <th>SAMPLE NUMBER</th> <th>SET 6 INCHES</th> <th>2ND 6 INCHES</th> <th>3RD 6 INCHES</th> <th>N VALUE</th> <th>SAMPLE RECOVERY</th> </tr> </table>							SAMPLING							SAMPLE TYPE	SAMPLE NUMBER	SET 6 INCHES	2ND 6 INCHES	3RD 6 INCHES	N VALUE	SAMPLE RECOVERY	<table border="1"> <tr> <th colspan="2">CHECKED BY M.C. SCHLUTER</th> <th colspan="2">APPROVED BY G. J. VAN RIESSEN</th> </tr> </table>				CHECKED BY M.C. SCHLUTER		APPROVED BY G. J. VAN RIESSEN			
SAMPLING																														
SAMPLE TYPE	SAMPLE NUMBER	SET 6 INCHES	2ND 6 INCHES	3RD 6 INCHES	N VALUE	SAMPLE RECOVERY																								
CHECKED BY M.C. SCHLUTER		APPROVED BY G. J. VAN RIESSEN																												
<table border="1"> <tr> <th colspan="7">CORING</th> </tr> <tr> <th>CORE SIZE</th> <th>RUN NUMBER</th> <th>RUN LENGTH</th> <th>RUN RECOVERY</th> <th>NO. RECOVERY</th> <th>PERCENT RECOVERY</th> <th>NO.</th> </tr> </table>							CORING							CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	NO. RECOVERY	PERCENT RECOVERY	NO.	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS					
CORING																														
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	NO. RECOVERY	PERCENT RECOVERY	NO.																								
SPT	17	5	9	17	26	2.0	61			grading no clay	Drill bit chatter @ 68 ft.																			
SPT	18	25	21	18	39	1.0	62																							
							63																							
							64			Calcareous SAND: white; dense; some cemented particles 0.25" in diameter; (highly weathered limestone)																				
							65																							
							66																							
							67																							
							68																							
							69																							
							70																							
							71																							
							72																							
							73																							
SPT	19	17	25	8	31	1.2	74																							
							75				Bottom of boring at 75 ft. Backfilled w/cement grout to surface. Water level not recorded.																			
							76																							
							77																							
							78																							
							79																							
							80																							
							81																							
							82																							
							83																							
							84																							
							85																							
							86																							
							87																							
							88																							
							89																							



BLACK & VEATCH

LOG OF BORING

BORING NO. B-7
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY						PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA			COORDINATES N 1432835 E 484547			ELEVATION (DATUM) 85.0 (MSL)		TOTAL DEPTH 74.0 FEET		DATE START 8/6/92	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS						LOGGED BY M.C. JONES				DATE FINISH 8/7/92	
SAMPLING						CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORING											
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD					
SPT	1	1	2	1	3	1.6	1			<u>SAND</u>: tan/orange; very loose; poorly graded; fine grained; moist; trace phosphate particles; trace clay; some organics grading trace organics grading light brown grading tan/orange; medium dense; wet;	Boring advanced w/3" diameter spade bit. Bentonite/water used as drilling fluid. Water encountered @ 13.5 ft.
SPT	2	3	3	3	6	1.1	2				
SPT	3	3	4	4	8	1.3	3				
SPT	4	3	3	4	7	1.3	4				
SPT	5	2	4	4	8	1.4	5				
							6				
							7				
							8				
							9				
							10				
							11				
							12				
							13				
SPT	6	5	6	8	14	0.9	14				
							15				
							16				
							17				
							18				
SPT	7	9	9	8	17	1.3	19			<u>SAND</u>: tan/orange; medium dense; poorly graded; fine grained; rounded; wet; some silt; trace phosphate particles grading light gray grading mottled tan/orange and light gray; trace clay grading light gray; loose	
							20				
							21				
							22				
							23				
							24				
SPT	8	9	8	8	14	1.4	25				
							26				
							27				
							28				
SPT	9	2	1	3	4	1.5	29				



BLACK & VEATCH

LOG OF BORING

BORING NO. B-7
SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790			
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1432835 E 484547		ELEVATION (DATUM) 85.0 (MSL)		TOTAL DEPTH 74.0 FEET	DATE START 8/6/92		
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS						LOGGED BY W.C. JONES		DATE FINISH 8/7/92			
SAMPLING								CHECKED BY M.C. SCHLUTER			
APPROVED BY G.J. VAN RIESSEN											
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD					
SPT	10	1	1	3	4	1.8	31				
SPT	11	1	1	WR	1	2.0	32				
SPT	12	2	1	2	3	2.0	33				
TW	13					0.0	34			grading mottled tan/orange & white	
TW	14					2.0	35				
SPT	15	4	5	6	11	2.0	36				
TW	16					2.0	37				
SPT	17	4	8	22	30	2.0	38				
							39			grading light gray w/blue	
							40				
							41				
							42				
							43				
							44			Silty SAND; olive green; very loose; poorly graded; fine grained; wet; trace clay; trace phosphate particles	
							45				
							46				
							47				
							48				
							49				
							50				
							51				
							52				
							53				
							54			grading trace clay @ 54 ft	
							55				
							56			Silty CLAY; olive green; stiff; low plasticity	
							57				
							58				
							59			Clayey SILT; olive green; very stiff grading 1" very shelly seams @58.5 ft	



BLACK & VEATCH

LOG OF BORING

BORING NO. B-7
SHEET 3 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790			
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1432835 E 484547				ELEVATION (DATUM) 85.0 (MSL)		TOTAL DEPTH 74.0 FEET	
SURFACE CONDITIONS LEVEL, GRASSY, SMALL SHRUBS								LOGGED BY W.C. JONES		DATE FINISH 8/7/92	
SAMPLING								CHECKED BY M.C. SCHLUTER			
								APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET Ø INCHES	2ND Ø INCHES	3RD Ø INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RSD RECOVERY	PERCENT RECOVERY	RSD					
SPT	18	8	9	14	23	2.0	61				Set 3" casing to 60 ft. Hole continued w/3" roller bit from 60 ft.
							62				
							63				
							64				
							65				
							66				
							67				
							68				
							69				
							70				
SPT	19	8	8	17	25	2.0	71				
							72				
							73				
SPT	20	50/5"	-	-	50+	0.3	74				Bottom of boring at 74 ft. Backfilled w/cement grout to surface. Water level not recorded.
							75				
							76				
							77				
							78				
							79				
							80				
							81				
							82				
							83				
							84				
							85				
							86				
							87				
							88				
							89				



BLACK & VEATCH

LOG OF BORING

BORING NO. B-8
SHEET 1 OF 4

CLIENT KISSIMMEE UTILITY AUTHORITY							PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433385 E 484535			ELEVATION (DATUM) 78.8 (MSL)		TOTAL DEPTH 103.5 FEET		DATE START 8/4/92	
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES							LOGGED BY M.C. JONES				DATE FINISH 8/4/92	
SAMPLING							CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	R20 RECOVERY	PERCENT RECOVERY	R20						
SPT	1	1	2	1	3	1.4	1			SAND: brown; very loose; poorly graded; fine grained; rounded; moist; roots grading tan/orange grading loose; trace phosphate particles grading iron oxide staining grading tan/white to orange; medium dense	Boring advanced w/4" diameter spade bit. Bentonite/water used as drilling fluid.	
SPT	2	3	3	3	6	1.0	2					
SPT	3	3	3	4	7	1.4	3					
SPT	4	4	4	4	8	1.8	4					
SPT	5	3	5	5	10	1.4	5					
							6					
							7					
							8					
							9					
							10					
							11					
							12					
							13					
SPT	6	3	4	4	8	1.0	14		SAND: dark brown; loose; poorly graded; fine grained; wet; slight organic odor	Water encountered @ 11.0 ft.		
							15					
							16					
							17					
							18					
SPT	7	8	14	26	40	1.8	19		grading light brown; dense			
							20					
							21					
							22					
							23					
SPT	8	6	14	19	33	1.0	24		grading tan/orange to white			
							25					
							26					
							27					
							28					
SPT	9	7	8	13	21	0.9	29		grading medium dense			



BLACK & VEATCH

LOG OF BORING

BORING NO. B-8
SHEET 2 OF 4

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790				
PROJECT LOCATION INTERCESSION CITY, FLORIDA		COORDINATES N 1433385 E 484535		ELEVATION (DATUM) 78.8 (MSL)		TOTAL DEPTH 103.5 FEET		DATE START 8/4/92				
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES				LOGGED BY W.C. JONES				DATE FINISH 8/4/92				
SAMPLING							CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	20 INCHES	30 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RSD RECOVERY	PERCENT RECOVERY	RSD						
SPT	10	8	13	19	32	1.8		31			grading tan/white; dense	
								32				
								33				
								34				
								35				
SPT	11	5	5	8	13	1.8		36			grading medium dense	
								37				
								38				
								39				
								40				
SPT	12	6	4	5	11	1.0		41			SAND; light gray w/blue; medium dense; fine grained; rounded; wet; some silt; trace clay; trace phosphate particles	
								42				
								43				
								44				
								45				
SPT	13	6	7	8	15	1.8		46			grading light gray	
								47				
								48				
								49				
								50				
								51				
								52				
								53				
SPT	14	7	7	9	16	1.0		54				
								55				
								56				
								57				
								58				
SPT	15	3	3	5	8	0.9		59				



BLACK & VEATCH

LOG OF BORING

BORING NO. B-8
SHEET 3 OF 4

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433385 E 484535		ELEVATION (DATUM) 78.8 (MSL)		TOTAL DEPTH 103.5 FEET	DATE START 8/4/92
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES						LOGGED BY W.C. JONES		DATE FINISH 8/4/92	
SAMPLING							CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE
CORING								GRAPHIC LOG	
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RND RECOVERY	PERCENT RECOVERY	RND	CLASSIFICATION OF MATERIAL		REMARKS
SPT	16	3	3	6	9	1.1			
SPT	17	2	WR	WR	WR	1.9	Silty SAND; mottled tan/orange & white; very loose; fine grained; slight plasticity; wet; some clay		
SPT	18	R	WR	WR	WR	0.7	Slight circulation loss from 75.0 to 78.5 ft.		
SPT	19	WR	WR	WR	WR	2.0	SPT went from 78.5 to 85.0 ft under own weight.		

CLIENT KISSIMMEE UTILITY AUTHORITY								PROJECT CANE ISLAND COMBUSTION TURBINE						PROJECT NO. 17790			
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433385 E 484535				ELEVATION (DATUM) 78.8 (MSL)				TOTAL DEPTH 103.5 FEET		DATE START 8/4/92			
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES						DATE FINISH 8/4/92			
SAMPLING								CHECKED BY M.C. SCHLUTER						APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY		DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL		REMARKS			
CORE SIZE	R/N NUMBER	R/N LENGTH	R/N RECOVERY	R/D RECOVERY	PERCENT RECOVERY	R/D											
SPT	20	WR	WR	WR	WR	2.0			91			occasional pieces of hardpan		SPT went from 88.5 to 100.0 ft under own weight.			
									92								
									93								
									94								
									95								
									96								
									97								
									98								
									99								
									100								
SPT	21	25	14	4	18	0.5			102			Calcareous SAND; white; medium dense; fine grained; rounded; some coarse cemented particles (weathered limestone)		Bottom of boring at 103.5 ft. Backfilled w/cement grout to surface. Water level not recorded.			
									103								
									104								
									105								
									106								
									107								
									108								
									109								
									110								
									111								
									112								
									113								
									114								
									115								
									116								
									117								
									118								
									119								



BLACK & VEATCH

LOG OF BORING

BORING NO. B-9
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY							PROJECT CANE ISLAND COMBUSTION TURE:NE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA			COORDINATES N 1433525 E 484555			ELEVATION (DATUM) 77.6 (MSL)		TOTAL DEPTH 70.0 FEET		DATE START 8/6/92		
SURFACE CONDITIONS FLAT, GRASSY, NEARBY TREES							LOGGED BY W.C. JONES				DATE FINISH 8/10/92	
SAMPLING							CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET @ INCHES	2ND @ INCHES	3RD @ INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS	
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD						
SPT	1	1	2	2	4	1.4	1			<u>SAND</u>: brown; loose; poorly graded; fine grained; rounded; moist; trace phosphate particles; roots grading tan/white grading white; trace iron oxide staining @ 6 ft grading tan/orange grading tan/white; wet grading tan/orange; medium dense; trace silt	Boring advanced w/4" diameter spade bit. Bentonite/water used as drilling fluid. Water encountered @ 10.0 ft.	
SPT	2	3	3	4	7	1.5	2					
SPT	3	5	7	8	15	1.7	3					
SPT	4	5	6	5	11	1.8	4					
SPT	5	4	4	4	8	20	5					
							6					
							7					
							8					
							9					
							10					
							11					
							12					
							13					
SPT	6	4	5	7	12	0.7	14					
							15					
							16					
							17					
							18					
SPT	7	10	10	7	17	1.3	19			Silty <u>SAND</u>: mottled tan/orange and white; medium dense; fine grained; rounded; wet; trace clay; slight plasticity <u>SAND</u>: dark orange; medium dense; poorly graded; fine grained; rounded; wet; heavy iron oxide staining grading light gray		
							20					
							21					
							22					
							23					
SPT	8	6	6	10	16	1.0	24					
							25					
							26					
							27					
							28					
SPT	9	8	6	7	13	0.7	29					

CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433525 E 484555				ELEVATION (DATUM) 77.6 (MSL)		TOTAL DEPTH 73.0 FEET		DATE START 8/6/92			
SURFACE CONDITIONS FLAT, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES				DATE FINISH 8/10/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL		REMARKS			
CORING															
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RWD RECOVERY	PERCENT RECOVERY	RWD									
SPT	10	1	WR	1	1	1.8	31								
							32								
							33								
							34								
							35								
							36								
							37								
							38								
SPT	11	1	1	WR	1	1.9	39								
							40								
							41								
							42								
							43								
SPT	12	1	WR	WR	WR	1.7	44								
							45								
							46								
							47								
							48								
SPT	13	1	WR	2	2	1.9	49								
							50								
							51								
							52								
							53								
							54								
SPT	14	1	WR	WR	1	2.0	55								
							56								
							57								
							58								
							59								
SPT	15	1	1	1	2	1.9									



BLACK & VEATCH

LOG OF BORING

BORING NO. B-9
SHEET 3 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433525 E 484555		ELEVATION (DATUM) 77.8 (MSL)		TOTAL DEPTH 70.0 FEET	
SURFACE CONDITIONS FLAT, GRASSY, NEARBY TREES						LOGGED BY W.C. JONES		DATE FINISH 8/10/92	
SAMPLING						CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD			
								CLASSIFICATION OF MATERIAL	REMARKS
SPT	16	1	WR	WR	WR	2.0	61		
							62		
							63		
							64		
							65		
							66		
							67		
							68		
							69		
SPT	17	5	2	9	11	2.0	70		
							71		
							72		
							73		
							74		
							75		
							76		
							77		
							78		
							79		
							80		
							81		
							82		
							83		
							84		
							85		
							86		
							87		
							88		
							89		

Silty **SAND**; blue/gray; medium dense; poorly graded; fine grained; rounded; wet; trace clay; trace phosphate particles

Calcareous **SAND**; white; medium dense; fine grained; rounded; some cemented particles (weathered limestone)

Bottom of boring at 70 ft.

Backfilled hole w/cement grout to surface.

Water level not recorded.

CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE										PROJECT NO. 17790																													
PROJECT LOCATION INTECESSION CITY, FLORIDA										COORDINATES N 1433520 E 484755										ELEVATION (DATUM) 79.4 (MSL)										TOTAL DEPTH 121.0 FEET										DATE START 8/7/92									
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES										LOGGED BY W.C. JONES										DATE FINISH 8/10/92																													
SAMPLING										CHECKED BY M.C. SCHLUTER										APPROVED BY G.J. VAN RIESSEN																													
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	20 INCHES	30 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS																																					
CORING																																																	
CORE SIZE	R/N NUMBER	R/N LENGTH	R/N RECOVERY	R/N RECOVERY	PERCENT RECOVERY	R/N																																											
SPT	1	1	1	1	2	1.0		1			SAND; brown; very loose; poorly graded; fine grained; roots; moist; trace phosphate particles grading tan/orange	Boring advanced w/3" diameter spade bit. Bentonite/water used as drilling fluid.																																					
SPT	2	2	1	2	3	1.9		2																																									
SPT	3	1	2	2	4	2.0		3																																									
SPT	4	3	3	3	6	1.9		4																																									
SPT	5	3	4	3	7	1.7		5																																									
								6																																									
								7																																									
								8																																									
								9																																									
								10																																									
SPT	6	2	7	9	16	1.1		11			grading out roots	Water encountered @ 9.0 ft.																																					
								12																																									
								13																																									
								14																																									
								15																																									
								16																																									
								17																																									
								18																																									
								19																																									
								20																																									
SPT	7	4	5	8	13	0.8		21			grading medium dense																																						
								22																																									
								23																																									
								24																																									
								25																																									
								26																																									
								27																																									
								28																																									
								29																																									
								30																																									
SPT	8	6	9	12	21	1.4		31			grading tan/white; trace silt																																						
								32																																									
								33																																									
								34																																									
								35																																									
								36																																									
								37																																									
								38																																									
								39																																									
								40																																									
SPT	9	3	4	7	11	1.3		41																																									



BLACK & VEATCH

LOG OF BORING

BORING NO. B-10
SHEET 2 OF 5

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790	
PROJECT LOCATION INTECESSION CITY, FLORIDA				COORDINATES N 1433520 E 484755		ELEVATION (DATUM) 79.4 (MSL)		TOTAL DEPTH 121.0 FEET	DATE START 8/7/92
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES						LOGGED BY W.C. JONES		DATE FINISH 8/10/92	
SAMPLING						CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN REESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG
CORING									
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD			
SPT	10	3	4	5	9	1.2	31		
							32		
							33		
							34		
							35		
							36		
							37		
							38		
							39		
SPT	11	6	6	8	14	1.4	40		
							41		
							42		
							43		
							44		
SPT	12	4	2	3	5	1.0	45		
							46		
							47		
							48		
							49		
SPT	13	3	2	3	5	1.0	50		
							51		
							52		
							53		
							54		
SPT	14	2	2	2	4	1.0	55		
							56		
							57		
							58		
							59		
SPT	15	WR	WR	WR	WR	2.0			

Silty SAND; white; loose; poorly graded; fine grained; rounded; wet; trace phosphate particles

grading medium dense

grading blue gray; loose

grading very loose

SPT 15 went from 58.5 to 64.0 feet under own weight.



BLACK & VEATCH

LOG OF BORING

BORING NO. B-10
SHEET 3 OF 5

CLIENT KISSIMMEE UTILITY AUTHORITY										PROJECT CANE ISLAND COMBUSTION TURBINE										PROJECT NO. 17790																													
PROJECT LOCATION INTECESSION CITY, FLORIDA										COORDINATES N 1433520 E 484755										ELEVATION (DATUM) 79.4 (MSL)										TOTAL DEPTH 121.0 FEET										DATE START 8/7/92									
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES										LOGGED BY W.C. JONES										APPROVED BY G.J. VAN REESSEN										DATE FINISH 8/10/92																			

SAMPLING										CHECKED BY M.C. SCHLUTER										APPROVED BY G.J. VAN REESSEN									
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS																		
CORING																													
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD																							
SPT	16	1	WR	WR	WR	2.0	61			grading mottled tan/light gray	SPT 16 went from 63.5 to 68.5 feet under own weight.																		
							62																						
							63																						
							64																						
							65																						
							66																						
							67																						
							68																						
SPT	17	WR	WR	WR	WR	2.0	69				SPT 17 went from 68.5 to 78.0 feet under own weight.																		
							70																						
							71																						
							72			grading trace clay @ 72 ft																			
							73																						
							74																						
							75																						
							76																						
							77																						
							78																						
							79																						
							80																						
							81																						
							82																						
SPT	18	WR	WR	WR	WR	1.0	83																						
							84			SAND: tan/orange; very loose; poorly graded; fine grained; rounded; wet; trace phosphate particles	SPT 18 went from 78.0 to 85.0 feet under own weight.																		
							85																						
							86																						
							87																						
							88																						
							89																						



BLACK & VEATCH

LOG OF BORING

BORING NO. B-10
SHEET 4 OF 6

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790			
PROJECT LOCATION INTECESSION CITY, FLORIDA				COORDINATES N 1433520 E 484755				ELEVATION (DATUM) 79.4 (MSL)		TOTAL DEPTH 121.0 FEET	
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES		DATE FINISH 8/10/92	
SAMPLING								CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN	
SAMPLE TYPE	SAMPLE NUMBER	SET 0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORING											
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	RND RECOVERY	PERCENT RECOVERY	RND					
SPT	19	WR	WR	WR	WR	1.5	91				
							92				
							93				
							94				
							95				
SPT	20	5	8	27	33	2.0	96				
							97				
							98				
							99				
							100				
							101				
							102				
							103				
							104				
SPT	21	WR	10	24	34	2.0	105				
							106				
							107				
							108				
							109				
NX	1	5	109.5	0	4	0	110				
			.22				111				
							112				
							113				
							114				
							115				
							116				
NX	2	5	116.0	0.33	28	7	117				
			1.4				118				
							119				

SPT 19 went from
88.5 to 96.0 feet
under own weight.Silty SAND; blue gray; very loose;
poorly graded; fine grained;
rounded; wet; trace phosphate
particlesCalcareous SAND; white; dense;
medium grained; rounded; wet;
slightly cemented particles 0.25"
dia.; occasional silt filled jointsVoid encountered
at 101.0 feet. Set
casing to 105.0
feet.SAND; brown; medium dense; poorly
graded; medium grained; rounded;
wet; trace phosphate particles;
interlayered w/blue gray silty sandCalcareous SAND; white; medium
dense; medium grained; rounded;
(weathered limestone)Set casing to 109.5
feet.LIMESTONE; fossiliferous; white;
soft to hard; highly weatheredVoid from 114.5 to
116 feet.



BLACK & VEATCH

LOG OF BORING

BORING NO. B-10
SHEET 5 OF 5

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790							
PROJECT LOCATION INTECESSION CITY, FLORIDA				COORDINATES N 1433520 E 484755"				ELEVATION (DATUM) 79.4 (MSL)		TOTAL DEPTH 121.0 FEET		DATE START 8/7/92			
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES				DATE FINISH 8/10/92			
SAMPLING								CHECKED BY- M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND	0 INCHES	3RD	0 INCHES	N	VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORING															
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD									
											121				
											122				Bottom of boring at 121.0 ft.
											123				
											124				Attempts to backfill
											125				at 60 ft and 50 ft
											126				were unsuccessful.
											127				Railroad ballast
											128				added to hole and
											129				boring was
											130				backfilled w/cement
											131				grout from 30 ft to
											132				surface.
											133				Water level not
											134				recorded.
											135				
											136				
											137				
											138				
											139				
											140				
											141				
											142				
											143				
											144				
											145				
											146				
											147				
											148				
											149				



BLACK & VEATCH

LOG OF BORING

BORING NO. B-11
SHEET 1 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790				
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433430 E 484725				ELEVATION (DATUM) 80.3 (MSL)		TOTAL DEPTH 84.0 FEET		
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES				
								DATE FINISH 8/12/92				
SAMPLING								CHECKED BY M.C. SCHLUTER				
								APPROVED BY G.J. VAN RIESSEN				
SAMPLE TYPE	SAMPLE NUMBER	SET	0 INCHES	2ND 0 INCHES	3RD 0 INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS
CORING												
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD						
SPT	1	1	1	2	3	0.9	1			SAND: brown; very loose; poorly graded; fine grained; moist; some roots; trace phosphate particles; trace charcoal wood	Boring advanced w/4" diameter spade bit. Bentonite/water used as drilling fluid.	
SPT	2	2	2	2	4	1.0	2			grading tan orange		
SPT	3	2	3	3	6	1.7	3			grading loose		
SPT	4	4	3	4	7	1.5	4					
SPT	5	4	3	2	5	1.7	5			grading light tan/orange		
SPT	6	5	7	8	15	1.2	6			grading medium dense; wet; some silt	Water encountered @ 12.0 ft.	
SPT	7	5	5	5	10	1.3	7			Silty SAND: light gray; medium dense; poorly graded; fine grained; rounded; wet; trace clay; trace phosphate particles		
SPT	8	5	6	7	13	1.2	8			grading no clay		
SPT	9	3	2	3	5	1.3	9			grading loose		



BLACK & VEATCH

LOG OF BORING

BORING NO. B-11
SHEET 2 OF 3

CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790							
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433430 E 484725				ELEVATION (DATUM) 80.3 (MSL)		TOTAL DEPTH 84.0 FEET		DATE START 8/11/92			
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES				DATE FINISH 8/12/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	1ST INCHES	2ND INCHES	3RD INCHES	N VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL		REMARKS		
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD									
SPT	10	2	2	1	3	1.1		31			grading very loose				
								32							
								33							
								34							
								35							
								36							
								37							
								38							
SPT	11	2	1	2	3	2.0		39			Silty SAND; mottled tan/orange to light gray; very loose; poorly graded; fine grained; round; wet; trace clay; trace phosphate particles				
								40							
								41							
								42							
								43							
SPT	12	6	1	2	3	1.9		44							
								45							
								46							
								47							
								48							
SPT	13	2	2	4	6	1.9		49			grading loose				
								50							
								51							
								52							
								53							
SPT	14	5	5	7	12	1.7		54			Silty SAND; olive green; medium dense; fine grained; rounded; wet; some shells; trace clay; trace phosphate particles				
								55							
								56							
TW	15					1.8		57							
								58							
TW	16					1.5		59							

Hole collapsed to 15 ft after retrieval of TW 16. Set 59 ft of 3" diameter casing.



BLACK & VEATCH

LOG OF BORING

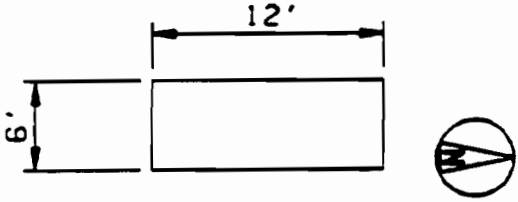
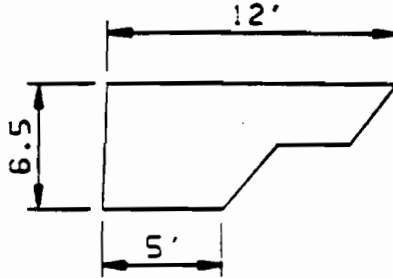
BORING NO. B-11
SHEET 3 OF 3

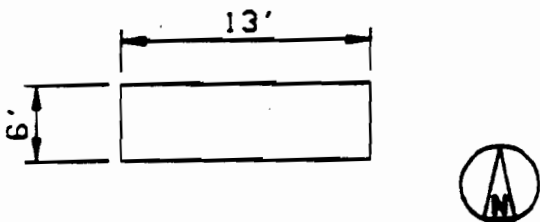
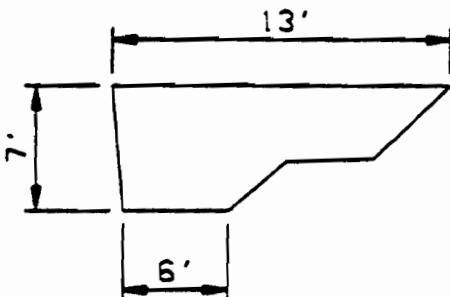
CLIENT KISSIMMEE UTILITY AUTHORITY				PROJECT CANE ISLAND COMBUSTION TURBINE				PROJECT NO. 17790							
PROJECT LOCATION INTERCESSION CITY, FLORIDA				COORDINATES N 1433430 E 484725				ELEVATION (DATUM) 80.3 (MSL)		TOTAL DEPTH 84.0 FEET		DATE START 8/11/92			
SURFACE CONDITIONS LEVEL, GRASSY, NEARBY TREES								LOGGED BY W.C. JONES				DATE FINISH 8/12/92			
SAMPLING								CHECKED BY M.C. SCHLUTER				APPROVED BY G.J. VAN RIESSEN			
SAMPLE TYPE	SAMPLE NUMBER	SET	1ST INCHES	2ND INCHES	3RD INCHES	N	VALUE	SAMPLE RECOVERY	DEPTH IN FEET	SAMPLE TYPE	GRAPHIC LOG	CLASSIFICATION OF MATERIAL	REMARKS		
CORING															
CORE SIZE	RUN NUMBER	RUN LENGTH	RUN RECOVERY	ROD RECOVERY	PERCENT RECOVERY	ROD									
TW	17						1.5		61						
SPT	18	5	6	7	13		1.1		62			grading very shelly			
									63						
SPT	19	5	8	17	25		2.0		64			grading with no shells			
									65						
									66						
									67						
SPT	20	50/2"	-	-	50+		0.1		68			Fossiliferous LIMESTONE: hard;			
									69			some solutions; drilling breaks along			
									70			fractures in rock core @ approx. 4			
									71			inch intervals			
									72						
									73						
									74						
NX	1	6	74.0	5.4	5.4	90	100		75						
									76						
									77						
									78						
									79						
NX	2	5	79.0	4.2	3.4	84	68		80						
									81						
									82						
									83						
									84						
									85				Bottom of boring at 84.0 ft.		
									86						
									87				Backfilled w/cement		
									88				grout to surface.		
									89				Water level not recorded.		

Appendix C

Test Pit Logs

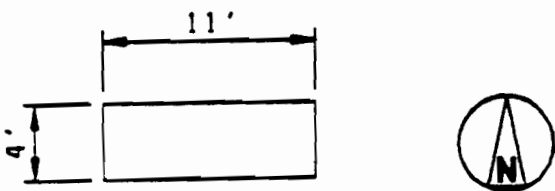
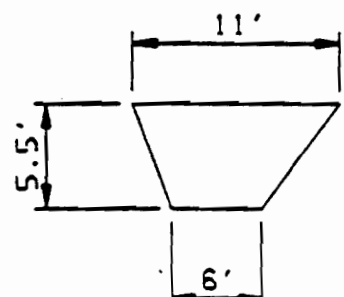
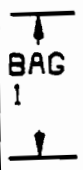
TEST PIT NO. TP-1

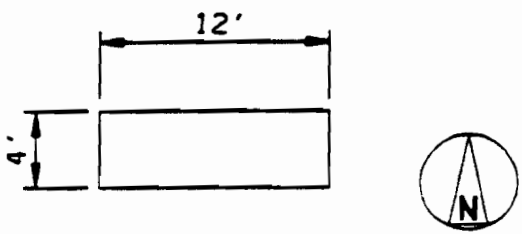
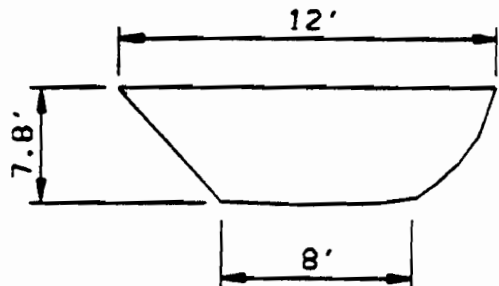
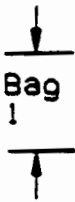
 BLACK & VEATCH		CLIENT KISSIMMEE UTILITY AUTHORITY		PROJECT NO. 17790	
COORDINATES N 1433125 , E 484975		ELEVATION (DATUM) 77.8 FT (MSL)		TOTAL DEPTH 6.5 FT	
DATE 7-31-92					
PROJECT LOCATION INTERCESSION CITY		SURFACE CONDITIONS FLAT GRASSY AREA			
METHOD OF EXCAVATION FORD BACKHOE				INSPECTOR M.C. SCHLUTER	
CHECKED BY M.C. SCHLUTER			APPROVED BY G.J. VAN RIESSEN		
PLAN VIEW SKETCH, DIMENSIONS, AND NORTH ARROW 			PROFILE VIEW SKETCH AND DIMENSIONS 		
SAMPLE TYPE AND NUMBER	DEPTH IN FEET	CLASSIFICATION AND DESCRIPTION OF MATERIAL			
BAG 1 	1	SAND, light to dark grey, dry, many roots (Topsoil)			
	2	SAND, tan/orange, fine grained, dry, some roots			
	3	grading out roots, moist, trace iron-staining			
	4	grading to some iron staining			
	5				
	6				
REMARKS: FREE WATER NOT FOUND IN PIT. PIT SIDES CAVING/SLOUGHING DURING EXCAVATION.					

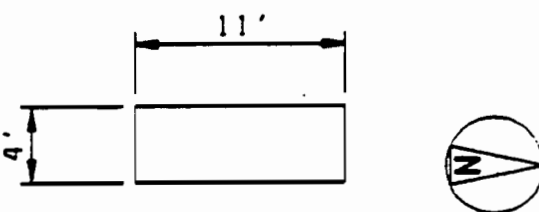
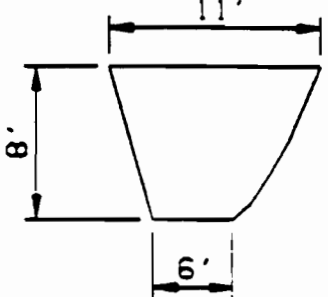
 BLACK & VEATCH		CLIENT KISSIMMEE UTILITY AUTHORITY		PROJECT NO. 17790	
COORDINATES N 1433166 , E 484684		ELEVATION (DATUM) 83.1 (MSL)		TOTAL DEPTH 7.0 FT.	
PROJECT LOCATION INTERCESSION CITY (FLA.)		SURFACE CONDITION S FLAT GRASSY AREA			
METHOD OF EXCAVATION FORD BACKHOE				INSPECTOR M.C. SCHLUTER	
CHECKED BY M.C. SCHLUTER			APPROVED BY G.J. VAN RIESSEN		
PLAN VIEW SKETCH, DIMENSIONS, AND NORTH ARROW			PROFILE VIEW SKETCH AND DIMENSIONS		
					

SAMPLE TYPE AND NUMBER	IN DEPTH FEET	CLASSIFICATION AND DESCRIPTION OF MATERIAL
		<u>SAND</u> ; light to dark grey; fine grained; dry; many roots (Topsoil)
BAG 1	1	
	2	<u>SAND</u> ; tan/orange; fine grained; dry; trace roots
	3	grading moist; no roots
	4	
	5	
	6	
	7	
	8	

REMARKS: FREE WATER NOT FOUND IN PIT. IRON-STAINING NOT FOUND IN PIT.
PIT SIDES CAVING/SLOUGHING DURING EXCAVATION

 BLACK & VEATCH		CLIENT KISSIMMEE UTILITY AUTHORITY		PROJECT NO. 17790	
COORDINATES N 1432758, E 486093		ELEVATION (DATUM) 69.3 FT (MSL)		TOTAL DEPTH 5.5 FT	
PROJECT LOCATION INTERCESSION CITY (FLA.)		SURFACE CONDITIONS FLAT GRASSY AREA			
METHOD OF EXCAVATION FORD BACKHOE				INSPECTOR M.C. SCHLUTER	
CHECKED BY M.C. SCHLUTER			APPROVED BY G.J. VAN RIESSEN		
PLAN VIEW SKETCH, DIMENSIONS, AND NORTH ARROW			PROFILE VIEW SKETCH AND DIMENSIONS		
					
SAMPLE TYPE AND NUMBER	DEPTH IN FEET	CLASSIFICATION AND DESCRIPTION OF MATERIAL			
 BAG 1	1	SAND; light to dark gray; fine grained; dry; many roots (Topsoil)			
	2	SAND; light grey to white; fine grained; dry; trace roots			
	3	grading wet			
	4	Silty SAND; dark brown to black; fine grained; wet; strong sulphur smell (Hardpan)			
	5				
	6				
REMARKS: WATER @ 5.0 FT. PIT EXCAVATION LIMITED DUE TO WATER IN PIT.					

 BLACK & VEATCH		CLIENT KISSIMME UTILITY AUTHORITY		PROJECT NO. 17790	
COORDINATES N 1431591, E 486892		ELEVATION (DATUM) 69.2 (MSL)		TOTAL DEPTH 7.8 FT	
DATE 07/31/92		PROJECT LOCATION INTERCESSION CITY (FLA.)		SURFACE CONDITIONS FLAT GRASSY AREA	
METHOD OF EXCAVATION FORD BACKHOE				INSPECTOR M.C. SCHLUTER	
CHECKED BY M.C. SCHLUTER			APPROVED BY G. VAN RIESSEN		
PLAN VIEW SKETCH, DIMENSIONS, AND NORTH ARROW 			PROFILE VIEW SKETCH AND DIMENSIONS 		
SAMPLE TYPE AND NUMBER	DEPTH IN FEET	CLASSIFICATION AND DESCRIPTION OF MATERIAL			
	1	<u>SAND</u> ; light to dark grey; loose; fine grained; dry; many roots (Topsoil)			
	2	<u>SAND</u> ; light grey with some dark lenses; fine grained; dry; trace to some roots			
	3	<u>SAND</u> ; light to dark grey; fine grained; moist			
	4	Silty <u>SAND</u> ; dark brown to black; fine grained; wet; sulphur smell			
	5				
	6	Silty <u>SAND</u> ; dark brown to black; fine grained; wet; sulphur (Hardpan)			
	7				
	8				
REMARKS: WATER @ 6.4 AFTER 2 HRS.					

 BLACK & VEATCH		CLIENT KISSIMMEE UTILITY AUTHORITY		PROJECT NO. 17790	
COORDINATES N 1430937, E 486431		ELEVATION (DATUM) 72.1 (MSL)		TOTAL DEPTH 8.0 FT.	
DATE 7/31/92		PROJECT LOCATION KISSIMMEE, FL.		SURFACE CONDITIONS FLAT GRASSY AREA	
METHOD OF EXCAVATION FORD BACKHOE				INSPECTOR M.C. SCHLUTER	
CHECKED BY M.C. SCHLUTER				APPROVED BY	
PLAN VIEW SKETCH, DIMENSIONS, AND NORTH ARROW			PROFILE VIEW SKETCH AND DIMENSIONS		
					
SAMPLE AND TYPE NUMBER	DEPTH IN FEET	CLASSIFICATION AND DESCRIPTION OF MATERIAL			
BAG 1	1	SAND; grey to dark grey; fine grained; dry; roots & organics (Topsoil)			
	2	SAND; lt grey w/dark streaks; fine grained; moist; some to trace roots			
BAG 2	3				
	4	Silty SAND; dark brown to black; hard; fine grained; cemented; moist; organics; trace roots; strong sulphur smell (hardpan)			
	5				
	6				
	7				
	8				
REMARKS: WATER SEEPING INTO PIT @ 7.2 FT.					

Appendix D

Piezometer Logs

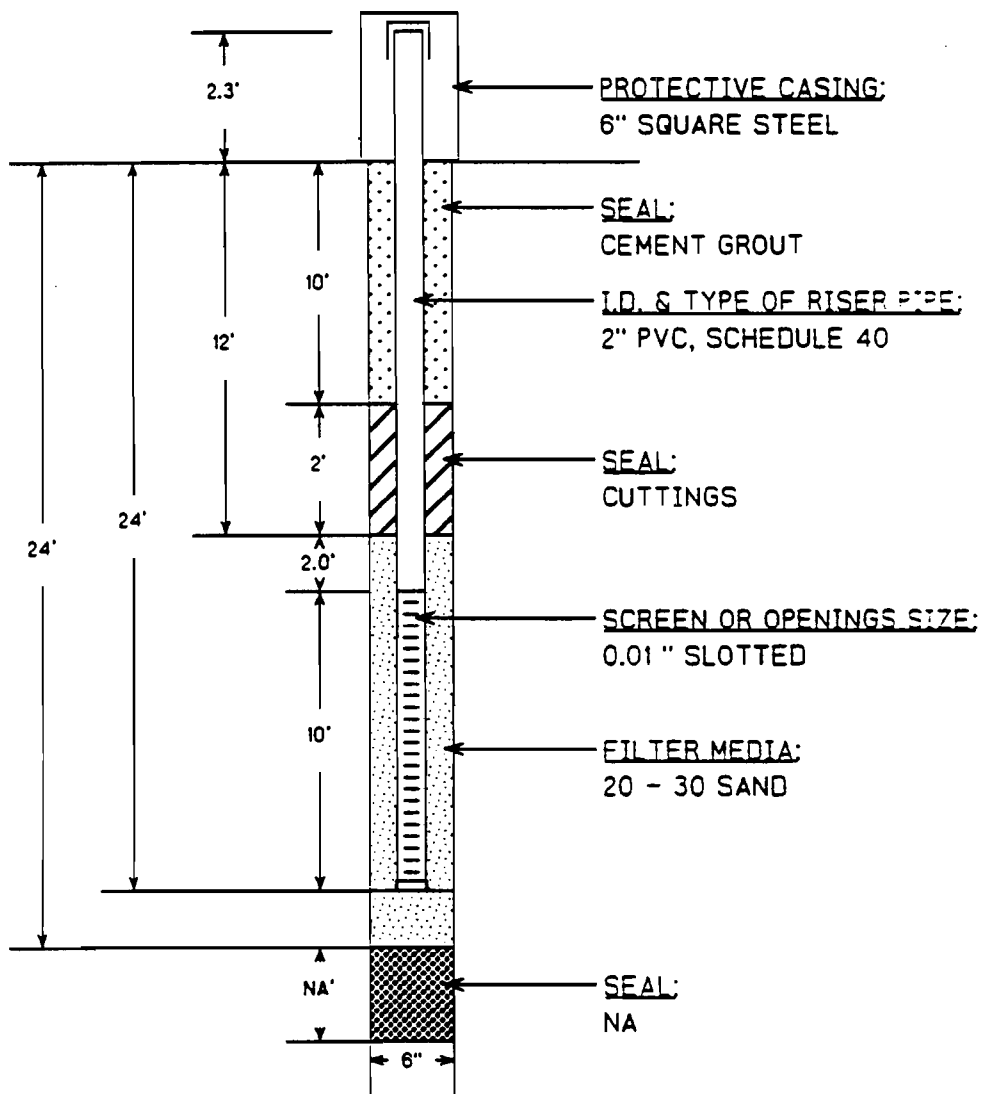


BLACK & VEATCH

PIEZOMETER INSTALLATION LOG

PIEZOMETER NO. P-1

CLIENT KISSIMME UTILITY AUTHORITY		PROJECT CANE ISLAND COMBUSTION TURBINE	PROJECT NO. 17790
PROJECT LOCATION INTERCESSION CITY, FL	COORDINATES N 1433544 E 485026	GROUND ELEVATION (DATUM) 78.0 (MSL)	DATE 8/3/92
STRATUM MONITORED		INSPECTOR C. JONES	
CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN	



METHOD OF INSTALLATION:
PIEZOMETER INSTALLED THROUGH 6" O.D. HOLLOW STEM AUGER

REMARKS:
WATER LEVEL RECORDED AT 8.2 FEET BELOW GROUND SURFACE ON 8/12/92.

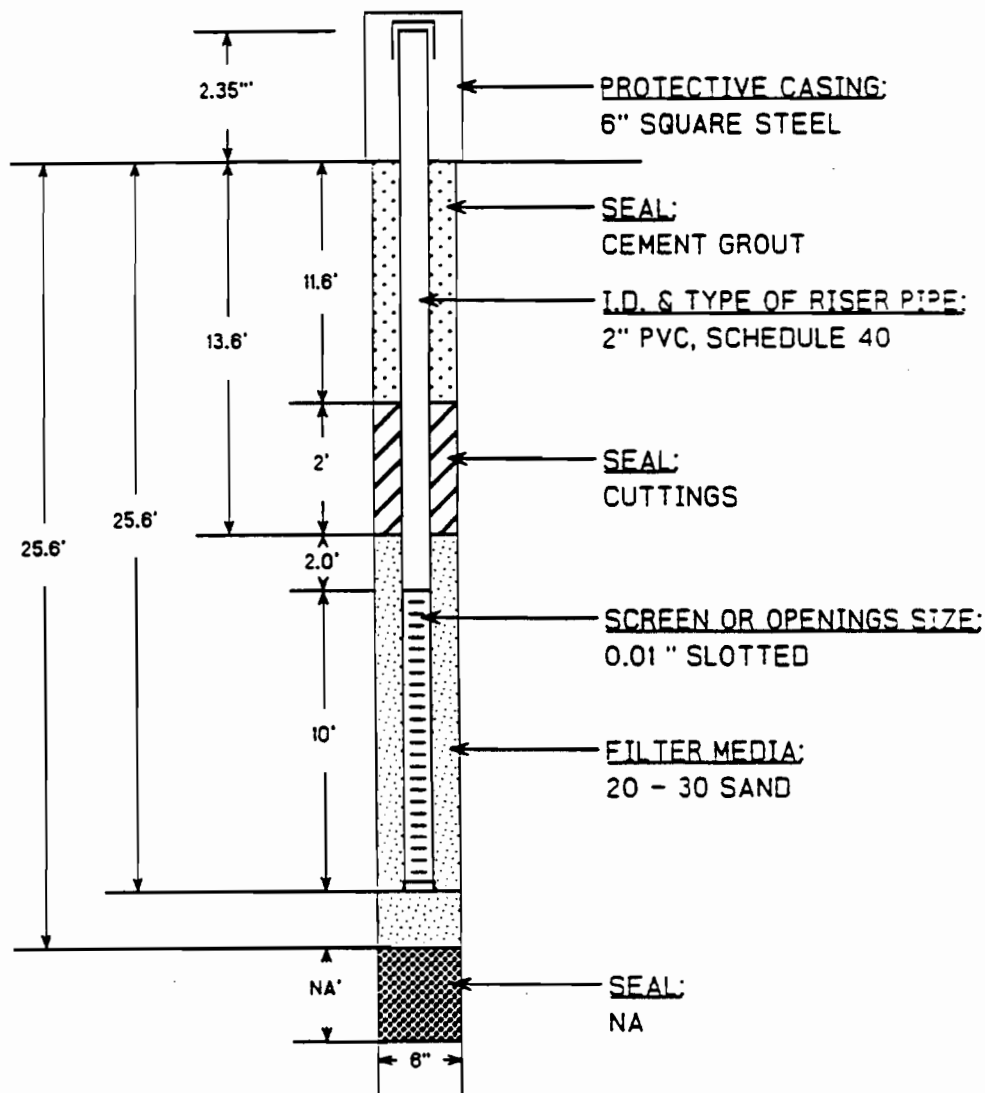


BLACK & VEATCH

PIEZOMETER INSTALLATION LOG

PIEZOMETER NO. P-2

CLIENT KISSIMME UTILITY AUTHORITY		PROJECT CANE ISLAND COMBUSTION TURBINE	PROJECT NO. 17790
PROJECT LOCATION INTERCESSION CITY, FL	COORDINATES N 1433105 E 484975	GROUND ELEVATION (DATUM) 78.0 (MSL)	DATE 8/3/92
STRATUM MONITORED		INSPECTOR C. JONES	
CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN	

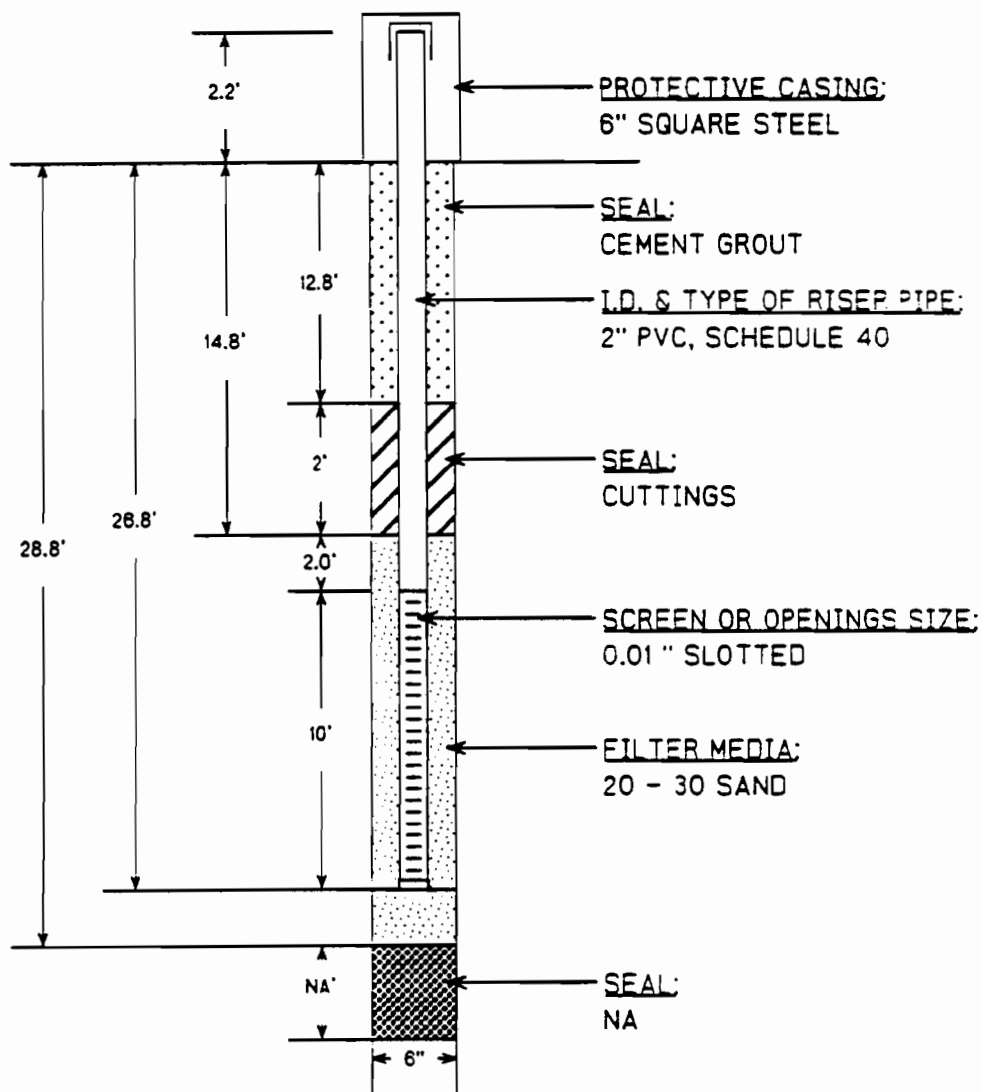


METHOD OF INSTALLATION:
PIEZOMETER INSTALLED THROUGH 6" O.D. HOLLOW STEM AUGER.

REMARKS:
WATER LEVEL RECORDED AT 8.35 FEET BELOW GROUND SURFACE ON 8/12/92.

**BLACK & VEATCH****PIEZOMETER
INSTALLATION LOG****PIEZOMETER NO. P-3**

CLIENT KISSIMME UTILITY AUTHORITY		PROJECT CANE ISLAND COMBUSTION TURBINE	PROJECT NO. 17790
PROJECT LOCATION INTERCESSION CITY, FL	COORDINATES N 1433188 E 484705	GROUND ELEVATION (DATUM) 83.0 (MSL)	DATE 8/4/92
STRATUM MONITORED		INSPECTOR C. JONES	
CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN	



METHOD OF INSTALLATION:
PIEZOMETER INSTALLED THROUGH 6" O.D. HOLLOW STEM AUGER.

REMARKS:
WATER LEVEL RECORDED AT 13.85 FEET BELOW GROUND SURFACE ON 8/12/92.

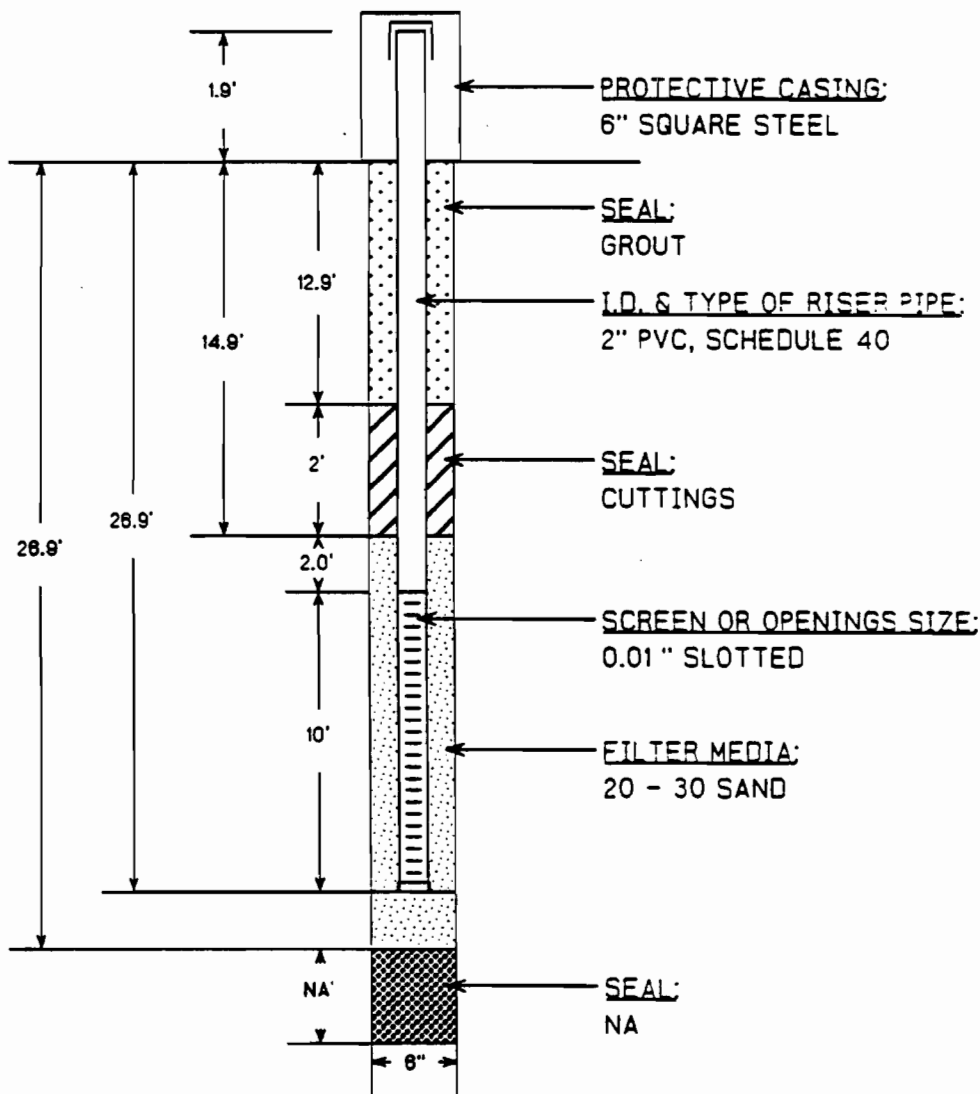


BLACK & VEATCH

PIEZOMETER INSTALLATION LOG

PIEZOMETER NO. P-4

CLIENT KISSIMMEE UTILITY AUTHORITY		PROJECT CANE ISLAND COMBUSTION TURBINE	PROJECT NO. 17790
PROJECT LOCATION INTERCESSION CITY, FL	COORDINATES N 1433407 E 484535	GROUND ELEVATION (DATUM) 78.5 (MSL)	DATE 8/4/92
STRATUM MONITORED		INSPECTOR C. JONES	
CHECKED BY M.C. SCHLUTER		APPROVED BY G.J. VAN RIESSEN	



METHOD OF INSTALLATION:
PIEZOMETER INSTALLED THROUGH 6" O.D. HOLLOW STEM AUGER.

REMARKS:
WATER LEVEL RECORDED AT 9.0 FEET BELOW GROUND SURFACE ON 8/12/92.

Appendix E

Laboratory Test Results

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

Laboratory Analysis Summary

Boring No.	Sample No.	Depth (ft.)	Organic Content %	Moisture Content %	Liquid Limit %	Plastic Limit %	Sieve Analysis				
							#10	#40	#60	#100	#200
B-1	SPT-3	6	---	---	---	---	100	87	47	15	2
B-1	SPT-6	15	---	---	---	---	100	95	78	58	52
B-1	SPT-9	30	---	43	NP	NP	100	98	83	37	21
B-1	SPT-13	50	---	43	48	35	---	---	---	---	---
B-1	SPT-14	55	---	26	NP	NP	---	---	---	---	---
B-2	SPT-4	8	---	---	---	---	100	89	49	14	2
B-2	SPT-6	15	2	---	---	---	100	86	53	11	2
B-2	SPT-10	35	---	---	---	---	100	100	89	32	15
B-3	SPT-8	25	---	---	---	---	100	76	52	18	7
B-3	SPT-10	35	---	17	NP	NP	100	97	80	27	12
B-3	SPT-15	53.5	---	45	---	---	99	92	89	84	51
B-4	SPT-6	15	---	---	---	---	100	85	49	11	3
B-4	SPT-8	25	---	---	---	---	100	77	57	18	6
B-4	SPT-9	30	---	34	NP	NP	100	99	98	79	17
B-4	SPT-11	40	---	30	NP	NP	99	95	83	44	35
B-4	SPT-18	70	---	---	---	---	68	46	35	25	17
B-5	SPT-12	45	---	23	NP	NP	100	99	99	94	25
B-6	SPT-6	15	---	---	---	---	100	88	51	14	6
B-6	SPT-11	40	---	32	NP	NP	100	98	86	42	21
B-6	TW-14	55	---	---	43	31	100	98	96	92	74
B-7	SPT-5	10	---	---	---	---	100	87	49	14	3
B-7	SPT-7	20	---	---	---	---	100	89	61	28	18
B-7	SPT-10	35	---	---	---	---	100	85	49	30	10
B-8	SPT-7	20	---	---	---	---	100	83	50	15	2
B-8	SPT-13	50	---	---	---	---	100	82	52	19	11
B-8	SPT-16	65	---	---	---	---	100	85	54	34	10
B-8	SP19	85	---	---	---	---	100	99	98	89	25
B-8	SPT-20	100	---	---	---	---	100	98	95	84	25

**Laboratory Analysis Summary
(continued)**

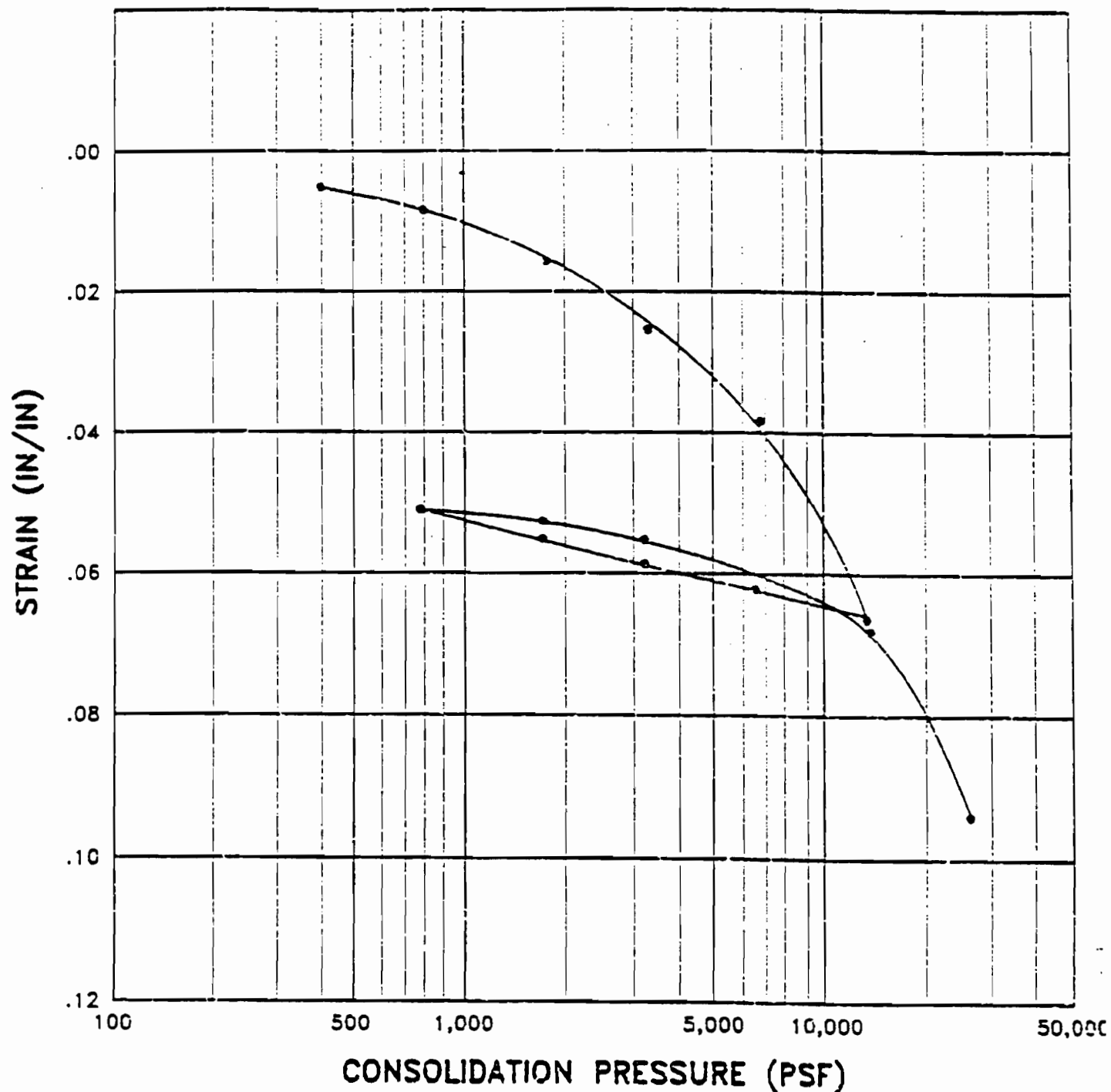
Boring No.	Sample No.	Depth (ft.)	Organic Content %	Moisture Content %	Liquid Limit %	Plastic Limit %	Sieve Analysis				
							#10	#40	#60	#100	#200
B-9	SPT-13	50	---	---	---	---	100	98	97	92	21
B-9	SPT-16	65	---	---	---	---	100	97	87	64	19
B-10	SPT-6	15	---	---	---	---	100	84	57	16	1
B-10	SPT-12	45	---	---	---	---	100	88	56	15	6
B-10	SPT-17	70	---	---	---	---	100	100	98	94	26
B-10	SPT-20	97.5	---	---	---	---	96	83	64	38	27
B-11	SPT-7	20	---	---	---	---	100	91	59	27	19
B-11	SPT-12	45	---	---	---	---	100	100	99	94	23
B-11	TU-16	55	---	---	NP	NP	100	95	92	84	35

LABORATORY ANALYSIS SUMMARY

[illegible]

Hydrometer Test Results

<u>Boring No.</u>	<u>Sample No.</u>	<u>Depth</u>	<u>Diameter (mm)</u>	<u>% Finer</u>
B-3	TW-14	50-52	.033	35
			.024	33
			.017	31
			.012	31
			.009	29
			.006	29
			.005	27
			.004	27
			.003	27
			.001	27
			.001	27
B-5	TW-16	60-62	.034	44
			.024	42
			.017	40
			.013	40
			.009	38
			.006	38
			.005	38
			.004	36
			.003	36
			.002	34
			.001	32
B-7	TW-16	55-57	.033	45
			.023	41
			.017	37
			.012	37
			.009	35
			.006	33
			.005	31
			.004	31
			.003	29
			.001	29
			.001	29
B-11	TW-17	57-59	.033	39
			.024	37
			.017	35
			.012	35
			.009	33
			.006	31
			.005	31
			.004	29
			.003	29
			.001	29
			.001	29



BORING: B-7 SAMPLE: B-7 DEPTH: 55' - 57'

MATERIAL DESCRIPTION: GREENISH-GRAY CLAY WITH SEAMS OF SHELL AND SILT

DRY DENSITY (pcf) 69.0

COMPRESSION INDICES C_c (VIRGIN) = 0.106 C_r (RECOMPRESSION) = 0.015 OCR = 2.0

REMARKS:

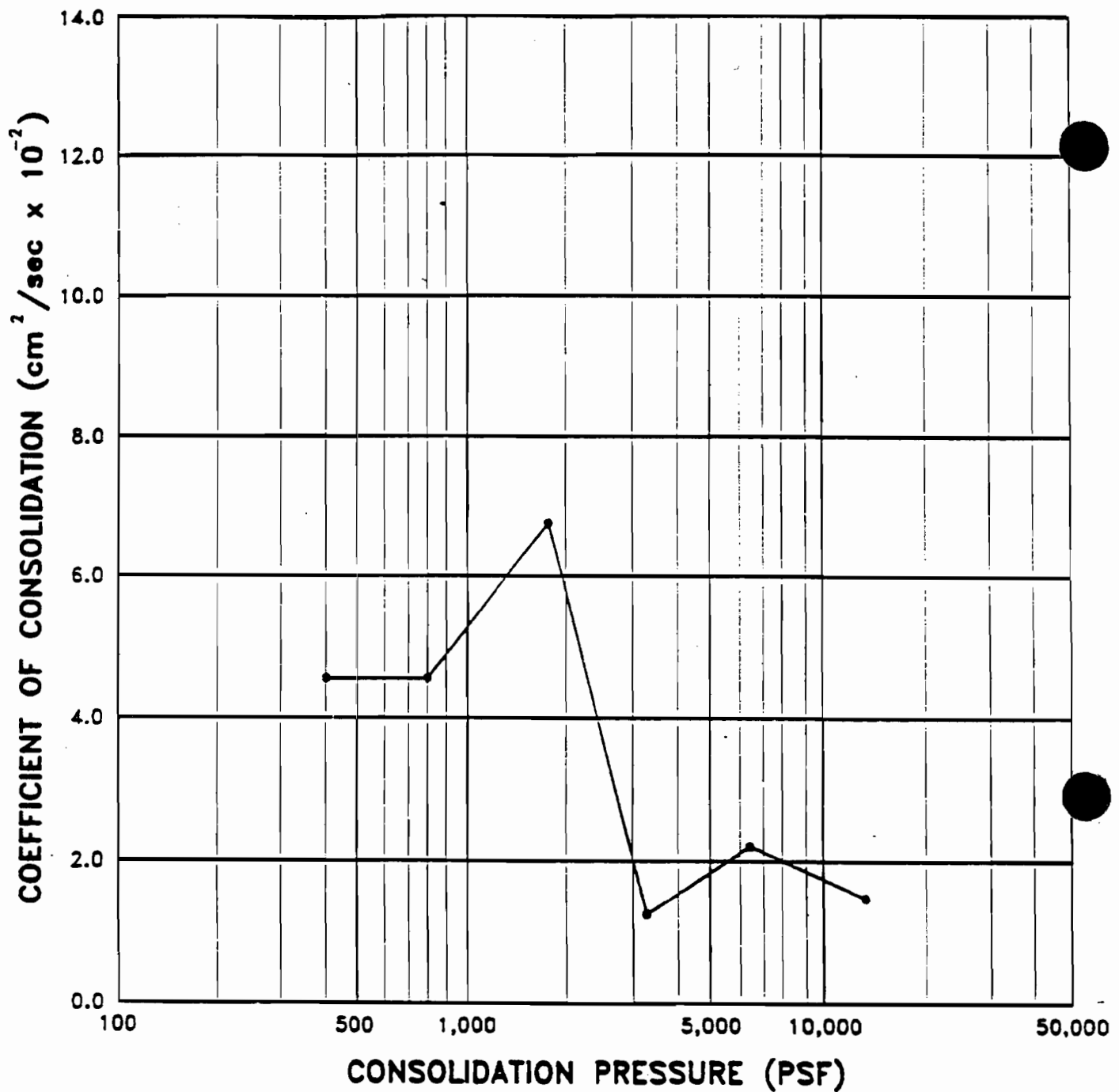
ONE DIMENSIONAL
CONSOLIDATION TEST REPORT

STRAIN VS. LOG PRESSURE

CANE ISLAND
- COMBUSTION TURBINE
PROGRAM

PH 1078.3

PLATE



BORING: B-7 SAMPLE: B-7 DEPTH: 55' - 57'

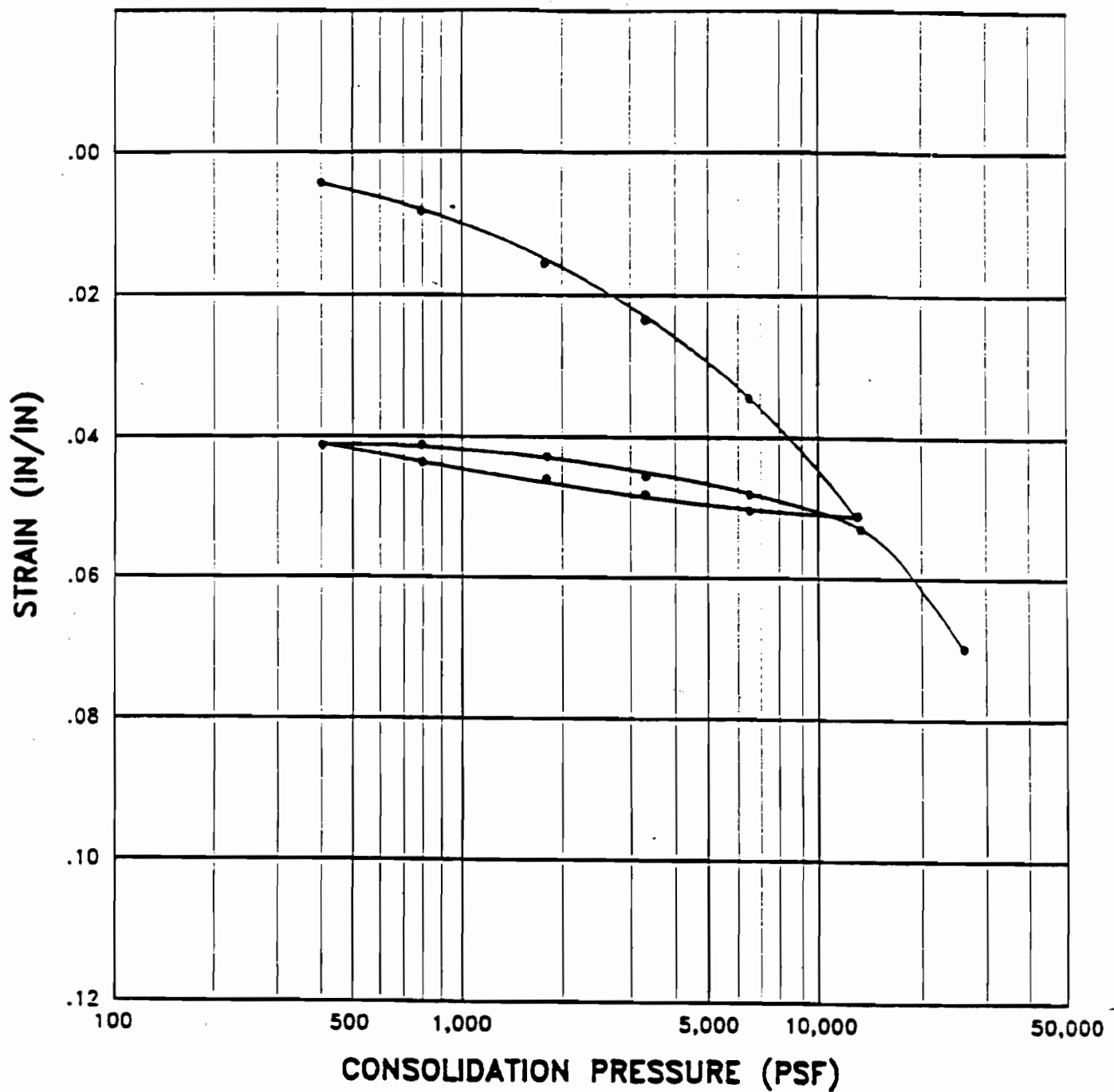
MATERIAL DESCRIPTION: GREENISH-GRAY CLAY WITH SEAMS OF SHELL AND SILT

ONE DIMENSIONAL
CONSOLIDATION TEST REPORT
COEFFICIENT OF CONSOLIDATION VS. LOG PRESSURE

CANE ISLAND
COMBUSTION TURBINE
PROGRAM

PN 1078.3

PLATE 2



BORING: B-11 SAMPLE: B-11 DEPTH: 57' - 59'

MATERIAL DESCRIPTION: GREENISH-GRAY SILTY TO CLAYEY FINE SAND

DRY DENSITY (pcf) 83.0

COMPRESSION INDICES C_e (VIRGIN)= 0.056 C_r (RECOMPRESSION)= 0.007 OCR = 2.3

REMARKS:

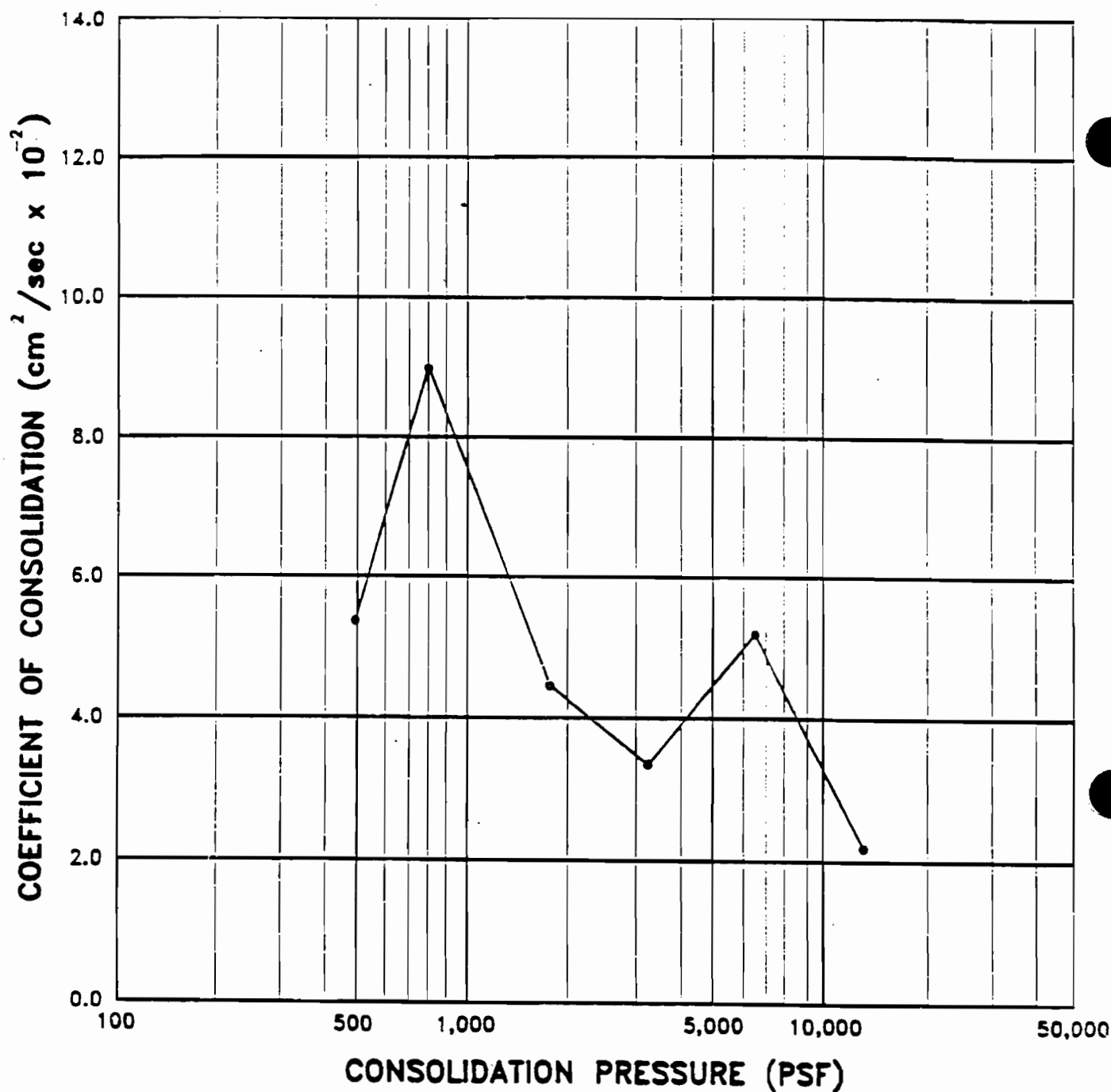
ONE DIMENSIONAL
CONSOLIDATION TEST REPORT

STRAIN VS. LOG PRESSURE

CANE ISLAND
COMBUSTION TURBINE
PROGRAM

PN 1078.3

PLATE 3



BORING: B-11 SAMPLE: B-11 DEPTH: 57' - 59'

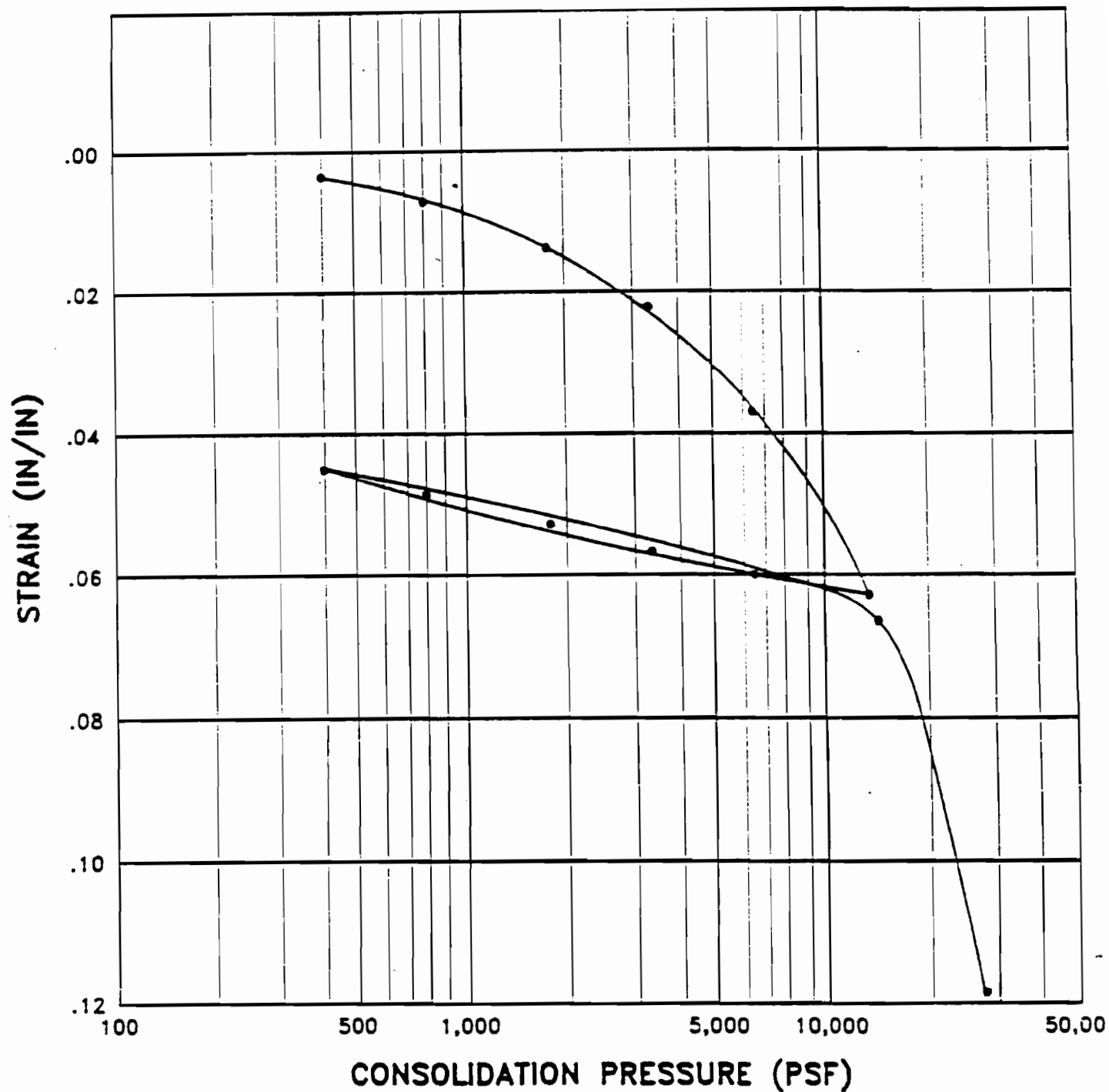
MATERIAL DESCRIPTION: GREENISH-GRAY SILTY TO CLAYEY FINE SAND

ONE DIMENSIONAL
CONSOLIDATION TEST REPORT
COEFFICIENT OF CONSOLIDATION VS. LOG PRESSURE

CANE ISLAND
COMBUSTION TURBINE
PROGRAM

PN 1078.3

PLATE 4



BORING: B-6 SAMPLE: B-6 DEPTH: 53.5' - 55'

MATERIAL DESCRIPTION: GREENISH-GRAY CLAYEY FINE SAND WITH INCLUSIONS OF LIME SILTS

DRY DENSITY (pcf) 82.0

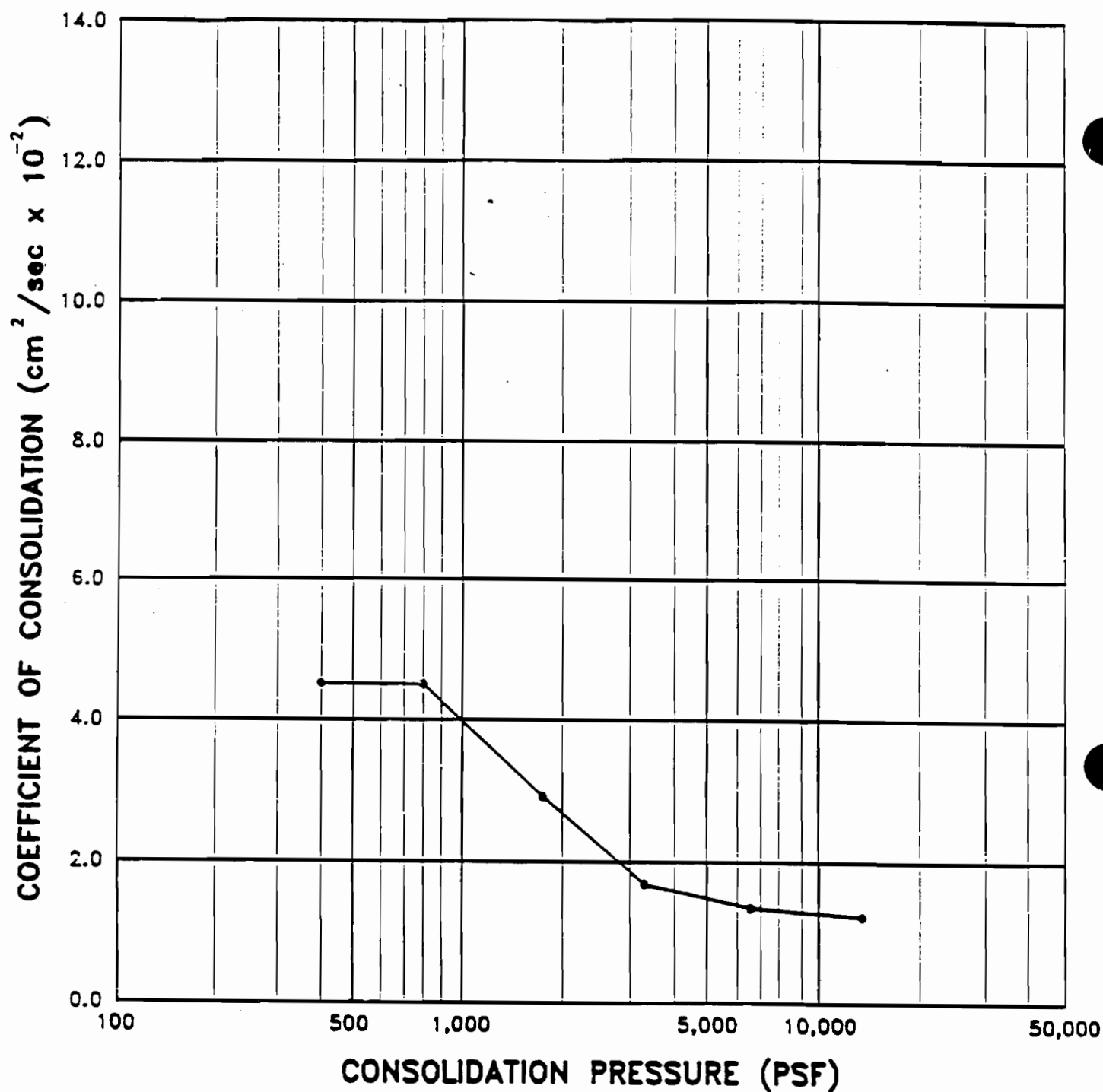
COMPRESSION INDICES C_c (VIRGIN) = 0.173 C_r (RECOMPRESSION) = 0.014 OCR = 3.1

ONE DIMENSIONAL
CONSOLIDATION TEST REPORT
STRAIN VS. LOG PRESSURE

CANE ISLAND
COMBUSTION TURBINE
PROGRAM

PN 1078.3

PLATE



BORING: B-5 SAMPLE: B-6 DEPTH: 53.5' - 55'

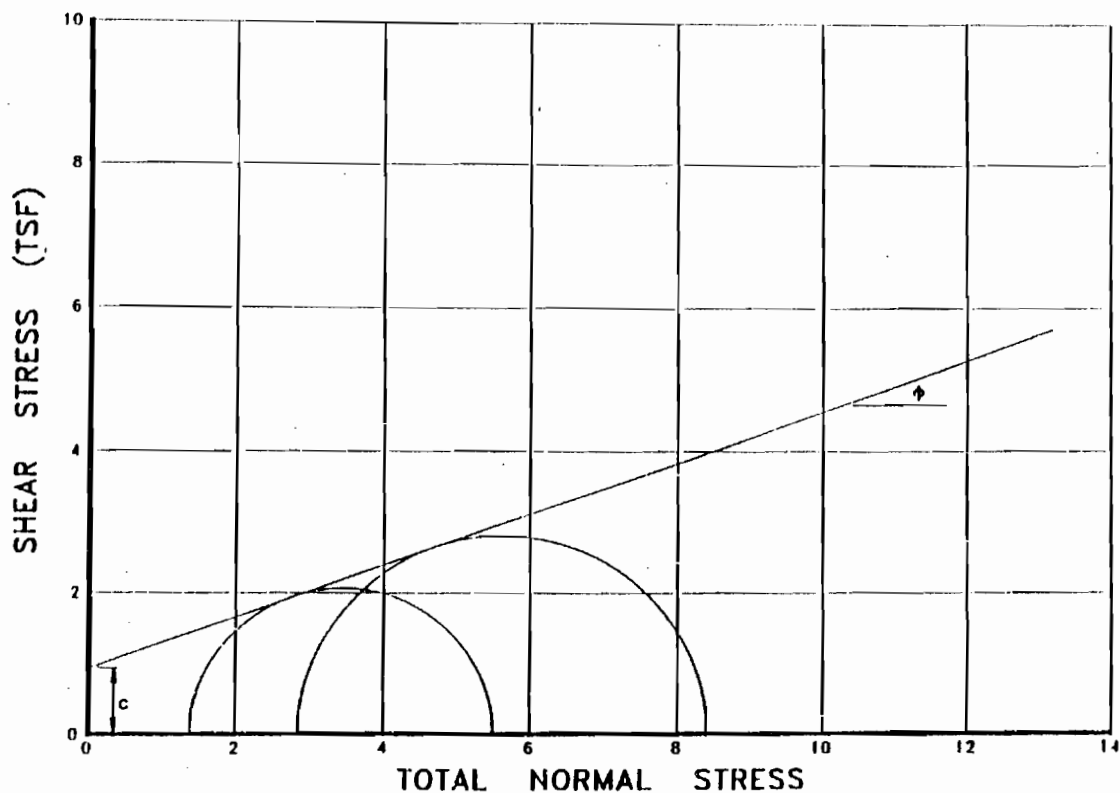
MATERIAL DESCRIPTION: GREENISH-GRAY CLAYEY FINE SAND WITH INCLUSIONS OF LIME SILTS

ONE DIMENSIONAL CONSOLIDATION TEST REPORT

COEFFICIENT OF CONSOLIDATION VS. LOG PRESSURE

CANE ISLAND COMBUSTION TURBINE PROGRAM

PN 1078.3

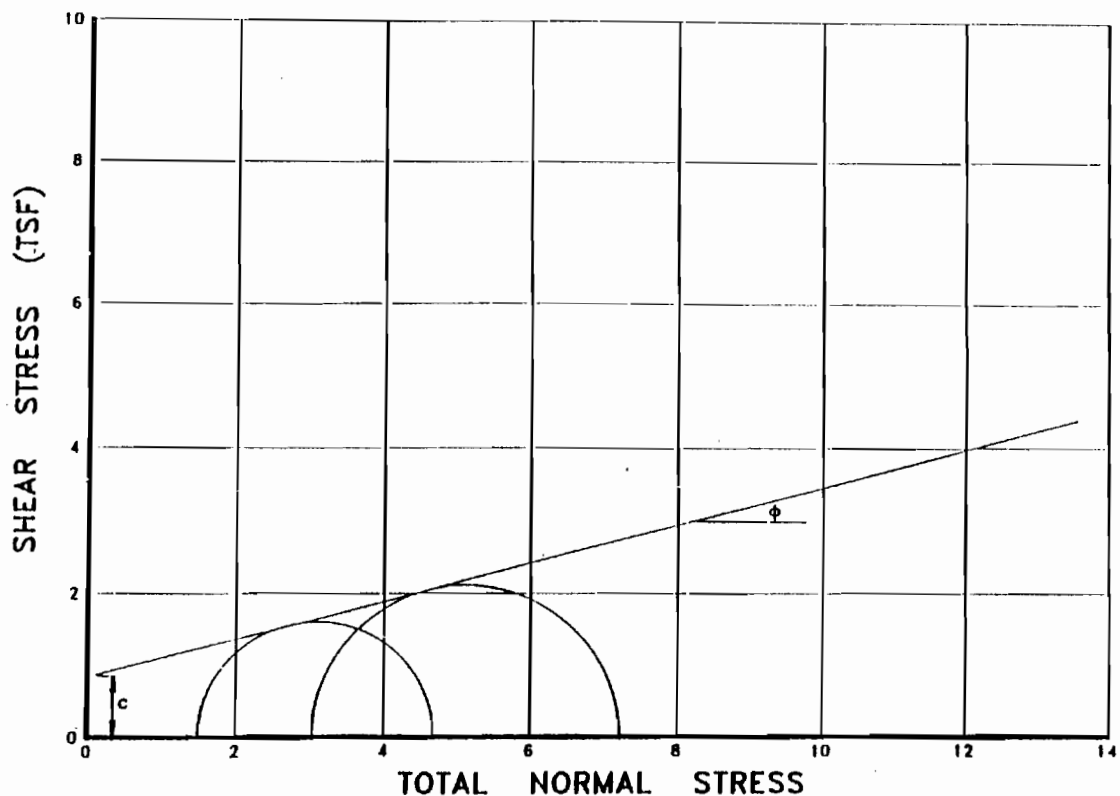


BORING NO. : B-3
 SAMPLE DESCRIPTION: GREENISH-GRAY
 CLAYEY SILT WITH SHELL FRAGMENTS
 COHESION (c) = 0.95 TSF
 ANGLE OF INTERNAL FRICTION (ϕ) = 19.8°
 DRY UNIT WEIGHT = 74.6 PCF

MULTI-STAGE UNCONSOLIDATED UNDRAINED
 TRIAXIAL FAILURE ENVELOPE

CANE ISLAND COMBUSTION TURBINE PROGRAM

PH 1078.3

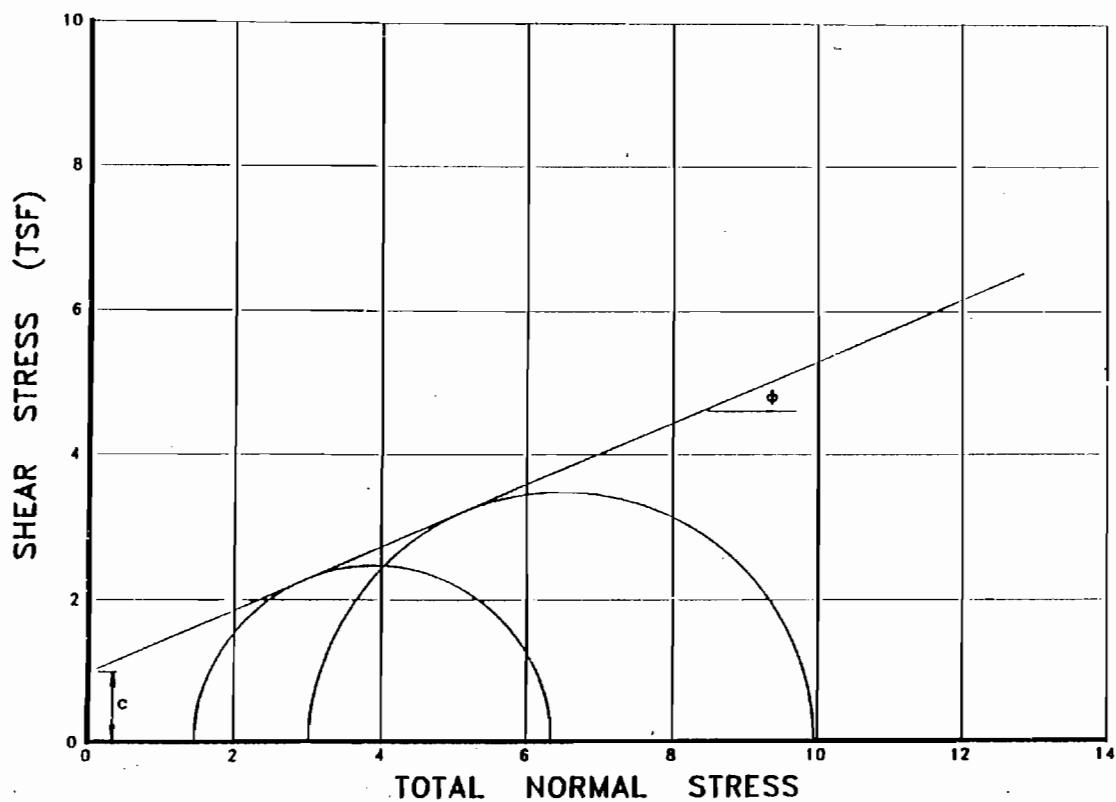


BORING NO. : B-6
 SAMPLE DESCRIPTION: GREENISH-GRAY CLAYEY
 FINE SAND WITH INCLUSIONS OF LIME SILTS
 COHESION (c) = 0.85 TSF
 ANGLE OF INTERNAL FRICTION (ϕ) = 14.6°
 DRY UNIT WEIGHT = 78.3 PCF

MULTI-STAGE UNCONSOLIDATED UNDRAINED
 TRIAXIAL FAILURE ENVELOPE

CANE ISLAND COMBUSTION TURBINE PROGRAM

PN 1078.3



BORING NO. : B-11
 SAMPLE DESCRIPTION: GREENISH-GRAY SILTY
 TO CLAYEY FINE SAND
 COHESION (c) = 1.0 TSF
 ANGLE OF INTERNAL FRICTION (ϕ) = 23.3°
 DRY UNIT WEIGHT = 83 PCF

MULTI-STAGE UNCONSOLIDATED UNDRAINED
 TRIAXIAL FAILURE ENVELOPE

CANE ISLAND COMBUSTION TURBINE PROGRAM

PN 1078.3



Advanced Testing Laboratories of Florida, Inc.

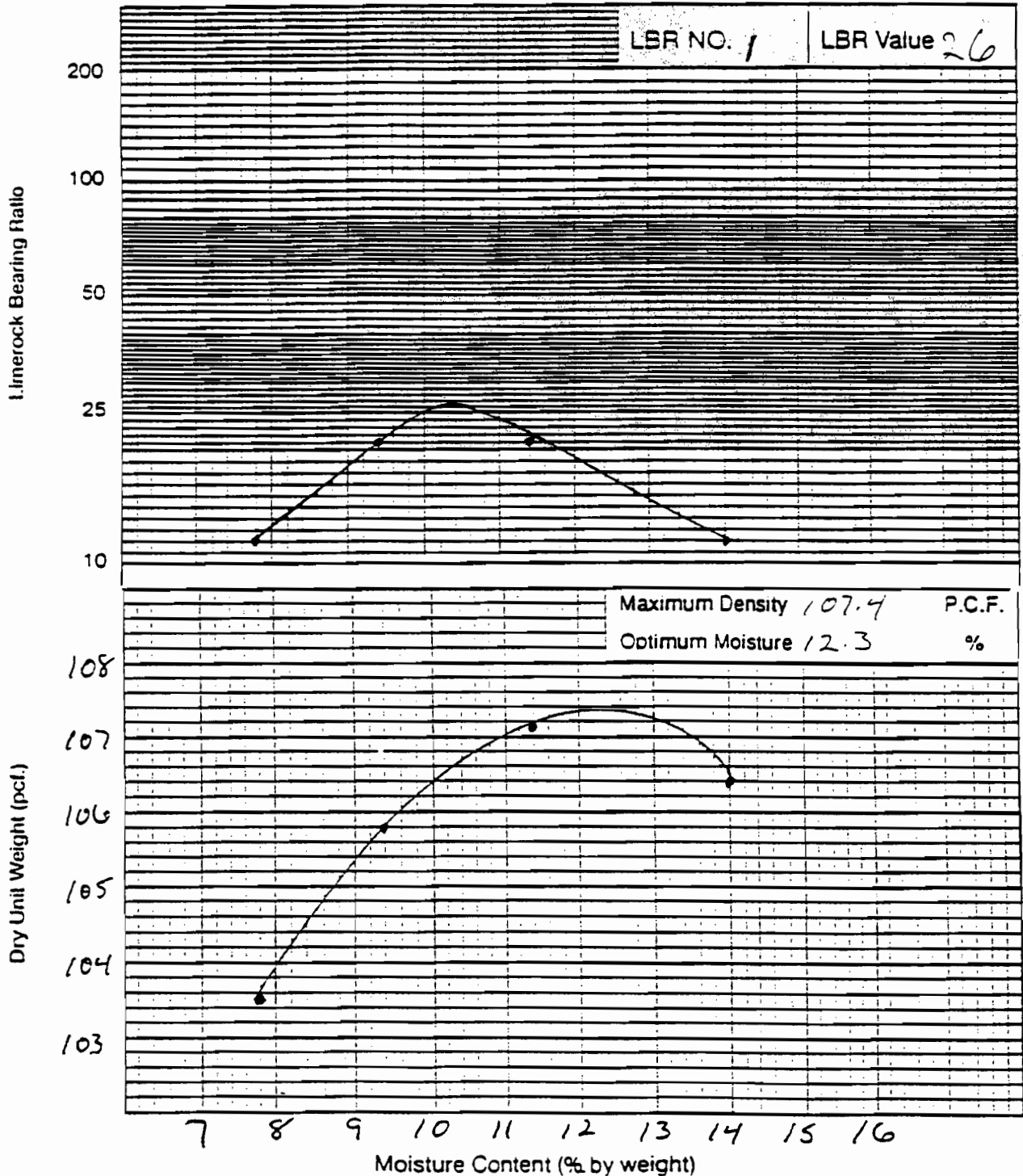
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

FILE NO.: 92-1131

PROJECT NAME: Cane Island

LOCATION: Test Pit # 1

SAMPLE DESCRIPTION: Tan Sand



LIMEROCK BEARING RATIO DATA



Advanced Testing Laboratories of Florida, Inc.

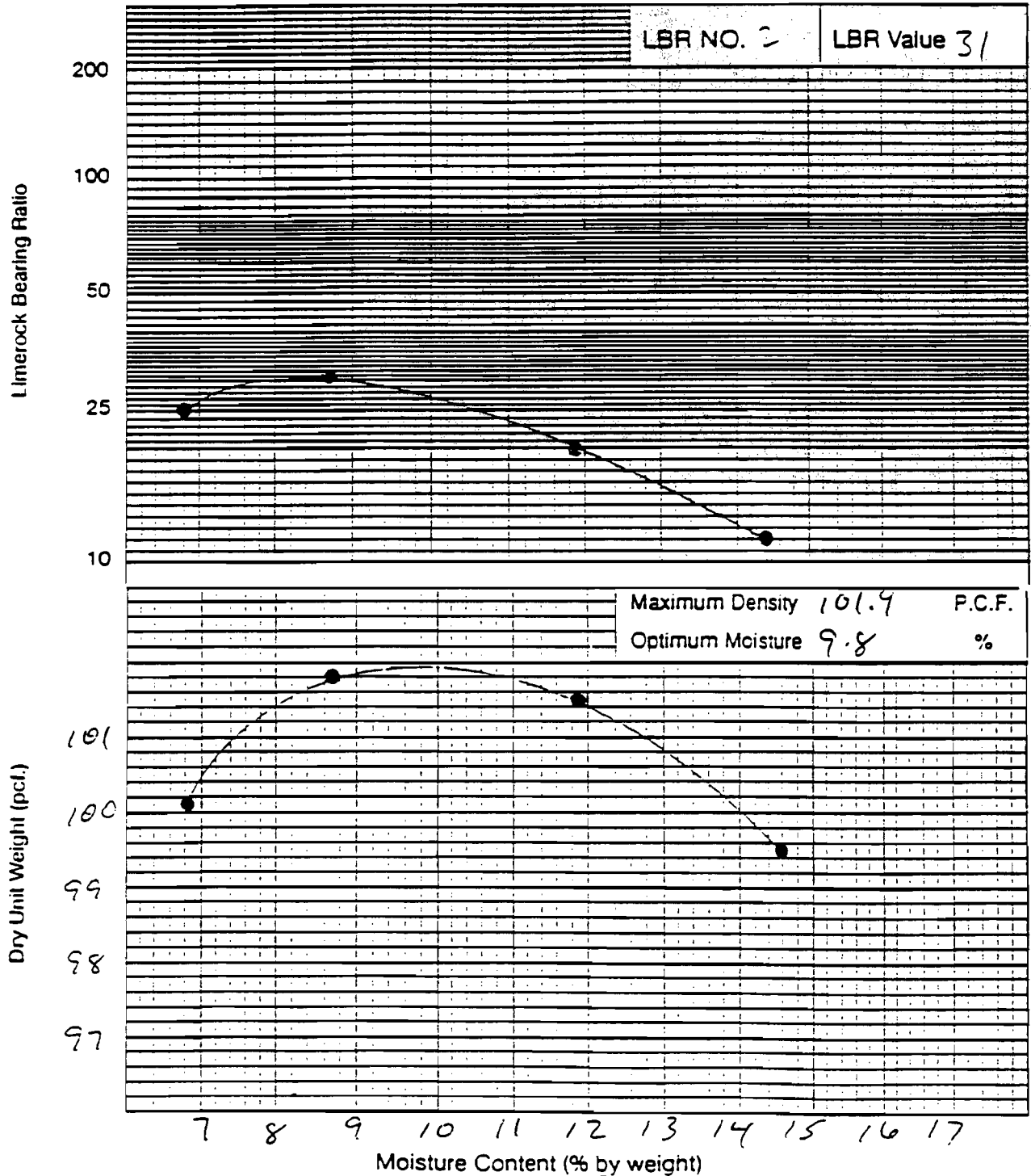
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

FILE NO.: 92-1131

PROJECT NAME: Cane Island

LOCATION:

SAMPLE DESCRIPTION: Gray-White Sand



LIMEROCK BEARING RATIO DATA



Advanced Testing Laboratories of Florida, Inc.

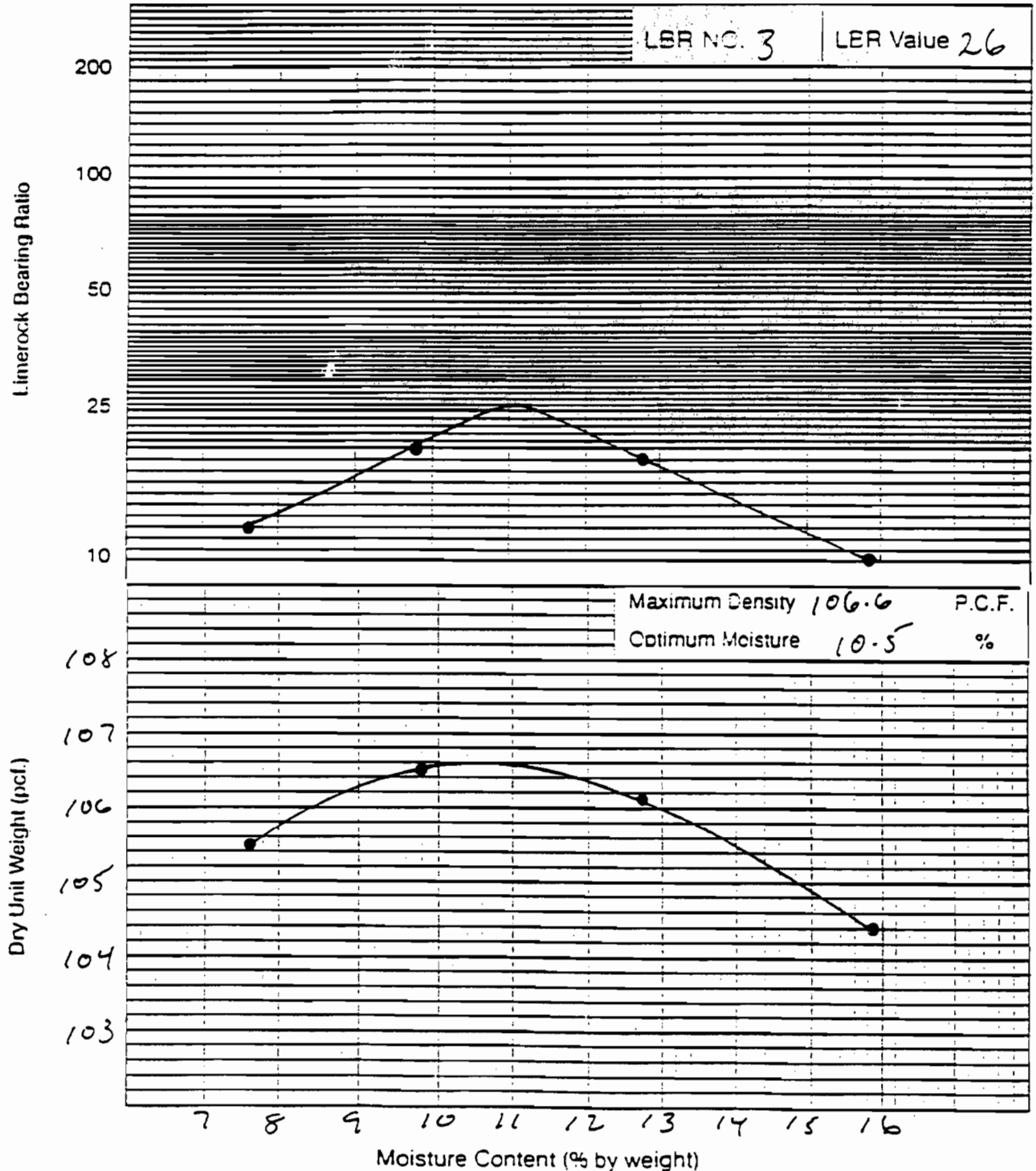
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

FILE NO.: 72-131

PROJECT NAME: Cane Island

LOCATION: T-5

SAMPLE DESCRIPTION: Brown sand with silt

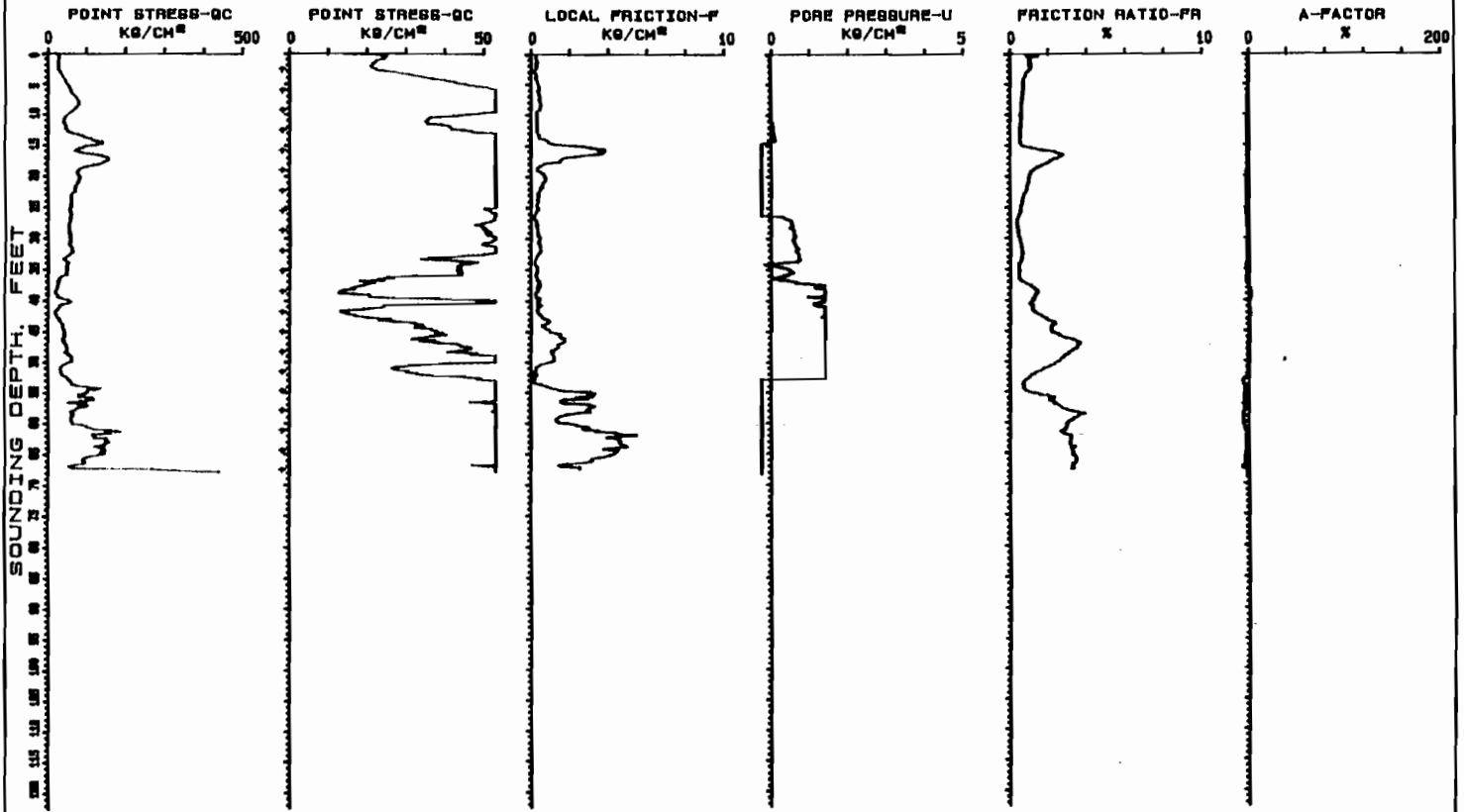


LIMEROCK BEARING RATIO DATA

Appendix F

Cone Penetrometer Soundings

PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING # C-1
SOUNDING DATE 09/08/92 09:54:28

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-1

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNGS MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
				#		%	°	+++	+++			
1	SILTY TO CLAYEY F.S.	23.7	.16	7 5	.048	50%-60%	46-46	52	—	—	—	—
2	CLAYEY FINE SAND	20.5	.22	8 5	.097	40%-50%	44-46	45	—	—	—	—
3	SILTY TO CLAYEY F.S.	24.2	.1	8 5	.146	40%-50%	42-44	53	—	—	—	—
4	SILTY TO CLAYEY F.S.	34.4	.16	11 8	.195	50%-60%	42-44	75	—	—	—	—
5	SILTY FINE SAND	43.3	.25	10 10	.244	60%-70%	42-44	95	—	—	—	—
6	SILTY FINE SAND	52.7	.34	13 12	.293	60%-70%	42-44	115	—	—	—	—
7	SILTY FINE SAND	61.4	.35	15 14	.341	60%-70%	42-44	135	—	—	—	—
8	SILTY FINE SAND	73.7	.37	18 16	.39	70%-80%	42-44	162	—	—	—	—
9	SILTY FINE SAND	66.2	.4	16 15	.439	60%-70%	42-44	145	—	—	—	—
10	SILTY FINE SAND	47.2	.21	11 10	.488	50%-60%	40-42	103	—	—	—	—
11	SILTY TO CLAYEY F.S.	34.6	.21	11 8	.519	(40%	38-40	76	—	—	—	—
12	SILTY FINE SAND	39.6	.17	9 9	.549	40%-50%	38-40	87	—	—	—	—
13	SILTY FINE SAND	48.4	.24	12 11	.58	40%-50%	40-42	106	—	—	—	—
14	FINE SAND	102.7	.44	20 22	.613	70%-80%	42-44	225	—	—	—	—
15	FINE SAND	126	1.29	25 30	.647	70%-80%	42-44	277	—	—	—	—
16	STIFF CLAY	65.8	3.51	65 27	.677	—	—	—	4.05	1.8	UD	16
17	SILTY FINE SAND	142.5	2.38	35 38	.708	70%-80%	44-46	313	—	—	—	—
18	FINE SAND	130.8	1.1	26 31	.741	70%-80%	42-44	287	—	—	—	—
19	SILTY FINE SAND	75.7	.23	18 16	.772	50%-60%	40-42	166	—	—	—	—
20	SILTY FINE SAND	74.3	.58	18 17	.803	50%-60%	40-42	163	—	—	—	—
21	SILTY FINE SAND	74.6	.59	18 17	.834	50%-60%	40-42	164	—	—	—	—
22	SILTY FINE SAND	63.1	.45	15 14	.864	40%-50%	38-40	138	—	—	—	—
23	SILTY FINE SAND	55.4	.25	13 12	.895	40%-50%	38-40	121	—	—	—	—
24	SILTY FINE SAND	52.5	.23	13 11	.926	(40%	38-40	115	—	—	—	—
25	SILTY FINE SAND	54.7	.19	13 12	.957	(40%	38-40	120	—	—	—	—
26	SILTY FINE SAND	51.9	.17	12 11	.987	(40%	36-38	114	—	—	—	—
27	SILTY FINE SAND	52	.11	13 11	1.018	(40%	36-38	114	—	—	—	—
28	SILTY FINE SAND	47.9	.2	11 10	1.049	(40%	36-38	105	—	—	—	—
29	SILTY FINE SAND	51.1	.27	12 11	1.08	(40%	36-38	112	—	—	—	—
30	SILTY FINE SAND	52.6	.33	13 12	1.111	(40%	36-38	115	—	—	—	—
31	SILTY FINE SAND	47.7	.33	11 11	1.141	(40%	36-38	104	—	—	—	—
32	SILTY FINE SAND	58.3	.4	14 13	1.172	(40%	36-38	128	—	—	—	—
33	SILTY FINE SAND	42.8	.24	10 10	1.203	(40%	34-36	94	—	—	—	—
34	SILTY FINE SAND	47.2	.1	11 10	1.234	(40%	36-38	103	—	—	—	—
35	SILTY FINE SAND	43.3	.22	10 10	1.264	(40%	34-36	95	—	—	—	—

C-1 CONTINUED

36	SILTY FINE SAND	39.9	.17	9	9	1.295	(40%	34-36	87	—	—	—	—
37	CLAYEY FINE SAND	19.4	.23	7	5	1.326	(40%	30-32	42	—	—	—	—
38	SANDY CLAY	15.3	.33	7	4	1.353	—	—	—	.81	4.5	.01	3
39	CLAYEY FINE SAND	14.1	.19	5	4	1.384	(40%	30	31	—	—	—	—
40	SILTY FINE SAND	51.5	.31	12	12	1.415	(40%	36-38	113	—	—	—	—
41	CLAYEY FINE SAND	23.5	.4	9	6	1.446	(40%	30-32	51	—	—	—	—
42	SANDY CLAY	12.4	.25	6	4	1.473	—	—	—	.62	4.8	.02	1-1.5
43	CLAYEY FINE SAND	23.7	.54	9	7	1.504	(40%	30-32	52	—	—	—	—
44	CLAYEY FINE SAND	34	.72	13	10	1.534	(40%	32-34	74	—	—	—	—
45	CLAYEY FINE SAND	38.1	.78	15	11	1.565	(40%	32-34	83	—	—	—	—
46	SILTY CLAY TO CLAY	34.5	1.41	23	13	1.593	—	—	—	1.98	2.4	UD	6
47	SILTY CLAY TO CLAY	39.1	1.59	26	14	1.62	—	—	—	2.27	2.4	UD	6
48	CLAYEY FINE SAND	45.6	1.21	18	14	1.651	(40%	34-36	100	—	—	—	—
49	SILTY TO CLAYEY F.S.	54.3	1.04	18	15	1.681	(40%	34-36	119	—	—	—	—
50	SILTY TO CLAYEY F.S.	57.9	1.12	19	16	1.712	(40%	34-36	127	—	—	—	—
51	SILTY TO CLAYEY F.S.	26.7	.26	8	6	1.743	(40%	30-32	58	—	—	—	—
52	SILTY TO CLAYEY F.S.	31.8	.03	10	7	1.774	(40%	30-32	69	—	—	—	—
53	SILTY FINE SAND	49.1	.1	12	10	1.804	(40%	34-36	108	—	—	—	—
54	FINE SAND	90.8	.4	18	20	1.838	(40%	36-38	199	—	—	—	—
55	SILTY TO CLAYEY F.S.	91.6	2.11	30	27	1.868	(40%	36-38	201	—	—	—	—
56	SILTY TO CLAYEY F.S.	105.9	2.84	35	33	1.899	40%-50%	38-40	232	—	—	—	—
57	SILTY TO CLAYEY F.S.	92.6	1.83	30	26	1.93	(40%	36-38	203	—	—	—	—
58	STIFF CLAY	60.4	2.9	60	24	1.961	—	—	—	3.56	2	UD	6
59	CLAYEY FINE SAND	55.5	1.84	22	18	1.992	(40%	34-36	122	—	—	—	—
60	SILTY TO CLAYEY F.S.	57.3	1.23	19	16	2.022	(40%	34-36	126	—	—	—	—
61	SILTY TO CLAYEY F.S.	122.3	2.69	40	35	2.053	40%-50%	38-40	269	—	—	—	—
62	DENSE CLAYEY FINE SAND	114	4.52	57	41	2.086	40%-50%	38-40	250	—	—	—	—
63	SILTY TO CLAYEY F.S.	145.2	4.27	48	46	2.117	50%-60%	38-40	319	—	—	—	—
64	STIFF CLAY	119.3	4.78	119	43	2.148	—	—	—	7.21	2.4	UD	6
65	CLAYEY FINE SAND	131.5	4.36	52	44	2.179	40%-50%	38-40	289	—	—	—	—
66	CLAYEY FINE SAND	84.1	3.26	33	30	2.209	(40%	36-38	185	—	—	—	—
67	SANDY CLAY	43.8	1.73	21	16	2.237	—	—	—	2.48	2.5	.01	6

$N^* = \text{POINT STRESS} \times (.2 + .04 \times \text{FRICTION RATIO})$

* NORMALLY CONSOLIDATED SANDS

** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES

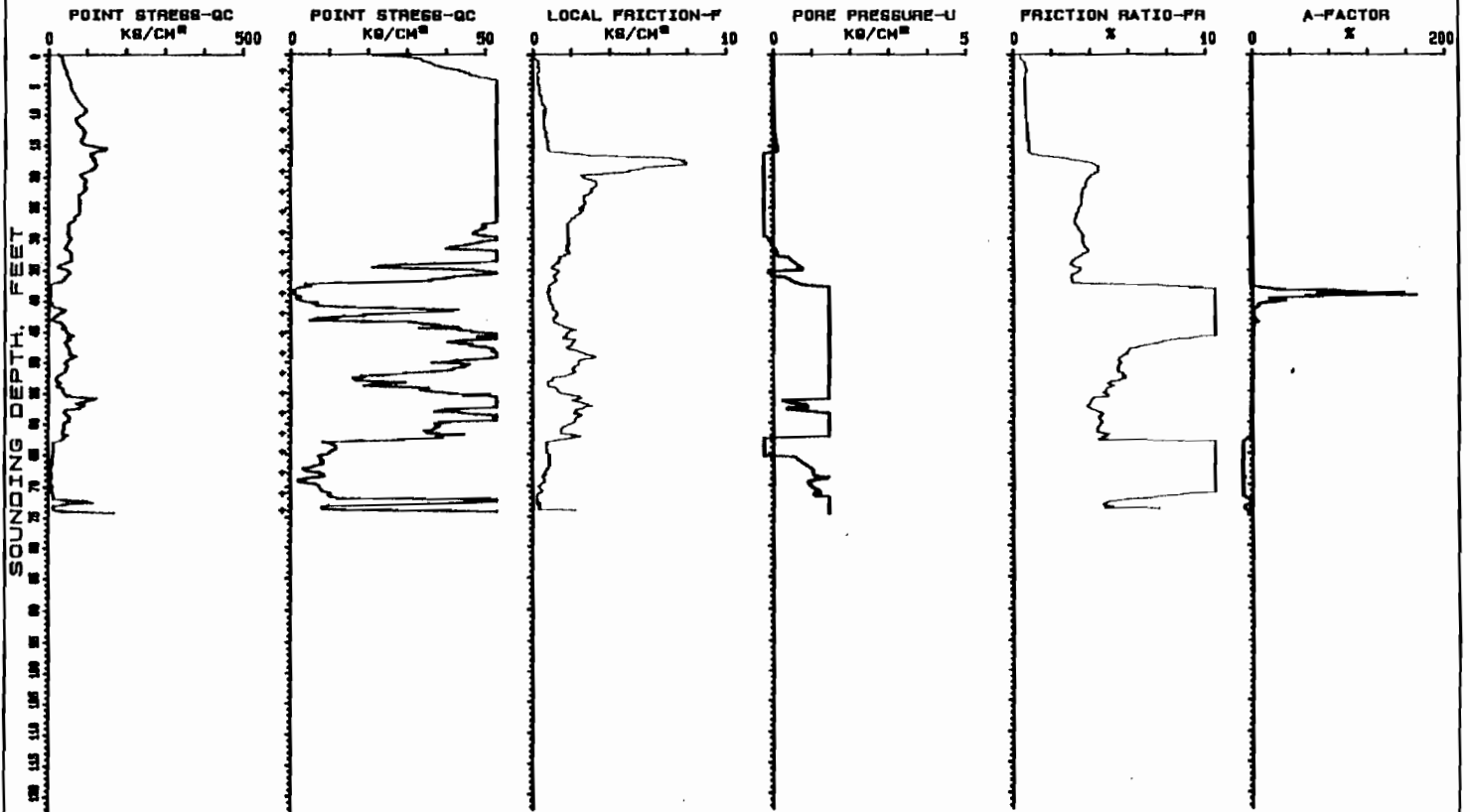
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THE ABOVE DATA WAS COMPUTED FOLLOWING 'BASIC' GUIDELINES BY P. K. ROBERTSON AND R. G. CAMPANELLA IN THE HANDBOOK
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SEPTEMBER, 1984

ADDITIONAL LOCAL CORRELATIONS DEVELOPED BY IN-SITU TECHNOLOGY HAVE ALSO BEEN USED IN COMPUTING THE ABOVE DATA.
IT IS THE POLICY OF IN-SITU TECHNOLOGY TO CONTINUALLY UPGRADE AND MODIFY C.P.T. CORRELATIONS AS
PUBLISHED RESEARCH AND LOCAL EXPERIENCE GROWS.

PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING # C-2
SOUNDING DATE 09/04/92 13:07:59

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-2

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNGS MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
				#		*	**	***	****			
1	SILTY TO CLAYEY F.S.	32.4	.27	10 8	.048	50%-70%	148	71	—	—	—	—
2	SILTY TO CLAYEY F.S.	37.1	.31	12 9	.097	60%-70%	46-48	81	—	—	—	—
3	SILTY FINE SAND	44.5	.26	11 10	.146	60%-70%	44-46	97	—	—	—	—
4	SILTY FINE SAND	48.7	.28	12 11	.195	60%-70%	44-46	107	—	—	—	—
5	SILTY FINE SAND	53.8	.35	13 12	.244	60%-70%	44-46	118	—	—	—	—
6	SILTY FINE SAND	58	.39	14 13	.293	60%-70%	42-44	127	—	—	—	—
7	SILTY FINE SAND	66.6	.44	16 15	.341	60%-70%	42-44	146	—	—	—	—
8	SILTY FINE SAND	75.6	.54	18 17	.39	70%-80%	42-44	166	—	—	—	—
9	SILTY FINE SAND	90.8	.67	22 21	.439	70%-80%	44-46	199	—	—	—	—
10	SILTY FINE SAND	85.8	.63	21 20	.488	70%-80%	42-44	188	—	—	—	—
11	SILTY FINE SAND	66	.58	16 16	.519	50%-60%	42-44	145	—	—	—	—
12	SILTY FINE SAND	76.8	.63	19 18	.549	60%-70%	42-44	166	—	—	—	—
13	SILTY FINE SAND	90.7	.69	22 21	.58	60%-70%	42-44	199	—	—	—	—
14	SILTY FINE SAND	82.2	.82	20 20	.611	60%-70%	42-44	180	—	—	—	—
15	SILTY FINE SAND	94.9	.8	23 22	.642	60%-70%	42-44	206	—	—	—	—
16	SILTY FINE SAND	120.5	1.62	30 31	.672	70%-80%	42-44	265	—	—	—	—
17	STIFF CLAY	113.7	6.77	113 50	.703	—	—	—	7.04	1.6	UD	16
18	STIFF CLAY	120.8	7.62	120 55	.734	—	—	—	7.48	1.5	UD	16
19	STIFF CLAY	104.8	4.91	104 41	.765	—	—	—	6.48	2.1	UD	16
20	CLAYEY FINE SAND	80.6	2.62	32 27	.796	50%-60%	40-42	177	—	—	—	—
21	CLAYEY FINE SAND	91.5	3.31	36 32	.826	60%-70%	40-42	201	—	—	—	—
22	CLAYEY FINE SAND	94.5	3.05	37 31	.857	60%-70%	40-42	207	—	—	—	—
23	CLAYEY FINE SAND	73.9	2.68	29 26	.888	50%-60%	40-42	162	—	—	—	—
24	CLAYEY FINE SAND	77.7	2.72	31 26	.919	50%-60%	40-42	170	—	—	—	—
25	CLAYEY FINE SAND	78.6	2.48	31 26	.949	50%-60%	40-42	172	—	—	—	—
26	CLAYEY FINE SAND	72.6	2.3	29 24	.98	40%-50%	38-40	159	—	—	—	—
27	CLAYEY FINE SAND	64.2	1.96	25 21	1.011	40%-50%	38-40	141	—	—	—	—
28	SANDY CLAY	48.8	1.81	24 17	1.038	—	—	—	2.95	2.6	.01	6
29	SANDY CLAY	46.6	1.85	23 17	1.066	—	—	—	2.8	2.5	.01	6
30	CLAYEY FINE SAND	55.6	1.83	22 18	1.096	(40%	36-38	122	—	—	—	—
31	SILTY CLAY TO CLAY	44.2	1.78	29 16	1.124	—	—	—	2.65	2.4	UD	6
32	SANDY CLAY	51.4	1.86	25 18	1.151	—	—	—	3.09	2.7	.01	6
33	CLAYEY FINE SAND	57.8	1.4	23 17	1.182	(40%	36-38	127	—	—	—	—
34	SANDY CLAY	37.4	1.23	18 12	1.209	—	—	—	2.21	3	.01	6
35	CLAYEY FINE SAND	42.4	1.21	16 13	1.24	(40%	34-36	93	—	—	—	—

C-2 CONTINUED

36	CLAYEY FINE SAND	45.9	1.06	18	13	1.271	(40%	35-38	100	—	—	—	—
37	SILTY CLAY TO CLAY	35.9	1.08	17	10	1.298	—	—	—	1.48	2.3	UD	6
38	SOFT CLAY TO MUCK	.6	.81	0	3	1.314	—	—	—	-.1	0	UD	(1
39	SOFT CLAY TO MUCK	.3	.85	0	3	1.33	—	—	—	-.12	0	UD	(1
40	SOFT CLAY TO MUCK	2.8	.92	2	4	1.346	—	—	—	.03	.3	UD	(1
41	CLAY	15.3	1.06	15	7	1.371	—	—	—	.81	1.4	.01	3
42	SILTY CLAY TO CLAY	30.1	1.26	20	11	1.399	—	—	—	1.73	2.3	UD	6
43	SOFT CLAY TO MUCK	6	1.07	6	5	1.415	—	—	—	.22	.5	UD	1
44	SILTY CLAY TO CLAY	35.9	1.44	23	13	1.442	—	—	—	2.08	2.4	UD	6
45	SILTY CLAY TO CLAY	44.7	2.05	29	17	1.469	—	—	—	2.63	2.1	UD	6
46	CLAYEY FINE SAND	52.1	1.74	20	17	1.5	(40%	34-36	114	—	—	—	—
47	CLAY	39.1	1.97	39	16	1.525	—	—	—	2.27	1.9	UD	6
48	SILTY CLAY TO CLAY	51.6	2.08	34	19	1.552	—	—	—	3.05	2.4	UD	6
49	STIFF CLAY	65.9	3.17	65	26	1.583	—	—	—	3.94	2	UD	6
50	CLAY	40.9	2.3	40	17	1.608	—	—	—	2.37	1.7	UD	6
51	SILTY CLAY TO CLAY	43.1	2.13	28	17	1.635	—	—	—	2.51	2	UD	6
52	CLAY	26.3	1.88	26	13	1.66	—	—	—	1.45	1.3	UD	3
53	CLAY	16.5	.88	16	7	1.685	—	—	—	.84	1.8	.01	1-1.5
54	CLAY	17.7	1.04	17	8	1.71	—	—	—	.91	1.6	.01	3
55	CLAYEY FINE SAND	43.4	1.47	17	15	1.741	(40%	32-34	95	—	—	—	—
56	SILTY TO CLAYEY F.S.	121.6	2.27	40	33	1.772	50%-60%	38-40	257	—	—	—	—
57	CLAYEY FINE SAND	90.5	2.76	36	29	1.803	(40%	36-38	199	—	—	—	—
58	CLAY	36.2	2.27	36	16	1.827	—	—	—	2.05	1.5	UD	6
59	SILTY CLAY TO CLAY	57	2.37	38	21	1.855	—	—	—	3.35	2.4	UD	6
60	SILTY CLAY TO CLAY	39.2	1.9	26	15	1.882	—	—	—	2.23	2	UD	6
61	SILTY CLAY TO CLAY	36.1	1.45	24	13	1.909	—	—	—	2.03	2.4	UD	—
62	SILTY CLAY TO CLAY	48	2.23	32	19	1.937	—	—	—	2.77	2.1	UD	—
63	SOFT CLAY TO MUCK	5.4	.81	5	4	1.953	—	—	—	.11	.6	UD	(1
64	CLAY	11.3	.69	11	5	1.978	—	—	—	.47	1.6	.02	1
65	SOFT CLAY TO MUCK	8.6	.85	8	5	1.994	—	—	—	.3	1	UD	1
66	SOFT CLAY TO MUCK	7.3	.87	7	5	2.01	—	—	—	.22	.8	UD	1
67	SOFT CLAY TO MUCK	4.9	.82	4	4	2.026	—	—	—	.07	.5	UD	(1
68	CLAY	7.4	.63	7	4	2.051	—	—	—	.22	1.1	.03	1
69	SOFT CLAY TO MUCK	2.1	.6	2	3	2.067	—	—	—	-.12	.3	UD	(1
70	CLAY	6.7	.34	6	3	2.092	—	—	—	.17	1.9	.03	(1
71	CLAY	8.8	.4	8	3	2.117	—	—	—	.3	2.2	.02	1
72	CLAYEY FINE SAND	14.6	.2	5	4	2.148	(40%	(30	32	—	—	—	—
73	SILTY TO CLAYEY F.S.	29.7	.31	9	7	2.179	(40%	(30	65	—	—	—	—

$N^* = \text{POINT STRESS} \times (.2 + .04 \times \text{FRICTION RATIO})$

* NORMALLY CONSOLIDATED SANDS

++ FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES

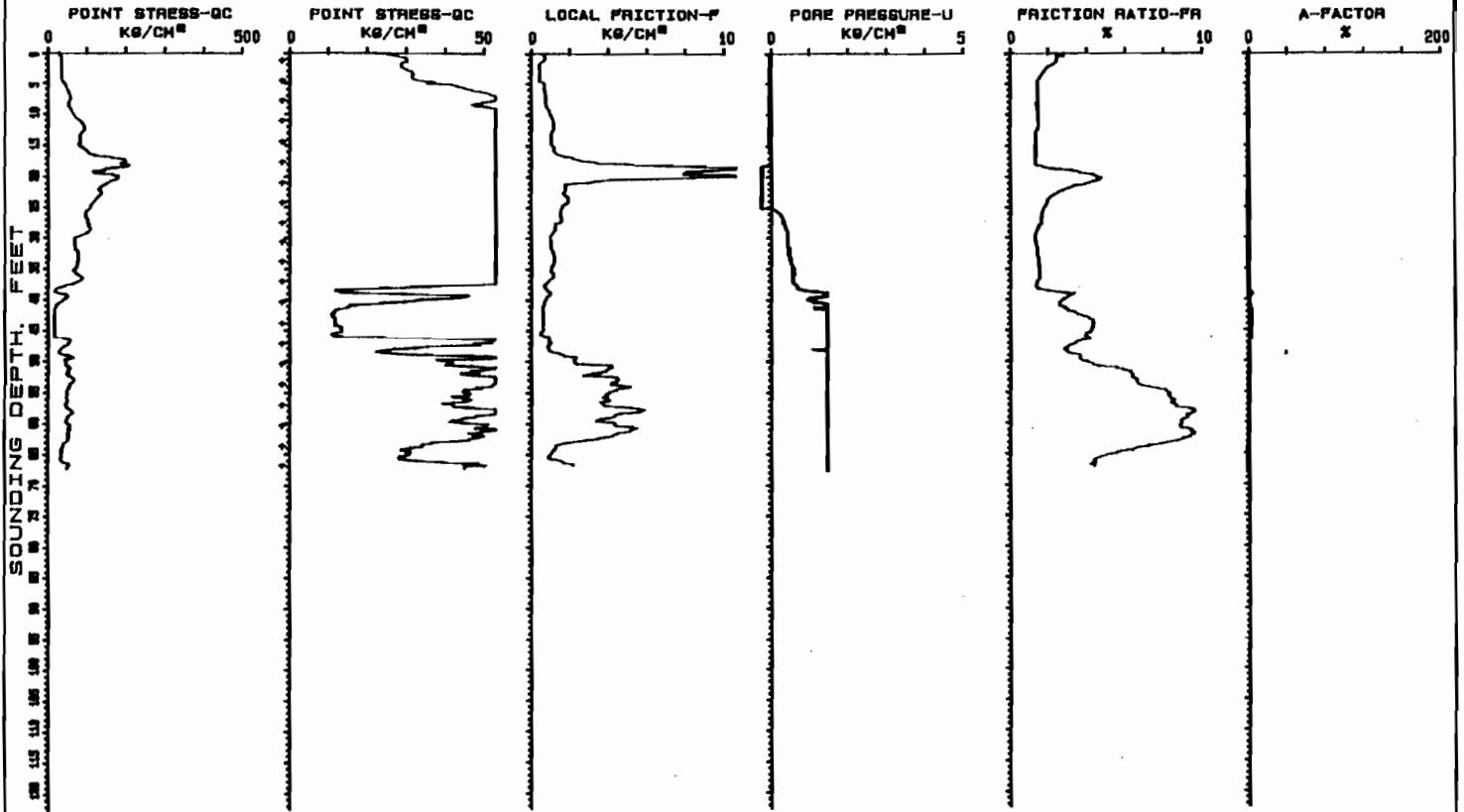
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PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING # C-3
SOUNDING DATE 09/04/92 16:07:13

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMEE UTILITIES KISSIMEE FL.
 CONE SOUNDING..... C-3

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N N° VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
				#		+	++	+++	+++			
1	CLAYEY FINE SAND	28.3	.63	11 8	.048	50%-60%	148	62	—	—	—	—
2	CLAYEY FINE SAND	28.1	.38	11 7	.097	50%-60%	44-46	61	—	—	—	—
3	SILTY TO CLAYEY F.S.	30.1	.37	10 8	.146	50%-60%	44-46	66	—	—	—	—
4	SILTY TO CLAYEY F.S.	31	.37	10 8	.195	50%-60%	42-44	68	—	—	—	—
5	SILTY TO CLAYEY F.S.	35.8	.46	11 9	.244	50%-60%	42-44	78	—	—	—	—
6	SILTY TO CLAYEY F.S.	45.3	.61	15 12	.293	60%-70%	42-44	99	—	—	—	—
7	SILTY TO CLAYEY F.S.	51.8	.67	17 13	.341	60%-70%	42-44	113	—	—	—	—
8	SILTY TO CLAYEY F.S.	51.7	.67	17 13	.39	60%-70%	42-44	113	—	—	—	—
9	SILTY TO CLAYEY F.S.	51	.74	17 13	.439	50%-60%	40-42	112	—	—	—	—
10	SILTY TO CLAYEY F.S.	60.4	.89	20 16	.488	60%-70%	40-42	132	—	—	—	—
11	SILTY TO CLAYEY F.S.	74.4	1.03	24 19	.519	60%-70%	42-44	163	—	—	—	—
12	SILTY FINE SAND	88.3	1.09	22 22	.549	60%-70%	42-44	194	—	—	—	—
13	SILTY FINE SAND	84.1	1.03	21 21	.58	60%-70%	42-44	185	—	—	—	—
14	SILTY FINE SAND	78.3	.96	19 20	.611	60%-70%	42-44	172	—	—	—	—
15	SILTY TO CLAYEY F.S.	70.5	.95	23 18	.642	50%-60%	40-42	155	—	—	—	—
16	SILTY FINE SAND	94.6	1.12	23 23	.672	60%-70%	42-44	208	—	—	—	—
17	SILTY FINE SAND	150.9	1.76	37 37	.703	80%-90%	44-46	331	—	—	—	—
18	SILTY FINE SAND	188	3.78	47 53	.734	80%-90%	44-46	413	—	—	—	—
19	STIFF CLAY	140.9	10.85	140 72	.765	—	—	—	8.74	1.2	UD	>6
20	STIFF CLAY	174.1	10.06	174 75	.796	—	—	—	10.81	1.7	UD	>6
21	SILTY TO CLAYEY F.S.	151.2	3.43	50 44	.826	70%-80%	42-44	332	—	—	—	—
22	SILTY FINE SAND	126.4	1.7	31 32	.857	70%-80%	42-44	278	—	—	—	—
23	SILTY FINE SAND	131.3	1.57	32 33	.888	70%-80%	42-44	288	—	—	—	—
24	SILTY FINE SAND	115.5	1.86	28 31	.919	60%-70%	40-42	254	—	—	—	—
25	SILTY FINE SAND	104.3	1.57	26 27	.949	60%-70%	40-42	223	—	—	—	—
26	SILTY TO CLAYEY F.S.	91.6	1.39	30 24	.98	50%-60%	40-42	201	—	—	—	—
27	SILTY TO CLAYEY F.S.	95.6	1.45	31 25	1.011	50%-60%	40-42	210	—	—	—	—
28	SILTY FINE SAND	99.8	1.23	24 25	1.042	50%-60%	40-42	219	—	—	—	—
29	SILTY FINE SAND	102.9	1.12	25 25	1.072	50%-60%	40-42	226	—	—	—	—
30	SILTY TO CLAYEY F.S.	67.1	.87	22 17	1.103	40%-50%	38-40	147	—	—	—	—
31	SILTY TO CLAYEY F.S.	63.5	.94	21 16	1.134	40%-50%	38-40	139	—	—	—	—
32	SILTY TO CLAYEY F.S.	65.7	.95	21 17	1.165	40%-50%	38-40	144	—	—	—	—
33	SILTY TO CLAYEY F.S.	72.7	1.09	24 19	1.195	40%-50%	38-40	159	—	—	—	—
34	SILTY TO CLAYEY F.S.	72.5	1.12	24 19	1.226	40%-50%	38-40	159	—	—	—	—
35	SILTY TO CLAYEY F.S.	66.4	.94	22 17	1.257	(40%	36-38	146	—	—	—	—

C-3 CONTINUED

36	SILTY TO CLAYEY F.S.	71.7	1.02	23	18	1.298	40%-50%	38-40	15	—	—	—	—
37	SILTY FINE SAND	79.5	.94	19	20	1.319	40%-50%	38-40	17	—	—	—	—
38	SILTY TO CLAYEY F.S.	35.3	.56	11	9	1.349	(40%)	32-34	77	—	—	—	—
39	CLAY	17	.81	17	7	1.374	—	—	—	.92	2.1	.01	3
40	CLAYEY FINE SAND	37.6	.71	15	10	1.405	(40%)	32-34	82	—	—	—	—
41	SANDY CLAY	16.9	.55	8	6	1.432	—	—	—	.9	3	.01	3
42	CLAY	10.8	.47	10	4	1.457	—	—	—	.52	2.2	.02	1-1.
43	CLAY	10.7	.57	10	4	1.482	—	—	—	.51	1.8	.02	1-1.
44	CLAY	11.2	.48	11	4	1.507	—	—	—	.54	2.3	.02	1-1.
45	CLAY	12.6	.5	12	5	1.532	—	—	—	.62	2.4	.01	1-1.
46	CLAY	10.4	.4	10	4	1.557	—	—	—	.48	2.5	.02	1-1.
47	SILTY TO CLAYEY F.S.	48.4	.89	16	13	1.588	(40%)	34-36	106	—	—	—	—
48	CLAYEY FINE SAND	32.3	.79	12	10	1.618	(40%)	30-32	71	—	—	—	—
49	SILTY CLAY TO CLAY	27.1	1.24	18	10	1.646	—	—	—	1.51	2.1	UD	3
50	CLAY	35.9	2.2	35	16	1.671	—	—	—	2.06	1.6	UD	6
51	CLAY	48	3.64	48	24	1.696	—	—	—	2.81	1.3	UD	6
52	CLAY	44.2	3.54	44	23	1.72	—	—	—	2.57	1.2	UD	6
53	CLAY	65	4.14	65	30	1.745	—	—	—	3.87	1.5	UD	6
54	CLAY	51	4.43	51	28	1.77	—	—	—	2.99	1.1	UD	6
55	CLAY	44.1	4.28	44	26	1.795	—	—	—	2.55	1	UD	6
56	CLAY	40.4	3.71	40	23	1.82	—	—	—	2.32	1	UD	6
57	CLAY	39.7	3.53	39	22	1.845	—	—	—	2.27	1.1	UD	6
58	CLAY	54.9	5.48	54	33	1.87	—	—	—	3.22	1	UD	6
59	CLAY	46.1	4.28	46	26	1.895	—	—	—	2.66	1	UD	6
60	CLAY	42.1	3.57	42	23	1.92	—	—	—	2.41	1.1	UD	6
61	CLAY	49.6	5.09	49	30	1.945	—	—	—	2.88	.9	UD	6
62	CLAY	46.5	4.39	46	27	1.97	—	—	—	2.68	1	UD	6
63	CLAY	41	2.89	41	20	1.994	—	—	—	2.33	1.4	UD	6
64	SANDY CLAY	30.8	1.21	15	11	2.022	—	—	—	1.69	2.5	.01	3
65	SANDY CLAY	30.4	.96	15	10	2.049	—	—	—	1.66	3.1	.01	3
66	SANDY CLAY	29.4	.9	14	9	2.076	—	—	—	1.6	3.2	.01	3

$N^* = \text{POINT STRESS} \times (1.2 + .04 \times \text{FRICTION RATIO})$

* NORMALLY CONSOLIDATED SANDS

** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES

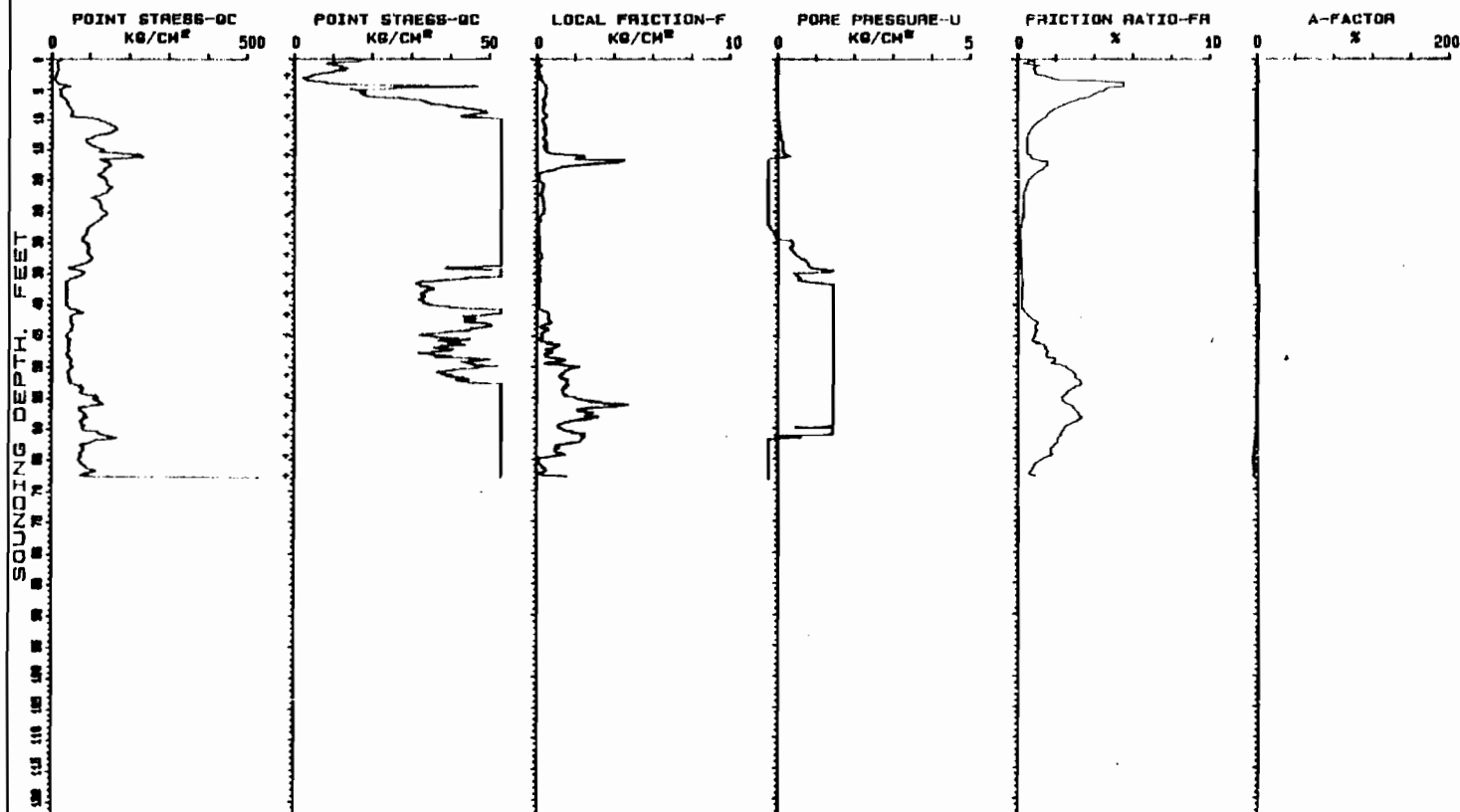
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**** NK OF 16 USED. FOR OVERCONSOLIDATED CLAYS, AN NK OF 17 IS SUGGESTED

THE ABOVE DATA WAS COMPUTED FOLLOWING 'BASIC' GUIDELINES BY P. K. ROBERTSON AND R. G. CAMPANELLA IN THE HANDBOOK
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PUBLISHED RESEARCH AND LOCAL EXPERIENCE GROWS.

PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING #..... C-4
SOUNDING DATE 09/08/92 11:36:35

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE

JOB NAME KISSIMEE UTILITIES
 ADVANCED TESTING
 ORLANDO FLORIDA
 CONE SOUNDING..... C-4

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
				#		*	**	***	****			
1	SANDY CLAY	9.7	.11	4 2	.027	—	—	—	.6	8.5	.02	16
2	CLAYEY FINE SAND	11.9	.1	4 3	.058	40%-50%	44-46	26	—	—	—	—
3	SOFT CLAY	.7	.17	0 1	.074	—	—	—	.03	.4	UD	1-1.5
4	CLAY	6.7	.34	6 3	.099	—	—	—	.4	1.9	.03	16
5	SANDY CLAY	19.9	.44	9 6	.126	—	—	—	1.22	4.4	.01	16
6	SANDY CLAY	16.4	.47	8 5	.153	—	—	—	1	3.4	.01	16
7	SILTY TO CLAYEY F.S.	32.3	.34	10 8	.184	50%-60%	42-44	71	—	—	—	—
8	SILTY TO CLAYEY F.S.	40.1	.31	13 9	.215	60%-70%	42-44	88	—	—	—	—
9	SILTY TO CLAYEY F.S.	47.2	.46	15 11	.246	60%-70%	42-44	103	—	—	—	—
10	FINE SAND	112.4	.24	22 23	.279	80%-90%	46-48	247	—	—	—	—
11	FINE SAND	148.6	.41	29 31	.312	190%	46-48	326	—	—	—	—
12	FINE SAND	151.8	.42	30 32	.345	190%	46-48	333	—	—	—	—
13	FINE SAND	99.8	.31	19 21	.378	70%-80%	44-46	219	—	—	—	—
14	SILTY FINE SAND	87.2	.46	21 19	.409	70%-80%	44-46	191	—	—	—	—
15	FINE SAND	120.4	.43	24 26	.442	70%-80%	44-46	264	—	—	—	—
16	FINE SAND	216	1.96	43 51	.476	190%	46-48	475	—	—	—	—
17	CLAYEY FINE SAND	132.5	4.19	53 43	.506	80%-90%	44-46	291	—	—	—	—
18	FINE SAND	139.7	1.04	27 32	.54	80%-90%	44-46	307	—	—	—	—
19	FINE SAND	119.1	.12	23 24	.573	70%-80%	44-46	262	—	—	—	—
20	FINE SAND	134.7	.06	26 27	.606	70%-80%	44-46	296	—	—	—	—
21	FINE SAND	145.3	.29	29 30	.639	80%-90%	44-46	319	—	—	—	—
22	FINE SAND	135.7	.19	27 28	.672	70%-80%	44-46	298	—	—	—	—
23	FINE SAND	106.2	.29	21 22	.706	60%-70%	42-44	233	—	—	—	—
24	FINE SAND	121.5	.32	24 26	.739	70%-80%	42-44	267	—	—	—	—
25	FINE SAND	133.7	.35	26 28	.772	70%-80%	42-44	294	—	—	—	—
26	FINE SAND	121.7	.11	24 25	.805	70%-80%	42-44	267	—	—	—	—
27	FINE SAND	102	0	20 20	.838	60%-70%	40-42	224	—	—	—	—
28	FINE SAND	85	.01	17 17	.872	50%-60%	40-42	187	—	—	—	—
29	FINE SAND	75.5	.04	15 15	.905	50%-60%	40-42	166	—	—	—	—
30	FINE SAND	81.6	.13	16 17	.938	50%-60%	40-42	179	—	—	—	—
31	FINE SAND	89.9	.05	17 18	.971	50%-60%	40-42	197	—	—	—	—
32	FINE SAND	92.1	.17	18 19	1.005	50%-60%	40-42	202	—	—	—	—
33	FINE SAND	91.9	.05	18 19	1.038	50%-60%	40-42	202	—	—	—	—
34	SILTY FINE SAND	42.8	.1	10 9	1.069	140%	36-38	94	—	—	—	—

C-4 CONTINUED

35	FINE SAND	77.5	.06	15	16	1.102	40%-50%	38-40	170	—	—	—	—
36	SILTY FINE SAND	42.4	.15	10	9	1.132	(40%)	36-38	93	—	—	—	—
37	SILTY TO CLAYEY F.S.	31.2	.02	10	6	1.163	(40%)	32-34	56	—	—	—	—
38	SILTY FINE SAND	33.5	0	8	7	1.194	(40%)	34-36	73	—	—	—	—
39	SILTY TO CLAYEY F.S.	32	.04	10	7	1.225	(40%)	32-34	70	—	—	—	—
40	SILTY TO CLAYEY F.S.	31.9	.05	10	7	1.256	(40%)	32-34	70	—	—	—	—
41	SILTY FINE SAND	70.5	.29	17	15	1.286	40%-50%	38-40	155	—	—	—	—
42	SILTY TO CLAYEY F.S.	44.3	.6	14	11	1.317	(40%)	34-36	97	—	—	—	—
43	SILTY TO CLAYEY F.S.	44.4	.67	14	12	1.348	(40%)	34-36	97	—	—	—	—
44	SILTY TO CLAYEY F.S.	46.2	.52	15	11	1.379	(40%)	34-36	101	—	—	—	—
45	SILTY TO CLAYEY F.S.	32.6	.09	10	7	1.409	(40%)	32-34	71	—	—	—	—
46	SILTY TO CLAYEY F.S.	37.2	.48	12	9	1.44	(40%)	32-34	81	—	—	—	—
47	CLAYEY FINE SAND	36.1	.73	14	10	1.471	(40%)	32-34	79	—	—	—	—
48	SILTY TO CLAYEY F.S.	35	.44	11	9	1.502	(40%)	32-34	77	—	—	—	—
49	CLAYEY FINE SAND	49.2	1.24	19	15	1.532	(40%)	34-36	108	—	—	—	—
50	SANDY CLAY	50.7	1.93	25	18	1.56	—	—	—	2.97	2.6	.01	6
51	SANDY CLAY	36.6	1.37	18	13	1.587	—	—	—	2.09	2.6	.01	6
52	SANDY CLAY	42.3	1.5	21	14	1.614	—	—	—	2.44	2.8	.01	6
53	SILTY TO CLAYEY F.S.	69	1.56	23	20	1.645	(40%)	36-38	151	—	—	—	—
54	SILTY TO CLAYEY F.S.	72	1.29	24	20	1.676	(40%)	36-38	158	—	—	—	—
55	SILTY TO CLAYEY F.S.	112.8	1.92	37	30	1.707	40%-50%	38-40	248	—	—	—	—
56	SILTY TO CLAYEY F.S.	133.7	3.98	44	43	1.738	50%-60%	38-40	294	—	—	—	—
57	CLAYEY FINE SAND	66.2	2.29	26	22	1.768	(40%)	36-38	145	—	—	—	—
58	CLAYEY FINE SAND	82.7	2.82	33	28	1.799	(40%)	36-38	181	—	—	—	—
59	SILTY TO CLAYEY F.S.	68.2	1.51	22	20	1.83	(40%)	36-38	150	—	—	—	—
60	SILTY TO CLAYEY F.S.	74.5	1.19	24	20	1.861	(40%)	36-38	163	—	—	—	—
61	SILTY TO CLAYEY F.S.	123.1	2.35	41	34	1.891	40%-50%	38-40	270	—	—	—	—
62	SILTY TO CLAYEY F.S.	104.2	2.44	34	31	1.922	40%-50%	38-40	229	—	—	—	—
63	SILTY TO CLAYEY F.S.	75.2	.98	25	19	1.953	(40%)	36-38	165	—	—	—	—
64	SILTY TO CLAYEY F.S.	69	1.37	23	19	1.984	(40%)	34-36	151	—	—	—	—
65	SILTY FINE SAND	65.5	.05	16	13	2.014	(40%)	34-36	144	—	—	—	—
66	FINE SAND	79.2	.24	15	17	2.048	(40%)	36-38	174	—	—	—	—
67	FINE SAND	94.8	.36	18	20	2.081	(40%)	36-38	208	—	—	—	—

$N^* = \text{POINT STRESS} \times (1.2 + .04 \times \text{FRICTION RATIO})$

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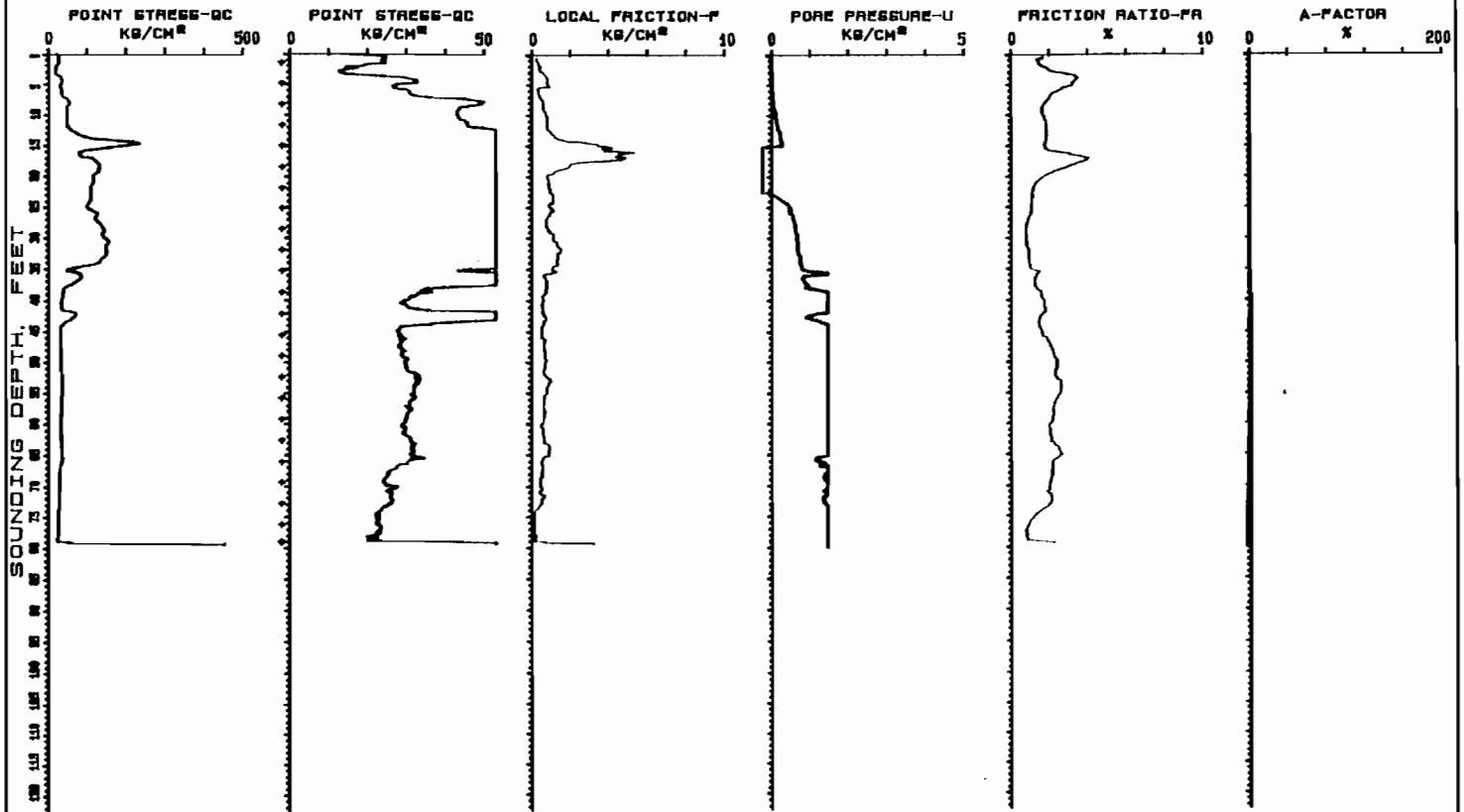
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PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING #..... C-5
SOUNDING DATE 09/02/92 11: 07: 25

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-5

DEPTH FEET	SOIL BEHAVIOR TYPE	GC (KG/CM ²)	LF (KG/CM ²)	N ₁ N ₂ VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
				=		*	**	***	****			
1	CLAYEY FINE SAND	23.8	.81	8 8	.048	50%-60%	45-45	22	--	--	--	--
2	SANDY CLAY	15.9	.44	7 5	.062	--	--	--	--	1.5	.01	5
3	CLAY	12.1	.63	12 5	.131	--	--	--	.75	1.9	.02	15
4	SANDY CLAY	29.2	.65	14 9	.175	--	--	--	1.82	3.4	.01	15
5	CLAYEY FINE SAND	28.4	.75	11 9	.224	40%-50%	42-44	22	--	--	--	--
6	SILTY TO CLAYEY F.S.	29.8	.35	9 7	.273	40%-50%	40-42	25	--	--	--	--
7	SILTY TO CLAYEY F.S.	35	.49	11 9	.322	50%-60%	40-42	27	--	--	--	--
8	SILTY TO CLAYEY F.S.	49.4	.81	16 12	.371	60%-70%	42-44	108	--	--	--	--
9	SILTY TO CLAYEY F.S.	43.1	.64	14 11	.419	50%-60%	40-42	34	--	--	--	--
10	CLAYEY FINE SAND	42.4	.8	16 12	.468	50%-60%	40-42	33	--	--	--	--
11	SILTY TO CLAYEY F.S.	44.7	.35	14 12	.499	50%-60%	40-42	35	--	--	--	--
12	SILTY TO CLAYEY F.S.	47.2	.63	15 13	.53	40%-50%	40-42	103	--	--	--	--
13	SILTY TO CLAYEY F.S.	66.5	1.09	22 18	.561	50%-60%	40-42	142	--	--	--	--
14	SILTY FINE SAND	122.7	1.84	30 31	.591	70%-80%	44-46	259	--	--	--	--
15	SILTY FINE SAND	204.4	3.69	51 36	.622	70%	46-48	449	--	--	--	--
16	STIFF CLAY	36.5	4.95	36 37	.653	--	--	--	5.35	1.7	UD	16
17	STIFF CLAY	38.9	4.65	38 38	.684	--	--	--	5.12	2.1	UD	16
18	SILTY FINE SAND	126.3	1.97	31 33	.714	70%-80%	42-44	277	--	--	--	--
19	FINE SAND	125.9	1.2	25 30	.748	70%-80%	42-44	275	--	--	--	--
20	FINE SAND	109.1	.8	21 25	.781	60%-70%	42-44	240	--	--	--	--
21	FINE SAND	111.6	.66	22 25	.814	60%-70%	42-44	245	--	--	--	--
22	SILTY FINE SAND	106.1	.98	25 25	.845	60%-70%	40-42	233	--	--	--	--
23	SILTY FINE SAND	105.1	1.11	25 25	.876	60%-70%	40-42	231	--	--	--	--
24	SILTY FINE SAND	104.9	1.07	26 25	.906	60%-70%	40-42	230	--	--	--	--
25	SILTY FINE SAND	95.7	1.06	23 23	.937	50%-60%	40-42	210	--	--	--	--
26	FINE SAND	122.4	.92	24 28	.97	60%-70%	42-44	259	--	--	--	--
27	FINE SAND	117.3	.75	23 26	1.004	60%-70%	40-42	252	--	--	--	--
28	FINE SAND	134.1	.78	25 30	1.037	50%-70%	42-44	295	--	--	--	--
29	FINE SAND	139	1.01	27 22	1.07	70%-80%	42-44	303	--	--	--	--
30	FINE SAND	142.1	1.1	28 32	1.103	70%-80%	42-44	312	--	--	--	--
31	FINE SAND	148.4	1.33	29 35	1.136	70%-80%	42-44	326	--	--	--	--
32	FINE SAND	145.4	1.51	29 35	1.17	60%-70%	40-42	319	--	--	--	--
33	FINE SAND	142.6	1.36	28 34	1.203	60%-70%	40-42	313	--	--	--	--
34	SILTY FINE SAND	126.1	1.32	31 31	1.234	50%-70%	40-42	277	--	--	--	--
35	CLAYEY FINE SAND	51.2	1.14	20 15	1.264	140%	36-38	112	--	--	--	--

1-5 CONTINUED

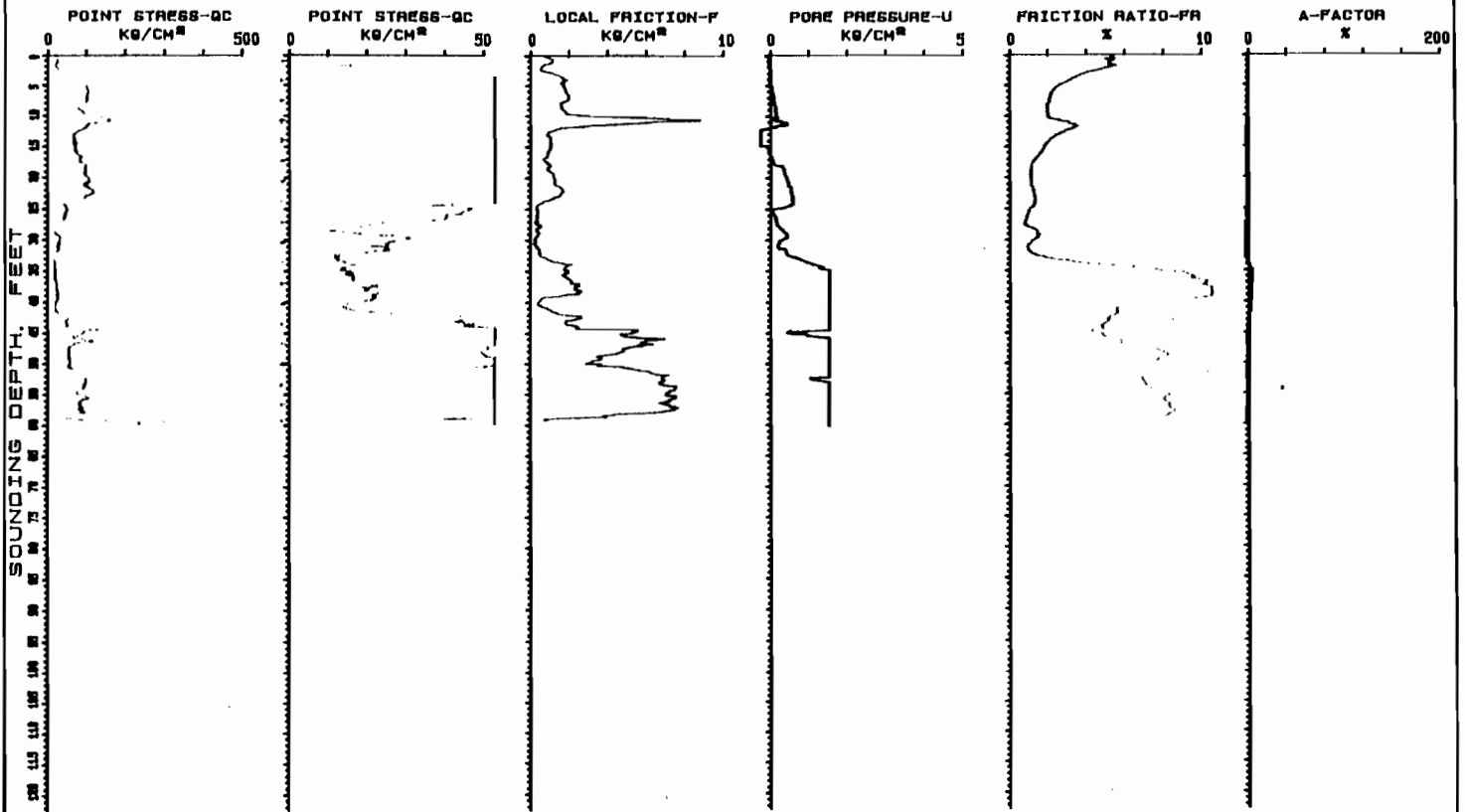
36	SILTY FINE SAND	73.9	.58	15 16	1.285	40%-50%	38-40	173	--	--	--	--
37	SILTY FINE SAND	68.1	.76	17 17	1.635	40%	38-38	143	--	--	--	--
38	CLAYEY FINE SAND	35.2	.77	15 11	1.357	40%	34-36	87	--	--	--	--
39	CLAYEY FINE SAND	32.9	.59	13 9	1.327	40%	32-34	73	--	--	--	--
40	CLAYEY FINE SAND	29.4	.56	11 5	1.416	40%	30-32	64	--	--	--	--
41	CLAYEY FINE SAND	30.4	.54	12 5	1.449	40%	30-32	65	--	--	--	--
42	SILTY FINE SAND	67.1	.6	16 16	1.48	40%	36-38	147	--	--	--	--
43	SILTY TO CLAYEY F.S.	55.5	.72	18 14	1.51	40%	36-38	122	--	--	--	--
44	CLAYEY FINE SAND	31.9	.53	12 9	1.541	40%	30-32	70	--	--	--	--
45	CLAYEY FINE SAND	27	.5	10 7	1.572	40%	30-32	59	--	--	--	--
46	CLAYEY FINE SAND	28.1	.6	11 6	1.603	40%	30-32	61	--	--	--	--
47	CLAYEY FINE SAND	27.9	.63	11 6	1.634	40%	30-32	61	--	--	--	--
48	CLAYEY FINE SAND	29.3	.56	11 8	1.664	40%	30-32	62	--	--	--	--
49	CLAYEY FINE SAND	26.2	.57	11 8	1.695	40%	30-32	62	--	--	--	--
50	CLAYEY FINE SAND	26.9	.7	11 9	1.725	40%	30-32	63	--	--	--	--
51	CLAYEY FINE SAND	25.3	.63	11 8	1.757	40%	30-32	64	--	--	--	--
52	CLAYEY FINE SAND	32	.69	12 9	1.767	40%	30-32	70	--	--	--	--
53	CLAYEY FINE SAND	32.7	.75	13 10	1.818	40%	30-32	71	--	--	--	--
54	CLAYEY FINE SAND	31.3	.73	12 9	1.849	40%	30-32	66	--	--	--	--
55	CLAYEY FINE SAND	31.1	.73	12 9	1.88	40%	30-32	66	--	--	--	--
56	CLAYEY FINE SAND	31.5	.62	12 9	1.91	40%	30-32	69	--	--	--	--
57	CLAYEY FINE SAND	30	.5	12 5	1.941	40%	30-32	66	--	--	--	--
58	CLAYEY FINE SAND	30	.56	12 9	1.972	40%	30-32	66	--	--	--	--
59	CLAYEY FINE SAND	29.3	.6	11 8	2.003	40%	30-32	64	--	--	--	--
60	CLAYEY FINE SAND	28.5	.47	11 8	2.034	40%	30	62	--	--	--	--
61	CLAYEY FINE SAND	29.3	.61	11 8	2.064	40%	30	64	--	--	--	--
62	CLAYEY FINE SAND	29.2	.62	11 8	2.095	40%	30	64	--	--	--	--
63	CLAYEY FINE SAND	31.3	.75	12 9	2.126	40%	30-32	66	--	--	--	--
64	CLAYEY FINE SAND	30.9	.88	12 10	2.157	40%	30	67	--	--	--	--
65	CLAYEY FINE SAND	29.5	.75	11 9	2.187	40%	30	64	--	--	--	--
66	CLAYEY FINE SAND	29.2	.47	11 8	2.218	40%	30	64	--	--	--	--
67	CLAYEY FINE SAND	26.8	.5	10 8	2.249	40%	30	58	--	--	--	--
68	CLAYEY FINE SAND	24.7	.52	9 7	2.28	40%	30	54	--	--	--	--
69	CLAYEY FINE SAND	23.3	.43	9 6	2.31	40%	30	51	--	--	--	--
70	CLAYEY FINE SAND	25.3	.48	10 7	2.341	40%	30	55	--	--	--	--
71	CLAYEY FINE SAND	24.3	.33	9 6	2.372	40%	30	53	--	--	--	--
72	CLAYEY FINE SAND	25.7	.57	10 7	2.403	40%	30	56	--	--	--	--
73	CLAYEY FINE SAND	24.9	.43	9 7	2.433	40%	30	54	--	--	--	--
74	SILTY TO CLAYEY F.S.	22.7	.16	7 5	2.464	40%	30	49	--	--	--	--
75	SILTY TO CLAYEY F.S.	22	.14	7 5	2.495	40%	30	48	--	--	--	--
76	SILTY TO CLAYEY F.S.	21.7	.12	7 5	2.526	40%	30	47	--	--	--	--
77	SILTY TO CLAYEY F.S.	23.1	.11	7 5	2.557	40%	30	50	--	--	--	--
78	SILTY TO CLAYEY F.S.	21.6	.2	7 5	2.587	40%	30	47	--	--	--	--
79	CLAYEY FINE SAND	36.6	.12	15 13	2.618	40%	30-32	64	--	--	--	--

- * $q = \text{POINT STRESS} + (1.2 + 0.04 \times \text{FRICTION RATIO})$
- NORMALLY CONSOLIDATED SANDS
- ** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES
- *** FOR OVERCONSOLIDATED SANDS, YOUNG'S MODULUS MAY BE AS MUCH AS 3 TO 8 TIMES HIGHER
- **** K OF 16 USED. FOR OVERCONSOLIDATED CLAYS, AN K OF 17 IS SUGGESTED

THE ABOVE DATA WAS COMPUTED FOLLOWING 1982¹ GUIDELINES BY P. W. ROBERTSON AND P. G. CAMPANELLA IN THE HANDBOOK
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PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING #..... C-6
SOUNDING DATE 09/08/92 11: 47: 40

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA-AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
JOB FILE NUMBER... MISSISSIMEE UTILITIES MISSISSIMEE FL.
CORE SOUNDING..... C-6

DEPTH FEET	SOIL BEHAVIOR TYPE	2C (KG/CM2)	LF (KG/CM2)	N, N1 VALUES	VERTICAL EFFECTIVE STRESS (KG/CM2)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS KG/CM2	UNDRAINED SHEAR STRENGTH (KG/CM2)	SENSITIVITY	COMP.	OCR
				#		+	++	+++	++++			
1	CLAY	20.6	.39	10 5	.039	—	—	—	.12	1	UD	3
2	CLAY	15.4	.37	15 5	.078	—	—	—	.37	2.2	.01	48
3	SILTY TO CLAYEY F.S.	39.4	.62	13 10	.126	60%-70%	44-46	36	—	—	—	—
4	SILTY TO CLAYEY F.S.	62	1.32	27 22	.175	70%-80%	45-46	180	—	—	—	—
5	SILTY TO CLAYEY F.S.	36	1.57	32 25	.224	70%-80%	45-46	211	—	—	—	—
6	SILTY TO CLAYEY F.S.	100.7	1.74	33 27	.273	70%-80%	45-46	221	—	—	—	—
7	SILTY TO CLAYEY F.S.	97.1	1.89	32 27	.322	70%-80%	44-46	213	—	—	—	—
8	SILTY TO CLAYEY F.S.	68.4	1.63	33 24	.371	70%-80%	44-46	194	—	—	—	—
9	SILTY TO CLAYEY F.S.	75.3	1.51	25 21	.419	70%-80%	42-44	183	—	—	—	—
10	SILTY TO CLAYEY F.S.	100.9	1.93	33 28	.468	70%-80%	44-46	221	—	—	—	—
11	STIFF CLAY	147.3	7.73	147 61	.493	—	—	—	9.17	1.2	UD	16
12	CLAYEY FINE SAND	32.4	3.06	36 31	.53	60%-70%	42-44	203	—	—	—	—
13	SILTY TO CLAYEY F.S.	63.7	.3	21 16	.561	50%-60%	40-42	140	—	—	—	—
14	SILTY TO CLAYEY F.S.	54.6	.33	21 17	.591	50%-60%	40-42	142	—	—	—	—
15	SILTY TO CLAYEY F.S.	66.2	.32	22 17	.622	50%-60%	40-42	145	—	—	—	—
16	SILTY TO CLAYEY F.S.	69.5	.34	23 17	.653	50%-60%	40-42	152	—	—	—	—
17	SILTY FINE SAND	78.9	.7	19 19	.684	50%-60%	40-42	173	—	—	—	—
18	SILTY FINE SAND	33	.73	33 22	.714	60%-70%	42-44	204	—	—	—	—
19	SILTY FINE SAND	91.6	.81	22 22	.745	60%-70%	40-42	201	—	—	—	—
20	SILTY FINE SAND	99.5	1.11	24 24	.776	60%-70%	42-44	218	—	—	—	—
21	SILTY FINE SAND	32	1.17	23 23	.807	60%-70%	40-42	202	—	—	—	—
22	SILTY FINE SAND	113.1	1.49	28 29	.838	60%-70%	42-44	248	—	—	—	—
23	SILTY TO CLAYEY F.S.	36.5	1.47	32 25	.868	60%-70%	40-42	212	—	—	—	—
24	SILTY TO CLAYEY F.S.	51.2	.78	17 13	.899	(40%	38-40	112	—	—	—	—
25	SILTY FINE SAND	47	.22	11 10	.93	(40%	35-38	103	—	—	—	—
26	SILTY TO CLAYEY F.S.	40.9	.3	13 9	.961	(40%	36-38	69	—	—	—	—
27	SILTY TO CLAYEY F.S.	28.6	.21	9 7	.991	(40%	34-36	62	—	—	—	—
28	SANDY CLAY	14.4	.39	7 4	1.019	—	—	—	.8	3.3	.01	3
29	CLAYEY FINE SAND	19.2	.29	7 5	1.049	(40%	30-32	42	—	—	—	—
30	SILTY TO CLAYEY F.S.	28.3	.15	9 6	1.08	(40%	32-34	62	—	—	—	—
31	SILTY TO CLAYEY F.S.	22.6	.12	7 5	1.111	(40%	30-32	49	—	—	—	—
32	CLAYEY FINE SAND	19.6	.38	7 5	1.142	(40%	30-32	43	—	—	—	—
33	CLAY	11.2	.47	11 4	1.167	—	—	—	.58	2.3	.02	1-1.5
34	CLAY	14.7	1.37	14 6	1.192	—	—	—	.79	1	.01	3
35	SOFT CLAY TO MUCK	13.2	1.63	13 5	1.208	—	—	—	.7	.8	UD	3

C-6 CONTINUED

35	CLAY	15.8	1.83	15	10	1.833	--	--	--	1.55	1.5	UD	5
37	CLAY	20.7	2.03	20	12	1.658	--	--	--	1.16	1	UD	5
38	CLAY	19.5	2.27	19	13	1.382	--	--	--	1.08	1.5	UD	5
39	CLAY	21	2.2	21	13	1.307	--	--	--	1.27	1.5	UD	5
40	SANDY CLAY	17.6	1.33	5	5	1.333	--	--	--	1.57	4.4	UD	5
41	SILTY CLAY TO CLAY	12.3	1.42	8	4	1.362	--	--	--	1.52	2.6	UD	1-1.5
42	SILTY CLAY TO CLAY	25.3	1.14	13	10	1.389	--	--	--	1.62	2.4	UD	5
43	CLAY	44	2.43	44	19	1.414	--	--	--	2.53	1.8	UD	5
44	SANDY CLAY	55.2	2.11	33	20	1.442	--	--	--	1.55	2.5	UD	5
45	STIFF CLAY	66.6	4.95	33	38	1.472	--	--	--	3.37	1.7	UD	5
46	CLAY	50.1	2.43	30	40	1.497	--	--	--	2.46	1.6	UD	5
47	CLAY	58.1	2.84	38	35	1.522	--	--	--	2.46	1.9	UD	5
48	CLAY	49.5	4.63	49	29	1.547	--	--	--	2.94	1	UD	5
49	CLAY	51	3.6	51	25	1.572	--	--	--	3.01	1.4	UD	5
50	CLAY	53.5	3.18	53	23	1.597	--	--	--	3.13	1.7	UD	5
51	CLAY	63	3.02	63	23	1.622	--	--	--	3.75	1.2	UD	5
52	STIFF CLAY	128.8	5.45	128	52	1.653	--	--	--	7.86	1.5	UD	12
53	CLAY	94	2.83	94	46	1.677	--	--	--	5.68	1.2	UD	5
54	CLAY	56.9	7.15	38	45	1.702	--	--	--	5.33	1.2	UD	5
55	CLAY	74.8	7.11	74	43	1.727	--	--	--	4.46	1	UD	5
56	CLAY	67.6	7.39	67	47	1.752	--	--	--	5.27	1.1	UD	5
57	CLAY	85.1	6.89	85	45	1.777	--	--	--	5.11	1.2	UD	5
58	CLAY	97.3	7.1	97	48	1.802	--	--	--	5.57	1.3	UD	5
59	SANDY CLAY	73.6	3.14	35	27	1.829	--	--	--	4.39	2.3	0	5

N=POINT STRESS*(1.2+.04*FRICTION RATIO)

* NORMALLY CONSOLIDATED SANDS

** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES

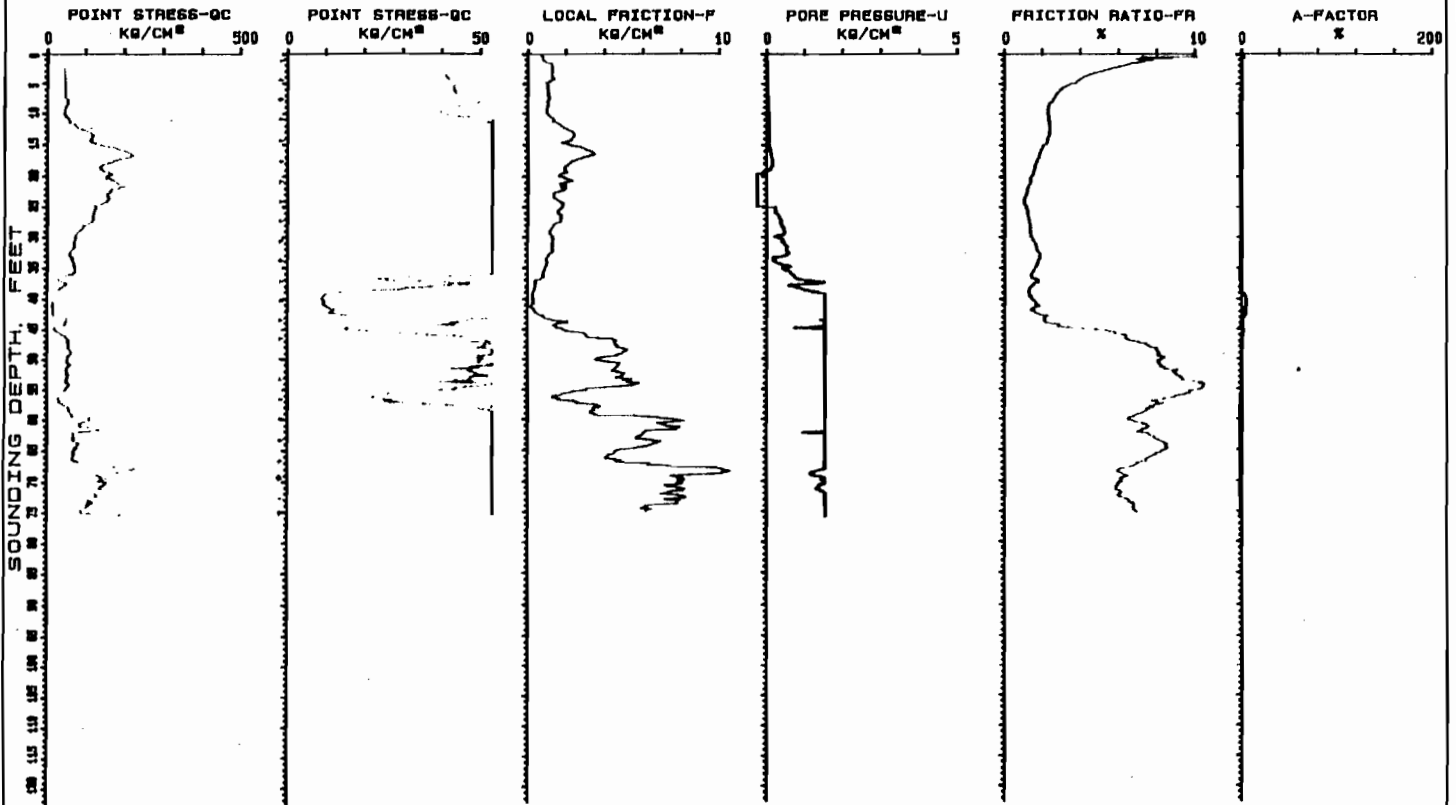
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PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING # C-7
SOUNDING DATE 09/08/92 09: 32: 43

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-7

DEPTH FEET	SOIL BEHAVIOR TYPE	2C (KG/CM2)	LF (KG/CM2)	N ₆₀ VALUES	VERTICAL EFFECTIVE STRESS (KG/CM2)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM2)	UNDRAINED SHEAR STRENGTH (KG/CM2)	SENSITIVITY	COMP.	OCR
1	CLAY	15.6	.89	15 8	.039	—	—	—	1	2.2	.01	16
2	SANDY CLAY	33.8	1.08	16 11	.083	—	—	—	2.06	3	.01	16
3	CLAYEY FINE SAND	41.7	1.15	18 13	.131	50%-70%	44-46	51	—	—	—	—
4	CLAYEY FINE SAND	40.7	1.15	18 13	.18	50%-70%	44-46	55	—	—	—	—
5	CLAYEY FINE SAND	42.9	1.04	17 13	.229	50%-70%	42-44	54	—	—	—	—
6	CLAYEY FINE SAND	42.8	.95	17 12	.278	50%-70%	42-44	54	—	—	—	—
7	CLAYEY FINE SAND	44	.98	17 13	.327	50%-60%	42-44	56	—	—	—	—
8	SILTY TO CLAYEY F.S.	50.5	1	16 14	.376	50%-70%	42-44	111	—	—	—	—
9	CLAYEY FINE SAND	43.1	.94	17 12	.424	50%-60%	40-42	54	—	—	—	—
10	CLAYEY FINE SAND	39.4	.89	15 11	.473	40%-50%	40-42	56	—	—	—	—
11	CLAYEY FINE SAND	51.6	1.14	20 15	.504	50%-60%	40-42	112	—	—	—	—
12	SILTY TO CLAYEY F.S.	66.8	1.45	22 19	.535	50%-60%	40-42	146	—	—	—	—
13	SILTY TO CLAYEY F.S.	98.9	2.01	32 26	.566	70%-80%	42-44	217	—	—	—	—
14	SILTY TO CLAYEY F.S.	111.4	2.34	37 32	.596	70%-80%	42-44	245	—	—	—	—
15	SILTY FINE SAND	124.4	1.8	31 32	.627	70%-80%	42-44	273	—	—	—	—
16	SILTY FINE SAND	184.3	2.82	46 48	.658	80%-90%	44-46	408	—	—	—	—
17	SILTY FINE SAND	213.1	3.2	53 55	.689	90%	44-46	466	—	—	—	—
18	SILTY FINE SAND	150.7	2.2	37 39	.719	80%-90%	44-46	231	—	—	—	—
19	SILTY FINE SAND	135.7	1.78	33 34	.75	70%-90%	42-44	256	—	—	—	—
20	FINE SAND	155.1	1.64	31 36	.783	70%-80%	42-44	341	—	—	—	—
21	FINE SAND	176	1.96	35 43	.817	80%-90%	44-46	357	—	—	—	—
22	FINE SAND	189	1.75	37 45	.85	80%-90%	44-46	415	—	—	—	—
23	FINE SAND	152	1.29	30 36	.883	70%-80%	42-44	334	—	—	—	—
24	FINE SAND	152.4	1.36	30 36	.916	70%-80%	42-44	335	—	—	—	—
25	SILTY FINE SAND	124.5	1.71	31 32	.947	50%-70%	42-44	273	—	—	—	—
26	SILTY FINE SAND	115.5	1.5	28 29	.978	50%-70%	40-42	254	—	—	—	—
27	SILTY FINE SAND	116.1	1.63	29 30	1.008	50%-70%	40-42	255	—	—	—	—
28	SILTY TO CLAYEY F.S.	94.6	1.44	31 25	1.039	50%-60%	40-42	208	—	—	—	—
29	SILTY TO CLAYEY F.S.	80.7	1.12	26 21	1.07	50%-60%	38-40	177	—	—	—	—
30	SILTY TO CLAYEY F.S.	68.7	1.12	22 18	1.101	40%-50%	38-40	151	—	—	—	—
31	SILTY TO CLAYEY F.S.	65.7	1.22	21 18	1.132	40%-50%	38-40	144	—	—	—	—
32	SILTY TO CLAYEY F.S.	62.3	1.16	20 17	1.162	(40%)	36-38	137	—	—	—	—
33	SILTY TO CLAYEY F.S.	62.6	1.1	17 15	1.193	(40%)	36-38	115	—	—	—	—
34	SILTY TO CLAYEY F.S.	62.3	.87	20 16	1.224	(40%)	36-38	137	—	—	—	—
35	SILTY TO CLAYEY F.S.	67.4	.85	22 17	1.255	(40%)	36-38	146	—	—	—	—

1-7 CONTINUED

36	SILTY TO CLAYEY F.S.	55.4	1.71	21 15	1.265	40%	36-38	103	—	—	—	—
37	BANDY CLAY	55.2	1.65	21 7	1.313	—	—	—	1.31	2.3	1.02	5
38	SILTY TO CLAYEY F.S.	56.7	1.81	22 5	1.343	40%	34-36	81	—	—	—	—
39	BANDY CLAY	52	1.81	2 3	1.371	—	—	—	1.8	5.3	1.02	1-1.5
40	BANDY CLAY	51.4	1.83	7 1	1.358	—	—	—	1.33	5	1.03	1-1.5
41	BANDY CLAY	51.6	1.83	7 1	1.426	—	—	—	1.33	4.6	1.03	1-1.5
42	CLAYEY FINE SAND	11.2	1.13	4 3	1.455	40%	30	24	—	—	—	—
43	SILTY TO CLAYEY F.S.	42.7	1.5	14 11	1.467	40%	34-36	53	—	—	—	—
44	BANDY CLAY	41.4	1.54	20 15	1.514	—	—	—	1.42	2.3	1.01	5
45	CLAY	15.1	1.42	15 9	1.539	—	—	—	1.78	1	1.01	3
46	CLAY	37.1	1.55	27 18	1.554	—	—	—	1.15	1.4	UD	5
47	CLAY	48.5	+	48 25	1.589	—	—	—	2.85	1.2	UD	5
48	CLAY	49.2	4.5	49 28	1.514	—	—	—	2.9	1	UD	5
49	CLAY	50.5	5.09	50 32	1.535	—	—	—	3.6	1.1	UD	5
50	CLAY	51.4	4.14	51 27	1.584	—	—	—	3.03	1.2	UD	5
51	CLAY	55	4.13	55 28	1.689	—	—	—	3.31	1.3	UD	5
52	CLAY	45.6	4.41	45 27	1.714	—	—	—	1.73	1	UD	5
53	CLAY	48.1	4.3	46 25	1.735	—	—	—	2.31	1.3	UD	5
54	CLAY	45.3	5.15	45 30	1.763	—	—	—	1.83	1.3	UD	5
55	CLAY	41.5	4.25	41 25	1.798	—	—	—	2.39	1.3	UD	5
56	CLAY	33.6	1.37	33 13	1.813	—	—	—	1.27	1.1	UD	3
57	CLAY	25.9	1.56	25 11	1.838	—	—	—	1.41	1.5	UD	3
58	STIFF CLAY	51.5	3.31	51 25	1.869	—	—	—	3.63	1.6	UD	5
59	STIFF CLAY	59.1	3.31	59 25	1.9	—	—	—	3.46	1.7	UD	6
60	STIFF CLAY	108.5	5.53	108 44	1.93	—	—	—	6.58	1.3	UD	5
61	CLAY	62.2	7.02	62 45	1.955	—	—	—	4.51	1.1	UD	5
62	STIFF CLAY	107.9	7.43	107 51	1.986	—	—	—	6.52	1.4	UD	5
63	CLAY	64.4	5.87	64 36	2.011	—	—	—	3.75	1	UD	6
64	CLAY	76.9	5.72	76 42	2.036	—	—	—	4.57	1.1	UD	5
65	CLAY	70.9	5.47	70 36	2.061	—	—	—	4.19	1.2	UD	5
66	CLAY	63.2	4.31	63 30	2.086	—	—	—	3.71	1.4	UD	5
67	STIFF CLAY	82.3	4.56	82 35	2.117	—	—	—	4.9	1.3	UD	5
68	DENSE CLAYEY FINE SAND	223.3	7.44	111 74	2.15	70%-80%	40-42	451	—	—	—	—
69	STIFF CLAY	124.7	10.22	124 66	2.181	—	—	—	7.34	1.2	UD	5
70	STIFF CLAY	138.1	7.9	138 59	2.211	—	—	—	8.37	1.7	UD	5
71	STIFF CLAY	133.4	7.32	133 56	2.242	—	—	—	6.08	1.3	UD	5
72	STIFF CLAY	123.4	7.71	123 56	2.273	—	—	—	7.45	1.3	UD	5
73	STIFF CLAY	104.9	7.81	104 52	2.304	—	—	—	6.29	1.3	UD	5
74	CLAY	99.1	7.48	99 50	2.328	—	—	—	5.92	1.3	UD	5
75	CLAY	83.9	5.06	83 41	2.353	—	—	—	4.97	1.3	UD	5

$N' = \text{POINT STRESS} \times (1.2 + .04 \times \text{FRICTION RATIO})$

* NORMALLY CONSOLIDATED SANDS

** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES

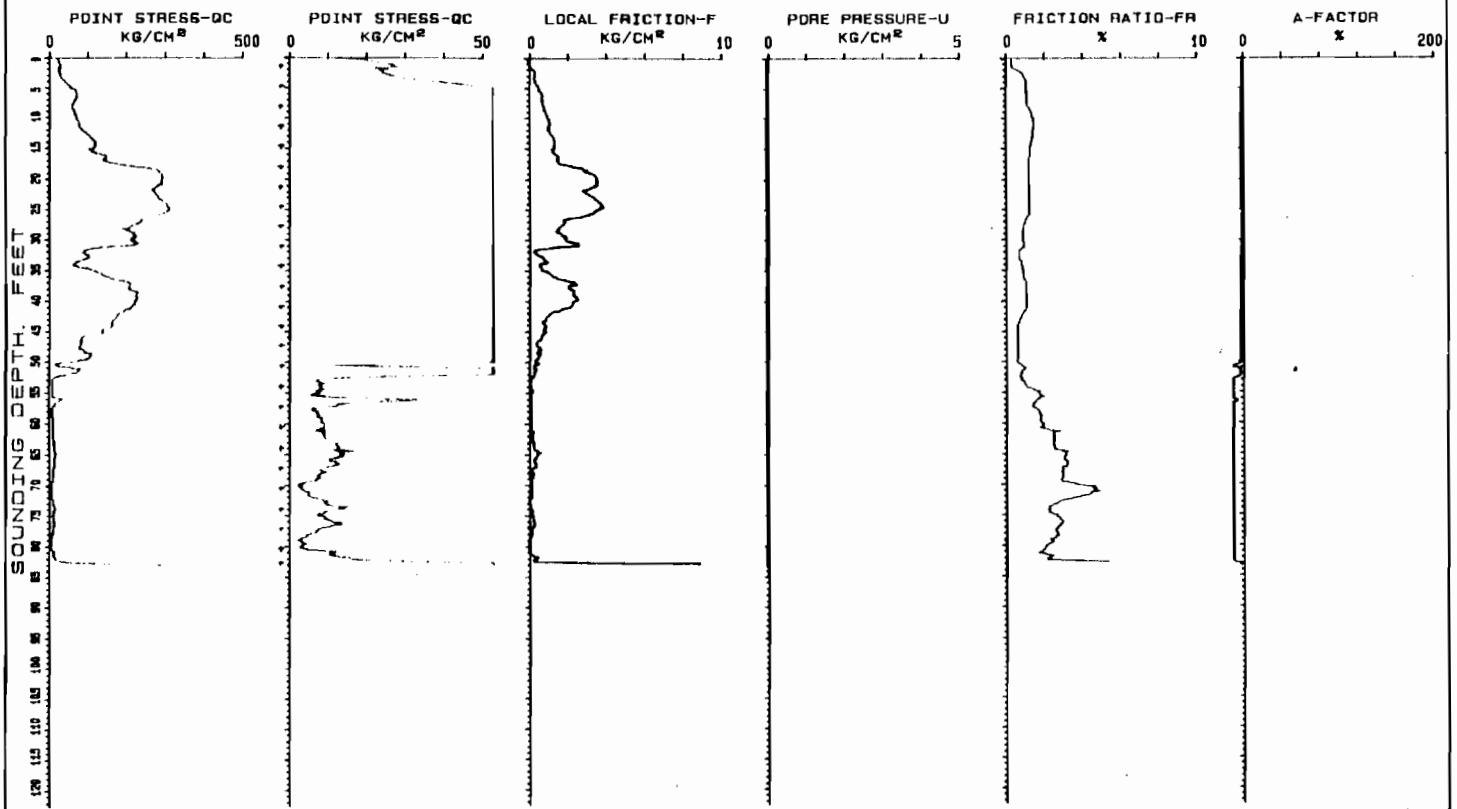
*** FOR OVERCONSOLIDATED SANDS, YOUNG'S MODULUS MAY BE AS MUCH AS 3 TO 5 TIMES HIGHER

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THE ABOVE DATA WAS COMPUTED FOLLOWING 'BASIC' GUIDELINES BY P. K. ROBERTSON AND R. S. CAMPANELLA IN THE HANDBOOK
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PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE # ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE
SOUNDING # C-8
SOUNDING DATE 09/25/92 10:31:39

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCED TESTING
JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
CONE SOUNDING..... C-8

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
1	SILTY TO CLAYEY F.S.	22	.07	7 5	.048	50%-60%	46-48	50	—	—	—	—
2	CLAYEY FINE SAND	22.3	.32	8 6	.097	40%-50%	44-46	49	—	—	—	—
3	CLAYEY FINE SAND	25.9	.34	10 7	.146	40%-50%	42-44	56	—	—	—	—
4	SILTY TO CLAYEY F.S.	36.6	.41	12 9	.195	50%-60%	42-44	80	—	—	—	—
5	SILTY TO CLAYEY F.S.	53.1	.57	17 13	.244	60%-70%	44-46	116	—	—	—	—
6	SILTY FINE SAND	69.6	.74	17 17	.274	70%-80%	44-46	153	—	—	—	—
7	SILTY TO CLAYEY F.S.	66.2	.76	22 16	.305	60%-70%	44-46	145	—	—	—	—
8	SILTY TO CLAYEY F.S.	58.1	.84	19 15	.336	60%-70%	42-44	127	—	—	—	—
9	SILTY TO CLAYEY F.S.	62.8	.93	20 16	.367	60%-70%	42-44	138	—	—	—	—
10	SILTY TO CLAYEY F.S.	67.7	1.07	22 18	.398	60%-70%	42-44	148	—	—	—	—
11	SILTY TO CLAYEY F.S.	77	1.14	25 20	.428	70%-80%	42-44	163	—	—	—	—
12	SILTY FINE SAND	82.3	1.07	20 21	.459	70%-80%	42-44	191	—	—	—	—
13	SILTY FINE SAND	102	1.31	25 26	.49	70%-80%	44-46	224	—	—	—	—
14	SILTY FINE SAND	116.7	1.4	29 29	.521	70%-80%	44-46	256	—	—	—	—
15	SILTY FINE SAND	107.6	1.3	26 27	.551	70%-80%	42-44	236	—	—	—	—
16	SILTY FINE SAND	123.1	1.48	30 31	.582	70%-80%	44-46	270	—	—	—	—
17	SILTY FINE SAND	139.2	1.54	34 34	.613	70%-80%	44-46	306	—	—	—	—
18	FINE SAND	209.5	2.61	41 52	.646	90%	46-48	460	—	—	—	—
19	FINE SAND	283.4	3.27	56 70	.679	90%	46-48	623	—	—	—	—
20	FINE SAND	288.3	3.6	57 72	.713	90%	46-48	634	—	—	—	—
21	FINE SAND	283.9	3.49	56 71	.746	90%	46-48	624	—	—	—	—
22	FINE SAND	264.2	2.96	52 65	.779	90%	46-48	581	—	—	—	—
23	FINE SAND	279.8	3.42	55 70	.812	90%	46-48	615	—	—	—	—
24	FINE SAND	299.8	3.81	59 75	.845	90%	46-48	659	—	—	—	—
25	FINE SAND	306.4	3.64	61 76	.879	90%	46-48	674	—	—	—	—
26	FINE SAND	273.7	2.99	54 67	.912	90%	44-46	602	—	—	—	—
27	FINE SAND	235.4	1.9	47 55	.945	90%	44-46	517	—	—	—	—
28	FINE SAND	207.4	1.61	41 48	.978	80%-90%	44-46	456	—	—	—	—
29	FINE SAND	212.9	1.65	42 49	1.011	80%-90%	44-46	468	—	—	—	—
30	FINE SAND	211.5	1.97	42 50	1.045	80%-90%	44-46	465	—	—	—	—
31	FINE SAND	207.9	1.9	41 49	1.078	80%-90%	42-44	457	—	—	—	—
32	FINE SAND	84.6	.33	16 18	1.111	50%-60%	38-40	186	—	—	—	—
33	FINE SAND	107.2	.82	21 25	1.144	50%-60%	40-42	235	—	—	—	—
34	SILTY FINE SAND	61.5	.65	15 15	1.175	40%	36-38	135	—	—	—	—
35	FINE SAND	105	.79	21 24	1.208	50%-60%	40-42	231	—	—	—	—

C-8 CONTINUED

36	FINE SAND	144.1	1.34	28	34	1.241	60%-70%	40-42	317	—	—	—	—
37	FINE SAND	198.3	2.43	39	49	1.275	70%-80%	42-44	436	—	—	—	—
38	FINE SAND	202	2.18	40	49	1.308	80%-90%	42-44	444	—	—	—	—
39	FINE SAND	224	2.38	44	54	1.341	80%-90%	42-44	492	—	—	—	—
40	FINE SAND	219.7	2.4	43	54	1.374	80%-90%	42-44	483	—	—	—	—
41	FINE SAND	210	1.97	42	50	1.407	70%-80%	42-44	462	—	—	—	—
42	FINE SAND	180.5	1.13	36	41	1.441	70%-80%	40-42	397	—	—	—	—
43	FINE SAND	166.7	.89	33	37	1.474	60%-70%	40-42	366	—	—	—	—
44	FINE SAND	161.1	.91	32	36	1.507	60%-70%	40-42	354	—	—	—	—
45	FINE SAND	134.6	.86	26	30	1.54	60%-70%	40-42	296	—	—	—	—
46	SILTY FINE SAND	86.6	.69	21	20	1.571	40%-50%	38-40	190	—	—	—	—
47	SILTY FINE SAND	79.8	.44	19	18	1.602	(40%	36-38	175	—	—	—	—
48	SILTY FINE SAND	86.4	.59	21	20	1.633	40%-50%	36-38	190	—	—	—	—
49	FINE SAND	107.2	.56	21	24	1.666	40%-50%	38-40	235	—	—	—	—
50	SILTY FINE SAND	55	.41	13	13	1.697	(40%	34-36	121	—	—	—	—
51	SILTY FINE SAND	51.2	.32	12	12	1.727	(40%	34-36	112	—	—	—	—
52	SILTY FINE SAND	53.5	.26	13	12	1.758	(40%	34-36	117	—	—	—	—
53	SANDY CLAY	6.2	.1	3	2	1.785	—	—	—	.18	6.1	.02	1
54	SANDY CLAY	7.8	.11	3	2	1.813	—	—	—	.28	6.5	.03	1
55	SILTY CLAY TO CLAY	7.2	.2	4	2	1.84	—	—	—	.23	3.4	.03	1
56	SILTY TO CLAYEY F.S.	28.4	.15	9	6	1.871	(40%	30-32	62	—	—	—	—
57	CLAYEY FINE SAND	12.4	.16	4	3	1.902	(40%	(30	27	—	—	—	—
58	SILTY CLAY TO CLAY	6.5	.14	4	2	1.929	—	—	—	.18	4.4	.03	(1
59	SANDY CLAY	7.6	.14	3	2	1.956	—	—	—	.24	5.4	.03	1
60	SILTY CLAY TO CLAY	8.1	.18	5	2	1.984	—	—	—	.27	4.4	.03	1
61	SILTY CLAY TO CLAY	7.1	.17	4	2	2.011	—	—	—	.21	3.9	.03	1
62	SANDY CLAY	8.7	.2	4	3	2.038	—	—	—	.3	4.3	.03	1
63	SANDY CLAY	12.5	.28	6	4	2.066	—	—	—	.54	4.3	.02	1-1.5
64	SANDY CLAY	12.3	.32	6	4	2.093	—	—	—	.52	3.8	.02	1
65	SILTY CLAY TO CLAY	13.4	.49	8	5	2.12	—	—	—	.55	2.7	.01	1-1.5
66	CLAY	9.6	.34	9	3	2.145	—	—	—	.34	2.7	.02	1
67	SILTY CLAY TO CLAY	11.1	.39	7	4	2.173	—	—	—	.43	2.8	.02	1
68	SILTY CLAY TO CLAY	9.1	.23	6	3	2.2	—	—	—	.31	3.8	.02	1
69	SILTY CLAY TO CLAY	7.4	.21	4	2	2.227	—	—	—	.2	3.3	.03	(1
70	SOFT CLAY TO MUCK	2.3	.15	2	1	2.244	—	—	—	-.13	1.5	UD	(1
71	CLAY	3.4	.18	3	1	2.268	—	—	—	-.06	1.8	.07	(1
72	SILTY CLAY TO CLAY	5.1	.11	3	1	2.296	—	—	—	.04	4.4	.04	(1
73	SANDY CLAY	9.2	.1	4	2	2.323	—	—	—	.3	9.1	.03	1
74	CLAYEY FINE SAND	12.9	.21	5	3	2.354	(40%	(30	28	—	—	—	—
75	CLAY	7.4	.25	7	2	2.379	—	—	—	.18	2.9	.03	(1
76	SILTY CLAY TO CLAY	10.5	.33	7	3	2.406	—	—	—	.37	3.1	.02	1
77	SILTY CLAY TO CLAY	8.6	.23	5	3	2.433	—	—	—	.24	3.6	.02	(1
78	CLAY	5.8	.18	5	2	2.458	—	—	—	.06	3.1	.04	(1
79	SENSITIVE FINE GRAINED	2	.04	1	1	2.48	—	—	—	-.18	4.1	.1	(1
80	SENSITIVE FINE GRAINED	2.8	.04	1	1	2.502	—	—	—	-.13	5.7	.07	(1
81	CLAYEY FINE SAND	11.6	.11	4	3	2.533	(40%	(30	25	—	—	—	—
82	SANDY CLAY	14.7	.4	7	5	2.56	—	—	—	.61	3.6	.01	1

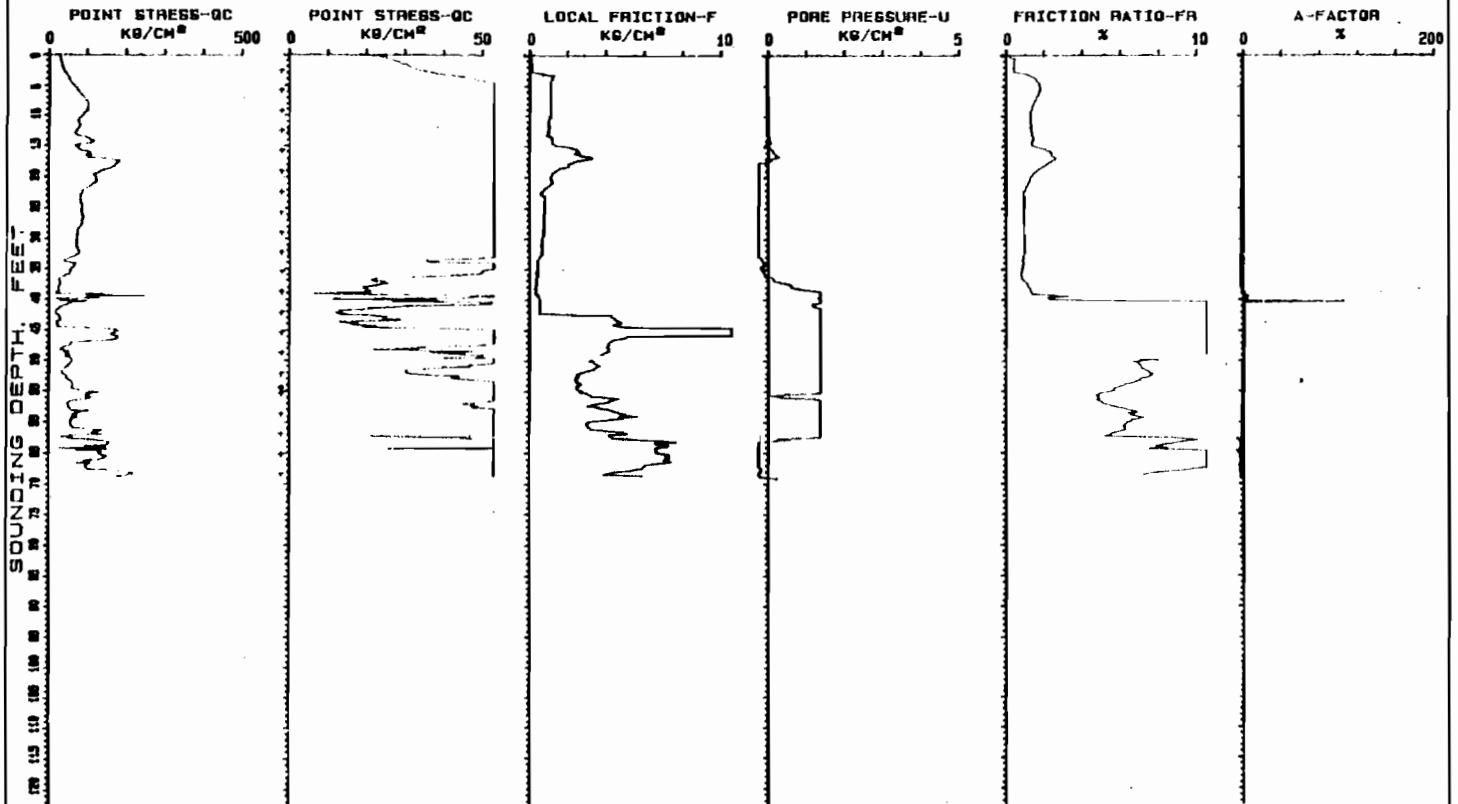
C-8 CONTINUED

- # $N^* = \text{POINT STRESS} \times (.2 + .04 \times \text{FRICTION RATIO})$
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- ** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES
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PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING # C-9
SOUNDING DATE 09/04/92 14: 41: 44

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCED TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-9

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
1	SILTY TO CLAYEY F.S.	25.8	.11	8 6	.048	50%-60%	148	56	—	—	—	—
2	SILTY TO CLAYEY F.S.	30.8	.1	10 7	.097	50%-60%	44-46	67	—	—	—	—
3	CLAYEY FINE SAND	36.7	.71	14 10	.146	60%-70%	44-46	80	—	—	—	—
4	CLAYEY FINE SAND	47.5	1.1	19 14	.195	60%-70%	44-46	104	—	—	—	—
5	SILTY TO CLAYEY F.S.	57.2	1.1	19 16	.244	60%-70%	44-46	125	—	—	—	—
6	SILTY TO CLAYEY F.S.	71.2	1.1	23 19	.274	70%-80%	44-46	156	—	—	—	—
7	SILTY FINE SAND	85.3	1.09	21 21	.305	70%-80%	44-46	187	—	—	—	—
8	SILTY FINE SAND	97.2	1.1	24 24	.336	70%-80%	44-46	213	—	—	—	—
9	SILTY FINE SAND	94.3	1.11	23 23	.367	70%-80%	44-46	207	—	—	—	—
10	SILTY FINE SAND	85	1.04	21 21	.398	70%-80%	44-46	187	—	—	—	—
11	SILTY TO CLAYEY F.S.	70.5	.97	23 18	.428	60%-70%	42-44	155	—	—	—	—
12	SILTY TO CLAYEY F.S.	75.5	1.01	25 19	.459	60%-70%	42-44	166	—	—	—	—
13	SILTY TO CLAYEY F.S.	61.7	.93	20 16	.49	60%-70%	40-42	135	—	—	—	—
14	SILTY FINE SAND	101.3	1.17	25 25	.521	70%-80%	42-44	222	—	—	—	—
15	CLAYEY FINE SAND	65.4	1.95	26 21	.551	50%-60%	40-42	143	—	—	—	—
16	SILTY TO CLAYEY F.S.	92.8	2.43	30 28	.582	60%-70%	42-44	204	—	—	—	—
17	SILTY TO CLAYEY F.S.	108.7	3.06	36 34	.613	70%-80%	42-44	239	—	—	—	—
18	SILTY FINE SAND	171.8	2.02	42 42	.644	80%-90%	44-46	377	—	—	—	—
19	FINE SAND	140.2	1.3	28 33	.677	70%-80%	44-46	308	—	—	—	—
20	FINE SAND	113.8	1.07	22 27	.71	70%-80%	42-44	250	—	—	—	—
21	FINE SAND	116.6	1.09	23 28	.743	70%-80%	42-44	256	—	—	—	—
22	SILTY FINE SAND	90.2	.67	22 21	.774	60%-70%	40-42	198	—	—	—	—
23	SILTY FINE SAND	76.6	.76	19 18	.805	50%-60%	40-42	168	—	—	—	—
24	SILTY FINE SAND	77.6	.76	19 19	.836	50%-60%	40-42	170	—	—	—	—
25	SILTY FINE SAND	81.3	.69	20 19	.866	50%-60%	40-42	178	—	—	—	—
26	SILTY FINE SAND	84	.73	21 20	.897	50%-60%	40-42	184	—	—	—	—
27	SILTY FINE SAND	80.8	.74	20 19	.928	50%-60%	40-42	177	—	—	—	—
28	SILTY FINE SAND	77.1	.74	19 18	.959	50%-60%	40-42	169	—	—	—	—
29	SILTY FINE SAND	68	.69	17 16	.989	40%-50%	38-40	149	—	—	—	—
30	SILTY FINE SAND	67.5	.65	16 16	1.02	40%-50%	38-40	148	—	—	—	—
31	SILTY FINE SAND	63.7	.63	15 15	1.051	40%-50%	38-40	140	—	—	—	—
32	SILTY FINE SAND	73.4	.64	18 17	1.082	40%-50%	38-40	161	—	—	—	—
33	SILTY FINE SAND	61.9	.48	15 14	1.112	(40%	38-40	136	—	—	—	—
34	SILTY TO CLAYEY F.S.	43.5	.38	14 10	1.143	(40%	36-38	95	—	—	—	—
35	SILTY FINE SAND	54.2	.36	13 12	1.174	(40%	36-38	119	—	—	—	—

C-9 CONTINUED

36	SILTY TO CLAYEY F.S.	46.3	.39	15	11	1.205	(40%	36-38	101	—	—	—	—
37	CLAYEY FINE SAND	21.1	.31	8	5	1.236	(40%	30-32	45	—	—	—	—
38	CLAYEY FINE SAND	18.9	.3	7	5	1.256	(40%	30-32	41	—	—	—	—
39	SANDY CLAY	13.8	.31	6	4	1.294	—	—	—	.71	4.3	.02	3
40	SILTY CLAY TO CLAY	14.4	.5	9	5	1.321	—	—	—	.75	2.8	.01	3
41	SILTY TO CLAYEY F.S.	41.4	.51	13	10	1.352	(40%	34-36	91	—	—	—	—
42	SILTY CLAY TO CLAY	12.8	.5	8	5	1.379	—	—	—	.64	2.5	.01	1-1.5
43	SOFT CLAY TO MUCK	23.7	4.44	23	23	1.395	—	—	—	1.32	.5	UD	3
44	SOFT CLAY TO MUCK	16.8	4.47	15	21	1.411	—	—	—	.68	.3	UD	3
45	STIFF CLAY	163.9	13.59	163	87	1.442	—	—	—	10.07	1.2	UD	16
46	SILTY TO CLAYEY F.S.	167.8	4.98	55	53	1.473	60%-70%	40-42	369	—	—	—	—
47	CLAY	52	4.07	52	27	1.498	—	—	—	3.07	1.2	UD	6
48	SOFT CLAY TO MUCK	17.1	4.13	17	20	1.514	—	—	—	.89	.4	UD	3
50	CLAY	55.1	3.34	55	24	1.539	—	—	—	3.26	1.6	UD	6
51	CLAY	44.4	3.47	44	23	1.564	—	—	—	2.58	1.2	UD	6
52	CLAY	29.2	2.56	29	16	1.589	—	—	—	1.63	1.1	UD	6
53	CLAY	41.1	2.42	41	18	1.614	—	—	—	2.37	1.7	UD	6
54	SILTY CLAY TO CLAY	56.4	2.47	37	21	1.641	—	—	—	3.32	2.2	UD	6
55	SILTY TO CLAYEY F.S.	112.9	2.8	37	34	1.672	40%-50%	38-40	248	—	—	—	—
56	STIFF CLAY	89.1	4.26	89	35	1.702	—	—	—	5.36	2	UD	6
57	CLAY	45.6	3.34	45	22	1.727	—	—	—	2.64	1.3	UD	6
58	SOFT CLAY TO MUCK	1.5	4.59	1	19	1.743	—	—	—	-.12	0	UD	11
59	CLAY	64.5	5.14	64	33	1.768	—	—	—	3.81	1.2	UD	6
60	CLAY	53.6	2.96	53	23	1.793	—	—	—	3.13	1.8	UD	6
61	STIFF CLAY	66.3	3.73	56	28	1.824	—	—	—	3.92	1.7	UD	6
62	CLAY	36.4	4.13	36	24	1.849	—	—	—	2.05	.8	UD	6
63	STIFF CLAY	136.1	7.09	136	56	1.88	—	—	—	8.27	1.9	UD	16
64	SOFT CLAY TO MUCK	17.3	6.47	17	29	1.896	—	—	—	.85	.2	UD	1-1.5
65	STIFF CLAY	125.2	7.17	125	54	1.927	—	—	—	7.59	1.7	UD	6
66	SOFT CLAY TO MUCK	42.7	6.95	42	36	1.943	—	—	—	2.43	.6	UD	6
67	CLAY	94.2	5.85	94	42	1.968	—	—	—	5.64	1.6	UD	6
68	SILTY FINE SAND	195.2	4	48	55	1.998	60%-70%	40-42	429	—	—	—	—

N²=POINT STRESS*(1.2+.04*FRICTION RATIO)

+ NORMALLY CONSOLIDATED SANDS

** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES

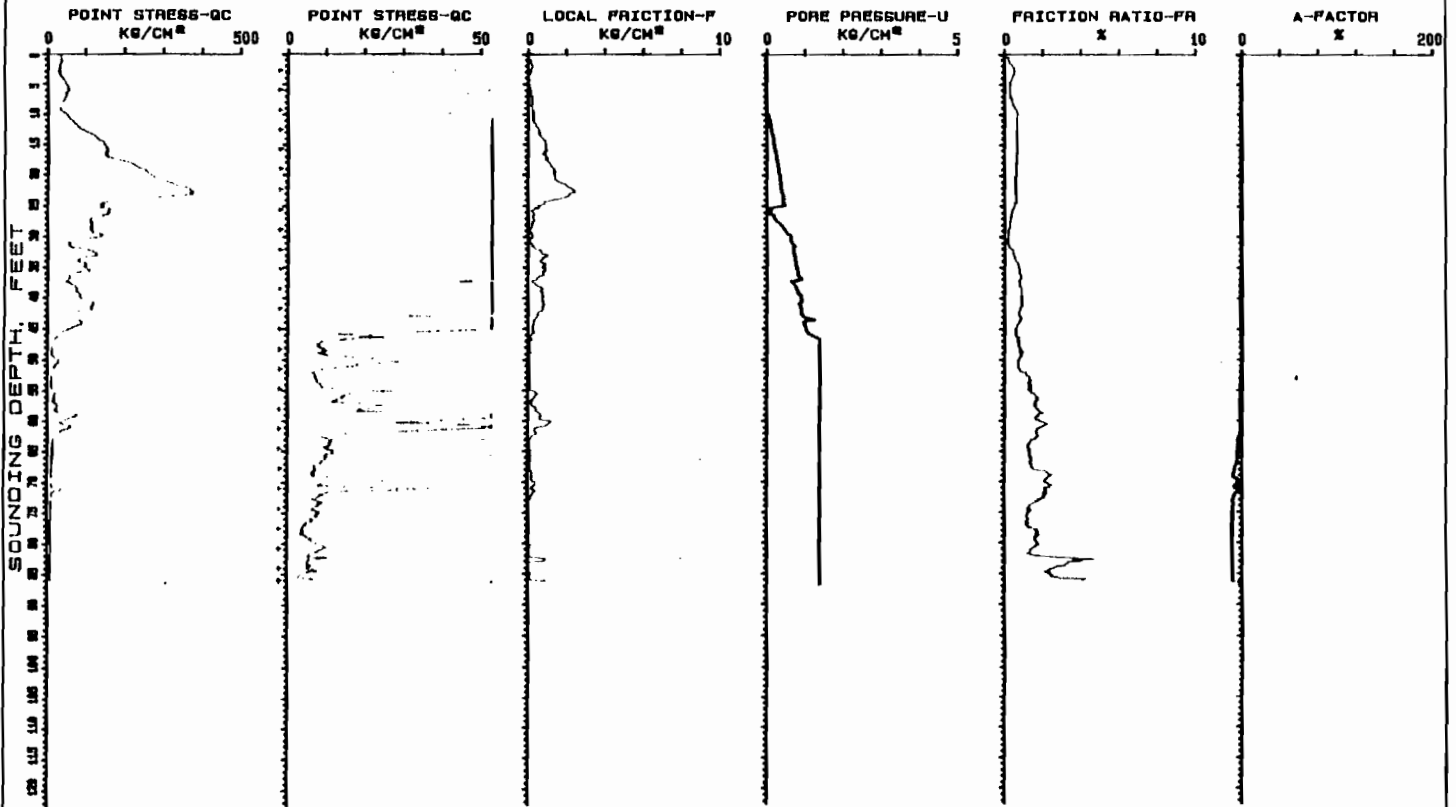
*** FOR OVERCONSOLIDATED SANDS, YOUNG'S MODULUS MAY BE AS MUCH AS 3 TO 6 TIMES HIGHER

**** NK OF 16 USED. FOR OVERCONSOLIDATED CLAYS, AN NK OF 17 IS SUGGESTED

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PUBLISHED RESEARCH AND LOCAL EXPERIENCE GROWS.

PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING #..... C-10
SOUNDING DATE 09/02/92 14:41:09

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-10

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM ²)	LF (KG/CM ²)	N ₁ N ₂ VALUES	VERTICAL EFFECTIVE STRESS (KG/CM ²)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM ²)	UNDRAINED SHEAR STRENGTH (KG/CM ²)	SENSITIVITY	COMP.	OCR
				#		*	**	***	****			
1	SILTY TO CLAYEY F.S.	33.7	.15	11 7	.048	50%-70%	148	74	--	--	--	--
2	SILTY TO CLAYEY F.S.	37.8	.24	9 7	.097	50%-60%	44-45	81	--	--	--	--
3	SILTY TO CLAYEY F.S.	26.5	.14	8 6	.146	40%-50%	42-44	58	--	--	--	--
4	SILTY FINE SAND	35.1	.16	8 7	.195	50%-60%	42-44	77	--	--	--	--
5	SILTY FINE SAND	47.2	.16	11 10	.244	50%-70%	42-44	103	--	--	--	--
6	SILTY FINE SAND	51.8	.17	12 11	.293	60%-70%	42-44	113	--	--	--	--
7	SILTY FINE SAND	43	.23	10 10	.341	50%-60%	40-42	94	--	--	--	--
8	SILTY TO CLAYEY F.S.	33.3	.23	11 8	.39	40%-50%	40-42	73	--	--	--	--
9	SILTY TO CLAYEY F.S.	26.4	.24	8 6	.439	(40%	35-40	58	--	--	--	--
10	SILTY TO CLAYEY F.S.	44.5	.31	14 10	.488	50%-60%	40-42	97	--	--	--	--
11	SILTY FINE SAND	58.3	.3	14 13	.519	50%-60%	40-42	128	--	--	--	--
12	SILTY FINE SAND	73.8	.51	18 17	.549	60%-70%	42-44	162	--	--	--	--
13	FINE SAND	100	.51	20 22	.583	70%-80%	42-44	220	--	--	--	--
14	FINE SAND	125.2	.25	25 28	.616	70%-80%	44-46	275	--	--	--	--
15	FINE SAND	144.3	.24	28 33	.649	70%-80%	44-46	317	--	--	--	--
16	FINE SAND	151.3	.33	30 34	.622	80%-90%	44-46	334	--	--	--	--
17	FINE SAND	150	.35	30 34	.715	70%-80%	44-46	330	--	--	--	--
18	FINE SAND	202.6	1.12	40 45	.749	190%	44-46	447	--	--	--	--
19	FINE SAND	238.6	1.34	47 53	.782	190%	44-46	524	--	--	--	--
20	DENSE OR CEMENTED SANDS	252.7	1.42	43 58	.818	190%	44-46	577	--	--	--	--
21	DENSE OR CEMENTED SANDS	294.1	1.71	49 66	.855	190%	46-48	647	--	--	--	--
22	DENSE OR CEMENTED SANDS	355.4	2.25	59 80	.892	190%	46-48	781	--	--	--	--
23	DENSE OR CEMENTED SANDS	369.4	2.17	51 83	.928	190%	46-48	812	--	--	--	--
24	FINE SAND	202.6	1.25	40 46	.962	80%-90%	44-46	445	--	--	--	--
25	FINE SAND	140.4	.56	28 30	.995	70%-80%	42-44	308	--	--	--	--
26	FINE SAND	155.2	.25	31 32	1.026	70%-80%	42-44	341	--	--	--	--
27	FINE SAND	109.1	.34	21 23	1.061	60%-70%	40-42	240	--	--	--	--
28	FINE SAND	111.6	.2	22 23	1.094	60%-70%	40-42	245	--	--	--	--
29	FINE SAND	111.3	.05	22 22	1.128	50%-70%	40-42	244	--	--	--	--
30	FINE SAND	131.3	.22	26 27	1.161	50%-70%	40-42	288	--	--	--	--
31	SILTY FINE SAND	53.6	.18	13 11	1.192	(40%	36-38	117	--	--	--	--
32	SILTY FINE SAND	81.9	.32	20 18	1.222	40%-50%	38-40	180	--	--	--	--
33	FINE SAND	124.8	.33	24 25	1.256	60%-70%	40-42	274	--	--	--	--
34	SILTY FINE SAND	77.5	.7	19 18	1.286	40%-50%	38-40	170	--	--	--	--
35	SILTY FINE SAND	91.8	.85	22 22	1.317	40%-50%	38-40	201	--	--	--	--

D-10 CONTINUED

36	SILTY TO CLAYEY F.S.	88.4	.33	11	17	1.348	(40%	35-38	.50	—	—	—	—
37	SILTY FINE SAND	82	.37	13	18	1.373	(40%	35-38	.51	—	—	—	—
38	SILTY FINE SAND	84.2	.33	13	15	1.409	(40%	35-38	.48	—	—	—	—
39	SILTY FINE SAND	71.8	.33	17	17	1.44	(40%	35-38	.57	—	—	—	—
40	SILTY FINE SAND	81.3	.35	20	19	1.471	(40%-50%	35-40	.61	—	—	—	—
41	FINE SAND	117.4	.34	13	27	1.504	50%-60%	35-40	.55	—	—	—	—
42	FINE SAND	107.4	.32	21	24	1.537	50%-60%	35-40	.55	—	—	—	—
43	CLAYEY FINE SAND	89.3	.45	11	8	1.568	(40%	30-32	.64	—	—	—	—
44	FINE SAND	89.3	.32	17	19	1.601	(40%-50%	35-40	.54	—	—	—	—
45	SILTY FINE SAND	86.5	.37	14	12	1.632	(40%	34-36	.54	—	—	—	—
46	CLAYEY FINE SAND	12.3	.18	7	—	1.663	(40%	(30	—	—	—	—	—
47	SANDY CLAY	3.9	.11	4	2	1.69	—	—	—	.44	3.4	.02	1-1.5
48	SANDY CLAY	7.3	.06	3	3	1.718	—	—	—	.31	12.4	.03	1
49	SANDY CLAY	7.5	.07	3	3	1.745	—	—	—	.31	10.3	.03	1
50	SILTY TO CLAYEY F.S.	27	.09	9	8	1.776	(40%	30-32	.53	—	—	—	—
51	CLAYEY FINE SAND	16.9	.14	6	—	1.806	(40%	(30	.37	—	—	—	—
52	SILTY CLAY TO CLAY	6.2	.12	—	2	1.834	—	—	—	.13	5	.04	1
53	SANDY CLAY	7.2	.11	2	2	1.861	—	—	—	.25	5.1	.03	1
54	SANDY CLAY	6.2	.1	—	2	1.888	—	—	—	.31	7.7	.03	1
55	SILTY TO CLAYEY F.S.	30	.32	10	7	1.919	(40%	30-32	.66	—	—	—	—
56	SANDY CLAY	13.6	.25	6	4	1.947	—	—	—	.55	3.3	.02	1-1.5
57	CLAYEY FINE SAND	16.9	.17	5	4	1.977	(40%	(30	.37	—	—	—	—
58	SANDY CLAY	18.6	.45	3	5	2.005	—	—	—	.34	4.1	.01	1-1.5
59	SILTY FINE SAND	75.4	.7	16	18	2.035	(40%	35-38	.55	—	—	—	—
60	CLAYEY FINE SAND	38.6	1.13	15	12	2.066	(40%	30-32	.64	—	—	—	—
61	SILTY FINE SAND	59.3	.32	14	14	2.097	(40%	34-36	.50	—	—	—	—
62	SANDY CLAY	16.3	.41	5	5	2.124	—	—	—	.31	4	.01	1-1.5
63	CLAYEY FINE SAND	11.3	.07	4	3	2.155	(40%	(30	.24	—	—	—	—
64	CLAYEY FINE SAND	10	.08	4	2	2.186	(40%	(30	.22	—	—	—	—
65	SANDY CLAY	11	.15	5	3	2.213	—	—	—	.44	7.1	.02	1
66	SANDY CLAY	9.6	.15	4	3	2.241	—	—	—	.35	6.2	.02	1
67	SANDY CLAY	7.9	.13	3	2	2.268	—	—	—	.24	5	.03	1
68	SILTY CLAY TO CLAY	6.9	.14	4	2	2.295	—	—	—	.17	4.6	.03	(1
69	SANDY CLAY	9.3	.21	4	3	2.323	—	—	—	.32	4.3	.03	1
70	CLAYEY FINE SAND	25	.38	10	7	2.353	(40%	(30	.55	—	—	—	—
71	SILTY TO CLAYEY F.S.	29.2	.26	9	7	2.384	(40%	(30	.64	—	—	—	—
72	SILTY CLAY TO CLAY	8.3	.21	5	3	2.411	—	—	—	.24	3.3	.03	(1
73	SANDY CLAY	7.9	.06	3	2	2.439	—	—	—	.22	11.4	.03	(1
74	SENSITIVE FINE GRAINED	7	.01	3	1	2.461	—	—	—	.16	53.7	.02	(1
75	SANDY CLAY	7.7	.09	3	2	2.488	—	—	—	.2	9.3	.03	(1
76	SENSITIVE FINE GRAINED	5.1	.06	2	1	2.51	—	—	—	.03	7.9	.03	(1
77	SENSITIVE FINE GRAINED	4.2	.06	2	1	2.532	—	—	—	-.03	7	.04	(1
78	CLAY	4.1	.1	4	1	2.557	—	—	—	-.04	3.3	.06	(1
79	SENSITIVE FINE GRAINED	5.1	.05	2	1	2.579	—	—	—	.02	6.6	.03	(1
80	SILTY CLAY TO CLAY	7.3	.15	4	2	2.606	—	—	—	.16	4.6	.03	(1
81	CLAYEY FINE SAND	8.5	.05	3	2	2.637	(40%	(30	.19	—	—	—	—
82	SILTY CLAY TO CLAY	4.9	.08	3	1	2.664	—	—	—	0	5.2	.05	(1
83	SOFT CLAY TO MUCK	4	.49	4	3	2.681	—	—	—	-.06	.8	UD	(1
84	SENSITIVE FINE GRAINED	3.7	.04	1	1	2.703	—	—	—	-.06	8.6	.05	(1
85	CLAY	3.2	.11	3	1	2.727	—	—	—	-.12	2.7	.07	(1

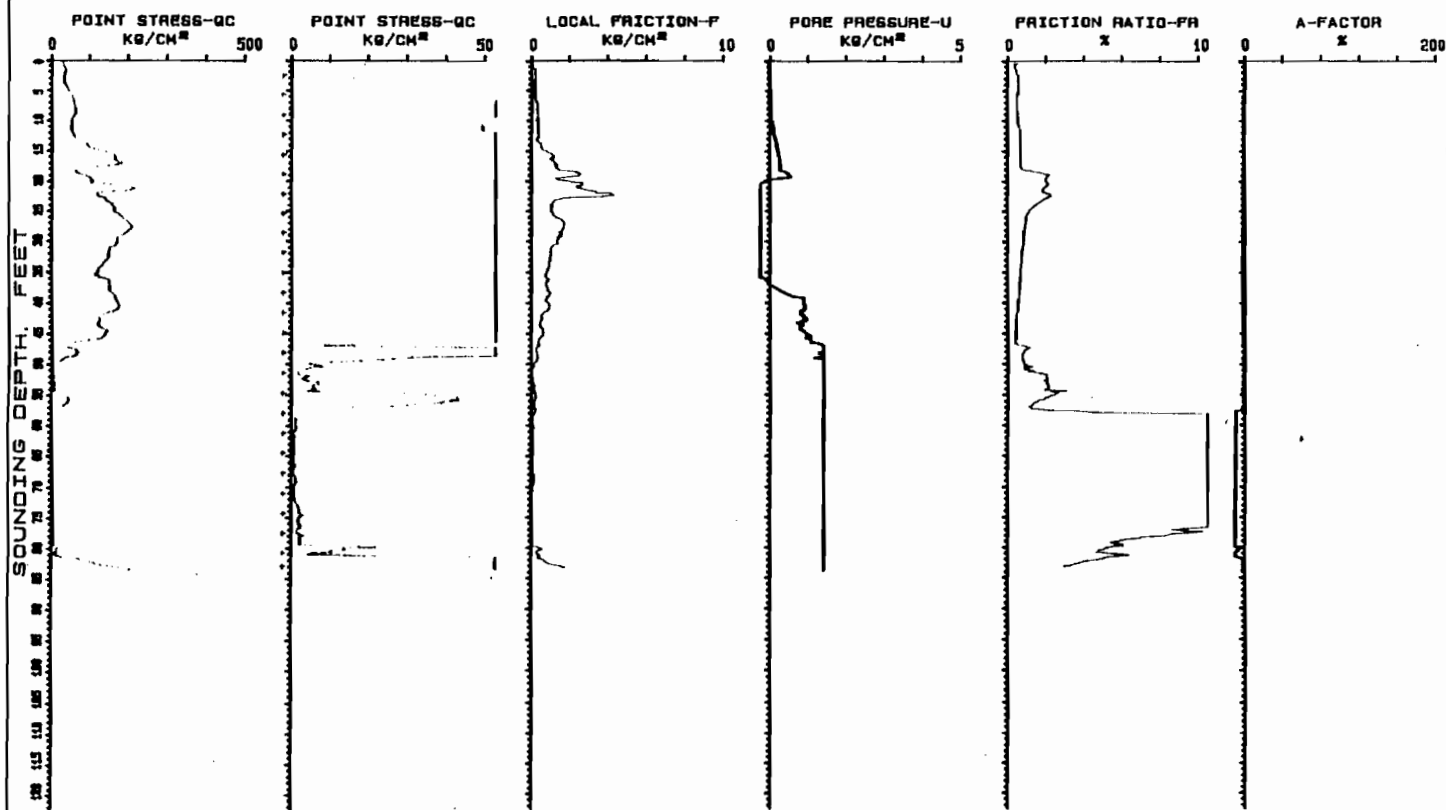
D-19 CONTINUED

- = $Q = \text{POINT STRESS} \times (1.2 + 0.04 \times \text{FRICTION RATIO})$
- + NORMALLY CONSOLIDATED SANDS
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FILE #..... ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING #..... C-11
SOUNDING DATE 09/04/92 09:14:30

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JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-11

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM2)	LP (KG/CM2)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM2)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM2)	UNDRAINED SHEAR STRENGTH (KG/CM2)	SENSITIVITY	COMP.	CCR
				#		+	++	+++	++++			
1	SILTY TO CLAYEY F.S.	29.3	.09	8 6	.048	50%-60%	42	54	—	—	—	—
2	SILTY TO CLAYEY F.S.	32.5	.13	10 7	.097	50%-70%	46-48	71	—	—	—	—
3	SILTY TO CLAYEY F.S.	27.6	.17	8 6	.146	50%-60%	42-44	51	—	—	—	—
4	SILTY TO CLAYEY F.S.	31.8	.18	10 7	.195	50%-60%	42-44	55	—	—	—	—
5	SILTY FINE SAND	43	.19	10 9	.244	60%-70%	42-44	54	—	—	—	—
6	SILTY FINE SAND	52.3	.19	13 11	.293	60%-70%	42-44	115	—	—	—	—
7	SILTY FINE SAND	57.1	.3	14 13	.341	60%-70%	42-44	125	—	—	—	—
8	SILTY FINE SAND	59.9	.32	14 13	.39	60%-70%	42-44	131	—	—	—	—
9	SILTY FINE SAND	58.7	.36	14 13	.439	60%-70%	42-44	129	—	—	—	—
10	SILTY FINE SAND	48.1	.38	12 11	.488	50%-60%	40-42	105	—	—	—	—
11	SILTY FINE SAND	49.1	.37	12 11	.519	50%-60%	40-42	108	—	—	—	—
12	SILTY FINE SAND	51.7	.39	12 12	.549	50%-60%	40-42	113	—	—	—	—
13	SILTY FINE SAND	60.7	.3	15 13	.58	50%-60%	40-42	133	—	—	—	—
14	SILTY FINE SAND	90.6	.57	22 20	.611	60%-70%	42-44	199	—	—	—	—
15	FINE SAND	123.1	.66	24 28	.644	70%-80%	42-44	270	—	—	—	—
16	FINE SAND	160.5	1.12	32 37	.677	80%-90%	44-46	353	—	—	—	—
17	FINE SAND	179.1	1.32	35 41	.711	80%-90%	44-46	354	—	—	—	—
18	SILTY TO CLAYEY F.S.	69.9	1.65	33 31	.741	50%-60%	40-42	153	—	—	—	—
19	CLAYEY FINE SAND	77	2.37	30 25	.772	50%-60%	40-42	169	—	—	—	—
20	SILTY TO CLAYEY F.S.	103	2.17	34 29	.803	60%-70%	42-44	226	—	—	—	—
21	FINE SAND	212	2.51	42 52	.836	70%	44-46	466	—	—	—	—
22	CLAYEY FINE SAND	120.3	4.11	48 41	.867	60%-70%	42-44	254	—	—	—	—
23	FINE SAND	137.5	1.37	27 33	.9	70%-80%	42-44	302	—	—	—	—
24	FINE SAND	154.4	1.07	30 35	.933	70%-80%	42-44	339	—	—	—	—
25	FINE SAND	158.5	1.05	31 36	.966	70%-80%	42-44	348	—	—	—	—
26	FINE SAND	176.9	1.38	35 41	1	80%-90%	42-44	369	—	—	—	—
27	FINE SAND	196.3	1.75	39 46	1.033	80%-90%	42-44	431	—	—	—	—
28	FINE SAND	200.7	1.6	40 47	1.066	80%-90%	42-44	441	—	—	—	—
29	FINE SAND	167.4	1.51	33 40	1.099	70%-80%	42-44	368	—	—	—	—
30	FINE SAND	169.3	1.34	33 39	1.132	70%-80%	42-44	372	—	—	—	—
31	FINE SAND	153.2	1.03	30 35	1.166	70%-80%	42-44	337	—	—	—	—
32	FINE SAND	145.8	1.02	29 33	1.199	60%-70%	40-42	320	—	—	—	—
33	FINE SAND	141.7	.96	28 32	1.232	60%-70%	40-42	311	—	—	—	—
34	FINE SAND	130.6	.88	26 30	1.265	60%-70%	40-42	287	—	—	—	—
35	FINE SAND	117.7	.79	23 27	1.299	50%-60%	40-42	258	—	—	—	—

2-11 CONTINUED

36	FINE SAND	131	.65	28	30	1.332	50%-70%	40-42	123	--	--	--	--
37	FINE SAND	149	.79	29	33	1.365	50%-70%	40-42	127	--	--	--	--
38	FINE SAND	145.9	.64	29	33	1.338	50%-70%	40-42	123	--	--	--	--
39	FINE SAND	161.4	.65	32	35	1.431	50%-70%	40-42	132	--	--	--	--
40	FINE SAND	171.8	.64	34	38	1.465	70%-80%	40-42	137	--	--	--	--
41	FINE SAND	170.1	.67	34	37	1.438	50%-70%	40-42	134	--	--	--	--
42	FINE SAND	126.7	.51	35	27	1.531	50%-60%	40-42	126	--	--	--	--
43	FINE SAND	123.2	.47	34	27	1.554	50%-60%	38-40	121	--	--	--	--
44	FINE SAND	125	.52	35	27	1.597	50%-60%	38-40	125	--	--	--	--
45	FINE SAND	138.8	.55	37	30	1.631	50%-60%	40-42	135	--	--	--	--
46	FINE SAND	105.6	.35	21	23	1.664	40%-50%	38-40	122	--	--	--	--
47	CLAY	8.2	.36	8	3	1.689	--	--	--	.33	2.2	.03	1
48	SILTY FINE SAND	65.5	.27	16	14	1.719	(40%	36-38	144	--	--	--	--
49	SILTY TO CLAYEY F.S.	31.2	.34	10	8	1.75	(40%	30-32	68	--	--	--	--
50	CLAY	3.9	.12	3	1	1.775	--	--	--	.05	3.3	.06	(1
51	SENSITIVE FINE GRAINED	2.2	.03	1	1	1.797	--	--	--	-.06	5.3	.09	(1
52	SENSITIVE FINE GRAINED	3.6	.04	1	1	1.819	--	--	--	.03	7.8	.05	1
53	SANDY CLAY	6.4	.09	3	2	1.846	--	--	--	.2	6.5	.02	1
54	SANDY CLAY	7	.11	3	2	1.874	--	--	--	.23	6	.04	1
55	SILTY TO CLAYEY F.S.	35.7	.24	11	8	1.905	(40%	30-32	76	--	--	--	--
56	SILTY FINE SAND	41.8	.16	10	9	1.935	(40%	32-34	91	--	--	--	--
57	CLAYEY FINE SAND	16.1	.14	6	4	1.966	(40%	30	35	--	--	--	--
58	SOFT CLAY TO MUCK	.1	.14	0	1	1.982	--	--	--	-.21	0	UD	(1
59	SOFT CLAY TO MUCK	.9	.01	0	0	1.998	--	--	--	-.17	8	UD	(1
60	SOFT CLAY TO MUCK	.7	.08	0	0	2.014	--	--	--	-.16	.9	UD	(1
61	SOFT CLAY TO MUCK	.4	.09	0	0	2.031	--	--	--	-.2	.4	UD	(1
62	SOFT CLAY TO MUCK	.2	.05	0	0	2.047	--	--	--	-.22	.4	UD	(1
63	SOFT CLAY TO MUCK	.01	.03	0	0	2.063	--	--	--	-.23	0	UD	(1
64	SOFT CLAY TO MUCK	.2	.07	0	0	2.079	--	--	--	-.23	.3	UD	(1
65	SOFT CLAY TO MUCK	.5	.11	0	1	2.095	--	--	--	-.21	.4	UD	(1
66	SOFT CLAY TO MUCK	.5	.14	0	1	2.111	--	--	--	-.21	.3	UD	(1
67	SOFT CLAY TO MUCK	.2	.1	0	0	2.127	--	--	--	-.23	.2	UD	(1
68	SOFT CLAY TO MUCK	.1	.15	0	0	2.143	--	--	--	-.24	.1	UD	(1
69	SOFT CLAY TO MUCK	.9	.16	0	1	2.16	--	--	--	-.2	.5	UD	(1
70	SOFT CLAY TO MUCK	.2	.05	0	0	2.176	--	--	--	-.24	.4	UD	(1
71	SOFT CLAY TO MUCK	.6	.01	0	0	2.192	--	--	--	-.22	4.1	UD	(1
72	SOFT CLAY TO MUCK	.2	.01	0	0	2.208	--	--	--	-.25	2.6	UD	(1
73	SENSITIVE FINE GRAINED	1.5	0	0	0	2.23	--	--	--	-.17	33.2	.13	(1
74	CLAY	1.7	.07	1	1	2.255	--	--	--	-.15	2.2	.14	(1
75	CLAY	2.2	.08	2	1	2.28	--	--	--	-.13	2.6	.11	(1
76	CLAY	1.5	.06	1	1	2.305	--	--	--	-.18	2.3	.16	(1
77	CLAY	1.3	.04	1	0	2.329	--	--	--	-.2	2.6	.19	(1
78	SENSITIVE FINE GRAINED	3.1	.02	1	1	2.351	--	--	--	-.09	11.7	.06	(1
79	SENSITIVE FINE GRAINED	2	.03	1	1	2.373	--	--	--	-.16	5.8	.1	(1
80	SANDY CLAY	17.4	.51	8	6	2.401	--	--	--	.8	3.3	.01	1-1.5
81	SOFT CLAY TO MUCK	3.9	.41	3	2	2.417	--	--	--	-.05	.9	UD	(1
82	SILTY FINE SAND	87	.63	31	20	2.448	(40%	34-36	191	--	--	--	--
83	FINE SAND	158.7	1.57	31	38	2.481	50%-60%	38-40	345	--	--	--	--

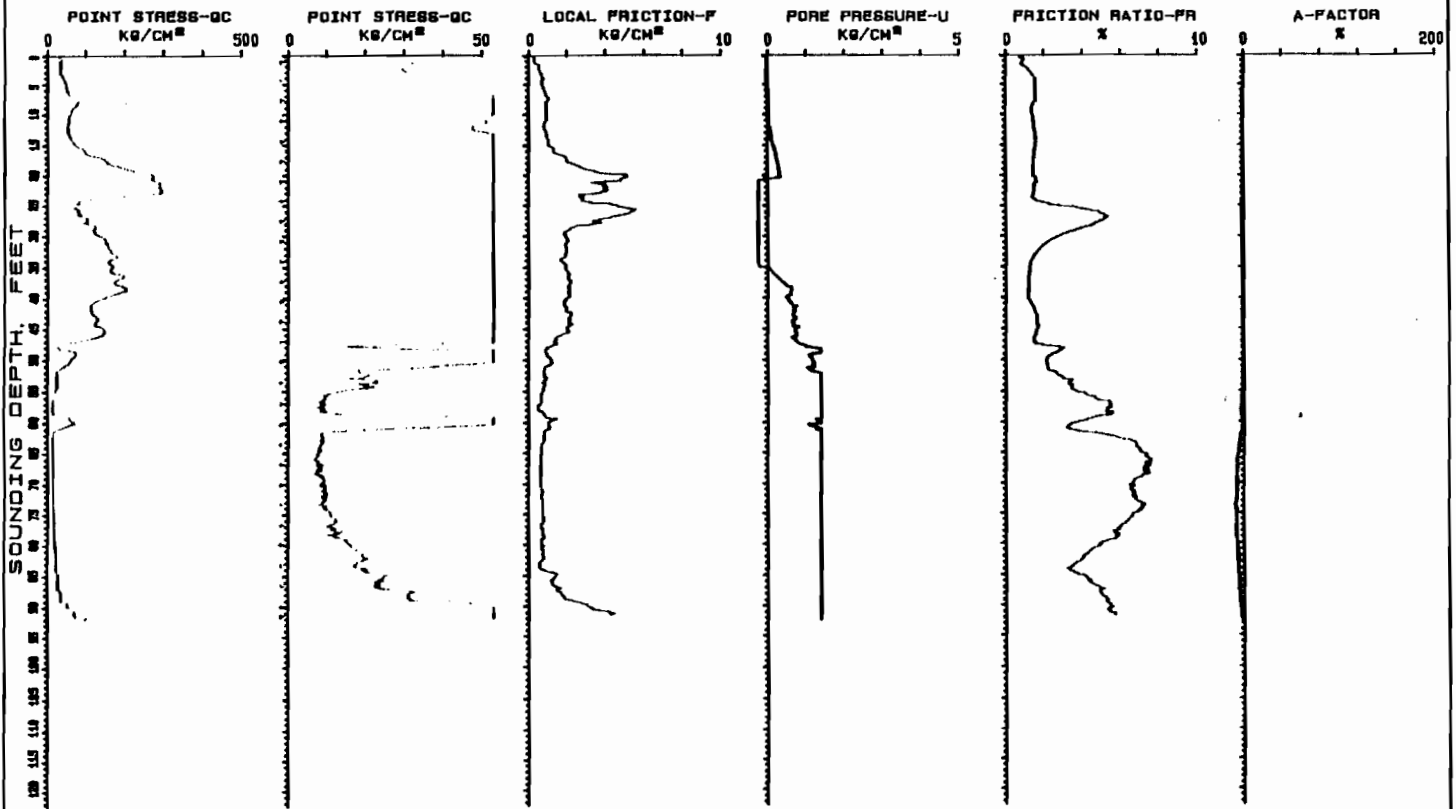
C-11 CONTINUED

- = $N = \text{POINT STRESS} \times (1.2 + .04 \times \text{FRICTION RATIO})$
- NORMALLY CONSOLIDATED SANDS
- FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES
- +++ FOR OVERCONSOLIDATED SANDS, YOUNG'S MODULUS MAY BE AS MUCH AS 2 TO 6 TIMES HIGHER
- ++++ NK OF 16 USED. FOR OVERCONSOLIDATED CLAYS. AN NK OF 17 IS SUGGESTED

THE ABOVE DATA WAS COMPUTED FOLLOWING 'BASIC' GUIDELINES BY P. K. ROBERTSON AND P. G. CAMPANELLA IN THE HANDBOOK
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PUBLISHED RESEARCH AND LOCAL EXPERIENCE GROWS.

PIEZOCONE SOUNDING TEST



* PUSH INTERRUPTED TO ADD ROD
PORE PRESSURE DECAY DATA MAY BE AVAILABLE

FILE # : ADVANCED TESTING
KISSIMMEE UTILITIES
KISSIMMEE FL
SOUNDING # : C-12
SOUNDING DATE 09/01/92 15:35:48

IN-SITU TECHNOLOGY SOIL BEHAVIOR TABLE FOR FLORIDA AND FLORIDA TYPE SOILS

JOB NAME ADVANCE TESTING
 JOB FILE NUMBER... KISSIMMEE UTILITIES KISSIMMEE FL.
 CONE SOUNDING..... C-12

DEPTH FEET	SOIL BEHAVIOR TYPE	QC (KG/CM2)	CF (KG/CM2)	N N' VALUES	VERTICAL EFFECTIVE STRESS (KG/CM2)	RELATIVE DENSITY (%)	FRICTION ANGLE (DEGREES)	YOUNG'S MODULUS (KG/CM2)	UNDRAINED SHEAR STRENGTH (KG/CM2)	SENSITIVITY	COMP.	OCR
				#		*	**	***	****			
1	SILTY TO CLAYEY F.S.	29.3	.23	3 7	.048	50%-60%	46	54	--	--	--	--
2	CLAYEY FINE SAND	28	.44	11 7	.097	50%-60%	44-46	51	--	--	--	--
3	CLAYEY FINE SAND	29.9	.51	11 8	.146	50%-60%	44-46	55	--	--	--	--
4	SILTY TO CLAYEY F.S.	37.9	.65	12 10	.195	60%-70%	42-44	63	--	--	--	--
5	SILTY TO CLAYEY F.S.	43.1	.59	14 11	.244	60%-70%	42-44	54	--	--	--	--
6	SILTY TO CLAYEY F.S.	47.6	.72	15 12	.293	60%-70%	42-44	104	--	--	--	--
7	SILTY TO CLAYEY F.S.	57.4	.83	19 15	.341	60%-70%	42-44	125	--	--	--	--
8	SILTY FINE SAND	77.6	.98	19 19	.39	70%-80%	42-44	170	--	--	--	--
9	SILTY TO CLAYEY F.S.	65.1	.81	21 16	.439	60%-70%	42-44	142	--	--	--	--
10	SILTY TO CLAYEY F.S.	55	.82	18 14	.488	60%-70%	40-42	121	--	--	--	--
11	SILTY TO CLAYEY F.S.	50.8	.81	16 13	.519	50%-60%	40-42	111	--	--	--	--
12	SILTY TO CLAYEY F.S.	47.6	.72	15 12	.549	40%-50%	40-42	104	--	--	--	--
13	SILTY TO CLAYEY F.S.	49.9	.8	16 13	.58	40%-50%	40-42	105	--	--	--	--
14	SILTY TO CLAYEY F.S.	57.1	.88	19 15	.611	50%-60%	40-42	125	--	--	--	--
15	SILTY TO CLAYEY F.S.	67.5	.94	22 17	.642	50%-60%	40-42	146	--	--	--	--
16	SILTY FINE SAND	92.5	1.22	23 23	.672	60%-70%	42-44	203	--	--	--	--
17	SILTY FINE SAND	121.7	1.7	30 31	.703	70%-80%	42-44	257	--	--	--	--
18	SILTY FINE SAND	154.8	2.02	38 39	.734	80%-90%	44-46	340	--	--	--	--
19	SILTY FINE SAND	198.2	2.68	49 50	.765	80%-90%	44-46	436	--	--	--	--
20	SILTY FINE SAND	265.8	4.09	66 70	.736	90%	46-48	584	--	--	--	--
21	SILTY FINE SAND	268.8	4.67	67 72	.826	90%	46-48	591	--	--	--	--
22	FINE SAND	283.1	3.84	56 72	.859	90%	46-48	622	--	--	--	--
23	SILTY FINE SAND	290.1	3.87	70 72	.89	90%	44-46	616	--	--	--	--
24	SILTY TO CLAYEY F.S.	104.2	2.57	34 31	.321	60%-70%	40-42	229	--	--	--	--
25	STIFF CLAY	62.7	3.74	62 27	.952	--	--	--	3.83	1.6	UD	16
26	CLAY	76.1	5.39	76 37	.977	--	--	--	4.66	1.4	UD	16
27	STIFF CLAY	93.4	4.5	93 37	1.007	--	--	--	5.74	2	UD	16
28	CLAYEY FINE SAND	94	3.48	37 33	1.038	50%-60%	40-42	206	--	--	--	--
29	SILTY TO CLAYEY F.S.	114.8	2.07	36 31	1.069	60%-70%	40-42	252	--	--	--	--
30	SILTY FINE SAND	131.1	1.76	32 33	1.1	60%-70%	40-42	236	--	--	--	--
31	SILTY FINE SAND	148.6	1.98	37 38	1.131	70%-80%	42-44	326	--	--	--	--
32	SILTY FINE SAND	158.1	1.85	39 39	1.161	70%-80%	42-44	347	--	--	--	--
33	FINE SAND	171.3	1.85	34 42	1.195	70%-80%	42-44	376	--	--	--	--
34	FINE SAND	156.3	1.6	31 38	1.228	70%-80%	42-44	343	--	--	--	--
35	FINE SAND	164.9	1.82	32 40	1.251	70%-80%	42-44	362	--	--	--	--

1-12 CONTINUED

38	FINE SAND	170.7	1.33	34	42	1.334	70%-80%	42-44	375	--	--	--	--
39	FINE SAND	178.5	1.33	35	44	1.337	70%-80%	42-44	383	--	--	--	--
40	FINE SAND	183	1.37	36	45	1.351	70%-80%	42-44	402	--	--	--	--
41	FINE SAND	186.5	1.33	37	45	1.334	70%-80%	42-44	410	--	--	--	--
42	SILTY FINE SAND	141.1	1.06	35	35	1.425	50%-70%	40-42	310	--	--	--	--
43	SILTY TO CLAYEY F.S.	107.5	1.73	32	33	1.455	50%-60%	38-40	338	--	--	--	--
44	SILTY TO CLAYEY F.S.	105.4	1.36	35	33	1.466	50%-60%	38-40	340	--	--	--	--
45	SILTY TO CLAYEY F.S.	120.2	2.15	40	33	1.517	50%-60%	38-40	354	--	--	--	--
46	SILTY TO CLAYEY F.S.	119.4	2	39	32	1.548	50%-60%	38-40	352	--	--	--	--
47	SILTY FINE SAND	140.5	1.36	35	35	1.578	50%-70%	40-42	305	--	--	--	--
48	SILTY FINE SAND	139.8	1.31	34	35	1.509	50%-70%	40-42	307	--	--	--	--
49	SILTY TO CLAYEY F.S.	92.3	1.33	27	22	1.64	40%	35-38	181	--	--	--	--
50	CLAY	15.4	1.21	15	8	1.665	--	--	--	.78	1.2	.01	1-1.5
51	SILTY FINE SAND	69.2	.3	17	17	1.696	40%	35-38	152	--	--	--	--
52	SILTY TO CLAYEY F.S.	56.4	1.03	13	15	1.725	40%	34-35	134	--	--	--	--
53	CLAYEY FINE SAND	39.1	1.06	15	12	1.757	40%	32-34	65	--	--	--	--
54	SILTY CLAY TO CLAY	17.6	.37	11	5	1.784	--	--	--	.3	2.6	.01	3
55	CLAY	16.5	.74	16	6	1.809	--	--	--	.63	2.2	.01	1-1.5
56	SILTY CLAY TO CLAY	13.8	.33	12	7	1.837	--	--	--	.37	2.6	.01	3
57	CLAY	12.4	.35	12	5	1.862	--	--	--	.57	1.9	.02	1-1.5
58	CLAY	8.8	.52	8	4	1.887	--	--	--	.34	1.7	.02	1
59	CLAY	8.4	.54	8	4	1.911	--	--	--	.31	1.5	.02	1
60	CLAY	8.3	.4	8	3	1.936	--	--	--	.3	2	.03	1
61	CLAYEY FINE SAND	39.2	.72	15	11	1.967	40%	30-32	66	--	--	--	--
62	SILTY TO CLAYEY F.S.	66.5	1.23	22	18	1.998	40%	34-36	146	--	--	--	--
63	SANDY CLAY	28.2	1	14	10	2.025	--	--	--	1.53	2.8	.02	3
64	CLAY	7.9	.72	7	4	2.05	--	--	--	.25	1	.03	1
65	CLAY	7.9	.68	7	4	2.075	--	--	--	.25	1.1	.03	1
66	CLAY	7.7	.53	7	4	2.1	--	--	--	.24	1.4	.03	1
67	CLAY	7	.56	7	4	2.125	--	--	--	.19	1.2	.03	(1)
68	CLAY	6.2	.52	6	3	2.15	--	--	--	.14	1.1	.04	(1)
69	CLAY	7.3	.55	7	4	2.175	--	--	--	.21	1.3	.03	(1)
70	CLAY	7.2	.53	7	4	2.2	--	--	--	.2	1.3	.03	(1)
71	CLAY	6.4	.48	6	4	2.224	--	--	--	.27	1.7	.02	1
72	CLAY	6.2	.51	6	4	2.249	--	--	--	.25	1.6	.03	1
73	CLAY	9.1	.58	9	4	2.274	--	--	--	.31	1.5	.02	1
74	CLAY	8.4	.61	8	4	2.299	--	--	--	.26	1.3	.02	1
75	CLAY	8.4	.64	8	4	2.324	--	--	--	.25	1.3	.02	1
76	CLAY	9	.63	9	4	2.349	--	--	--	.29	1.4	.02	1
77	CLAY	10.6	.62	10	5	2.374	--	--	--	.39	1.6	.02	1
78	CLAY	12.1	.66	12	5	2.399	--	--	--	.48	1.7	.02	1
79	CLAY	9.8	.59	9	4	2.424	--	--	--	.33	1.6	.02	1
80	CLAY	12.2	.62	12	5	2.449	--	--	--	.47	1.9	.02	1
81	CLAY	13.8	.7	13	6	2.474	--	--	--	.57	1.9	.01	1
82	SILTY CLAY TO CLAY	15.7	.53	10	5	2.501	--	--	--	.69	2.9	.01	1-1.5
83	SANDY CLAY	17.6	.58	8	6	2.528	--	--	--	.8	3	.01	1-1.5
84	SANDY CLAY	19.3	.62	9	6	2.556	--	--	--	.9	3	.01	1-1.5
85	SANDY CLAY	17	.55	8	6	2.583	--	--	--	.76	3.1	.01	1-1.5
86	SANDY CLAY	20.3	.48	10	6	2.61	--	--	--	.96	4.1	.02	1-1.5
87	CLAY	26.4	1.21	26	10	2.635	--	--	--	1.34	2.1	UD	3
88	CLAY	22.8	1.1	22	9	2.66	--	--	--	1.11	2	UD	1-1.5
89	CLAY	24.4	1.36	24	10	2.685	--	--	--	1.21	1.7	UD	1-1.5

C-12 CONTINUED

88	SILTY CLAY TO CLAY	31.6	1.46	81	82	2.712	--	--	--	1.65	2.1	JD	3
89	CLAY	33.9	1.75	83	84	2.737	--	--	--	1.73	1.8	JD	3
90	CLAY	43.2	2.73	49	51	2.762	--	--	--	2.74	1.7	JD	3
91	STIFF CLAY	62.9	3.47	62	65	2.793	--	--	--	3.6	1.6	GD	6

C-13 CONTINUED

- * $N_1 = \text{POINT STRESS} \times (1.2 + 0.04 \times \text{FRICTION RATIO})$
- * NORMALLY CONSOLIDATED SANDS
- ** FOR OVERCONSOLIDATED SANDS, SLIGHTLY REDUCE ABOVE FRICTION ANGLES
- *** FOR OVERCONSOLIDATED SANDS, YOUNG'S MODULUS MAY BE AS MUCH AS 3 TO 6 TIMES HIGHER
- **** NK OF 16 USED. FOR OVERCONSOLIDATED CLAYS, AN NK OF 17 IS SUGGESTED

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PUBLISHED RESEARCH AND LOCAL EXPERIENCE GROWS.

Appendix G

Soil Resistivity Test Results

DATE: October 14, 1992

CANE ISLAND

WEATHER: PTLY CLOUDY, DRY 80°F

TEST LOCATION: SR-1

Wenner Method

Spacing (ft.)	Power				Potentials	
	Volts		Milliamperes		Millivolts	
	E-W	N-S	E-W	N-S	E-W	N-S
2.5	210	180	4	5	98 x 100	100 ⁺ x 100
5	202	210	4	5	61 x 100	73 x 100
10	198	210	5	5	22 x 100	29 x 100
15	190	180	5	6	90 x 10	12 x 100
20	160	180	6	5	57 x 10	55 x 10
25	180	155	5	6	29 x 10	32 x 10
30	205	150	5	6	16 x 10	26 x 10



**Advanced Testing
Laboratories of Florida, Inc.**
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

File No.:

Scale:

(FINE ISLAND)

Kewner Method

Kewner Method

Spacing (ft.)	Power				Potential	
	Volts		Milliampers		Millivolts	
	E-W	N-S	E-W	N-S	E-W	N-S
2.5	160	170	6	6	94 x 100	88 x 100
5	150	180	6	5	54 x 100	42 x 100
10	160	170	6	6	16 x 100	22 x 100
15	160	210	6	5	74 x 10	70 x 10
20	200	160	4	6	34 x 10	56 x 10
25	150	150	6	6	28 x 10	28 x 10
30	150	150	6	6	16 x 10	24 x 10



Scale:

(FIVE ISLAND)

Weaver Method

Weaver Method

 Advanced Testing Laboratories of Florida, Inc. Consultants in Geotechnical Engineering, Construction Materials Testing and Structural Threshold Inspection		
	File No.:	Scale:



**Advanced Testing
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Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

File No.:

Scale:

CHINE ISLAND

Canner Method

TEST LOCATION: SR-5

Canner Method

**Advanced Testing
Laboratories of Florida, Inc.**
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

File No.:

Scale:

(FINE ISLAND)

Wenner Method

TEST LOCATION: SR-6

**Advanced Testing
Laboratories of Florida, Inc.**
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

File No.:

Scale:

(A) JE ISLAND

Wiener Method

Wiener Method

Spacing (ft.)	Power				Polarization	
	Volts		Milliampères		Millivolts	
	E-W	N-S	E-W	N-S	E-W	N-S
2.5	210	195	4	6	100+ x 100	100+ x 100
5	200	205	5	5	68 x 100	83 x 100
10	210	200	5	5	32 x 100	43 x 100
15	160	180	6	6	22 x 100	23 x 100
20	155	175	6	6	15 x 100	15 x 100
25	170	160	6	6	78 x 10	96 x 10
30	180	190	6	6	42 x 10	57 x 10



**Advanced Testing
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Materials Testing and Structural Threshold Inspection

File No.:

Scale:

CANE ISLAND

TEST LOCATION: SR-8

Werner Method

File No.:

Scale:

CANE ISLAND

TEST LOCATION: SR-9

Wenner Method

**Advanced Testing
Laboratories of Florida, Inc.**
Consultants in Geotechnical Engineering, Construction
Materials Testing and Structural Threshold Inspection

File No.:

Scale:

CANE ISLAND

TEST LOCATION: SR-10

Keener Method

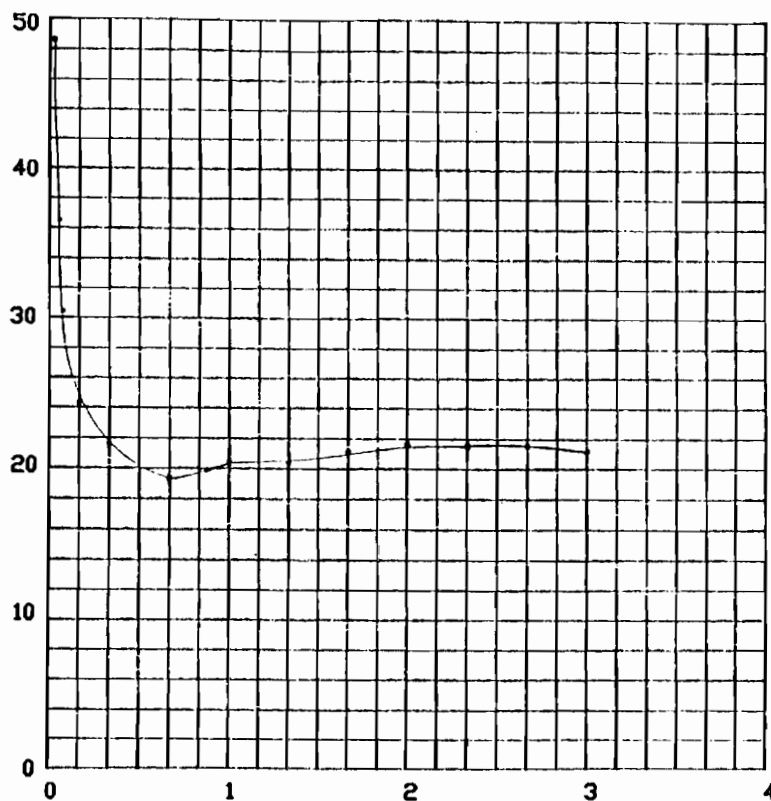
File No.:

Scale:

Appendix H

Double Ring Infiltrometer Test Results

Infiltration Rate, in/hr



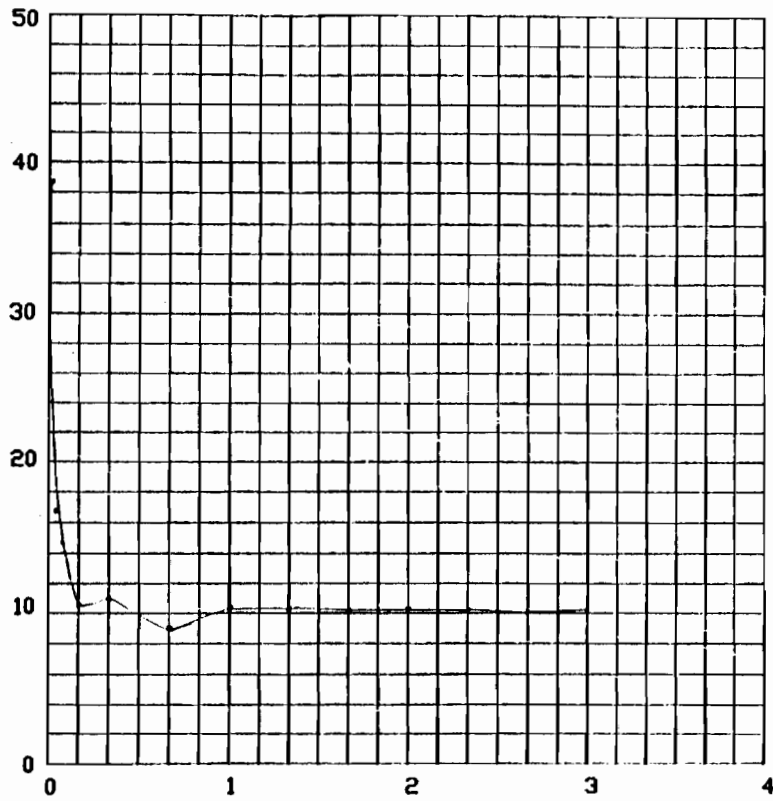
Time, hours

Cane Island

Test: I-1

Combustion Turbine Project

Infiltration Rate, in/hr



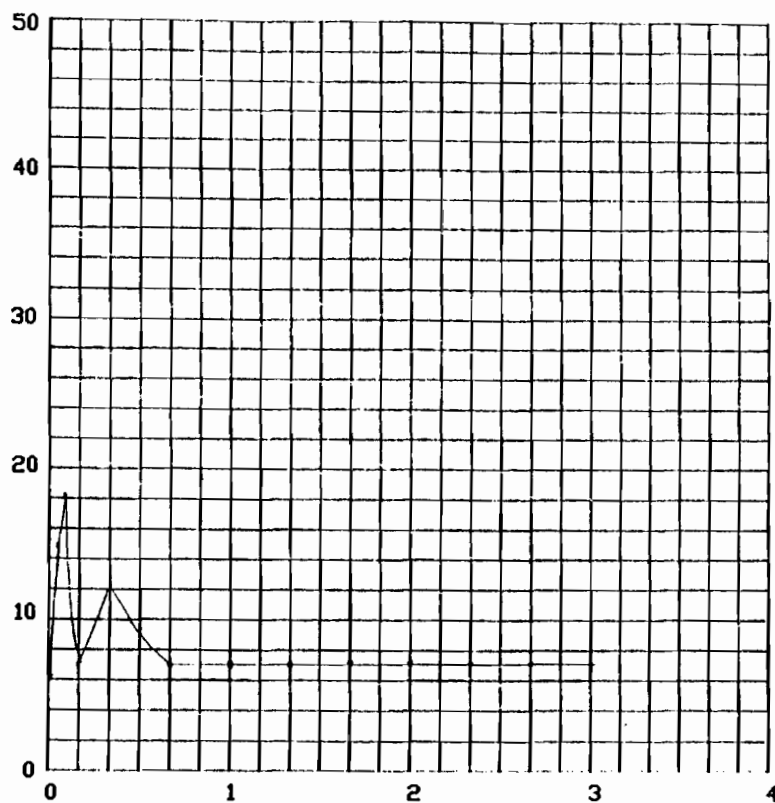
Time, hours

Cane Island

Combustion Turbine Project

Test: I-2

Infiltration Rate, in/hr

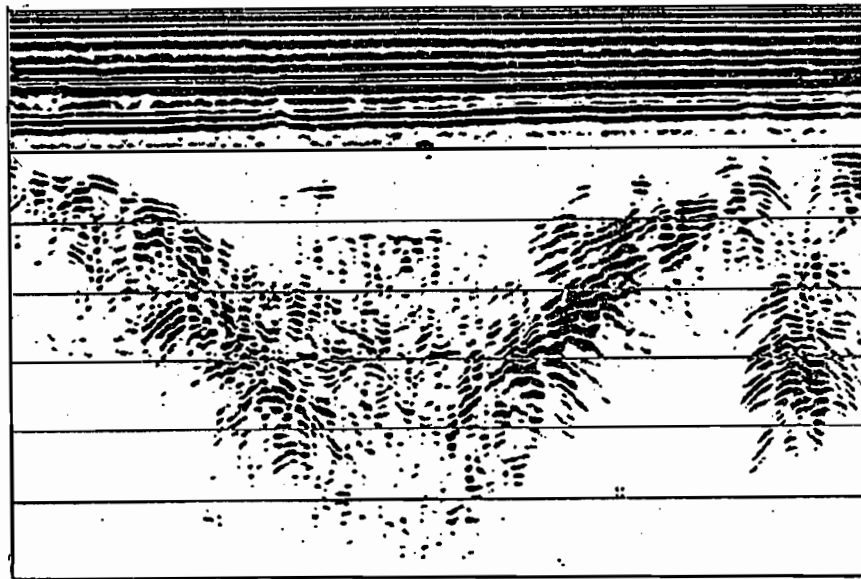


Time, hours

Test: I-3

Cane Island
Combustion Turbine Project

KARSTIC FOUNDATION HAZARDS AT THE CANE ISLAND SITE, OSCEOLA COUNTY, FLORIDA



A report prepared for

BLACK & VEATCH

Power Division

P.O. Box 8405

Kansas City, Missouri 64114

By

P.E. LAMOREAUX & ASSOCIATES, INC.

Consulting Hydrologists, Geologists,
Engineers, & Environmental Scientists

P.O. Box 4412

Oak Ridge, Tennessee 37831

FEBRUARY, 1993

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FEBRUARY 26, 1993

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GLOSSARY OF ACRONYMS AND ABBREVIATIONS USED

BLS: Below land surface.

EM: Electro-magnetic.

GPR: Ground penetrating radar.

Mhz: MegaHertz

MSL: Mean sea level (assumed to be the same as NGVD: National Geodetic Vertical Datum.)

NS: Nanoseconds (10^{-9} seconds).

N value: The number of blows of a standard hammer required to drive the sampling device one foot into the sediment being tested in an SPT boring (see below). The N value is an indicator of the bearing strength of the sediment.

PELA: P.E. LaMoreaux & Associates, Inc.

SPT: Standard Penetration Test. A test of soil bearing strength conducted by drilling a hole into the sediment. A standard sampling device (a split-spoon sampler) is then lowered to the bottom of the hole and driven into the sediment with a standard weight hammer falling a specified distance. The number of blows required to drive the sampler one foot is the N value for the sediment at that level.

USGS: United States Geological Survey.

WR: Weight of rod. In the SPT test (see above), conditions where the

sampler sinks the prescribed one foot under the weight of the rod alone, without dropping the hammer. I.e., $N = 0$; the sediment has zero bearing strength.

KARSTIC FOUNDATION HAZARDS at the CANE ISLAND SITE, OSCEOLA COUNTY, FLORIDA

SUMMARY

Two of eleven foundation borings at the Cane Island power plant site penetrated an interval of zero bearing strength ("weight of rod") sediment and unusually deep limestone bedrock: conditions indicative of potential sinkhole subsidence. P.E. LaMoreaux & Associates, Inc., consulting hydro-geologists, was engaged to investigate the extent of this hazard.

Sinkholes are characteristic of a karst terrane, a type of landscape formed on unusually soluble rock, most frequently limestone. In a karst terrane drainage is internal: downward into the limestone through dissolved channels. If unconsolidated sediments overlay the limestone, these may be eroded downward through these channels resulting in depressions in the land surface: sinkholes. If the near surface sediments are cohesive they may remain unaltered while erosion proceeds upward from below. Eventually the surface will either collapse suddenly or gradually "sag" downward due to the lack of support from below.

The subsurface zone which is being undermined by karstic erosion is called a "ravelling" zone by engineers. It is characterized by very low bearing strength sediments: in the SPT test, 0 to 1 or 2 blows per foot. Because these are located over channels where the limestone has been intensely dissolved, the depth to limestone is greater.

Obviously such ravelling zones are foundation hazards, particularly for heavy loads. The downward erosion process is continuous over time, although it may be sporadic in the short term. Sinkholes may have formed and been covered over during "temporary" periods of inactivity. Such features are called buried sinkholes and they will most probably continue to develop. The presence of a ravelling zone at depth indicates that karstic erosion is continuing.

The Orlando, Florida, area is a mantled karst terrane: that is, the limestone is overlain by younger, unconsolidated sediments. The Cane Island site is located southwest of Orlando. It is an elevated sandy area, approximately one mile long and 1,000 feet wide, surrounded by swamps.

Beneath the Orlando area, the Ocala Group limestones of Eocene age are overlain by clayey sediments of Miocene age, the Hawthorn Group, and more recent sands at the surface. The total thickness of unconsolidated clays and sands over the limestone varies from zero to 200 feet. At Cane Island the depth to limestone is approximately 70 feet, except beneath buried sinkholes.

The Ocala limestone is the uppermost in a thick sequence of limestones which are riddled with dissolved cavities: the highly permeable Floridan Aquifer. Water in this aquifer is confined by the clays above the limestone. An unconfined aquifer in the surficial sands is perched above the clay. The surface water table is generally higher than the artesian pressure (potentiometric level) of the Floridan

Aquifer, driving recharge downward through the clay. It is this downward movement of water which erodes the clay downward into the dissolved cavities in the limestone causing sinkholes.

The landforms (geomorphology) of the Orlando area are also related to areas of sinkhole occurrence. The western portion of the metropolitan area is located on three high, sandy ridges, whereas the eastern part is generally low, swampy ground. Recharge rates are highest beneath the three ridges and lower in the swampy plain. Most sinkholes also develop on the ridges.

Cane Island is similar to the ridges, although on a much smaller scale. The water table beneath the island is higher than beneath the surrounding swamp, causing greater recharge which is the driving force for karstic erosion.

Data compiled by the Florida Sinkhole Research Institute indicates that the risk of sudden sinkhole collapse is **very low** at the site. However, the potential hazard from buried sinkholes is still present. Slow, gradual subsidence may occur over these zones, particularly under heavy foundation loads. Structures only partially over a buried sinkhole may experience differential settlement.

Data from exploratory drilling is not sufficient to document this hazard: The borings are too far apart. A continuous cross-section, such as can be made with ground penetrating radar, is highly cost-effective. Ground penetrating radar (GPR) emits a beam of radar waves downward into the ground and detects

the reflections of these waves from various geologic features. The antenna is pulled across the ground surface, producing a continuous cross-section. Because GPR generally performs well in sandy areas, it was tried here.

GPR profiles over the anomalous borings demonstrated clearly that these were buried sinkholes and that such features were more extensive than interpretation of the SPT results had indicated. In order to completely assess the extent of this potential hazard, thirty-five west-to-east GPR profiles, 50 feet apart, were made, covering most of the southern half of Cane Island. The data from the profiles were compiled onto a large-scale map of the island delineating areas where ravelling zones were probably present. The original foundation borings and supplementary data all corroborated the GPR findings on the map. Uncontrolled GPR profiles on the north end of Cane Island indicate that a similar problem should be anticipated there.

The buried areas of karstic erosion shown on the map are significant long-term foundation dangers for heavy structures. Design modification is necessary to correct the problem. It is recommended that a limited number of additional SPT borings be made where the hazardous zones underlay the footprint of a structure in order to provide the detailed assessment of the conditions which is necessary to formulate the most cost-effective corrective measures.

INTRODUCTION, SCOPE, AND PURPOSE

This investigation was undertaken at the request of Black and Veatch, consulting engineers. Black and Veatch has been engaged by the Kissimmee Utility Authority to design and construct a Combustion Turbine Electrical Generating Plant at a site near Intercession City, Florida. The site area is locally known as Cane Island.

As part of the assessment of foundation conditions at the site, Black and Veatch had eleven SPT borings and twelve electric piezocone soundings performed and 4 piezometers installed. In addition, infiltration studies, shallow test pits and near-surface electrical resistivity measurements were made. The geotechnical tests were performed by Advanced Testing Laboratories of Florida, Inc. These investigations were conducted within the area of Unit I and II of the planned construction, on the southern half of Cane Island (Black and Veatch, 1992).

Two of the test borings, B-8 and B-10, encountered significant sections, *circa* 30' of "weight of rod" materials and unusually deep limestone bedrock. These two conditions are characteristic of "ravelling zones": zones within the unconsolidated overburden where karstic erosion is undermining the area. When such zones migrate to the surface by continual upward collapse, the result is ground surface subsidence in the form of a sinkhole, whether it occurs slowly and gradually, or catastrophically. In either case, the results are damaging to man's structures.

In order to assess the extent and severity of these potential problems, Black and Veatch engaged P.E. Lamoreaux and Associates, Inc. (PELA), consulting hydrogeologists with a recognized expertise in karst studies, to conduct a detailed site evaluation. In brief, this evaluation was to include:

1. A review of background literature;
2. An evaluation of the site SPT borings and piezocone soundings;
3. A review of aerial photography of the site;
4. A site reconnaissance;
5. A detailed geophysical study of the site utilizing such techniques as are appropriate to **thoroughly** assess the extent of the karstic hazard in the most **cost-effective** manner;
6. A report of the investigation.

This report constitutes the results of that study.

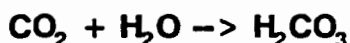
KARST PROCESSES IN CENTRAL FLORIDA AND THE FORMATION OF SINKHOLES

Sinkholes are closed, basin-shaped depressions in the land surface formed by dissolution of the bedrock. They are generally of moderate dimensions, measured in ten's and even hundred's of feet in diameter. Sinkholes function as drainage basins, funneling water down into the subsurface. They owe their origin to the fact that the underlying bedrock dissolves in ground

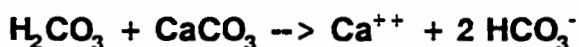
water more rapidly than most rocks. Most sinkholes are formed in limestone and dolomite, although a few less common rocks are also soluble.

Sinkholes are only one part of the total landscape that is formed on rocks that are relatively easily dissolved. The solution process also creates unusually large pores and channels in the bedrock, even caves, through which ground water may move readily. Where this ground water resurges to the land surface, large springs occur, including some of the largest in the world. This total landscape characteristic of soluble rock areas is known as a karst terrain. Much of Florida is a classic, although somewhat atypical, karst terrain. The following discussion will explain, in a general way, how this landscape forms.

As rainwater falls and infiltrates through the soil it absorbs carbon dioxide from the atmosphere and even more from the soil, which has high CO₂ levels generated by decaying organic matter. This makes the recharge water weakly acidic as carbonic acid. It is this acid which attacks limestone (CaCO₃) and dissolves it.



**carbon dioxide gas + water →
(yields) carbonic acid;**



**carbonic acid + (attacks)
limestone → (yields) calcium ions
and bicarbonate ions (dissolved in
water).**

Thus, rainwater percolates downward through the soil and unconsolidated sediment overlying the limestone, becoming a weak solution of carbonic acid as it does. When it reaches the limestone it continues moving downward through any interconnected pores or fractures, under the force of gravity. As the weak carbonic acid flows downward through the limestone, it dissolves and enlarges any pores or cracks through which it flows. The most favored vertical pathway dissolves more rapidly than the surrounding areas, because it carries more water. Because it is now larger, it can transmit water in ever greater quantities, thus pirating drainage from the surrounding rock mass. This "self-accelerating" process results in a few greatly enlarged tubes or pipes permeating down through the limestone, with little rock dissolved in between.

Because the water is most highly charged with carbonic acid when it first encounters the limestone, the solution process is most rapid at the limestone surface and decreases as the water seeps downward into the limestone and the CO₂ is consumed. However, for various complex reasons there is still some dissolving power remaining, even when the infiltrating water reaches the zone where all pores are already full of water--the saturated or phreatic zone. Within the saturated zone the ground water moves laterally to points of discharge, and it continues to dissolve the rock through which it flows, albeit very slowly. In the Tertiary limestones present in Florida there is sufficient original porosity for the water to move through both pores and fractures. Thus,

the end result of this continued solution is a rock mass riddled with enlarged pores, and possibly with caves dissolved along favorable fractures. The foregoing is a generalized and simplified explanation. For more details see Beck and Wilson (1987).

This karstic framework was long ago imprinted upon the Tertiary limestones underlying most of Florida. Since this process began, these limestones have also been covered over by the sea and blanketed with overlying layers of marine and coastal sediment--generally clays and sands. This results in a *mantled karst terrain*, one where the limestone is mantled by overlying layers of unconsolidated sediment. This geologic framework will be described in more detail in a later section.

Although there are generally five different types of sinkholes identified by geologists (Beck, 1988; White, 1988; Waltham, 1989), these are the result of only two different processes: the transport of surficial material downward along solutionally-enlarged channels, or collapse of the rock roof over large bedrock cavities (Fig. 1).

It was explained above how the natural solution process dissolves the limestone most rapidly at its surface. If the limestone is bare, or almost bare (that is, exposed at the ground surface), water flows over the limestone surface toward the dissolved "pipes" and then downward. As water converges on these pipes it dissolves the limestone around them resulting in a bowl-shaped depression. This is the classic **solution sinkhole** (Fig. 1). It develops imper-

ceptibly and is not generally an engineering hazard except for the fact that additional voids may underlie the solution pipe.

If the limestone contains some insoluble minerals in addition to the CaCO_3 , these may be left behind on the surface as a thin soil residue which tends to accumulate in the bottom of these sinkholes. The slopes of the basin, however, are generally rocky. If a sufficient mantle of residual soil accumulates, the basin may become plugged and a small sinkhole lake may result.

If the residual soil becomes thick enough, the terrain is termed a subsoil karst. However, if the limestone is mantled by sediments of an outside origin (for example, marine sands), the terrain is termed a mantled karst. In terms of the processes which will form sinkholes, the two situations are the same. The overlying, unconsolidated sediment may simply be termed "cover" and the resulting sinkholes are cover collapse or cover subsidence sinkholes (see Fig. 1). Conditions within the limestone are similar to those described previously, but the basin and the solution pipe which drains it are covered and infilled with loose sediment. The Orlando area is a mantled karst.

Precipitation will now infiltrate through the sediment and seep down to the limestone surface. There it will migrate down the basin slope to the solution pipe which drains it, and through that deeper into the limestone aquifer. The loose sediment directly above the solution pipe may gradually erode and be

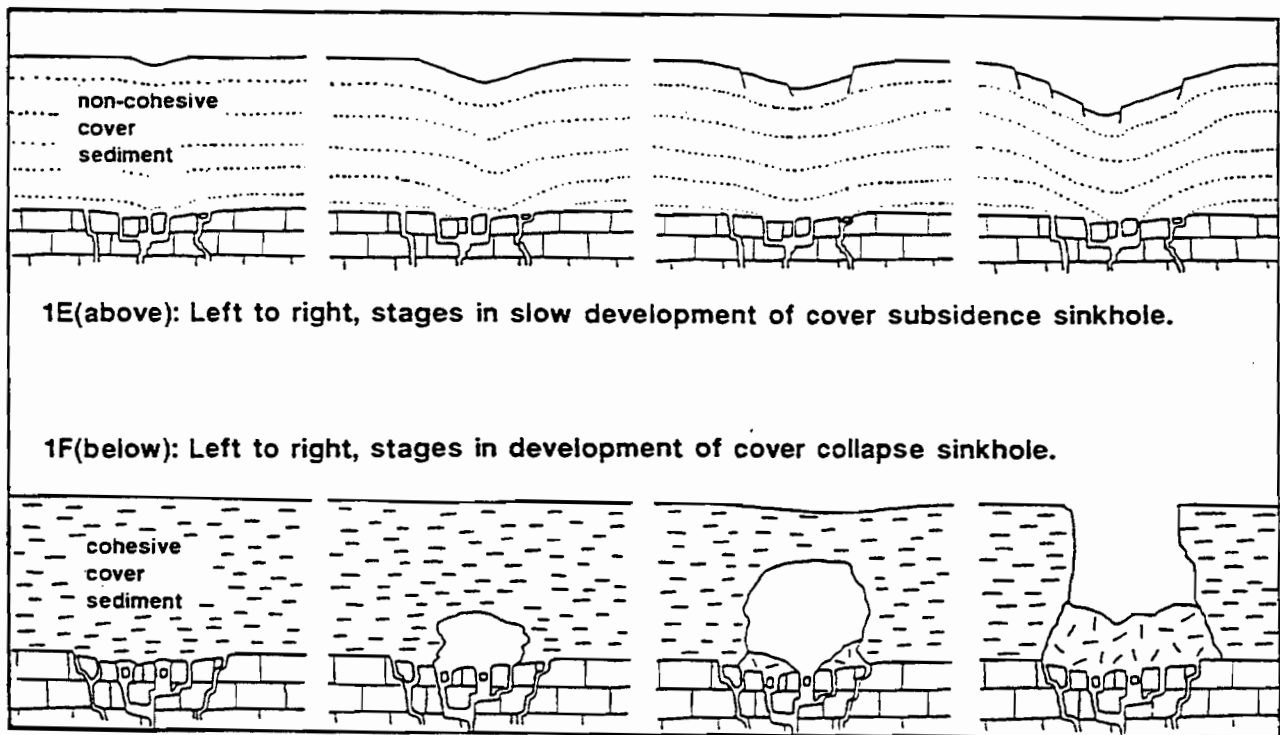
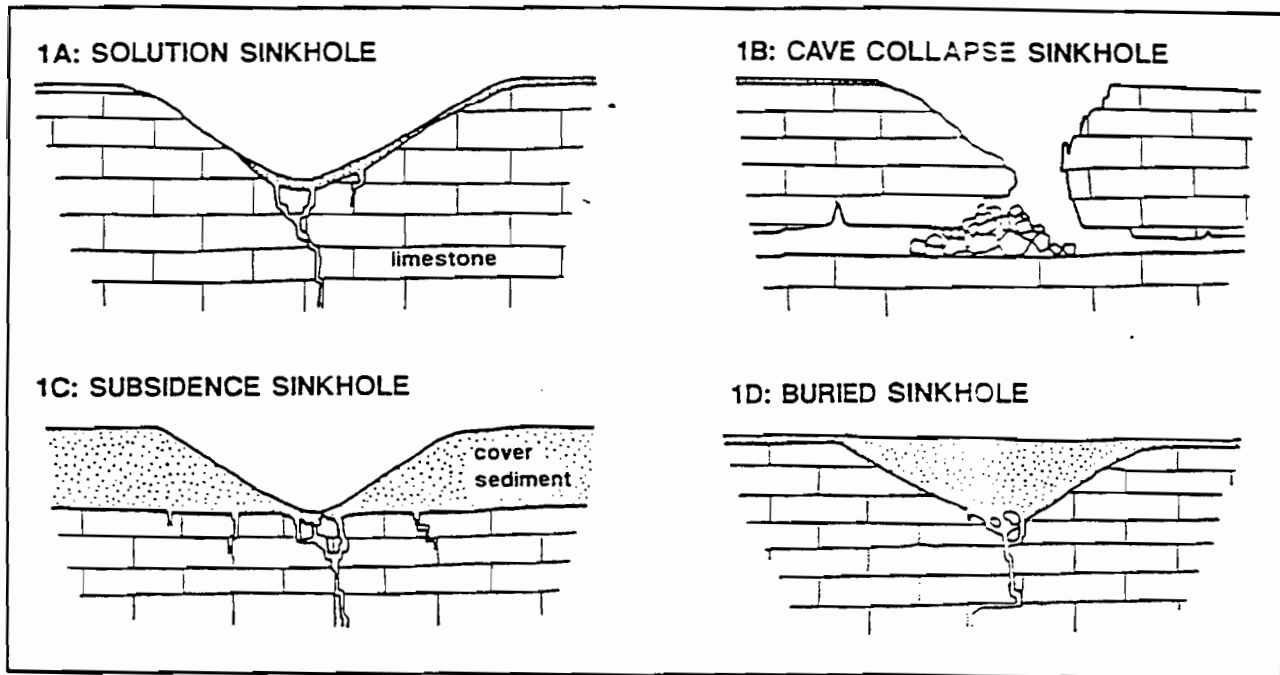


Figure 1: Types of sinkholes. E and F are subtypes of C. The process of origin is discussed in the text. (Diagram modified after Culshaw & Waltham, 1987).

transported down the pipe, with the aid of infiltrating water, leaving a soil cavity over the pipe.

If the sediment overlying the limestone is very loose, the process of downward erosion and surface subsidence may take place gradually and continuously. As sand is transported down the pipe grain by grain, sand from above settles down to take its place. A cavity is never formed, but the sediment is slowly eroded from beneath the ground surface, causing a slow, gradual settling. The rate of subsidence may be only inches per year, but it is still a sinkhole: **a cover subsidence sinkhole** (Fig. 1). Such sinkholes can cause cracking of rigid structures built over the subsiding area and have caused homes to be condemned and declared a total loss.

Such gradual sinkhole development may also occur where a clay stratum overlies the limestone and is below the water table. As support is eroded from beneath the clay by erosion down the solution pipe. This loose, very plastic, water-saturated clay may "sag" gradually under the weight of the overlying sediment or structures. Because the basic cause of this subsidence is erosion of material downward into the dissolved voids in the limestone, this is a sinkhole. Because the cover sediment gradually subsides, this too is a cover subsidence sinkhole.

If the sediment is somewhat cohesive, a void may form in the sediment overlying the limestone and gradually enlarge over time. More cohesive strata within the overburden

sediment may cause the cavity to expand laterally, with a flat roof. Eventually the upward enlargement of the void may leave only a thin roof of soil which is not strong enough to support its own weight, resulting in collapse. At that moment, a large, gaping sinkhole suddenly appears in the ground surface: **a cover collapse sinkhole** (Fig. 1). The limestone and the pipe may be visible in the bottom of the hole.

However, the scenario is often more innocuous. If the mantling sediment is relatively noncohesive, the soil cavity may erode upward rapidly, without becoming very large. In fact, as the roof of the cavity "crumbles" and is deposited on the floor of the cavity, the cavity simply migrates upward without increasing in size, like a bubble rising through a liquid. When this reaches the surface a small hole suddenly appears; this is also a cover collapse sinkhole. In this case, all that is visible in the hole is loose overburden sediment. The engineering implications and hazards to man's structures resulting from cover collapse sinkholes are obvious. It is important to understand that the position of the solution pipe and the processes operating in the subsurface have not changed and that this erosion process will continue with repeated collapses. However, the time frame is variable, sporadic, and unpredictable.

The sudden collapse of a cover collapse sinkhole creates a bowl-shaped, funnel-shaped, or cylindrical depression in the ground surface. However, after the sudden development of this basin, natural processes will begin to fill it. The sides will erode outward and the eroded

sediment will infill the basin, creating a broader, shallower depression. This low area will also collect runoff and sediment from the surrounding area. It may be wet and swampy, possibly even forming a small lake, where organic growth will infill the basin over time. These processes, and others, may infill the sinkhole completely, eventually leaving no sign of its previous existence. Such a feature is now termed a **buried sinkhole** (Fig. 1)

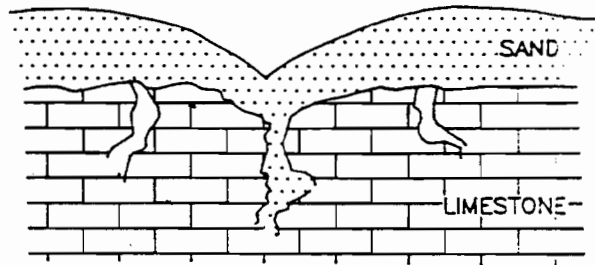
Figure 1D shows a buried solution sinkhole. However, in Central Florida it is common to have cover collapse or cover subsidence sinkholes buried. Figure 2 shows schematically how a subsidence sinkhole may have evolved to a "buried" condition in Central Florida. Cross-sections such as shown in Figure 2C are common in this area.

Buried sinkholes have serious engineering implications. Obviously, the original sinkhole is subject to reactivation and may collapse or subside again. Less obviously, the sediment infilling the ancient sinkhole differs from the surrounding strata which were breached. In the case that it is infilled by lake sediment, it may often be a very fine-grained, organic-rich, muck. In general, the infilling sediment is younger and less compact. Such sediment is subject to compaction and settling to a greater degree than the surrounding strata. Thus, differential settlement may damage man's rigid structures built over such a site. It is very difficult to determine if minor subsidence over a buried sinkhole is due to a minor amount of renewed erosion down the solution pipe or compaction and settling of the infilling

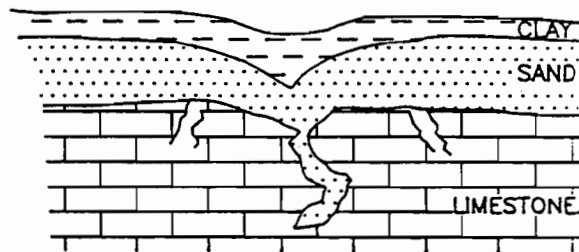
sediment.

All four of the aforementioned types of sinkholes--solution, cover collapse, cover subsidence, and buried were the result of the downward movement of material along solutionally enlarged channels through the limestone. However, the dissolution of the limestone may also produce caves at depth. The walls of these caves continue to be dissolved by the ground water flowing through them, over time making the passage-ways larger and larger. Simultaneously, the upper surface of the limestone is also being lowered by solutional attack. These processes may result in a situation where a large cave is close to the limestone surface with only a thin rock roof over the void. If this rock roof suddenly collapses into the cave, a **bedrock collapse or cave collapse sinkhole** is formed (Fig. 1).

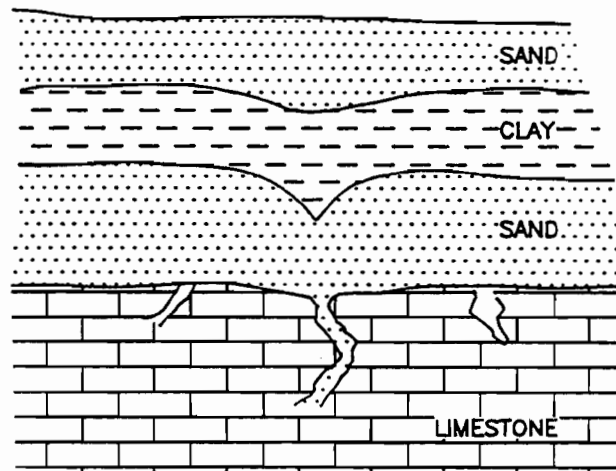
Bedrock collapse sinkholes are generally very steep-walled, or even overhung. They are often deeper than they are wide and relatively cylindrical. Because the walls are in solid rock, they will maintain this profile for a long time, in terms of man's life span. Thus, examples of bedrock collapse sinkholes are not difficult to find. However, White (1988, p. 359) states "Because the rate of surface down-wasting is extremely slow on a human time scale, [bedrock] collapse dolines are rarely observed in the act of collapsing." (Doline is the technical synonym for sinkhole.) Waltham (1989, p. 17) states that bedrock collapse sinkholes are "rare, except on a geologic time scale." The Florida Sinkhole Research Institute has reports on more than 1,700 sinkholes



A - SUBSIDENCE SINKHOLE



B - SUBSIDENCE SINKHOLE COVERED BY MARINE CLAYS



C - SUBSIDENCE SINKHOLE COVERED BY CLAYS, AND MOST RECENTLY BY SAND, COMPLETELY BURYING AND HIDING THE SINKHOLE.

FIGURE 2: DEVELOPMENT OF A BURIED SUBSIDENCE SINKHOLE.

which have developed in Florida in approximately the last 25 years, and not one of these was definitely a bedrock collapse sinkhole. All of them were cover collapse or cover subsidence sinkholes.

Cover collapse and cover subsidence sinkholes are together termed "subsidence sinkholes," because the basic mode of origin is subsidence of the overburden whether slow or rapid. The engineers have termed this upward erosion process "ravelling" and refer to these sinkholes as ravelling sinkholes.

Cover subsidence sinkholes are broad, shallow, slowly developing, and almost always cause damage simply by undermining and cracking rigid foundations. It is sinkholes of this type that are suspected of causing the cracking of homes in Dunedin, Florida, causing over \$10 million in damages.

Whereas cover collapse sinkholes are generally obvious, cover subsidence sinkholes may often go unrecognized, even when damage occurs. Therefore, data on the number of cover subsidence sinkholes which have developed in Central Florida are unrepresentative of the magnitude of this problem.

The mechanism responsible for cover collapse and cover subsidence sinkholes is the downward erosion of unconsolidated sediment aided by ground water flowing down into voids in the limestone. The sinkhole develops from the bottom up, by a stoping process which, as mentioned previously, is termed ravelling by geotechnical engineers. Above the water table this upward collapsing cavity is an air filled

void. However, under phreatic conditions (below the water table), the upward migrating erosion pipe may be filled with a water-sediment slurry with no bearing strength: "weight of rod" material in SPT borings. Surface collapse or subsidence is only the final conclusion of these ongoing subsurface processes. The nature of the overburden sediment determines what will occur as additional materials ravel downward into the limestone voids.

SITE LOCATION

Cane Island is located southwest of Orlando, peripheral to the metropolitan area, in the northwest corner of Osceola County, Section 29 and 32, T28E, R25S (Fig. 3).

Cane Island is not an island in the truest sense of the word; it is not surrounded by water. It is, however, surrounded by the extensive wetlands of the Reedy Creek Swamp. The island is a locally elevated, sandy, dry area with elevations from 73 to 86 feet above MSL. The surrounding swamp, in the immediate vicinity, occurs at an elevation of 65 to 73 feet above MSL. Natural drainage is to Reedy Creek which flows south-southeast.

GEOLOGY

One of the most important aspects of karst in the Orlando area is that it is thickly mantled. Typically, the area is underlain by 30 to 60 feet of undifferentiated Pleistocene sand, 90 to 150 feet of Pliocene-Miocene clayey

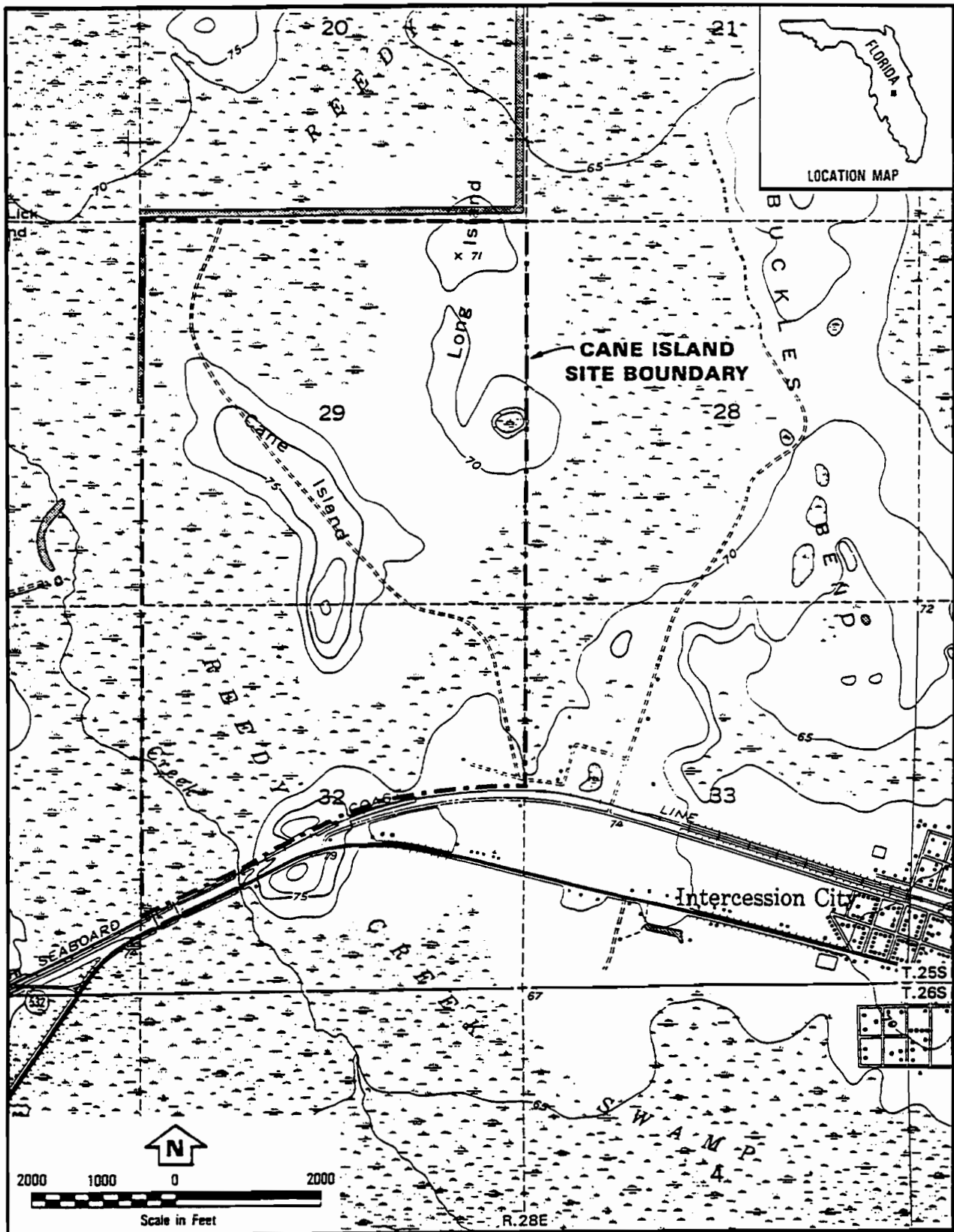


Figure 3: Location and general topography of the Cane Island site, Osceola County, Florida. Base map: USGS "Intercession City, FL" 7 1/2' quadrangle.

strata, and more than a thousand feet of cavernous, Eocene limestone and dolomite. The limestones and dolomite form the Floridan Aquifer. A generalized stratigraphic column for Orange and Seminole Counties is shown in Table 1.

Sediments in the Orlando area are nearly flat-lying. In general, the bedrock dips approximately southeast at gradients ranging from less than 10 feet per mile to as much as 30 feet per mile (Barraclaugh, 1962; Lichtler and others, 1968, Scott and Hajishafie, 1980).

The top of the Eocene limestone is highly irregular because of paleokarst development. Drill holes show variations in the altitude of the top of the limestone in excess of 100 feet over distances of a few tens of feet. Rapid local variations are probably caused by the presence of buried vertical solution shafts in the limestone. Consequently, the elevation of the top of the limestone is very difficult to map. The use of widely-spaced, isolated drill holes can introduce substantial local errors. For example, the elevations shown on a recent map by Scott and Hajishafie (1980) appear to be correct near Rock Spring, in northwest Orange County, where the limestone crops out at an elevation of 35 feet. However, the map shows the limestone at an elevation of -35 feet at nearby Wekiwa Spring, where it can be seen in the spring pool at an elevation of approximately +10 feet.

Four faults have been mapped in Orange and Seminole Counties. The faults occur in eastern and southeastern Orange County. The faults may control the position of the St. Johns River, but

they are otherwise unimportant with respect to the karst hydrogeology of the Orlando area. They are totally unrelated to the Cane Island site, in the southwestern corner of the Orlando area.

HYDROGEOLOGY

Karst development in the Orlando area is made possible by the presence, usually at depth, of a thick, carbonate aquifer called the Floridan Aquifer, in which extensive cavernous porosity has developed. Over most of the area, the Floridan Aquifer is confined by the overlying clayey sediments of the Hawthorn Group. At the surface, the undifferentiated Plio-Pleistocene sand comprises an unconfined aquifer. Karst development must be considered within the context of this double aquifer system. The hydrologic conditions in both aquifers are described in the following subsections. For a summary, refer to Table 1.

Surficial Aquifer

In Orange, Seminole, and Osceola counties an unconfined aquifer occurs in the surficial sands of Pleistocene and Recent age. Water in the aquifer is replenished by local precipitation and lost by natural discharge into lakes and streams or by downward percolation into the Floridan Aquifer in areas where the potentiometric surface of the Floridan is below the water table of the surficial aquifer. The surficial water table tends to conform to the local topography. Surficial water moves laterally under the influence of gravity, toward places of discharge. The surficial aquifer is bounded at depth

TABLE 1
WATER-BEARING CHARACTERISTICS AND DESCRIPTION OF THE GEOLOGIC UNITS
IN ORANGE AND SEMINOLE COUNTIES
(Modified from Lichtler and others, 1968)

Series	Formation Name	Thickness (feet)	Description	Water-bearing Characteristics	Aquifer
Pleistocene to Recent	Undifferentiated deposits (0.0-1.6 million years ago)	0-75	Clear to frosted, fine to coarse, quartz sand, with occasional shells and thin clay layers.	Varies widely in quantity and quality of water produced.	Surficial (unconfined)*
Miocene	Hawthorn Group (11.2-23.7 million years ago)	0-200	Gray-green, clayey, quartz sand and silt; phosphatic sand; and buff, impure, phosphatic limestone, mostly in lower part.	Generally impermeable except for limestone, shell, or gravel beds.	Generally an aquitard. Confines underlying aquifers. Some beds serve as intermediate (shallow artesian)* aquifer. Lower limestone beds may be part of Floridan Aquifer.
	Ocala Group (35.6-40.0 million years ago)	0-200	Cream to tan, fine, soft to medium hard, granular, porous, some dolomitic limestone.	Moderately high transmissivity. Most wells also penetrate underlying formations.	Floridan.
	Avon Park Limestone (40.0-43.6 million years ago)	400-600	Upper section mostly cream to tan, granular porous limestone. Lower section mostly dense, hard, brown, crystalline dolomites.	Overall transmissivity very high. Contains many interconnected solution cavities. Many large capacity wells draw water from this formation.	Floridan.
Eocene	Lake City Limestone (43.6-52.0 million years ago)	More than 700. Total unknown	Dark brown crystalline layers of dolomite alternating with cherty fossiliferous layers of limestone.	Similar to Avon Park Limestone. Cities Orlando and Winter Park obtain water supply from this formation.	Floridan.

*terminology of Lichtler and others, 1968.

by the relatively less permeable Hawthorn Group.

The water table in the surficial aquifer in the Orlando area ranges in depth from 0 to 20 feet except under sand ridges where it may be much deeper. The water table occurs within a few feet of the land surface beneath lowlands and relatively flat areas and may be higher than the land surface in low swampy areas, such as the Reedy Creek Swamp. Water table fluctuations occur in response to changes in recharge and discharge. Water table fluctuations range from a few feet beneath the low lying areas to as much as 15 feet beneath ridges (Lichtler and others, 1968).

Floridan Aquifer

The Floridan Aquifer is the principle artesian aquifer of the Florida peninsula. It was defined by Parker and others (1955) to include carbonate rocks of middle Eocene (Lake City and Avon Park Limestones), upper Eocene (Ocala Limestone), Oligocene (Suwannee Limestone), and Miocene (Tampa Limestone) age, and carbonate beds of the lower Hawthorn Group where they are in hydrologic contact with the rest of the aquifer. The Suwannee and Tampa Limestones are absent in this area. The aquifer is confined by relatively impermeable clay-rich units in the Hawthorn Group which extends over most of the state. The confining unit may be locally discontinuous or perforated by ancient and recent sinkhole development.

In the area of the site in northwestern Osceola County, the

potentiometric surface of the Floridan Aquifer occurred between 70 and 80 feet above MSL in May, 1992 (Mularoni, 92). The surface slopes to the east in this area. Annual fluctuation of the potentiometric surface ranges from 5 to 8 feet (Barracough, 1962; Lichtler and others, 1968). The surficial water table generally occurs 10-15 feet below the land surface in the Orlando area. The potentiometric surface of the Floridan Aquifer is at an average depth of 50 feet below the land surface in most of the Orlando area, resulting in an average head difference of approximately 35 to 40 feet (Lichtler and others, 1968). This drives infiltration and recharge downward through the leaky confining beds.

The Floridan Aquifer is one of the largest and most productive aquifers in the country. Yields from the upper zone of the aquifer are as high as 4,000 gal/min. The overall average transmissivity of the Floridan is 2 million ft/day (Lichtler and others, 1968; Schiner and German, 1983). Porosity in the Floridan Aquifer is cavernous. Logs of 63 wells drilled in the Orlando area penetrated 88 cavities in the Upper Floridan Aquifer with a mean height of 10.7 feet. For more details on this cavernous framework, see Beck and Wilson, (1987).

GEOMORPHOLOGY

The geomorphology of the Orlando area, including northern Osceola County and the site, is shown on Figure 4, using provinces identified by White (1970). The western side of the Orlando area is dominated by three sandy ridges

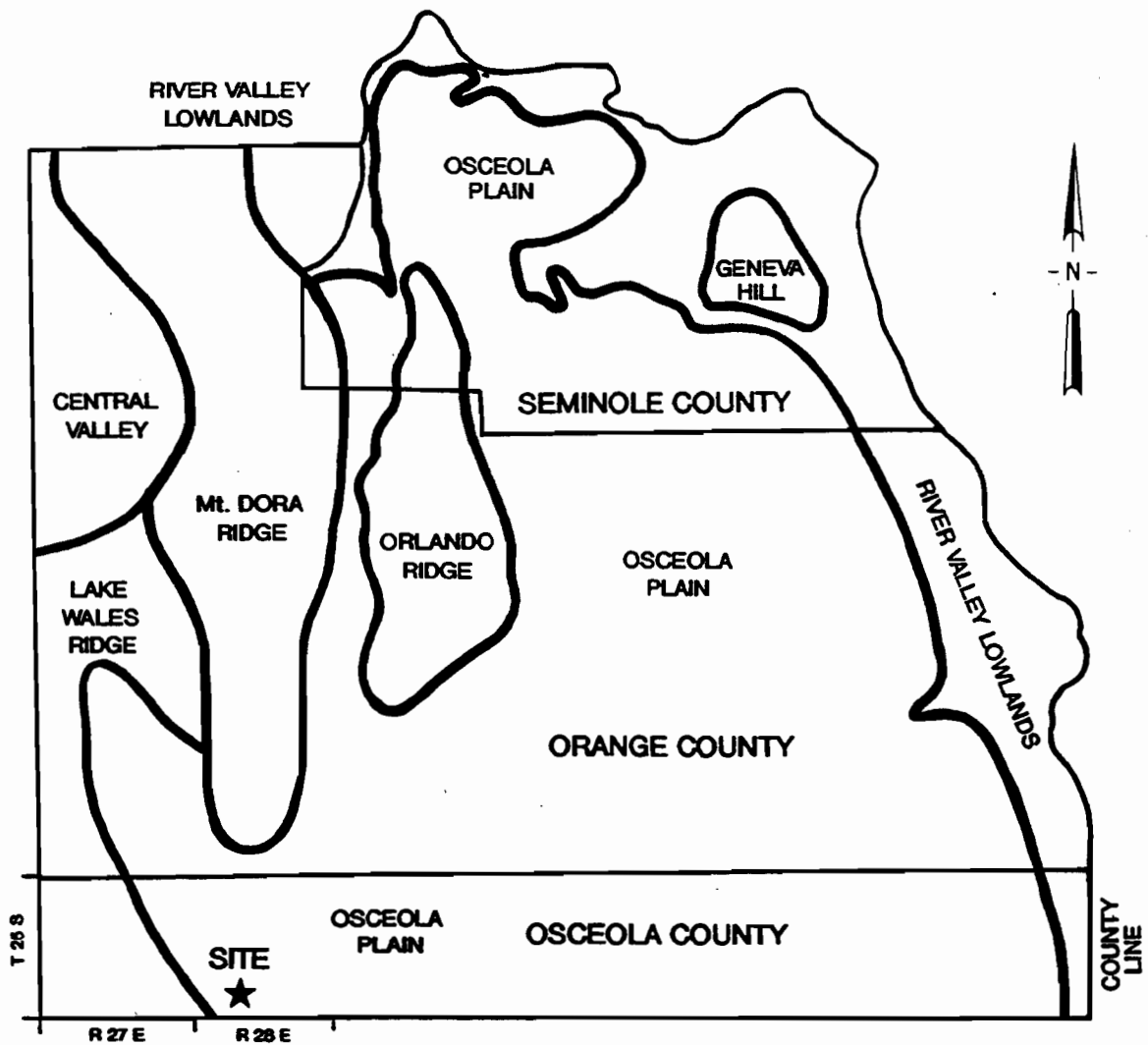


FIGURE 4. GEOMORPHIC AREAS OF ORANGE, SEMINOLE, AND NORTHERN OSCEOLA COUNTIES, (AFTER WHITE, 1970).
 THE CANE ISLAND SITE IS IDENTIFIED BY A STAR NEAR THE SOUTHWEST CORNER OF THE MAP.



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generally exceeding 105 feet above MSL: the Lake Wales Ridge, the southern extension of the Mt. Dora Ridge, and the Orlando Ridge. All three areas are apparently former beach ridges underlain by beach and dune sands.

These ridges are apparently areas where the unconsolidated sediments overlying the limestone are thicker, although no consistent relationship is discernable based on the topography of the limestone surface (Scott and Hajishafie, 1980). The ridge areas are zones of very high ground water recharge (Wilson and Beck, 1992). Surface drainage is poorly developed and the land surface is many feet above the potentiometric surface level of the Floridan Aquifer. The land surface is presently characterized by numerous closed lake basins which are ancient sinkholes and karst lakes. Most of the recent sinkhole development occurs on these elevated, sandy ridges. The potentiometric surface is marked by local highs (Tibbals, 1975) indicating areas of recharge which are probably caused by leakage through sinkhole collapse features.

The major portion of central and eastern Orange County and Northern Osceola County, including the lowlands between the aforementioned ridges, is part of a broad, flat area termed the Osceola Plain (White, 1970). Elevations range from 35 to 105 feet above MSL, but elevations between 50 and 85 feet above MSL are common. The Osceola Plain is generally an area of moderate to poor ground water recharge. A surface drainage network is crudely developed. Where surface drainage is absent,

swampy conditions are prevalent, such as the Reedy Creek Swamp in the site area. Ancient sinkhole lakes occur in scattered localities, but are not common overall.

Wilson and Beck (1992) demonstrate that the incidence of cover collapse sinkholes in the Orlando area correlates with the geomorphology, as well as the hydrogeology, of the area. The boundaries of "sinkhole prone areas" shown by Wilson and others (1987, Map 5) coincide with the boundaries of the three ridges. As mentioned, the ridge areas are zones of high ground water recharge. It is the downward movement of infiltrating ground water which causes erosion and eventually leads to sinkhole collapse or subsidence. Cane Island is similar to the ridge areas, although on a smaller scale. The shallow water table, as measured in piezometers on-site, is 5 feet higher along the crest of the island than near the perimeter, which is still higher than in the adjacent wetlands. Thus, ground water recharge is higher on the island **which creates the potential for sinkhole erosion.**

ASSESSING THE RISK OF SINKHOLE COLLAPSE

According to Beck (1991, P. 231) "The first step in evaluating the risk of sinkhole damage at a site planned for development is a statistical analysis of the risk of sinkhole collapse." This should be specific to the intended use of the site. Second, cost-effective measures which could be undertaken to ameliorate the hazard must be identified. If the sinkhole hazard is significant, and

if there are appropriate measures by which the hazard may be minimized or avoided at an acceptable cost, then, and only then, is it warranted to conduct a detailed, site specific investigation.

For the purpose of assessing the karstic hazard at the Cane Island site, the potential for cover collapse sinkholes may be evaluated in light of the database collected by the Florida Sinkhole Research Institute. These data were previously analyzed by Wilson and others (1987), for the Orlando area. The Cane Island site is approximately two miles outside the study area investigated therein, but the local hydrogeology and geomorphology is sufficiently consistent that the hazard evaluation of Wilson and others (1987) is appropriate for the site.

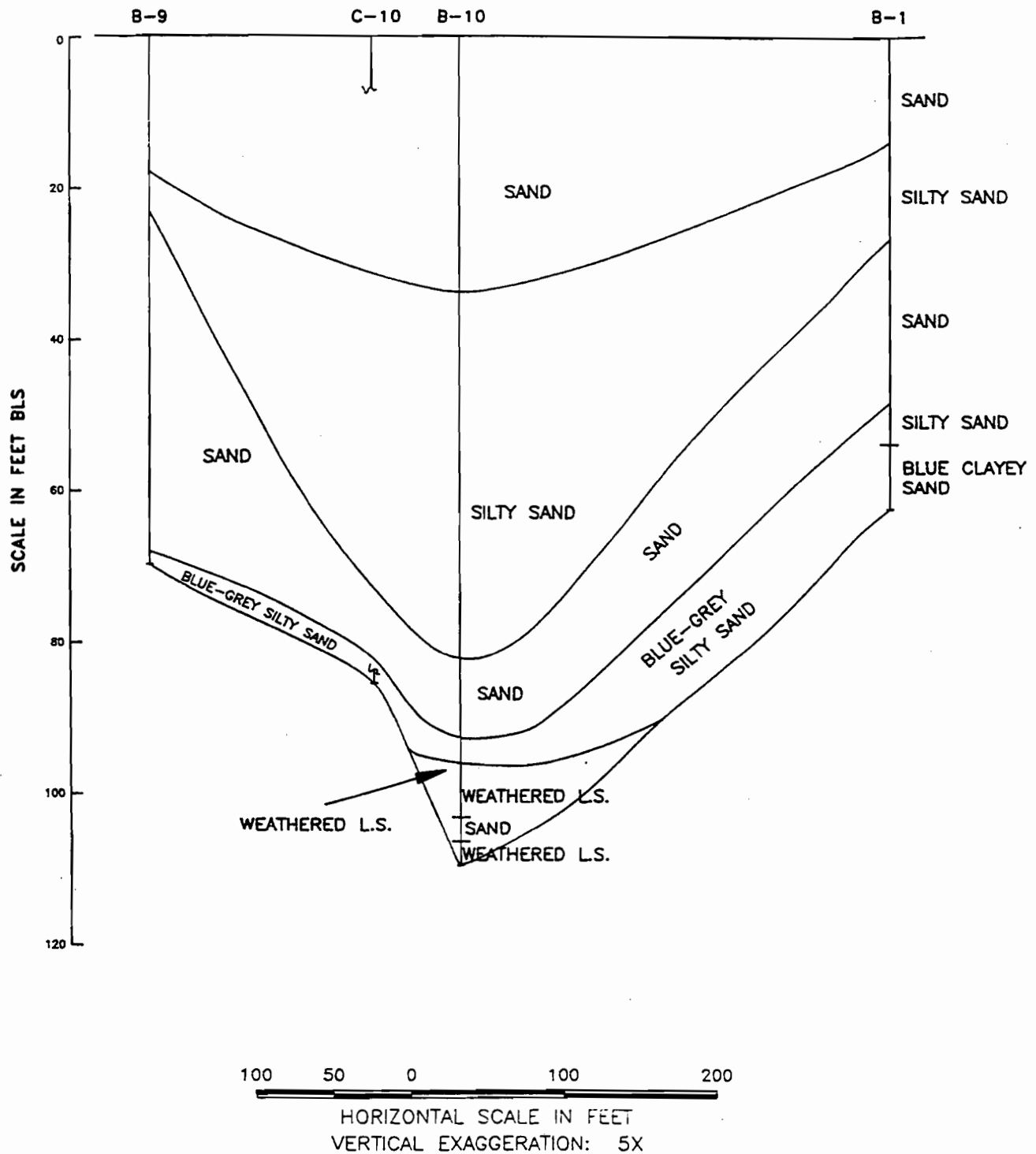
Map 5 (ibid.) classifies this area as "low sinkhole hazard." Further, Map 1 (ibid.) identifies this as an area of poor recharge, and the conclusions (ibid., p. 99) state that "92% of all recent collapses have occurred in the **high** recharge area, or within 1/2 mile of its boundary," thus excluding the site. Moreover, Wilson and others also conclude that "91% of the recent sinkholes have occurred in areas where the depth of limestone is between 80 and 170 feet below land surface." At Cane Island, most of the SPT borings and piezocone soundings conducted encountered limestone approximately seventy feet below land surface. Thus, based on all the data compiled by Wilson and others (1987), the risk of sinkhole **collapse** at the Cane Island site is **very low**. It is prudent at this point to emphasize the fact that **the risk is still finite, but very low**.

However, the database compiled by the Florida Sinkhole Research Institute inventoried cover **collapse** sinkholes, almost exclusively. **Thus, the foregoing conclusion does NOT apply to the hazard of slowly developing cover subsidence sinkholes.** Moreover, even if cover subsidence does not "actively" occur, **buried sinkholes** may still present a serious hazard to heavy foundation loads because of the potential for differential compaction and settlement as described on page 5 herein. Thus, it is necessary to determine if the "weight of rod" zones encountered in borings B-8 and B-10 are indicative of buried sinkholes with significant ravelling zones.

Figure 5 shows a geologic cross-section through SPT borings B-9, B-10, and B-1. Piezocone sounding C-10 is also shown on the diagram, however only the depth to limestone was used from this sounding because the computer interpretation of the piezocone data did not correlate in any significant fashion with the geologic descriptions from the split spoon samples. The cross-section shows a broad, bowl-shaped depression in the limestone surface which was partially infilled by the silty sand, and completely "buried" by the overlying surficial sands.

Although the surficial sediments down to approximately 35-55 feet BLS show normal densities and N values in all three borings, the sediment below that is "very loose" to "weight of rod." Boring B-10 encountered some 40 feet of WR material directly above the limestone. This would appear to indicate that karstic erosion is continuing to undermine the area, which will eventually lead to surface

FIGURE 5: GEOLOGIC CROSS-SECTION THROUGH
B-9, B-10, AND B-1, CONSTRUCTED
BY STANDARD METHOD.



subsidence.

However, "Cross-sections based on drilling data are helpful, but should always be viewed as approximations of reality because of the rapid lateral changes that may occur in the near-surface stratigraphy of karst terranes. Drillholes provide little or no information about the lateral continuity of subsurface horizons, unless the holes are spaced very closely. In karst areas, 'very closely' may mean only one to two meters apart, and few projects can afford such extensive drilling" (Wilson and Beck, 1988, at a national ASCE symposium on karst, p. 10.)

Note that the cross-section in Figure 5 is approximately 450 feet wide with data only at both ends and in the middle. It was constructed as most such cross-sections are prepared, assuming that the geologic boundaries between the data points are straight, or gently curving, lines. However, if the depression detected by boring B-10 is not 450 feet wide, and we have no reason to assume that it is, then this cross-section would appear somewhat different in detail, although its overall interpretation would be the same. Further, note that there is no reason to assume that boring B-10 was fortuitously drilled precisely in the center of the depression: **The hole might well be even deeper!** Thus, it is necessary to obtain more detailed information on the nature and extent of the anomalies detected by borings B-10 and B-8 (similar, but not shown). **Moreover, if B-8 and B-10 indicate buried sinkholes, how many other similar features are on site and what is their extent?**

Ground penetrating radar (GPR) can provide excellent documentation of the lateral extent, depth and thickness of the shallow subsurface strata, where the geologic conditions are suitable for its application. It produces a continuous graphic cross-section much like a seismic record. Radar profiles have been used to document subsurface karst features such as limestone pinnacles, buried sinkholes, karstic cavities, and vertical solution shafts (karren).

Because the southern half of Cane Island is generally grassy, rather than wooded, it is suitable for conducting multiple, closely spaced radar profiles which may be combined to provide a three-dimensional picture of the subsurface conditions. Although ground penetrating radar will not provide useful data under all geologic conditions, it is the most rapid and cost-effective technique for such investigations where it works.

Ground penetrating radar is most successful in areas where the soil and shallow strata have low electrical conductivity, generally less than 2 millimhos/meter. The SPT borings on Cane Island indicate that the shallow sediments are generally sands and silty sands, which usually have low electrical conductivity and are favorable for GPR investigations. Therefore, it was decided to conduct a field trial to test the applicability of GPR at the site. If the trial proved successful, then a complete sequence of transects covering the entire site would be run.

AN INTRODUCTION TO GROUND PENETRATING RADAR

Ground penetrating radar can produce a continuous profile of shallow sediment strata. Radar profiles can be used to infer the presence of subsurface features, either natural or man-made, which have distinctive cross-sections. Like most geophysical techniques, radar data does not identify the type of sediment encountered, so corroboration by drilling is necessary.

Radar is a microwave form of electromagnetic energy. The frequencies employed for effective ground penetration are usually at the lower end of the radar range. Both the velocity and the depth of penetration of the radar wave are functions of the electrical characteristics of the sediment strata penetrated. EM waves are radiated into the ground as an antenna is towed across the ground surface. The antenna alternately radiates signal pulses, and then receives the reflected signals (Fig. 6).

When the transmitted radar waves strike an interface between strata with different electrical conductivities, part of the wave is reflected, and the remaining wave energy continues downward. The wave nature of the reflected energy produces a series of positive and negative peaks (peaks and troughs) which are sensed by the receiver if they exceed a certain threshold. Normally, each reflection produces three detectable surges of alternate polarity which are plotted as three parallel bands on a strip chart (Fig. 7).

The radar beam is roughly conical

in shape and has an included angle of 90° front to back and 60° laterally. Only subsurface interfaces which are perpendicular to some portion of the radiated signal will reflect the wave back to the antenna receiver. Horizontal interfaces will reflect back from directly below the antenna. They are plotted on the strip chart at a distance below the surface proportional to the total time required for the signal to reach the interface and return to the receiver (the two-way travel time). The vertical scale on the strip chart, then, is not depth but time, in nanoseconds (billionths of a second). Because the velocity of the wave will vary in different strata, the depth scale is not constant. It is essential to be able to calibrate the reflections against drilling data to properly calibrate the printout.

The reflections are plotted as if the interface was horizontal and vertically below the antenna. If a curving interface is reflecting other portions of the conical radar beam, they will be plotted at positions where no interface actually exists. However, a knowledge of the geometry of the reflectors and the physics of the reflecting process permits useful information to be gained from these false patterns (see Beck and Wilson, 1988, for a more complete discussion).

Eventually the radar signal is absorbed by the material through which it passes. Absorption of the signal is termed attenuation and it is the limiting factor for radar penetration. Materials which are electrically highly conductive attenuate the signal very rapidly. In highly resistive materials, such as dry

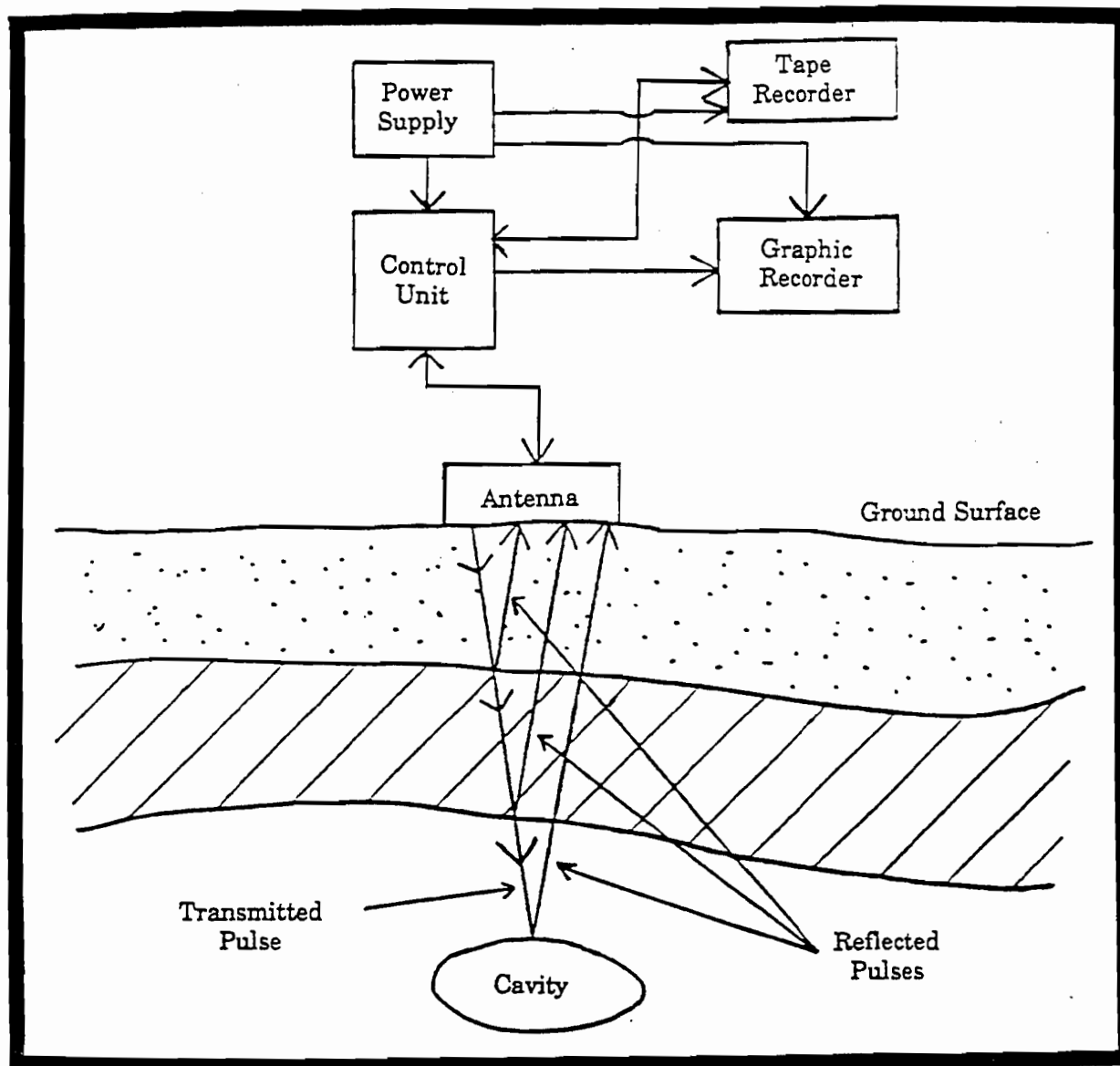


Figure 6: Conceptual diagram showing the assembly and operation of ground penetrating radar. As the antenna/receiver is pulled across the ground surface, a continuous record of reflections is printed on a strip chart (see Figures 7 and 8). The model used in this study did not have a tape recorder for making a reproducible record of the data.

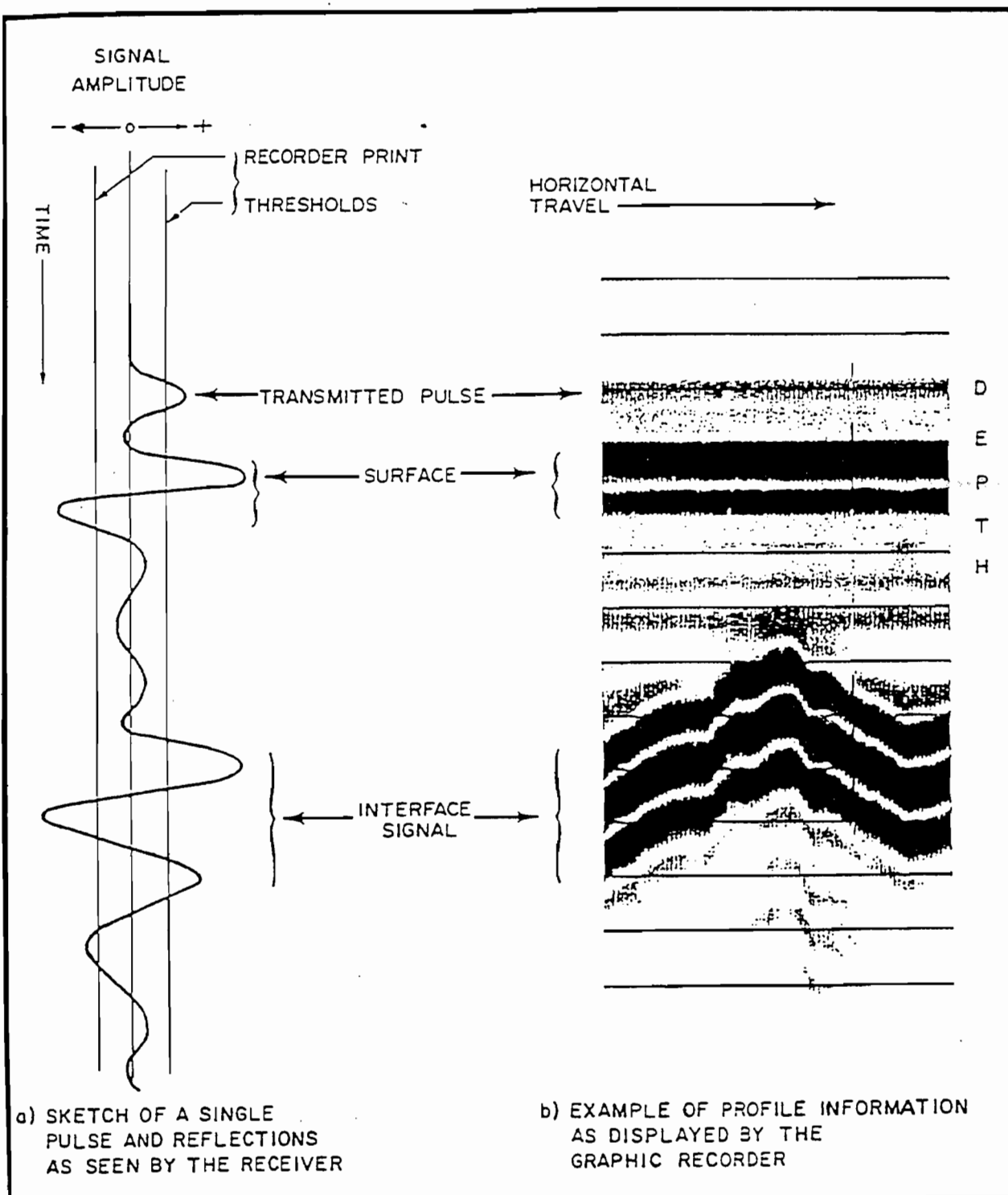


Figure 7: Diagrammatic explanation showing how the reflected electromagnetic (radar) wave is transferred to the strip chart. The signal pulse diagram (left) shows an instantaneous pulse and the reflections while the graphic printout from the strip chart (right) shows a continuous set of pulses received as the antenna/receiver is pulled across the ground surface.

quartz sand, penetration depths as great as 100 feet may be attained. However, in certain materials which are highly conductive, such as clays or saline ground water, the rapid attenuation may limit the penetration to only a few feet.

As the antenna is pulled across the ground surface, continuously receiving reflections, the chart paper simultaneously moves under the recorder stylus printing out a continuous cross-section of the subsurface stratigraphic interfaces. The horizontal scale of the printout will depend on the rate at which the antenna is pulled and on the feedrate of the chart paper. Therefore, known positions must be regularly marked on the printout to fix the horizontal scale.

SINKHOLE FEATURES ON GPR

Because of the three-line reflection of each interface plus the false reflections from curving interfaces, the interpretation of ground penetrating radar charts is not straightforward. Below is one example of how radar may document the subsurface processes forming a sinkhole.

Figure 8 shows a typical buried sinkhole subject to reactivation. The top of a clay stratum shows as a distinct horizontal three band reflection marked by a v-shaped depression in the center of the chart: a result of previous sinkhole subsidence. The V-shape of the buried sinkhole and the curving hyperbolic pattern beneath it are both complex geometric reflections from a depression in the clay surface. The "V" on the chart, however, does not exactly trace the surface of the clay because of the plot-

ting complexities mentioned previously.

This interpretation of the radar data in Figure 8 was corroborated by hand auger sampling. Approximately six months after this profile was made, a small cover collapse sinkhole, approximately 10 feet wide, opened in the center of this depression. Note the two, small solid reflectors below the hyperbolic pattern. These may mark the top and bottom of the upward migrating void which subsequently caused this small collapse.

Note that the limestone is not recorded on the profile. The clay attenuated the radar beam before the limestone was reached. Despite the fact that the limestone was not shown on the radar chart, the signature of the sinkhole and the processes which are occurring are obvious.

RADAR TRIALS AT CANE ISLAND

On November 5, 1992, preliminary ground penetrating radar trials were conducted on Cane Island. The GPR unit was a model SIR III manufactured by GSSI using a 120 Mhz antenna. It was operated by Michael Powers, a trained and experienced radar operator, under subcontract to PELA. The initial trials experimented with various machine settings in order to obtain the optimum graphic record. The time scale was set at 300 NS, full scale two-way travel time. The graphic printer was operated at 32 scans/second and 200 lines/inch.

The first trial was conducted W to E over the site of boring B-8 and

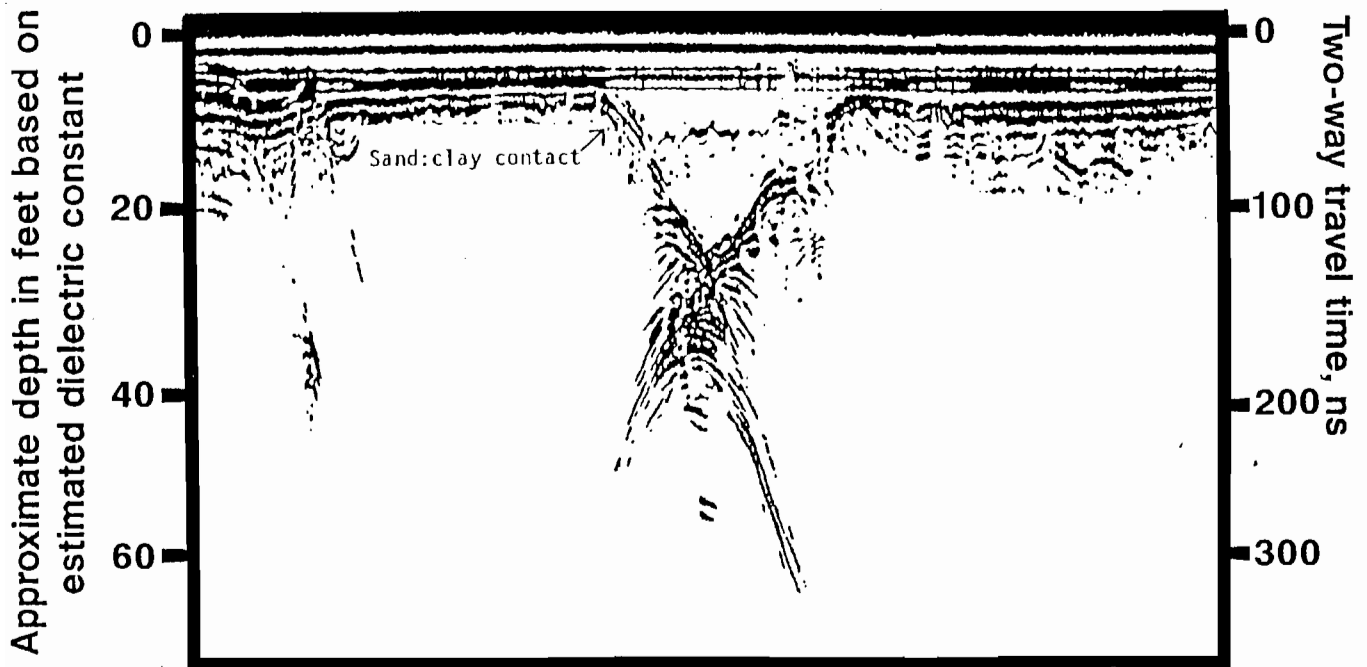


Figure 8: Ground penetrating radar profile showing a buried sinkhole which later reactivated. Note the v-shaped depression in the sand:clay interface in the center of the profile, marking an old subsidence event which was buried and infilled. The hyperbolic reflection below the depression is a "ghost" produced by the geometry and plotting of the reflections from the depression. It does not indicate a cavity, as some authors have supposed. The two double bands directly beneath the base of the "V" below the hyperbola may indicate the top and bottom of an upward stopping cavity; this sinkhole again collapsed a few months after this profile was made. This profile was made with the same radar unit used in the present study, with a slightly different antenna (80 MHz).

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continuing to the east side of the island through several other mapped locations (SR-9, C-12, and SR-3). Several shallow soil layers and the water table were clearly evident near the top of the record (Fig. 9a). At some depth below the water table a generally continuous interface was detected which later proved to be the sand:silty sand contact present at 15-20 feet BLS in most borings.

This interface provided obvious and striking evidence of buried karstic activity. The radar record shows that B-8 is located near the center of a broad and deep depression where the aforementioned interface disappears off the bottom of the chart (Fig. 9a). The boring log of B-8 shows that a sand:silty sand interface was encountered at 68.5 feet BLS, far deeper than the 15-20 foot depth at which this interface was generally detected. In addition, this same trial transect revealed **two additional depressions** in this same interface, **both apparently due to karstic activity**, which were **undetected by any of the borings or piezocone soundings on site** (Fig. 9b).

The second radar trial was conducted W to E from B-9 through C-10, B-10 and B-1--the same cross-section as shown in Figure 5, which was based on the SPT borings alone. Figure 9a and 9b show the results of this radar profile. Again the continuous, dramatically obvious, diagnostic interface across the radar graph is the sand:silty sand contact. Obviously the simplified cross-section of Figure 5 is totally in error with respect to specific locations, although the general diagnosis of the cause of the problem was correct. Rather than one

broad basin there are three distinct areas of subsidence: one just west of C-10, one just east of B-10, and a broader but shallower depression on the eastern side of the island.

In order to assess the applicability of GPR over the entire island, and to determine the extent of the karstic hazard on the island, a third trial was conducted, generally south to north, end to end, along the dirt road in the center of the island. Since this trial was on the order of a mile in length, it is impossible to include the entire record. In fact, it is adequate to note that the results were similar to the two earlier trials already discussed. There were some areas where there was no karstic activity noted, and others where the density of subsidence features was similar to that on Figure 10a and 10b. However, these areas were "randomly" mixed along the entire length of the island and it was not possible to conclude *a priori* that any areas of the island were void of the hazard of karstic subsidence.

There are two obvious conclusions from the radar trials.

1. Areas of "buried" (hidden) karstic activity are far more extensive on Cane Island than the preliminary SPT borings had indicated. These areas constitute a significant foundation problem and should be delineated and investigated in detail.

2. On the Cane Island Site, ground penetrating radar can produce a detailed cross-

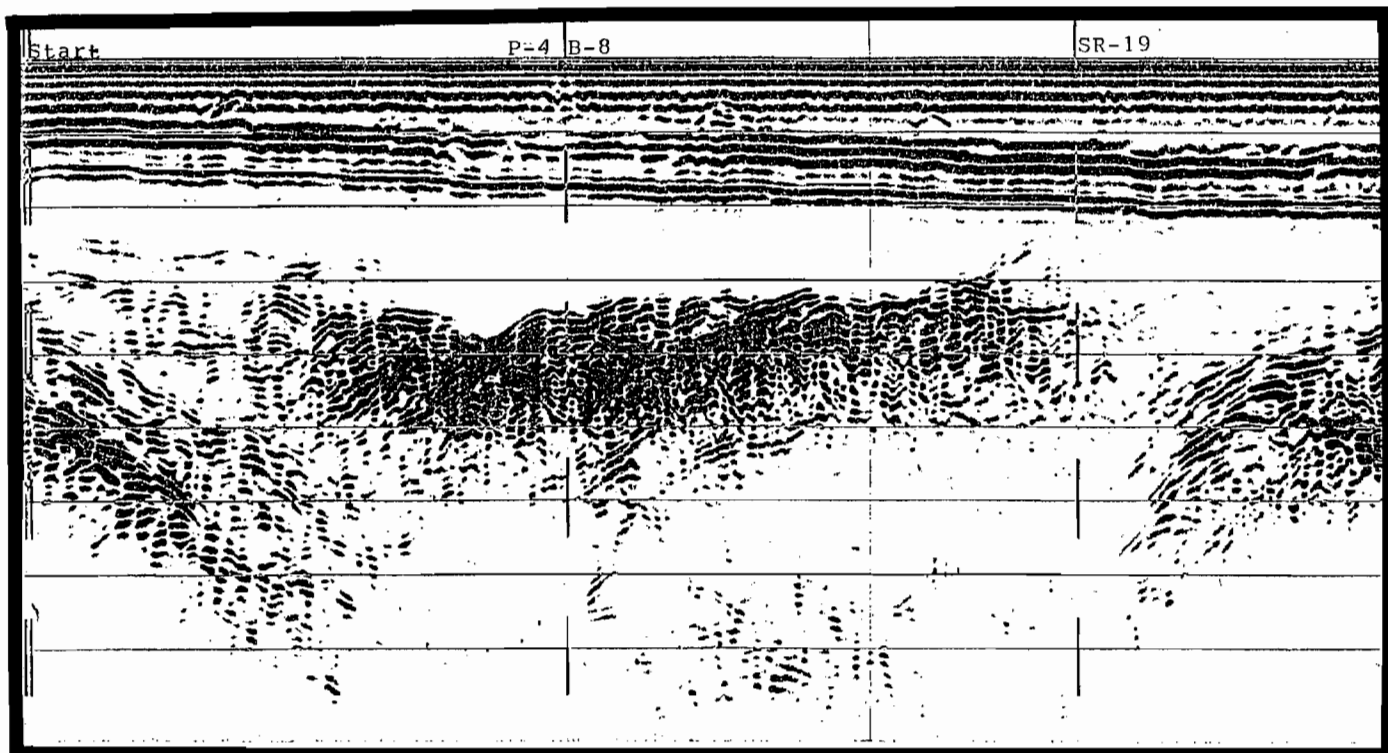


Figure 9a: Western half of ground penetrating radar trial run at Cane Island, W to E through boring B-8. Radar Instrument was a GSSI model SIR III with a 120 MHz antenna; time scale = 300 NS full scale. The undulating Interface across the center of all the trial profiles is a sand:silty-sand contact approximately 15-20' below ground surface. Scanning from left to right above, note how this interface plunges downward, disappears, and then returns to the surface, outlining the upper portion of a broad area of subsidence.

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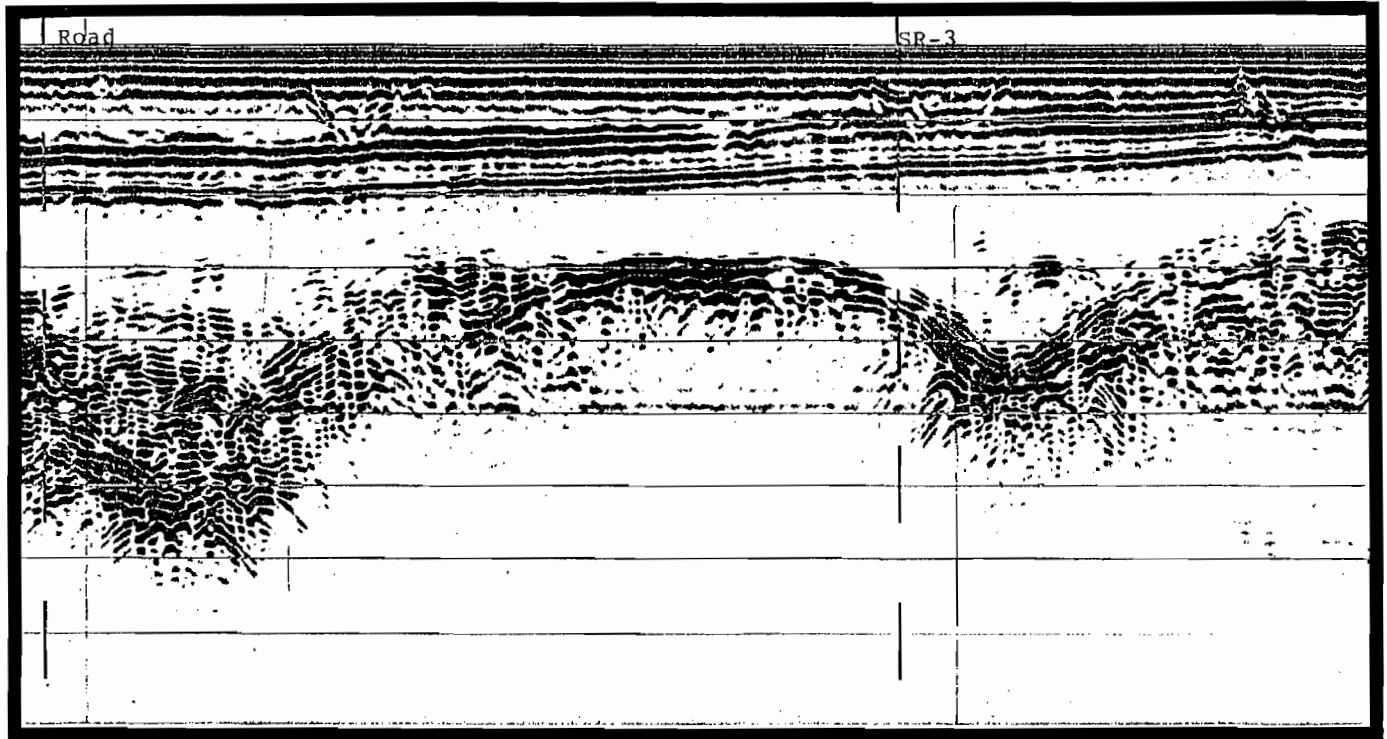


Figure 9b: Eastern half of profile 9a.

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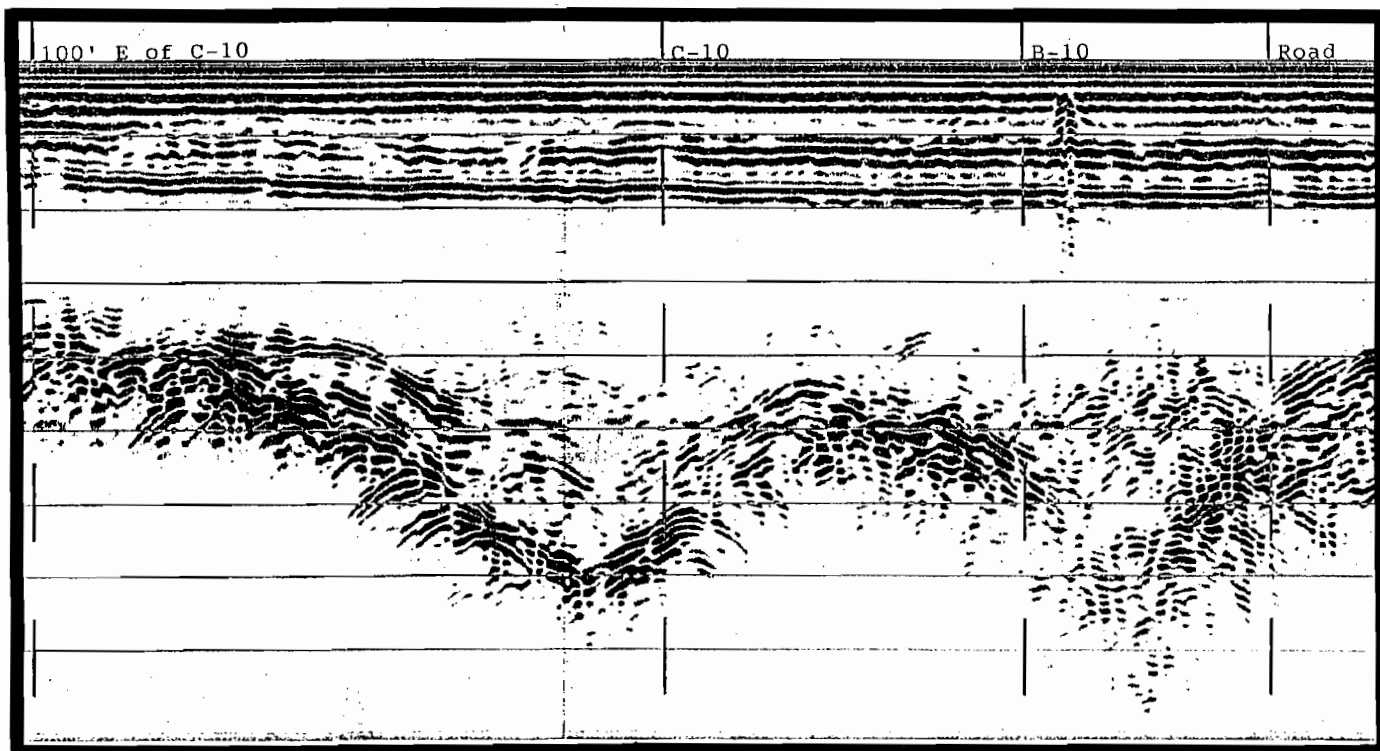


Figure 10a: Western half of a GPR trial at Cane Island run W to E through borings B-9, B-10, and B-1. Instrument and settings as on 9a.

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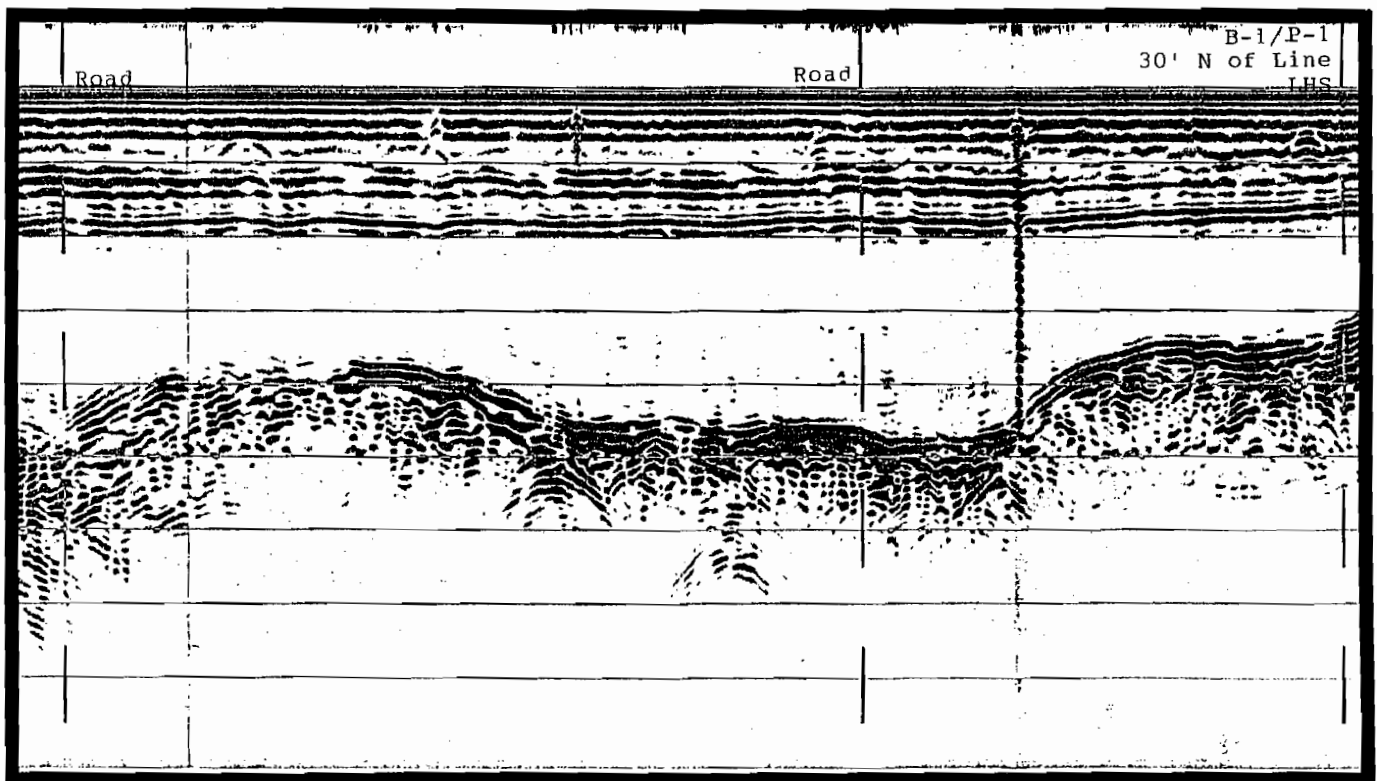


Figure 10b: Eastern half of profile 10a.

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section of the shallow strata which can be used to identify areas of buried karstic activity which are potential foundation hazards.

THE RADAR SURVEY

In light of the above conclusions, PELA recommended, and Black & Veatch approved, a detailed radar evaluation of the southern half of Cane Island. The investigation was to consist of a series of west to east profiles across the island, at 50 foot intervals. The survey was to begin at the southern end of the island and continue northward over the planned areas for Unit I and II development. The northward extent of the radar survey is limited by the presence of denser forest and scrub vegetation which makes it impossible to conduct radar traverses without first clearing the vegetation. Since it was not known whether the latter step would be necessary, or permitted, and since the immediate concern was for the first phases to be constructed, the detailed radar survey was limited to the southern half of the island (Fig. 11).

The distance of 50 feet between profiles was selected based on the preliminary trials. From the karstic features detected in the trials, it was hypothesized that the smallest significant buried features would be generally circular and larger than 50 feet in diameter; therefore, at least a portion of such features should be detected on one of the radar profiles at this spacing.

In addition, uncontrolled radar

profiles would also be conducted on the dirt roads along both the eastern and western sides of the northern half of the island. This information, in combination with the radar data obtained down the center of the north end of the island during the radar trials, would provide an indication as to the **general** nature and intensity of the karstic hazard which will need to be anticipated here.

While the radar operator was conducting the site survey, Mr. Myron Schluter of Black and Veatch also requested that a radar profile be conducted over a portion of the entrance road. On-site analysis of the results indicated that some portions of this road were underlain by buried karstic features and, moreover, that several of these areas were the sites of present depressions which might indicate that subsidence was ongoing. In view of this finding, Mr. Schluter authorized PELA to conduct a detailed, controlled radar survey along the entire entrance corridor and to provide preliminary results to him as soon as possible so that these findings might be considered in the design of the entrance road.

In order to provide controlled locations for the radar survey, Central Survey, Inc., was engaged to survey and mark the west to east (W-E) transects. A series of thirty-four W-E lines was surveyed and staked. Stakes were placed 300 feet west of center, 150 feet west of center, at the center, 150 feet east of center, and 300 feet east of center to provide horizontal control points for each individual radar transect. This grid was then located with respect to

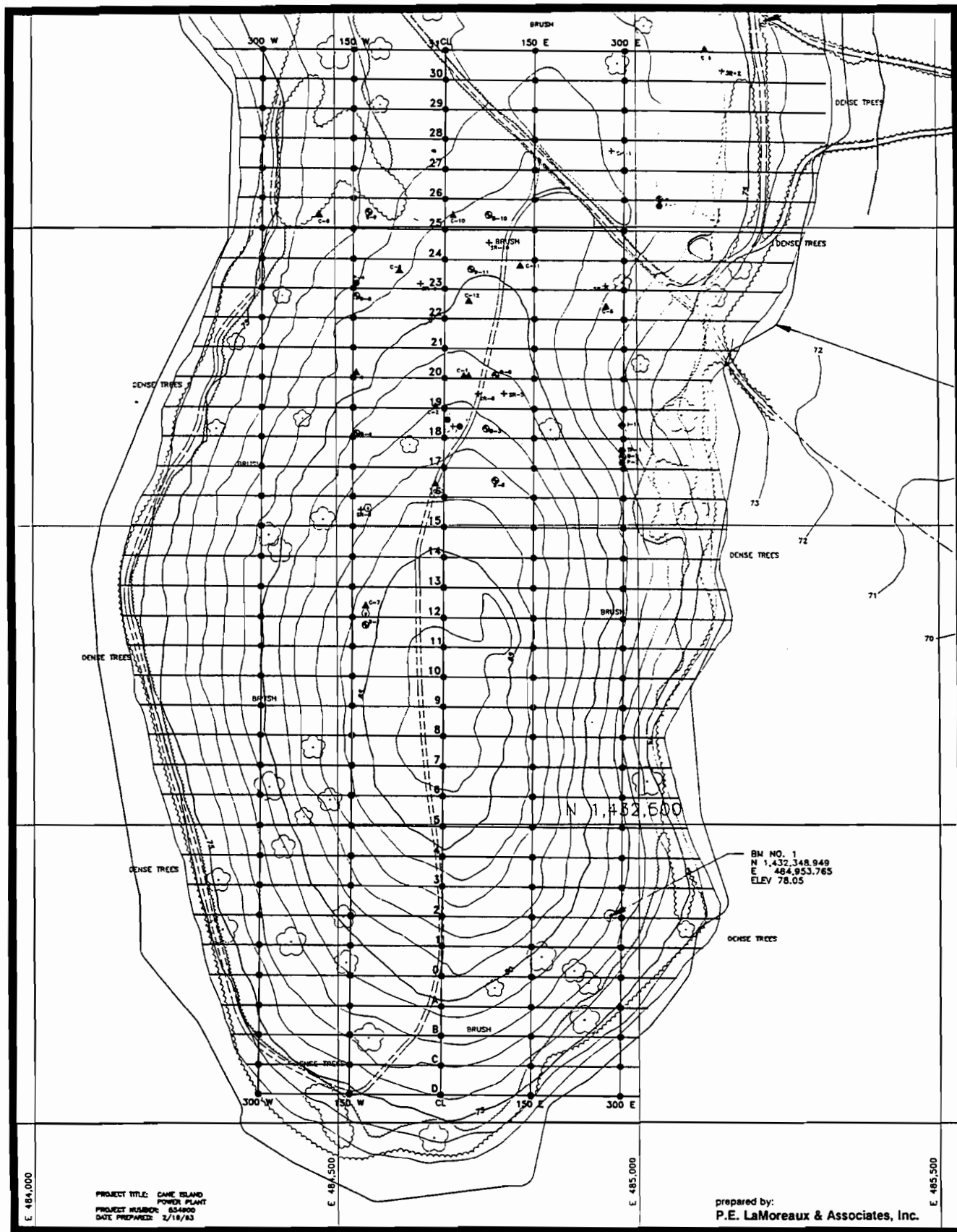


Figure 11: Map showing the grid of surveyed W to E transects used to locate GPR profiles on the southern half of Cane Island. The W to E lines are 50' apart.

previously surveyed bench marks on site so that the radar transects could be accurately located on the site map (Fig. 11).

On November 17 and 18, 1992, Mr. Michael Powers and Dr. Barry Beck, with Mr. Myron Schluter, were on site. Mr. Powers conducted radar transects along each W-E line, annotating them appropriately. Dr. Beck and Mr. Schluter added a thirty-fifth W-E line to the north end of the grid by taping distances and siting along the rows of existing stakes. When the thirty-five transects had been completed satisfactorily, radar traverses were also conducted on the north end of the island, as planned.

In addition, a short radar investigation was conducted along the dirt road extending northward into the wetlands from the north end of the island. Finally, the aforementioned radar survey along the entrance corridor was conducted, as previously described.

On December 12, 1992, Mr. Powers returned to the site, accompanied by a technician, to conduct a radar profile along the complete entrance corridor to the island. Flags were placed at measured 500 foot intervals for control, and the exact location of the starting point was taped from a known location on the island. During the radar survey other identifiable control points were also marked on the charts.

Within a week, copies of this data were provided to Mr. Schluter for his use. At that time Dr. Beck and Mr. Schluter discussed, orally, the significance of the

subsidence features shown on these radar graphs. In view of the need for a rapid decision, they decided jointly that it would be prudent to reinforce the sections of the entrance road overlaying the potentially hazardous zones with Geogrid, in order to lessen the possibility of a costly accident while heavy equipment was being delivered to the power plant site. While recognizing that this limited reinforcement did not provide 100% safety, it was jointly agreed that such measures were the only cost-effective means of significantly reducing the risk of loss.

The thirty-five radar transects across Cane Island were interpreted and analyzed and the results are plotted on the accompanying large scale map of the site (Fig. 12, in pocket). Features indicative of buried karstic subsidence were common, particularly in the northern part of the area studied. Many of these features were on the order of one hundred feet wide, or more, and it was logical to assume that such features on one profile were continuous with adjacent, similar features on the neighboring profile. When these buried areas of subsidence were connected and plotted, they delineated linear, branching subsidence "troughs," apparently joint controlled. The limits of these features, and the more expected, quasi-circular subsidence features, were mapped at two levels: the outer boundary includes the entire extent of the depression on the radar; the inner zone shows the deep, central portion of the depression wherein hazardous foundation conditions are likely to be most extensive.

The potentially hazardous zones,

as shown on the map, were plotted from the radar data alone. The information from the original SPT borings conducted on the site serves as a cross-check on the validity of the map. Borings B-2, B-8, B-9, and B-10 are all located **within the indicated hazardous zones. All show extensive zones of very loose to "weight of rod" sediment.** Borings B-1, B-4, B-5, B-6, B-7, and B-11 are all located **outside the hazardous zones. None of these borings encountered extensive zones of very loose to "WR" sediment,** although one particular sand layer, approximately fifteen feet thick, has a generally loose consistency across the entire site.

Boring B-3 was in an area where the sand:silty sand interface was abruptly absent. That is, the interface was not depressed as it was on other areas of the site, there was simply a short segment where this interface was absent (Fig. 13). However, this missing zone appeared on several adjacent profiles delineating a linear feature of unknown nature. Boring B-3 does not show any extensive thickness of very low N value sediment, nor unusually deep limestone, so it would appear that this feature does not indicate an area of karstic undermining and subsidence. Its precise nature and origin is a matter of speculation. However, if heavy foundation loads are planned over this zone, it should be investigated in more detail.

The piezocone soundings may also be used to corroborate the significance of the potentially hazardous zones on the map. Although the geologic descriptions provided by the computer interpretation of the piezocone

data did not appear to match the sample descriptions provided by the geologist on site, the N values calculated from the piezocone measurements are probably applicable. Piezocone soundings C-8 and C-11 were both located within the deep, central portions of the subsidence zones, and both indicated significant zones of very loose to WR sediment. Soundings C-5 and C-10 were located within the areas of buried subsidence, but outside the deepest portions. C-10 showed an extensive thickness of very loose material, twenty-five to thirty-five feet. C-5, however, did not show any very loose sediment. All four of these soundings encountered the limestone at depths in excess of seventy-five feet.

Soundings C-1, C-2, C-3, C-4, C-7, C-9, and C-12 were located outside of the mapped hazardous zones. None of these encountered any significant zones of very loose materials and the depth to limestone was less than seventy-five feet for all soundings except C-12. Although C-12 did not encounter limestone until 92.1 feet BLS, there were **no** zones of very loose sediment encountered.

Thus, the mapped zones of potential karstic subsidence interpreted from the radar profiles are confirmed by both the SPT borings and the piezocone soundings. The deep, central portions of the buried zones of subsidence are generally underlain by deeper than normal limestone and a significant thickness of very loose to "weight of rod" sediment, probably indicative of zones of active, gradual, long-term karstic subsidence: the ravelling zones of the engineer's terminology. Those areas within the

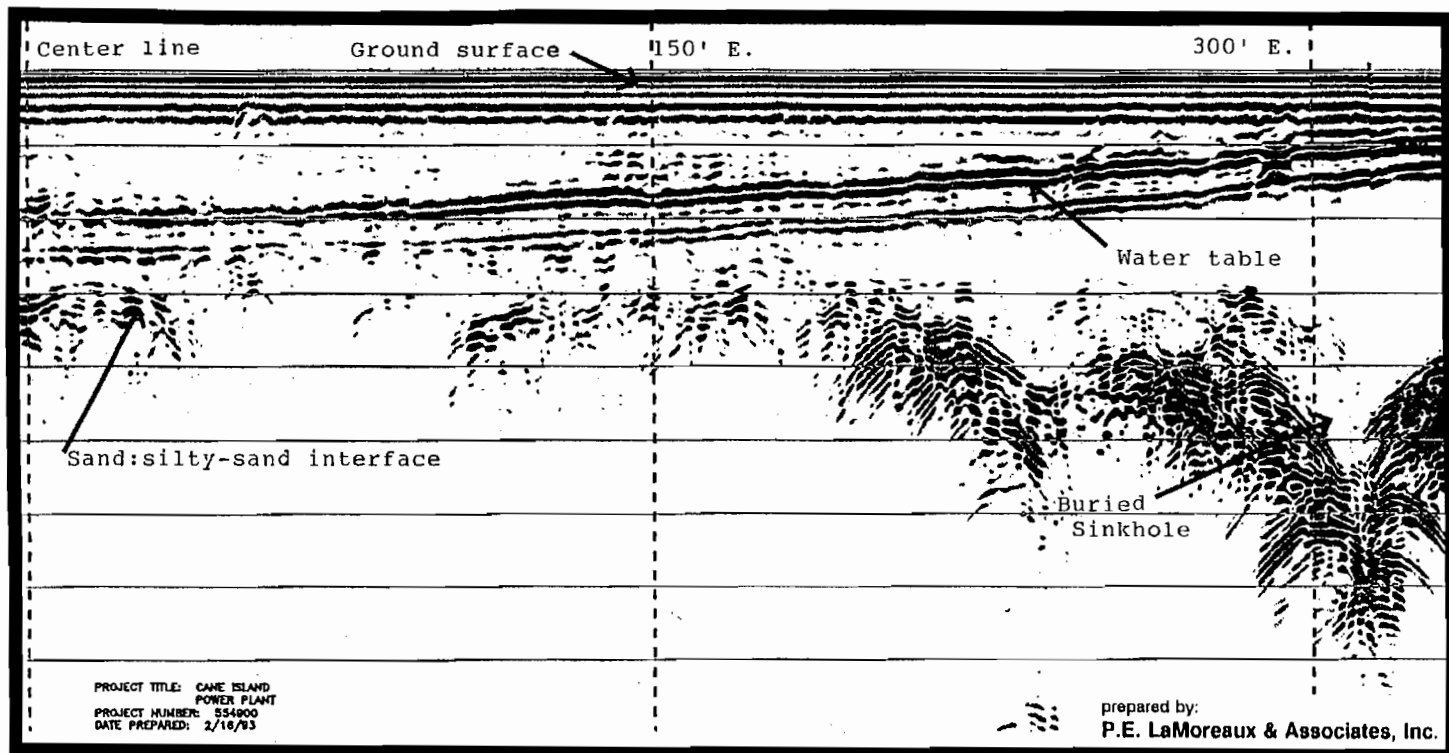


Figure 13: Portion of radar profile #18 (see Fig. 11 for location). Note the deep, v-shaped subsidence in the sand:silty-sand interface at 300 ft. east. This is typical of the major karstic subsidence anomalies, or buried sinkholes, plotted on the map. Note that halfway between the center line and 150 ft. east, a portion of this same interface is abruptly absent. This same anomaly is present on six adjacent transects. It is indicated on the large-scale map, although its origin is uncertain (see p. 28 of the text.)

zones of buried subsidence, but not central to those zones, may also encounter similar conditions although the probability is not as certain and the zones are not as extensive.

Fourteen borings or piezocone soundings located outside of the mapped subsidence zones did not show any significant indication of karstic subsidence, although one sand layer did consistently show a loose (not very loose) consistency across the site. Note that this study analyzed only the potential problems of karstic subsidence and did not consider any other possible foundation problems which might be present on site.

The radar investigations on the northern half of the island were uncontrolled: that is, the location was not surveyed accurately. However, the transects were made along the three dirt roads which are plainly visible on the air photo, and major landmarks were marked for approximate horizontal control. The roads generally traverse the long dimension of the island, one on each side and one down the middle. In the areas between the roads the vegetation was too dense for any additional transects. A review of the radar records indicates that the density of buried karstic features on the north end of the island is generally similar to that documented on the southern half of the island.

CONCLUSIONS

SPT borings and electric piezocone soundings encountered

conditions possibly indicative of buried karstic subsidence on the southern half of Cane Island. Ground penetrating radar cross-sections of the island confirmed that these features were buried sinkholes and that such conditions were much more extensive than the SPT borings had detected. Many of these areas were linear zones of subsidence, apparently controlled by fractures in the bedrock, as well as the more classic, quasi-circular, sinkhole-type features. A preliminary GPR investigation of the northern half of the island indicates that these buried karstic features are equally common there.

Karstic erosion will undoubtedly continue to undermine the land surface through these buried features. The probability of continued, gradual subsidence in these zones constitutes a serious hazard for heavy foundation loads. There is only a slight possibility of reactivation of these features by catastrophic collapse, based on historic records of sinkhole collapse in the Orlando area.

RECOMMENDATIONS

The large-scale map (Fig. 12) accompanying this report delineates buried areas of karstic subsidence. The central portions of these zones, as indicated on the map, undoubtedly pose a significant, long-term foundation hazard. However, the peripheral areas of the zones of buried subsidence also have a significant risk of encountering hazardous foundation conditions. The extent of the zero to low bearing strength zones should be confirmed with detailed

SPT borings located where the mapped zones underlay the planned footprint of structures. It is prudent to assume that the entire extent of the buried subsidence, not the central portion alone, is characterized by hazardous foundation conditions, and to investigate any areas where a planned structure is located over an area of buried subsidence.

The buried areas of karstic subsidence delineated on the accompanying map (Figure 12) are significant long-term foundation dangers for heavy structures. Construction should not take place without appropriate design modifications for this hazard.

In light of the serious foundation problems encountered and mapped herein, it is recommended that additional SPT borings be conducted to confirm the extent and severity of the hazardous conditions. Such additional investigation should be designed in conjunction with Black & Veatch engineers so as to provide the most cost-effective design information for that ground modification necessary to improve site conditions to an acceptable standard for the intended use.

Plans for the development of Units III and IV on the north end of the island should anticipate similar hazards and should include a detailed radar survey to be made after the land is cleared. The radar survey should be the first step in the foundation investigation so that the radar data can be used to locate the SPT borings and the electric piezocone soundings at appropriate locations where they will yield the maximum information.

Because buried sinkholes are localized hazards which can be accurately delineated, the most cost-effective mechanism of dealing with this hazard is simply to avoid it. That is, if possible, the exact locations of the structures should remain flexible until after the radar investigation identifies the hazardous areas. The relocation of a planned structure by 50 or 100 feet may completely eliminate the need for expensive ground improvement.

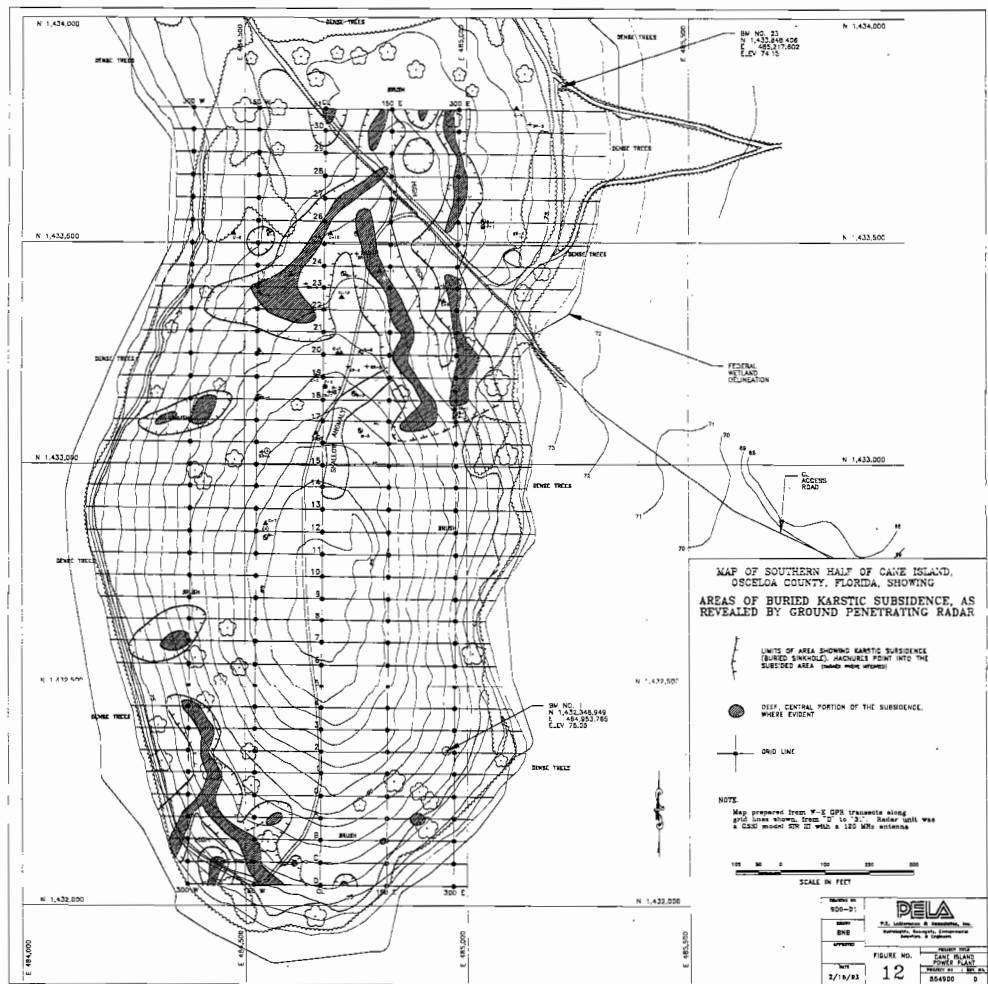
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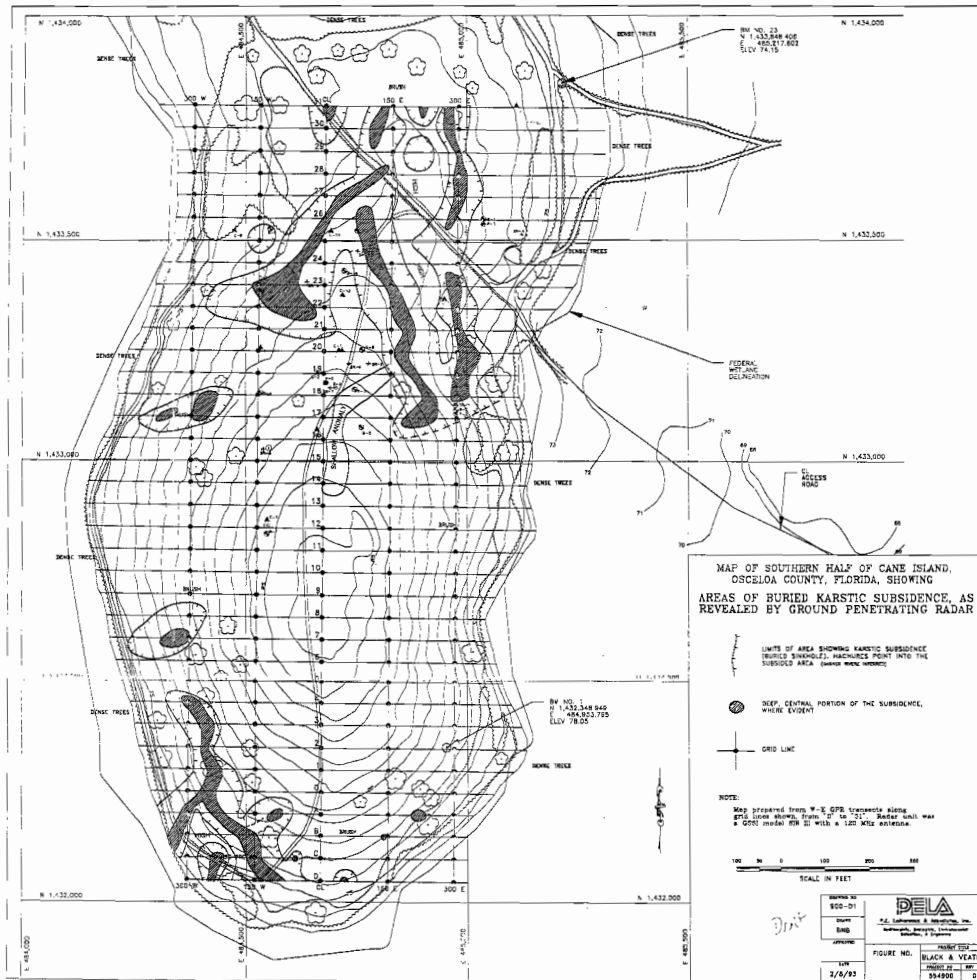
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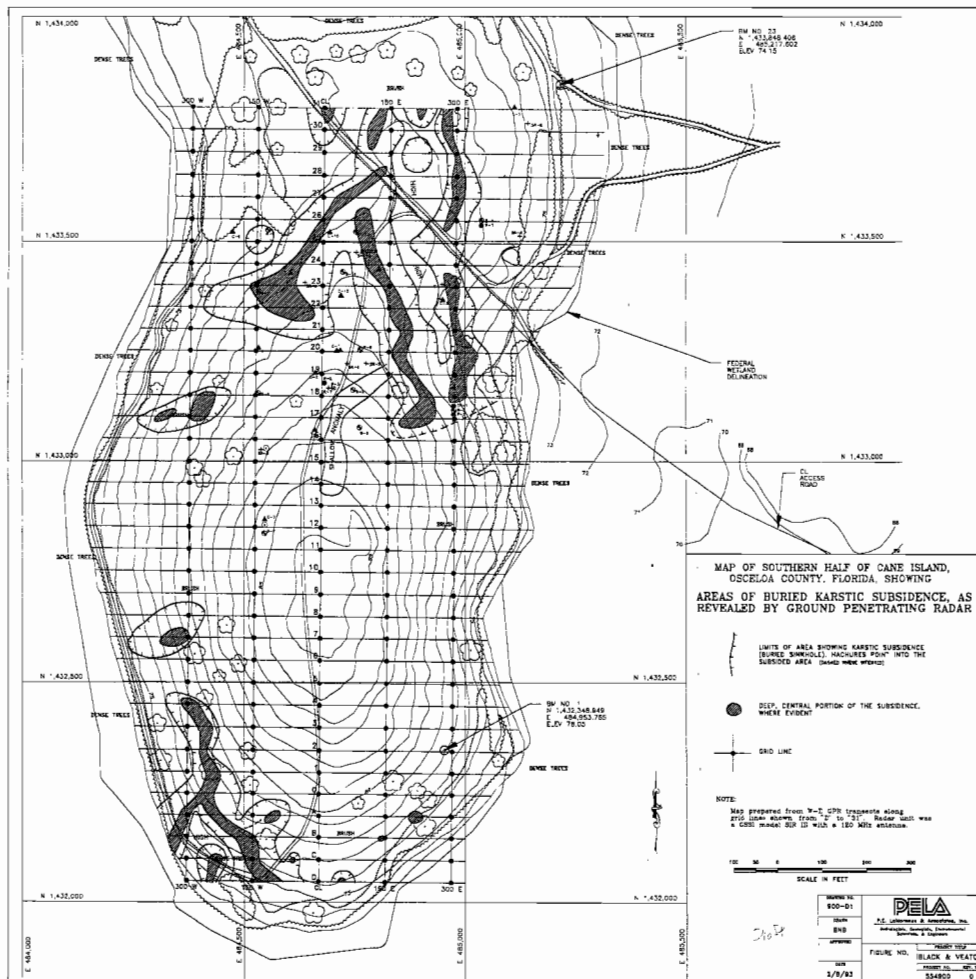
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IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.







FINAL WELL REPORT
WELL PW-1
AND PW-2

CANE ISLAND
COMBUSTION TURBINE PROJECT
KISSIMMEE UTILITY AUTHORITY

PREPARED BY
CENTECH UTILITY CORPORATION
6109 ORIENT ROAD
TAMPA, FL. 33610
PH. (813) 626-2258
FX. (813) 620-3385

TABLE OF CONTENTS

WELL PW-1

SECTION 1	DRILLERS LOGS
SECTION 2	GEOPHYSICAL LOGS
SECTION 3	DEVELOPMENT AND TEST PUMPING DATA
SECTION 4	PUMPING RECOMMENDATIONS
SECTION 5	WATER WELL LOGS

**CENTECH
DAILY DRILLING REPORT**

Date: 8-3-93
TWS.

Owner: Law Island
Well No: 2-A

Casing/Hole Diameter _____ Inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift _____ feet

End of Shift _____ feet

End of Shift _____ feet

Log of Materials Encountered

Depth

Description	From	To

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Mobilized rig to site.

Driller: Rich Huang

Helper: Robert Edson

(Use other side for more comments)

**CENTECH
DAILY DRILLING REPORT**

Date: 8-4-93
wed.

Owner: Care Island
Well No: 2-A

Casing/Hole Diameter _____ Inch

Depth to Water (below ground)

Depth of Well _____

Start of Shift _____ feet

Start of Shift _____ feet

End of Shift _____ feet

End of Shift _____ feet

Log of Materials Encountered

Depth:

Description	From	To

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Set up Equ. on first well.
Dug mud pit; mixed mud and prepared
to start drilling.

Driller: Mark Lucas

Helper: Robert Egan

(Use other side for more comments)

DAILY DRILLING REPORT

Date: 8-5-95
THURS.

Owner: Cave Island
Well No: 2-A

Casing/Hole Diameter 12 Inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 0 feet

End of Shift _____ feet

End of Shift 70' feet

Log of Materials Encountered

Depth

Description	From	To
Orange Sand	0	10'
Orange Sandy Clay	10'	30'
White Sandy Clay	30'	40'
Green Sandy Clay with some shell	40'	65'
Soft white low stone	65'	70'

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Drilled 6" pilot hole, tripped out, made up 18" bit and drilled to 70'. Made up 12" casing, tripped out, set 60' of 12" steel casing, ran 42' of 2" time pipe, made up header, mixed + pumped 30 bags of port cement and cleared up

Driller: John Henry

Helper: Robert Brown

(Use other side for more comments)

**CENTECH
DAILY DRILLING REPORT**

Date: 8-6-93
FT:

Owner: Carver Island
Well No: 2-A

Casing/Hole Diameter 12 Inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 12 feet

End of Shift _____ feet

End of Shift 20 feet

Log of Materials Encountered

Depth

Description	From	To

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Cut off 12" header, pulled 2" knee pipe,
dig out mud pit, broke out 12" bit and
made up 12" bit on casing.
Could not start cutting 6" pilot hole, had to
wait on sub, for 6" bit.

Driller: Jack Long Helper: Robert Ebron

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-9-93
mon.

Owner: Carroll Island
Well No: 2-A

Casing/Hole Diameter 12 inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 70' feet

End of Shift _____ feet

End of Shift 155' feet

Log of Materials Encountered

Depth

Description	From	To
<u>soft gray lime stone</u>	<u>70'</u>	<u>120'</u>
<u>soft tan lime stone</u>	<u>120'</u>	<u>155'</u>

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Mach up 6" bit, tripped in hole and started
drilling pilot hole. Circulated hole for 2 hrs.
tripped out and logged pilot hole.

Driller: Phil Long Helper: Robert Ebron

(Use other side for more comments)

**CENTECH
DAILY DRILLING REPORT**

Date: 8-10-93
Tues.

Owner: Coke Island
Well No: 2-A

Casing/Hole Diameter 12 inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 70' feet

End of Shift _____ feet

End of Shift 150' feet

Log of Materials Encountered

Depth:

Description	From	To
<u>Running 5" pilot hole.</u>	<u>70'</u>	<u>150'</u>

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Had trouble with the bracket on 124, did not
leave the shop till 1:00 PM.

Driller: Phil Long Helper: Robert Ebron

(Use other side for more comments)

**CENTECH
DAILY DRILLING REPORT**

Date: 8-11-93
wed.

Owner: Box Island
Well No: 2-A

Casing/Hole Diameter 8" inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 150' feet

End of Shift _____ feet

End of Shift 150' feet

Log of Materials Encountered

Depth

Description	From	To

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Tripul back to bottom, circulate hole and helped Ralph
make up 8" casing. Tripul out, Set 150' of 8"
Steel casing, ran 138' of 2" hole pipe and made up
bracket. Pumped 3 yds of red cement and cleaned
up. Took delivery on 1 pallet of portland cement.

Driller: Mark Henry Helper: Poland Ebron, Ralph D.

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-12-92
Thurs.

Owner: Corn Island
Well No: 2-A

Casing/Hole Diameter 8" inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 150' feet

End of Shift 14:30 feet

End of Shift 220' feet

Log of Materials Encountered

Depth

Description	From	To
<u>Soft tan lim. Stone</u>	<u>155'</u>	<u>175'</u>
<u>Med. brown lim. Stone</u>	<u>175'</u>	<u>185'</u>
<u>Soft white lim. Stone</u>	<u>185'</u>	<u>205'</u>
<u>Med. brown lim. Stone</u>	<u>205'</u>	<u>220'</u>
<u>with some broken areas</u>		
<u>1' 10" of Draw Down at 220' at 50 GPM</u>		

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Tagged cement between 8"-12" casings at 15'
cased & pumped 5 bags of port cement and cleaned
up. Pulled 2" line pipe. Cut off 8" leader, made
up 8" bit and tripped in hole. Tagged cement in 5' hole 8"
at 144'. Drilled with mud to 210', switched over to reverse
air and cleaned up hole.

Driller: Mark Loney

Helper: Robert Eborn

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-15-95
Fri.

Owner: Cape Island
Well No: 2-A

Casing/Hole Diameter 8" Inch

Depth to Water (below ground)

Depth of Well

Start of Shift 14:30 feet

Start of Shift 220' feet

End of Shift 14' feet

End of Shift 300' feet

Log of Materials Encountered

Depth

Description	From	To
Med brown lime stone	220'	230'
Soft white lime stone	230'	235'
Med brown lime stone	235'	240'
Hard brown dolomite	240'	245'
Soft white lime stone	245'	255'
Hard brown dolomite	255'	260'
Soft white lime stone	260'	300'

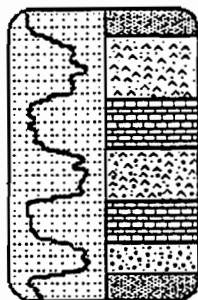
Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Drill Down at 240' 1' 5" at 66 GPM
" " 260' 1' 1" "
" " 280' 1' 1" "
" " 300' 1' "

Finished drilling hole to 300' air developed with slight air for 45
min and tripped out.

Driller: Mike Henry Helper: Robert Ebran

(Use other side for more comments)



Southern Resource Exploration Inc.

P.O. Box 14311
Gainesville, Florida 32604
Phone 904-372-5950

GAM, RES (16-64), SP

COMPANY : Centech Utilities
WELL : XUA-2A
LOCATION/FIELD :
COUNTY : Osceola
STATE : Florida
SECTION : 29

TOWNSHIP : 32 RANGE : 28

OTHER SERVICES:

DATE : 08/09/93
DEPTH DRILLER : 155'
LOG BOTTOM : 155.30
LOG TOP : 0.60

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ELEV. PERM. DATUM:
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DRL MEASURED FROM: TOC

ELEVATIONS
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DF :
GL :

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CASING THICKNESS:

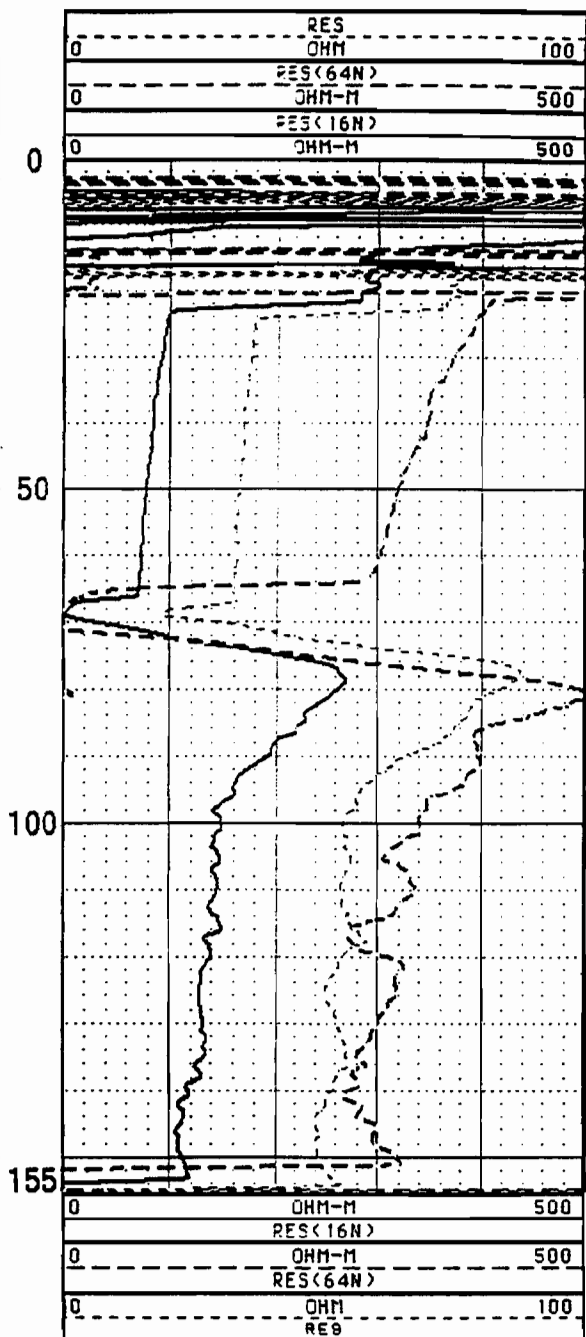
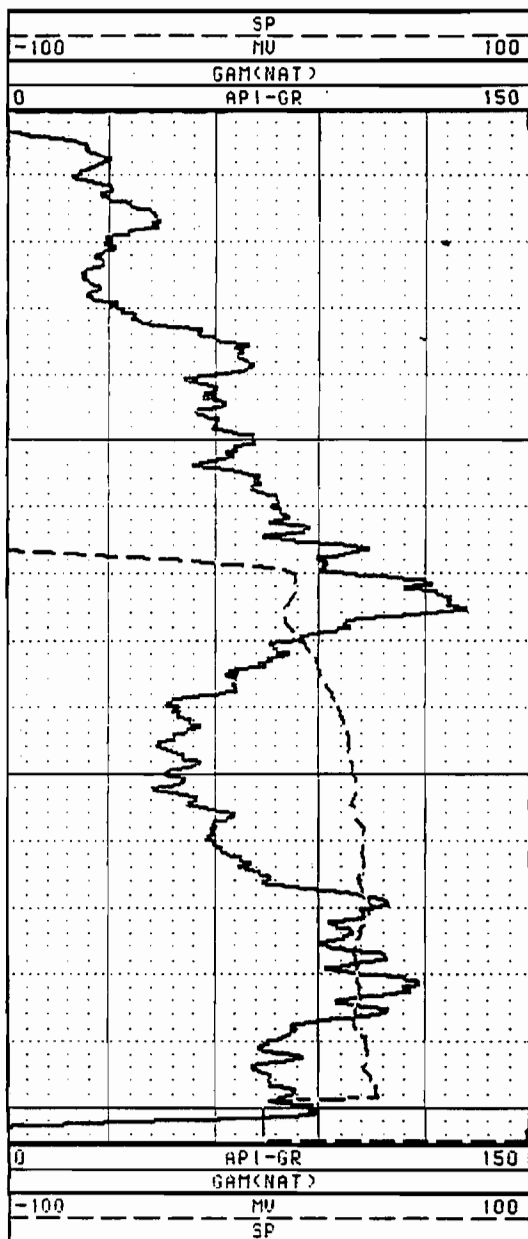
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FIELD OFFICE : GUL
RECORDED BY : M. Fried

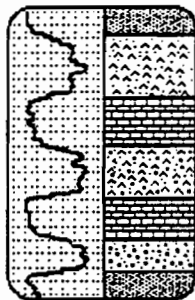
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FLUID DENSITY :
NEUTRON MATRIX :
REMARKS :

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RM :
RM TEMPERATURE :
MATRIX DELTA T :
FLUID DELTA T :

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PLOT : 9040B 2
THRESH: 5000

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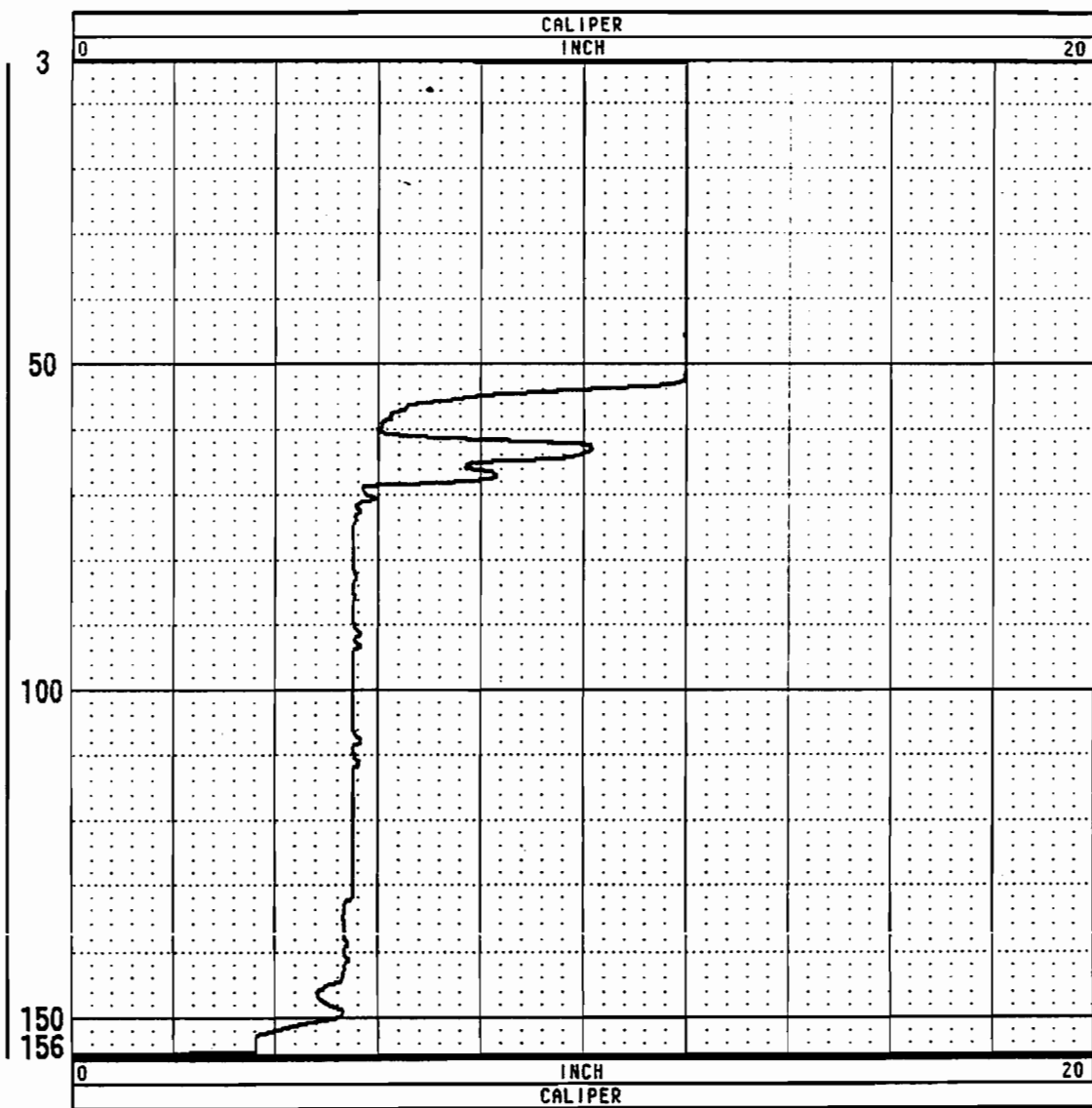
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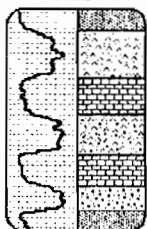
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Gainesville, Florida 32604
Phone 904-372-5950

Caliper Log

COMPANY	: Centech Utilities	OTHER SERVICES:	
WELL	: KUA-2A		
LOCATION/FIELD	:		
COUNTY	: Osceola		
STATE	: Florida		
SECTION	: 29	TOWNSHIP	: 32
		RANGE	: 28
DATE	: 08/09/93	PERMANENT DATUM	:
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LOG TOP	: 4.00	DRL MEASURED FROM:	TOC GL :
CASING DRILLER	: 69	LOGGING UNIT	: 1
CASING TYPE	: steel	FIELD OFFICE	: GUL
CASING THICKNESS:		RECORDED BY	: M. Fried
BIT SIZE	: 6	BOREHOLE FLUID	: mud
MAGNETIC DECL.	:	RM	:
MATRIX DENSITY	:	RM TEMPERATURE	:
FLUID DENSITY	:	MATRIX DELTA T	:
NEUTRON MATRIX	:	FLUID DELTA T	:
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		TYPE	: ANIMC
		LOG	: 0
		PLOT	: CALIPER 2
		THRESH	: 5000

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GAM, RES (16-64), SP

COMPANY : Centech Utilities
WELL : KUA-JA
LOCATION/FIELD :
COUNTY : Osceola
STATE : Florida
SECTION : 29

TOWNSHIP : 32 RANGE : 28

OTHER SERVICES:

DATE : 08/29/93
DEPTH DRILLER : 155
LOG BOTTOM : 155.30
LOG TOP : 2.60

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ELEVATIONS
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DF :
GL :

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CASING TYPE : steel
CASING THICKNESS:

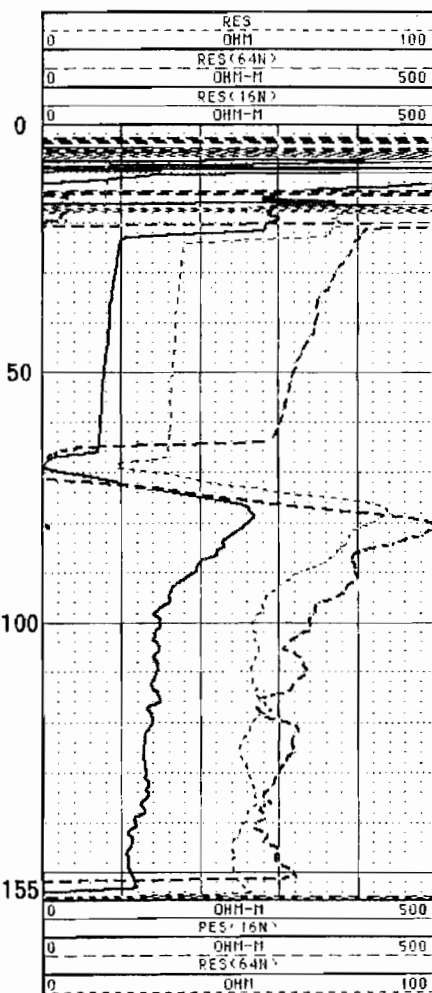
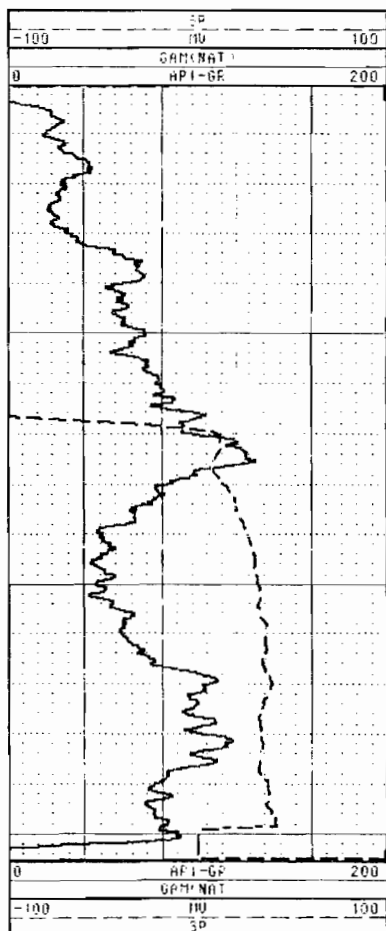
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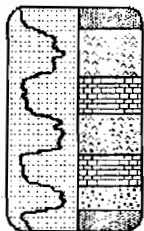
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FLUID DENSITY :
NEUTRON MATRIX :
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RM TEMPERATURE :
MATRIX DELTA T :
FLUID DELTA T :

FILE : ORIGINAL
TYPE : 9841A
LOG : 1
PLOT : 9840A ?
THRESH: 5000

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**Southern
Resource
Exploration Inc.**

P.O. Box 14311
Gainesville, Florida 32604
Phone 904-372-5950

CALIPER LOG

COMPANY : Centech Utilities
WELL : KUR-2A
LOCATION/FIELD :
COUNTY : Osceola
STATE : Florida
SECTION : 29

TOWNSHIP : 32 RANGE : 28

OTHER SERVICES:

DATE : 08/09/93
DEPTH DRILLER : 155'
LOG BOTTOM : 156.10
LOG TOP : 4.00

PERMANENT DATUM :
ELEV. PERM. DATUM :
LOG MEASURED FROM: TOC
DRL MEASURED FROM: TOC

ELEVATIONS
KB :
DF :
GL :

CASING DRILLER : 69
CASING TYPE : steel
CASING THICKNESS:

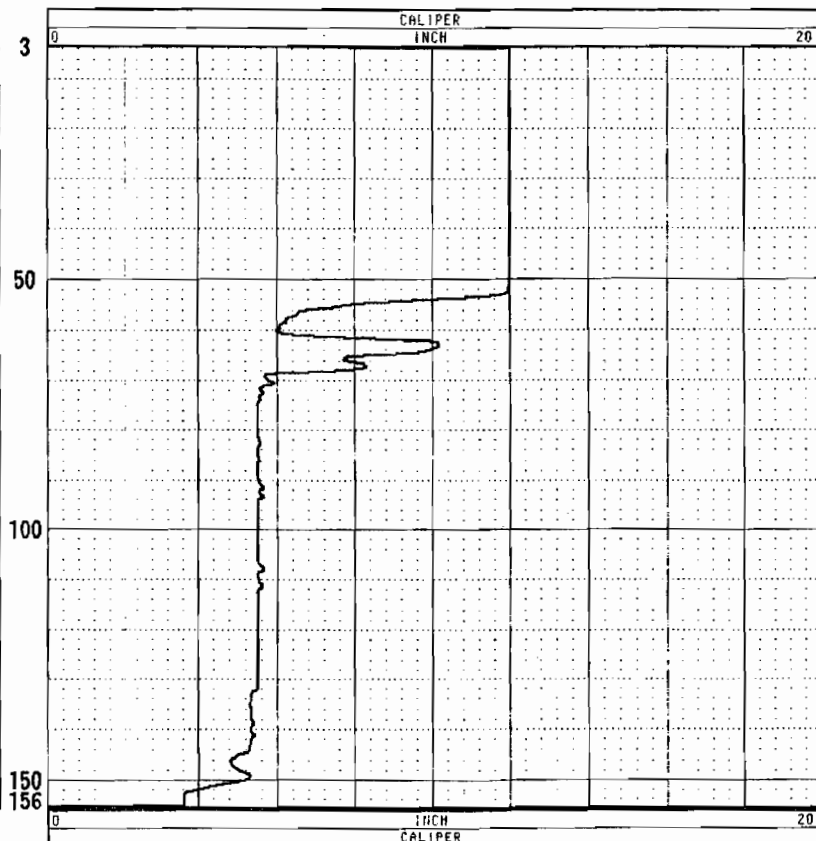
LOGGING UNIT : 1
FIELD OFFICE : GUL
RECORDED BY : M. Fried

BIT SIZE : 6
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FLUID DENSITY :
NEUTRON MATRIX :
REMARKS :

BOREHOLE FLUID : mud
RM :
RM TEMPERATURE :
MATRIX DELTA T :
FLUID DELTA T :

FILE : ORIGINAL
TYPE : ANIMC
LOG : 2
PLOT : CALIPER 2
THRESH: 5000

ALL SERVICES PROVIDED SUBJECT TO STANDARD TERMS AND CONDITIONS



DEVELOPMENT AND TEST PUMPING

DEVELOPMENT:

The wells were developed as the open bore hole was drilled via the reverse air method. At completion of the open bore hole drilling the drill pipe was tripped back up inside of the 8" steel casing and the well was straight air developed with 300 CFM at 200 PSI for 4 hours to remove any drill cuttings which might have settled back into the formation. The well was then equipped with a diesel engine driven test pump and pumped at a capacity of 150% of final design until clear.

TEST PUMPING:

The wells were test pumped as per the specifications utilizing the following equipment.

- A) Peerless Pump Co. 6 HXB 3 stage bowl rated at 450 GPM at 3600 RPM.
- B) 70' of 4" x 1" product lubricated column assembly with 5' bearing centers.
- C) 4 x 4 x 10C Peerless Pump Co. discharge head.
- D) Amarillo 1:2 right angle gear drive.
- E) Detroit Diesel "371" engine.
- F) 300' of 6" Class 160 push joint PVC pipe.
- G) 6" gate valve for flow control.
- H) 6" x 3" orifice plate with manometer tube 2'0" back from plate.

CANE ISLAND COMBUSTION TURBINE PROJECT WELL NO. PW-1

START OF TEST DATE 08/18/93 9:45:00 am

STATIC WATER LEVEL 13.8'

TIME OF DAY	TIME OF TEST	WATER LEVEL	FLOW RATE	COMMENTS
	0:00:30		200	
	0:01:00		200	
	0:01:30		200	
	0:02:00		200	
	0:02:30		200	
	0:03:00		200	
	0:03:30		200	
	0:04:00		200	
	0:04:30		200	
9:50:00	0:05:00	15.80	200	
	0:06:00	15.84	200	
	0:07:00	15.77	200	
	0:08:00	15.33	200	
	0:09:00	15.50	200	
9:55:00	0:10:00	15.50	200	
	0:11:00		200	
	0:12:00		200	
	0:13:00		200	
	0:14:00		200	
10:00:00	0:15:00	15.75	200	
	0:20:00	15.82	200	
	0:25:00	15.84	200	
	0:30:00	15.81	200	
	0:35:00	15.82	200	
	0:40:00	15.83	200	
	0:45:00	15.84	200	
	0:50:00	15.81	200	
	0:55:00	15.83	200	
10:45:00	1:00:00	15.84	200	
	1:05:00	15.84	200	
	1:10:00	15.86	200	
	1:15:00	15.90	200	
	1:20:00	15.92	200	

	1:25:00	15.91	200	
	1:30:00	15.96	200	
	1:35:00	15.92	200	
	1:40:00	15.92	200	
	1:45:00	15.91	200	
	1:50:00	15.91	200	
	1:55:00	15.90	200	
11:45:00	2:00:00	15.92	200	
	2:30:00	15.92	200	
12:45:00	3:00:00	15.97	200	
	3:30:00	16.01	200	
1:45:00	4:00:00	15.98	200	
	4:30:00	15.97	200	
2:45:00	5:00:00	15.98	200	
3:45:00	6:00:00	15.99	200	
	7:00:00	16.02	200	
	8:00:00	16.00	200	
	9:00:00	15.99	200	
	10:00:00	15.86	200	
	11:00:00	15.93	200	
9:45:00	12:00:00	16.04	200	
	13:00:00	16.00	200	
	14:00:00	15.98	200	
	15:00:00	15.98	200	
	16:00:00	15.98	200	
	17:00:00	15.98	200	
	18:00:00	15.98	200	
	19:00:00	16.00	200	
	20:00:00	16.00	200	
	21:00:00	16.02	200	
	22:00:00	16.03	200	
	23:00:00	16.03	200	
9:45:00	24:00:00	16.03	200	COLLECT CHEMICAL ANALYSIS
	24:00:15		0	Recovery readings.
	24:00:30		0	Recovery readings.
	24:00:45		0	Recovery readings.
	24:01:00	14.40	0	Recovery readings.
	24:01:15	14.55	0	Recovery readings.
	24:01:30	14.55	0	Recovery readings.

	24:01:45	14.41	0	Recovery readings.
	24:02:00	14.00	0	Recovery readings.
	24:02:30	13.71	0	Recovery readings.
	24:03:00	13.53	0	Recovery readings.
	24:03:30	13.44	0	Recovery readings.
	24:04:00	13.42	0	Recovery readings.
	24:04:30	13.42	0	Recovery readings.
9:50:00	24:05:00	13.45	0	Recovery readings.
	24:05:30	13.89	0	Recovery readings.
	24:06:00	14.28	0	Recovery readings.
	24:06:30	14.35	0	Recovery readings.
	24:07:00	14.34	0	Recovery readings.
	24:07:30	14.31	0	Recovery readings.
	24:08:00	13.99	0	Recovery readings.
	24:08:30	13.99	0	Recovery readings.
	24:09:00	13.99	0	Recovery readings.
	24:09:30	13.99	0	Recovery readings.
9:55:00	24:10:00	14.29	0	Recovery readings.
	24:11:00	14.30	0	Recovery readings.
	24:12:00	14.28	0	Recovery readings.
	24:13:00	14.27	0	Recovery readings.
	24:14:00	14.27	0	Recovery readings.
10:00:00	24:15:00	14.30	0	Recovery readings.
	24:16:00	14.30	0	Recovery readings.
	24:17:00	14.27	0	Recovery readings.
	24:18:00	14.27	0	Recovery readings.
	24:19:00	14.28	0	Recovery readings.
	24:20:00	14.26	0	Recovery readings.
	24:21:00	14.25	0	Recovery readings.
	24:22:00	14.23	0	Recovery readings.
	24:23:00	14.23	0	Recovery readings.
	24:24:00	14.24	0	Recovery readings.
	24:25:00	14.23	0	Recovery readings.
	24:26:00	14.23	0	Recovery readings.
	24:27:00	14.23	0	Recovery readings.
	24:28:00	14.21	0	Recovery readings.
	24:29:00	14.22	0	Recovery readings.
10:15:00	24:30:00	14.20	0	Recovery readings.
	24:31:00	14.20	0	Recovery readings.

	24:32:00	14.20	0	Recovery readings.
	24:33:00	14.22	0	Recovery readings.
	24:34:00	14.20	0	Recovery readings.
	24:35:00	14.20	0	Recovery readings.
	24:36:00	14.21	0	Recovery readings.
	24:37:00	14.20	0	Recovery readings.
	24:38:00	14.19	0	Recovery readings.
	24:39:00	14.19	0	Recovery readings.
	24:40:00	14.18	0	Recovery readings.
	24:41:00	14.18	0	Recovery readings.
	24:42:00	14.18	0	Recovery readings.
	24:43:00	14.21	0	Recovery readings.
	24:44:00	14.20	0	Recovery readings.
10:30:00	24:45:00	14.18	0	Recovery readings.
	24:46:00	14.20	0	Recovery readings.
	24:47:00	14.19	0	Recovery readings.
	24:48:00	14.19	0	Recovery readings.
	24:49:00	14.15	0	Recovery readings.
	24:50:00	14.15	0	Recovery readings.
	24:51:00	14.15	0	Recovery readings.
	24:52:00	14.16	0	Recovery readings.
	24:53:00	14.15	0	Recovery readings.
	24:54:00	14.15	0	Recovery readings.
	24:55:00	14.15	0	Recovery readings.
	24:56:00	14.13	0	Recovery readings.
	24:57:00	14.13	0	Recovery readings.
	24:58:00	14.13	0	Recovery readings.
	24:59:00	14.14	0	Recovery readings.
10:45:00	25:00:00	14.15	0	Recovery readings.
	25:05:00	14.13	0	Recovery readings.
	25:10:00	14.14	0	Recovery readings.
	25:15:00	14.13	0	Recovery readings.
	25:20:00	14.11	0	Recovery readings.
	25:25:00	14.11	0	Recovery readings.
	25:30:00	14.12	0	Recovery readings.
	25:35:00	14.12	0	Recovery readings.
	25:40:00	14.11	0	Recovery readings.
	25:45:00	14.13	0	Recovery readings.
	25:50:00	14.13	0	Recovery readings.

	25:55:00	14.12	0	Recovery readings.
11:45:00	26:00:00	14.12	0	Recovery readings.
	26:30:00	14.10	0	Recovery readings.
	27:00:00	14.10	0	Recovery readings.
	27:30:00	14.11	0	Recovery readings.
1:45:00	28:00:00	14.12	0	Recovery readings.

PUMPING RECOMMENDATIONS WELL PW-1

Based on sound pump application practices and the tested yield of 89.69 GPM per foot of drawdown we recommend pumping up to 450 GPM for this well.

Poor Original

CANE ISLAND COBUSTION TURBINE PROJECT

FIELD TEST OF WELL PUMP PW-1 (NORTH)

RATED CAPACITY 200 GPM

% of capacity	GPM	PSI	PWL	LOSSES	TDH/ft
30%	60	96	18.5	1	241.26
40%	80	95.5	19	2	239.61
50%	100	95	19.5	3	238.95
60%	120	93	19	4	233.83
70%	140	89	19	5	224.59
80%	160	82	19	6	208.42
90%	180	74	19.5	7	190.44
100%	200	65	19.5	8	169.65
110%	220	56	20	12	149.36

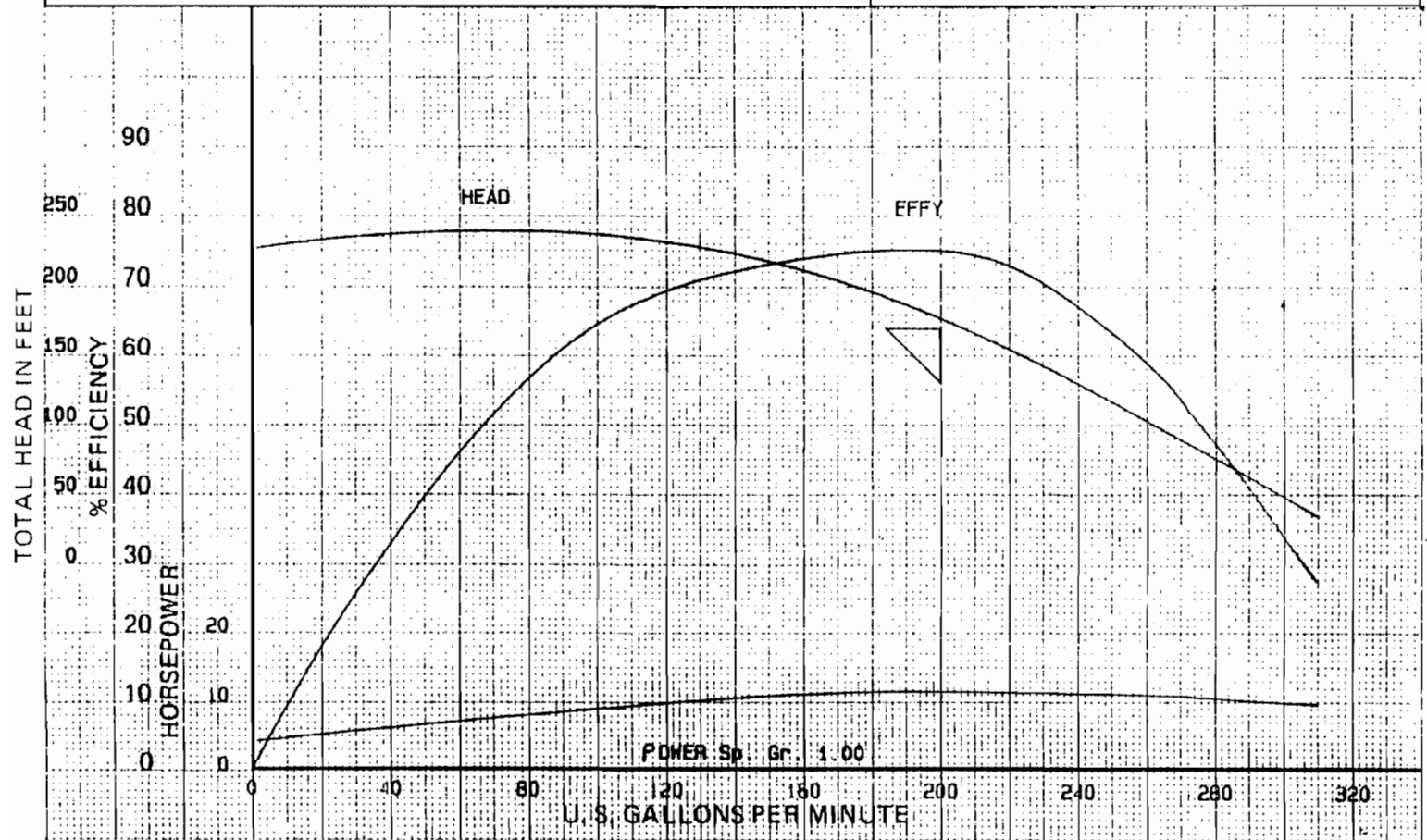
HYDRAULIC PERFORMANCE WARRANTY
GUARANTEED AT DESIGNATED POINT
ONLY AND IS CONTINGENT ON

1. PROPER NPSH OR SUBMERGENCE AVAILABLE.
2. PROPER AND ADEQUATE FLOW TO PUMP SUCTION.
3. FLUID FREE OF GAS, AIR AND ABRASIVE MATTER.
4. IMPELLER WITH PROPER LATERAL ADJUSTMENT. (VERT PUMP ONLY)

Peerless Pump Compar.,

A member of the Sterling Group
Indianapolis, IN 46206

CURVE NO. C187848



PLOTTED BY JS Pump Type: 8LB Stages: 7 RPM: 1765 Test No: 187848 Dia: 5.94
DATE 11-16-93 Pump No: 1 S/O: 4-2405MR Impeller: 2616464
CERTIFIED SHOP TEST CURVE

WELL COMPLETION REPORT

FORM 0124
Rev. 4/85

WELL PERMIT NO. SF072193A

Owner Kissimmee Utility Authority Address 1701 W. Carroll St. City Kissimmee, Florida State 34742
 Contractor's Signature [Signature] License No. 9151 Completion Date 8-13-93 Casing Depth 150' Total Depth 300' PW-1
 Driller's Name Rick Lowery Registration No. _____

TYPE OF WORK: Construct (☒) Repair () Abandon ()

WELL USE: Domestic Well () Public () Monitor () Test ()
 Irrigation () Fire Well (☒) Other Industrial

METHOD: Rotary with MUD (☒) or Air () Cable Tool () Jet ()
 Casing Driven () Other Grouted

STATIC WATER LEVEL 14' 3" Ft. below top of casing

PUMPING WATER LEVEL _____ Ft. after _____ Hrs. at _____ GPM

PUMP SIZE _____ H.P. CAPACITY _____ GPM

PUMP TYPE _____ INTAKE DEPTH _____
 From top of ground

LOCATION

Located Near Old Tampa Rd.
& 17, 92

County Osceola

29 32 25 28
 W Section Township Range

Latitude-Longitude

Cuttings sent to District? () Yes
 (☒) No

LOCATE IN SECTION

Note: PWS Wells attach a site map if well location is different from site location on permit application.

Grout	Casing & Screen		Depth (ft)		DRILL CUTTINGS LOG Examine cuttings every 20 ft. or at formation changes Give color, grain size, and type of material Note cavities, depth to producing zones.
	Thickness & Depth	Diameter & Depth	From	To	
2"	8"	150'	0	10	Orange Sand
0-150'			10	20	Orange Sandy Clay
			20	40	White Sandy Clay
			40	65	Green Sandy Clay & Shell
			65	70	Soft White Lime Stone
			70	120	Soft Gray Lime Stone
			120	175	Soft tan Lime Stone
			175	240	Soft tan lime stone with some areas of white lime stone
			240	245	Hard brown dolomite
Number of bags			245	255	Soft white lime stone
68			255	260	Hard brown dolomite
			260	300	Soft white lime stone

Casing: Black Steel (☒) Galv. () PVC () Fiberglass ()

Screen: Type _____ Slot size _____

Screened from _____ (ft.) to _____ (ft.)

Type of grout with % additives Net

Water: Clear (☒) Colored () Sulphur () Salty () Iron ()

Conductivity _____ Chlorides _____ mg/l

**FINAL WELL REPORT
WELL PW-2**

**CANE ISLAND
COMBUSTION TURBINE PROJECT
KISSIMMEE UTILITY AUTHORITY**

**PREPARED BY
CENTECH UTILITY CORPORATION
6109 ORIENT ROAD
TAMPA, FL. 33610
PH. (813) 626-2258
FX. (813) 620-3385**

TABLE OF CONTENTS

WELL PW-2

SECTION 1	DRILLERS LOGS
SECTION 2	GEOPHYSICAL LOGS
SECTION 3	DEVELOPMENT AND TEST PUMPING DATA
SECTION 4	PUMPING RECOMMENDATIONS
SECTION 5	WATER WELL LOG

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.

DAILY DRILLING REPORT

Date: 8-16-93
Mon.

Owner: Cape Island
Well No: 2-B

Casing/Hole Diameter _____ Inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 17 feet

End of Shift _____ feet

End of Shift 66 feet

Log of Materials Encountered

Depth

Description	From	To
<u>Orange Sand</u>	<u>0'</u>	<u>12'</u>
<u>Orange Sandy Clay</u>	<u>12'</u>	<u>22'</u>
<u>white Sandy Clay</u>	<u>22'</u>	<u>30'</u>
<u>Orange Sandy Clay</u>	<u>30'</u>	<u>40'</u>
<u>light green Sandy Clay</u>	<u>40'</u>	<u>50'</u>
<u>Green Sandy Clay</u>	<u>50'</u>	<u>60'</u>
<u>green Sand Clay with Shells</u>	<u>60'</u>	<u>66'</u>

Hit lime Stone at 66' but lost Circulation.

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Moved eq. to new site, set up, dug and pit and
mixed and made up 8" bit and set pit hole to
66', lost circulation. Tipped out and made up 10" bit
cleaned out pit at old site and back filled.

Driller: Mark Lopez

Helper: Richard Ebron

(Use other side for more comments)

DAILY DRILLING REPORT

Date: 5-17-93
Tues.

Owner: Cox Island
 Well No: 2-B

Casing/Hole Diameter _____ Inch
 Depth of Well _____
 Start of Shift 0 _____ feet
 End of Shift 0 _____ feet

Depth to Water (below ground) _____
 Start of Shift _____ feet
 End of Shift _____ feet

Log of Materials Encountered

Depth

Description	From	To
<u>Running 8" pilot</u>	<u>0</u>	<u>59'</u>

Drilled to 59' losing some returns, pulled
up to make a seal change and later changed
to Triplex 19" bit. ran out and moved rig.

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

off hole and water on disc on moving
well location.

Driller: Mike Lundy Helper: Poland Ebron

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-18-93
wed

Owner: San. Island
Well No: 2-B

Casing/Hole Diameter _____ inch

Depth to Water (below ground)

Depth of Well _____

Start of Shift _____ feet

Start of Shift _____ feet

End of Shift _____ feet

End of Shift _____ feet

Log of Materials Encountered

Depth

Description	From	To

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Drilled 2" hole back to 60', pumped 15 bags of port
cement slurry. Drill works then tripped hole out. (hole casing
aborted 4 1/2' w/ 1" line pipe down to 50',
mixed & pumped 15 bags of port cement got returns to
surface and cleared i.p.

Driller: Mark Ljung Helper: Robert Ebron

(Use other side for more comments)

DAILY DRILLING REPORT

Date: 8-19-75
Thurs

Owner: Lower School
Well No: 26

Casing/Hole Diameter _____ Inch

Depth to Water (below ground) _____

Depth of Well _____

Start of Shift _____ feet

Start of Shift _____ feet

End of Shift _____ feet

End of Shift _____ feet

Log of Materials Encountered

Depth

Description	From	To

Mixed + pumped 10 bags of port cement to top
well 26 ft.

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Obtained spec. to new well location, set up, dug hole
2 ft. mixed mud, made up 2" bit to cut pilot hole
and made up 18" casing.

Driller: Mark Luning

Helper: Robert Ebers

(Use other side for more comments)

DAILY DRILLING REPORT

Date: 8-22-95
FR.

Owner: Cape Isabel
Well No: 2-C

Casing/Hole Diameter 18 inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 12 feet

End of Shift _____ feet

End of Shift 50' feet

Log of Materials Encountered

Depth

Description	From	To
<u>Orange Sand</u>	<u>0</u>	<u>10'</u>
<u>orange sandy clay.</u>	<u>10'</u>	<u>25'</u>
<u>white sandy clay.</u>	<u>25'</u>	<u>35'</u>
<u>orange sandy clay.</u>	<u>35'</u>	<u>40'</u>
<u>green sandy clay with some</u>	<u>40'</u>	<u>50'</u>
<u>shell.</u>		

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Drilled 8" pilot hole to 40', tripped out, stuck up 22"
bit, scanned pilot hole to 40', tripped out and set 40' of
18" steel casing. Ran 33' of 2" true pipe, made up
header - mixed - pumped 30 bags of port cement and
cleared up.

Driller: Rich Henry

Helper: Richard Ebron

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-27-43
W.D.

Owner: Gen. T. Schuch
Well No: 2-C

Casing/Hole Diameter 12 Inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 5:12 feet

End of Shift _____ feet

End of Shift 1:15 feet

Log of Materials Encountered

Depth

Description	From	To
Green clay with some shell	52'	55'
and chert at 55'		
dark soil	59'	1:15'

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

Drilled 1" pilot hole to 55', tapered out, made up 12"
bit and turned back up hole. Reamed pilot hole back to
55' tapered out and set 55' of 12" casing.
Ran 31' of 2" line pipe pumped 3 yds of wet cement
and cleaned up.

Driller: Ed. Long

Helper: Robert E. Long

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 10/11/75
Thurs.

Owner: Case School
Well No: 2-1

Casing/Hole Diameter 12 inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 7:55 feet

End of Shift _____ feet

End of Shift 7:55 feet

Log of Materials Encountered

Depth

Description	From	To

Traced cement at 58' between 8" & 12" casing.

Remarks: (Character of drilling, casing added, miscellaneous work items, etc.)

Drilled 2" hole pipe cut off 12" hole, and traced
up 42' of 1" frame pipe between 12" & 12" casing's pumped
3 yds of port cement, "got full returns" and cleaned up.
made up 8" bit and traced in hole. Made 8" casing
was to site and made up casing.

Driller: Mike Lacey

Helper: Robert E. Brown

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 2-25-78
well

Owner: Cape Island
Well No: 2-C

Casing/Hole Diameter 2 Inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 75' feet

End of Shift _____ feet

End of Shift 150' feet

Log of Materials Encountered

Depth

Description	From	To
<u>red white line stone</u>	<u>75'</u>	<u>85'</u>
<u>soft to red white line stone</u>	<u>85'</u>	<u>115'</u>
<u>soft to red line stone</u>	<u>115'</u>	<u>150'</u>

Remarks: (Character of drilling, casing added, miscellaneous work items, etc):

Drilled 8" pilot hole to 150', turned out mud, up 12"
bit + screen and small pilot hole back to 150'

Driller: John Henry

Helper: Richard Brown

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-27-93
101

Owner: John T. Brown
Well No: 2-C

Casing/Hole Diameter 7 inch

Depth to Water (below ground)

Depth of Well

Start of Shift _____ feet

Start of Shift 150' feet

End of Shift 1512' feet

End of Shift 2110' feet

Log of Materials Encountered

Depth

Description	From	To
Soft tan lime stone	150'	180'
Med tan lime stone	180'	185'
Med white lime stone	185'	210'
Med to med brown lime stone	210	225'
Med to med brown dolomite	225'	235'
Soft white lime stone	235'	2110'

Remarks: (Character of drilling, casing added, miscellaneous work items, etc):

Tagged cement at 9', mixed + pumped 3 bags of 12+ cement
and cleaned up. Pulled up 5" bit, tapered in hole. Tagged
cement inside 5" at 143'. Drilled to 220' and switched
over to reverse air and cleaned up hole.

Driller: John T. Brown

Helper: Richard Brown

(Use other side for more comments)

CENTECH DAILY DRILLING REPORT

Date: 8-28-95
Set

Owner: Carroll School
Well No: 2-C

Casing/Hole Diameter 6 Inch

Depth to Water (below ground)

Depth of Well

Start of Shift 15:10 feet

Start of Shift 240' feet

End of Shift 14:20 feet

End of Shift 360' feet

Log of Materials Encountered

Depth

Description	From	To
<u>Soft white lime stone</u>	<u>240'</u>	<u>245'</u>
<u>Soft white lime stone with some</u>	<u>245'</u>	<u>290'</u>
<u>white lime</u>		
<u>Soft tan lime stone</u>	<u>280'</u>	<u>285'</u>
<u>Hard brown dolomite</u>	<u>285'</u>	<u>290'</u>
<u>Soft white lime stone</u>	<u>290'</u>	<u>315'</u>
<u>Hard to med brown dolomite</u>	<u>315'</u>	<u>325'</u>

Remarks: (Character of drilling, casing added, miscellaneous work items, etc)

<u>Soft white lime stone</u>	<u>325'</u>	<u>330'</u>
<u>Hard brown dolomite with some</u>	<u>330'</u>	<u>340'</u>
<u>broken areas</u>		
<u>Draw Down at</u>	<u>280' - 5'</u>	<u>300' - 4'</u>
	<u>340' - 2'</u>	
	<u>280' - 4' 7"</u>	<u>320' - 3' 7"</u>
	<u>360' - 1' 7"</u>	<u>→</u>

Driller: John Lacey Helper: Richard Egan

(Use other side for more comments)

**GEOPHYSICAL LOGS
WERE NOT RUN ON THIS
WELL AS PER THE
SPECIFICATIONS**

DEVELOPMENT AND TEST PUMPING

DEVELOPMENT:

The wells were developed as the open bore hole was drilled via the reverse air method. At completion of the open bore hole drilling the drill pipe was tripped back up inside of the 8" steel casing and the well was straight air developed with 300 CFM at 200 PSI for 4 hours to remove any drill cuttings which might have settled back into the formation. The well was then equipped with a diesel engine driven test pump and pumped at a capacity of 150% of final design until clear.

TEST PUMPING:

The wells were test pumped as per the specifications utilizing the following equipment.

A) Peerless Pump Co. 6 HXB 3 stage bowl rated at 450 GPM at 3600 RPM.

B) 70' of 4" x 1" product lubricated column assembly with 5' bearing centers.

C) 4 x 4 x 10C Peerless Pump Co. discharge head.

D) Amarillo 1:2 right angle gear drive.

E) Detroit Diesel "371" engine.

F) 300' of 6" Class 160 push joint PVC pipe.

G) 6" gate valve for flow control.

H) 6" x 3" orifice plate with manometer tube 2'0" back from plate.

CANE ISLAND COMBUSTION TURBINE PROJECT WELL NO. P'W-2

START OF TEST DATE 08/31/93 10:45 AM

STATIC WATER LEVEL 14

TIME OF DAY	TIME OF TEST	WATER LEVEL	FLOW RATE	COMMENTS
	0:00:30	20.00	200	
	0:01:00	20.33	200	
	0:01:30	20.33	200	
	0:02:00	20.33	200	
	0:02:30	20.42	200	
	0:03:00	20.42	200	
	0:03:30	20.50	200	
	0:04:00	20.42	200	
	0:04:30	20.42	200	
9:50:00	0:05:00	20.42	200	
	0:06:00	20.50	200	
	0:07:00	20.50	200	
	0:08:00	20.50	200	
	0:09:00	20.50	200	
9:55:00	0:10:00	20.50	200	
	0:11:00	20.50	200	
	0:12:00	20.50	200	
	0:13:00	20.50	200	
	0:14:00	20.50	200	
10:00:00	0:15:00	20.50	200	
	0:20:00	20.50	200	
	0:25:00	20.50	200	
	0:30:00	20.50	200	
	0:35:00	20.50	200	
	0:40:00	20.50	200	
	0:45:00	20.54	200	
	0:50:00	20.54	200	
	0:55:00	20.58	200	
10:45:00	1:00:00	20.54	200	
	1:05:00	20.58	200	
	1:10:00	20.50	200	
	1:15:00	20.50	200	
	1:20:00	20.50	200	

	1:25:00	20.50	200	
	1:30:00	20.50	200	
	1:35:00	20.50	200	
	1:40:00	20.50	200	
	1:45:00	20.50	200	
	1:50:00	20.50	200	
	1:55:00	20.50	200	
11:45:00	2:00:00	20.50	200	
	2:30:00	20.67	200	
12:45:00	3:00:00	20.67	200	INCREASED PUMPING RATE
	3:30:00	26.42	300	
1:45:00	4:00:00	26.42	300	
	4:30:00	26.48	300	
2:45:00	5:00:00	26.48	300	
3:45:00	6:00:00	26.48	300	INCREASED PUMPING RATE
	7:00:00	29.67	400	
	8:00:00	29.71	400	
	9:00:00	29.71	400	
	10:00:00	29.67	400	
	11:00:00	29.67	400	
9:45:00	12:00:00	29.58	400	
	13:00:00	29.58	400	
	14:00:00	29.58	400	
	15:00:00	29.58	400	
	16:00:00	29.58	400	
	17:00:00	29.58	400	
	18:00:00	29.58	400	
	19:00:00	29.58	400	
	20:00:00	29.54	400	
	21:00:00	29.54	400	COLLECT CHEMICAL ANALYSIS
	22:00:00		0	SHUT DOWN TEST PUMP
	23:00:00		0	
9:45:00	24:00:00		0	
	24:00:15	14.42	0	Recovery readings.
	24:00:30	15.00	0	Recovery readings.
	24:00:45	15.00	0	Recovery readings.
	24:01:00	15.08	0	Recovery readings.
	24:01:15	15.08	0	Recovery readings.
	24:01:30	14.96	0	Recovery readings.

	24:01:45	14.96	0	Recovery readings.
	24:02:00	14.92	0	Recovery readings.
	24:02:30	14.92	0	Recovery readings.
	24:03:00	14.88	0	Recovery readings.
	24:03:30	14.88	0	Recovery readings.
	24:04:00	14.88	0	Recovery readings.
	24:04:30	14.83	0	Recovery readings.
9:50:00	24:05:00	14.79	0	Recovery readings.
	24:05:30	14.75	0	Recovery readings.
	24:06:00	14.71	0	Recovery readings.
	24:06:30	14.71	0	Recovery readings.
	24:07:00	14.67	0	Recovery readings.
	24:07:30	14.58	0	Recovery readings.
	24:08:00	14.58	0	Recovery readings.
	24:08:30	14.54	0	Recovery readings.
	24:09:00	14.54	0	Recovery readings.
	24:09:30	14.54	0	Recovery readings.
9:55:00	24:10:00	14.50	0	Recovery readings.
	24:11:00	14.50	0	Recovery readings.
	24:12:00	14.50	0	Recovery readings.
	24:13:00	14.50	0	Recovery readings.
	24:14:00	14.50	0	Recovery readings.
10:00:00	24:15:00	14.46	0	Recovery readings.
	24:16:00	14.46	0	Recovery readings.
	24:17:00	14.46	0	Recovery readings.
	24:18:00	14.46	0	Recovery readings.
	24:19:00	14.46	0	Recovery readings.
	24:20:00	14.46	0	Recovery readings.
	24:21:00	14.46	0	Recovery readings.
	24:22:00	14.46	0	Recovery readings.
	24:23:00	14.46	0	Recovery readings.
	24:24:00	14.44	0	Recovery readings.
	24:25:00	14.44	0	Recovery readings.
	24:26:00	14.44	0	Recovery readings.
	24:27:00	14.44	0	Recovery readings.
	24:28:00	14.42	0	Recovery readings.
	24:29:00	14.42	0	Recovery readings.
10:15:00	24:30:00	14.42	0	Recovery readings.
	24:31:00	14.42	0	Recovery readings.

	24:32:00	14.42	0	Recovery readings.
	24:33:00	14.42	0	Recovery readings.
	24:34:00	14.40	0	Recovery readings.
	24:35:00	14.40	0	Recovery readings.
	24:36:00	14.40	0	Recovery readings.
	24:37:00	14.40	0	Recovery readings.
	24:38:00	14.40	0	Recovery readings.
	24:39:00	14.38	0	Recovery readings.
	24:40:00	14.38	0	Recovery readings.
	24:41:00	14.38	0	Recovery readings.
	24:42:00	14.38	0	Recovery readings.
	24:43:00	14.38	0	Recovery readings.
	24:44:00	14.35	0	Recovery readings.
10:30:00	24:45:00	14.35	0	Recovery readings.
	24:46:00	14.35	0	Recovery readings.
	24:47:00	14.33	0	Recovery readings.
	24:48:00	14.33	0	Recovery readings.
	24:49:00	14.33	0	Recovery readings.
	24:50:00	14.33	0	Recovery readings.
	24:51:00	14.33	0	Recovery readings.
	24:52:00	14.33	0	Recovery readings.
	24:53:00	14.33	0	Recovery readings.
	24:54:00	14.33	0	Recovery readings.
	24:55:00	14.33	0	Recovery readings.
	24:56:00	14.33	0	Recovery readings.
	24:57:00	14.33	0	Recovery readings.
	24:58:00	14.33	0	Recovery readings.
	24:59:00	14.33	0	Recovery readings.
10:45:00	25:00:00	14.33	0	Recovery readings.
	25:05:00	14.31	0	Recovery readings.
	25:10:00	14.31	0	Recovery readings.
	25:15:00	14.29	0	Recovery readings.
	25:20:00	14.29	0	Recovery readings.
	25:25:00	14.27	0	Recovery readings.
	25:30:00	14.27	0	Recovery readings.
	25:35:00	14.27	0	Recovery readings.
	25:40:00	14.27	0	Recovery readings.
	25:45:00	14.27	0	Recovery readings.
	25:50:00	14.25	0	Recovery readings.

	25:55:00	14.25	0	Recovery readings.
11:45:00	26:00:00	14.25	0	Recovery readings.
	26:30:00	14.21	0	Recovery readings.
	27:00:00	14.19	0	Recovery readings.
	27:30:00	14.15	0	Recovery readings.
1:45:00	28:00:00	14.13	0	Recovery readings.

PUMPING RECOMMENDATIONS WELL PW-2

Based on sound pump application practices and the tested yield of 25.67 GPM per foot of drawdown we recommend pumping up to 450 GPM for this well.

Poor Original

CANE ISLAND COBUSTION TURBINE PROJECT
FIELD TEST OF WELL PUMP PW-2 (SOUTH)
RATED CAPACITY 200 GPM

% of capacity	GPM	PSI	PWL	LOSSES	TDH/ft
30%	60	96	16.5	1	239.26
40%	80	95	17	2	236.45
50%	100	94	18	3	235.14
60%	120	91	18.5	4	228.71
70%	140	86	19.5	5	218.16
80%	160	80	20	6	204.80
90%	180	71	20	7	184.01
100%	200	60	21	8	159.60
110%	220	50	22	12	137.50

HYDRAULIC PERFORMANCE WARRANTY

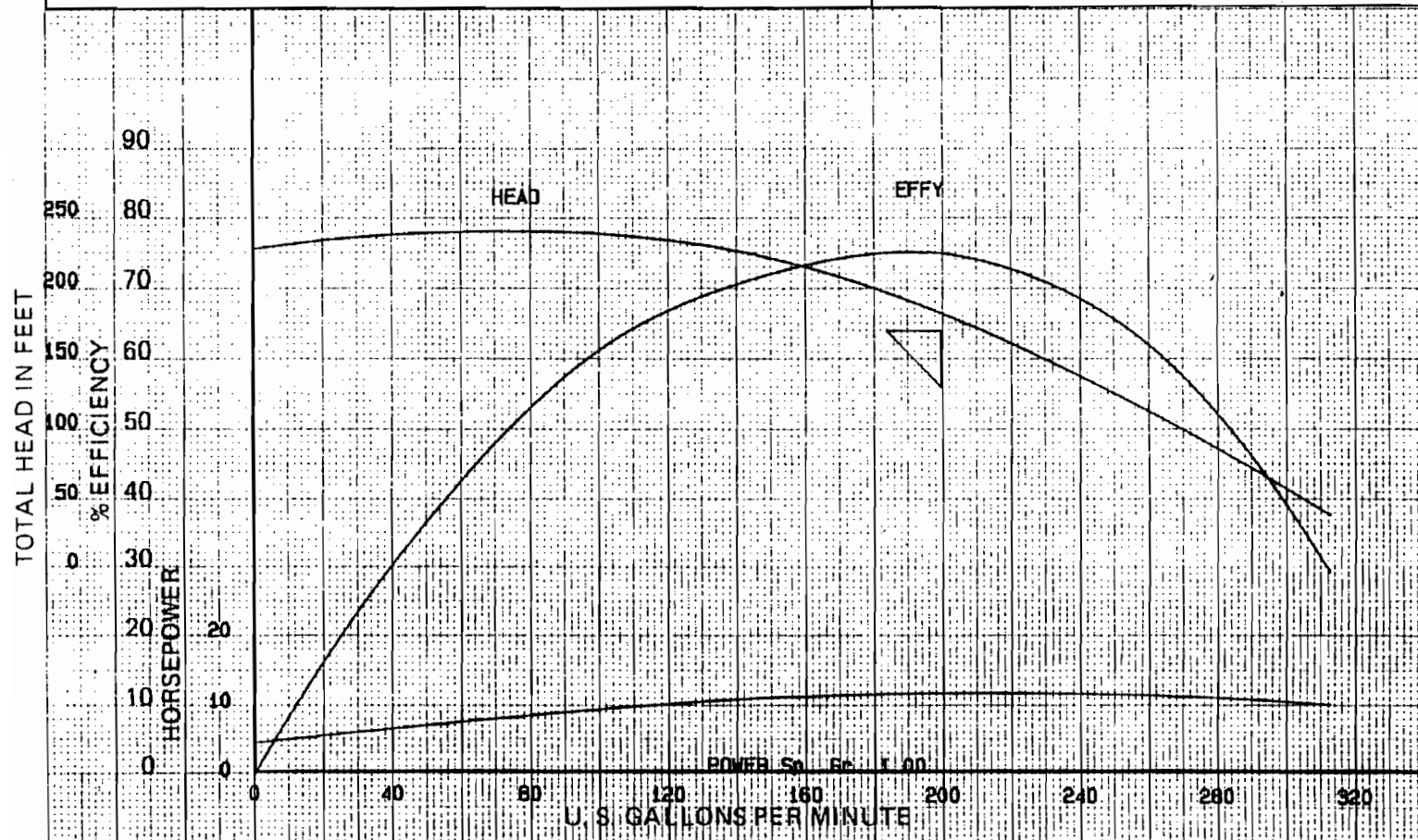
GUARANTEED AT DESIGNATED POINT
ONLY AND IS CONTINGENT ON

1. PROPER NPSH OR SUBMERGENCE AVAILABLE.
2. PROPER AND ADEQUATE FLOW TO PUMP SUCTION.
3. FLUID FREE OF GAS, AIR AND ABRASIVE MATTER.
4. IMPELLER WITH PROPER LATERAL ADJUSTMENT. (VERT PUMP ONLY)

Peerless Pump Company

A member of the Sterling Group
Indianapolis, IN 46206

CURVE NO. C187849



PLOTTED BY JS Pump Type: 8LB
DATE 11-16-93 Pump No: 2

Stages: 7
S/O: 4-2405MA

RPM: 1765

Test No: 187849

Dia: 5.94

Impeller: 2616464

WELL COMPLETION REPORT

FORM 0124
Rev. 4/85

WELL PERMIT NO. SFC72193B

Kissimmee Utility Authority 1701 W. Carroll St., Kissimmee, Florida 34742
 Owner [Signature] Address 9151 City 150' State 360' Zip PW-2
 Contractor's Signature Rick Lowery License No. 8-28-93 Completion Date 150' Casing Depth 360' Total Depth PW-2 Well #
 Driller's Name Rick Lowery Registration No.

PAGE 1 of 2

TYPE OF WORK: Construct (☒) Repair () Abandon ()
 WELL USE: Domestic Well () Public () Monitor () Test ()
 Irrigation () Fire Well (☒) Other Industrial
 METHOD: Rotary with MUD (☒) or Air () Cable Tool () Jet ()
 Casing Driven () Other Grouted
 STATIC WATER LEVEL 14'2" Ft. below top of casing
 PUMPING WATER LEVEL Ft. after Hrs. at GPM
 PUMP SIZE H.P. CAPACITY GPM
 PUMP TYPE INTAKE DEPTH From top of ground

LOCATION
 Located Near Old Tampa Rd.
and 17, 92
 County Osceola
29, 32 25 28
 Section Township Range
 Latitude-Longitude

Cuttings sent to District? () Yes
 (☒) No

LOCATE IN SECTION

Note: PWS Wells attach a site map if well location is different from site location on permit application.

Grout	Casing & Screen	Depth (ft)		DRILL CUTTINGS LOG Examine cuttings every 20 ft. or at formation changes Give color, grain size, and type of material Note cavities, depth to producing zones.	
Thickness & Depth	Diameter & Depth	From	To		
2"	8"	150'	0	10	Orange Sand
0-150			10	25	Orange Sandy Clay
			25	35	White Sandy Clay
			35	40	Orange Sandy Clay
			40	65	Green Clay with some shell
			65		Lost circulation
			65	75	Med. rock
			75	115	Soft to med. white, lime stone
			115	185	Soft to med. tan lime stone
			185	210	Soft white lime stone
Number of bags			210	225	Med. to hard brown lime stone
					stone
66			225	235	Hard brown dolomite

Casing: Black Steel (☒) Galv. () PVC () Fiberglass ()
 Screen: Type Slot size
 Screened from (ft.) to (ft.)
 Type of grout with % additives Net
 Water: Clear (☒) Colored () Sulphur () Salty () Iron ()
 Conductivity Chlorides mg/l

WELL PERMIT NO. SF072193B

Zip _____

PW-2
Well #

Registration No. _____

Conductivity _____ Chlorides _____ mg/l



10.9 Ground Water Quality Data

Ground water quality monitoring reports from April 1995 to February 1998 are included herein.

**KUA/Cane Island
Unit 1 and 2
Groundwater Quality Data
(DER Parameter Monitoring Reports)**

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

3319 Maguire Boulevard
Suite 212
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 6-10-96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 4-1-96 to 6-30-96
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

Note: Pursuant to Rule 17-28.700(6)(k)3., at any time there is a change in the permitted volume, location or chemical, physical or microbiological composition of the discharge plume, the permittee shall notify the department and, if required by the department, submit a new report stating the volume and chemical, physical and microbiological compositions of the discharge at the point of release or contact with the ground water at the site boundary.

CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A.K. Sharma
Owner or Authorized Representative's Signature
S/28196
Date

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Sample Date: 04/25/96

Monitoring Well # 3049A17008

Well Type: ☐ Background

Well Name MW - 5

☐ Site Boundary

Classification of Groundwater G-II

☐ Intermediate

Well Purged Prior to Sample Collection Yes

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		-72.6	FEET		
00400	pH (FIELD)	Grab	150.1	6.23	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	206	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	12	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	1.92	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	14.5	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	20	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

3319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 6-10-96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 4-1-96 to 6-30-96
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

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A. K. Sharma 5/28/96
Owner or Authorized Representative's Signature Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

2nd Quarter 1996

RECEIVED

MAY 15 1998

BLACK & VEATCH

GMS# 3049M06279

Monitoring Well # 3049A17007

Well Name MW - 1

Classification of Groundwater G-II

Well Purged Prior to Sample Collection Yes

Sample Date: 04/25/96

Well Type: ☒ Background

☐ Site Boundary

☐ Intermediate

☐ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		71.8	Feet		
00400	pH (FIELD)	Grab	150.1	4.86	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	160	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	10	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	14.7	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	15	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	13.1	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	7	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District
3319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHISHOLM
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 4-5-96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 1-1-96 to 3-31-96
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

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A.K. Sharma
Owner or Authorized Representative's Signature

3/28/96
Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Monitoring Well # 3049A17009

Well Name MW - 6

Classification of Groundwater G-II

Well Purged Prior to Sample Collection Yes

Sample Date: 02/01/96

Well Type: ☐ Background

☐ Site Boundary

☐ Intermediate

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		71.91	Feet		
00400	pH (FIELD)	Grab	150.1	5.52	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	64	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	33	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	1.28	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	5.95	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	14	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District
3319 Maguire Boulevard
Tallahassee, Florida 32303-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 4-5-96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 1-1-96 to 3-31-96
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

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Alex Sharma 3/28/96
Owner or Authorized Representative's Signature Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Monitoring Well # 3049A17008

Well Name MW - 5

Classification of Groundwater G-II

Well Purged Prior to Sample Collection Yes

Sample Date: 02/01/96

Well Type: ☐ Background

☐ Site Boundary

☐ Intermediate

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		72.35	Feet		
00400	pH (FIELD)	Grab	150.1	6.04	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	82	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	37	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	1.27	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	5.99	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	8	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District
3210 Maguire Boulevard
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 4-5-96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 1-1-96 to 3-31-96
date date

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Au Sharma 3/28/96
Owner or Authorized Representative's Signature Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

RECEIVED

MAY 15 1998

BLACK & VEATCH

GMS# 3049M06279

Monitoring Well # 3049A17007

Well Name MW - 1

Classification of Groundwater G-II

Well Purged Prior to Sample Collection Yes

Sample Date: 02/01/96

Well Type: ☒ Background

☐ Site Boundary

☐ Intermediate

☐ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		72.01	Feet		
00400	pH (FIELD)	Grab	150.1	4.99	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	72	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	10	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	4.14	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	22	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	15.3	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	7	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

2219 Maguire Boulevard
Suite 222
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 M06279

Date 1/5/96

DER Per # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848 Osceola
Address City State Zip County

A. K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 10/1/95 to 12/31/95
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

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A. K. Sharma
Owner or Authorized Representative's Signature

1/3/96
Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Sample Date: 11/09/95

Monitoring Well # 3049A17009

Well Type: ☐ Background

Well Name MW-6

☐ Site Boundary

Classification of Groundwater G-II

☐ Intermediate

Well Purged Prior to Sample Collection Yes

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		72.71	Feet		
00400	pH (FIELD)	Grab	150.1	6.23	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	42	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	70	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	0.24	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	1.41	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	5	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

3219 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 M06279

Date 1/5/96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848 Osceola
Address City State Zip County

A. K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 10/1/95 to 12/31/95
date date

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A. Sharma
Owner or Authorized Representative's Signature

1/3/96
Date

FLORIDA STATE
KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Sample Date: 11/09/95

Monitoring Well # 3049A17008

Well Type: ☐ Background

Well Name MWE-5

☐ Site Boundary

Classification of Groundwater G-II

☐ Intermediate

Well Purged Prior-to-Sample Collection Yes

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		73.21	Feet		
00400	pH (FIELD)	Grab	150.1	6.75	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	44	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	21	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	0.14	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	1.65	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	5	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	0.6	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District
2218 Magnolia Boulevard
Suite 222
Orlando, Florida 32803-1767



LAWTON GILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 M06279

Date 1/5/96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848 Osceola
Address City State Zip County

A. K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 10/1/95 to 12/31/95
date date

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A. K. Sharma

1/31/96

Owner or Authorized Representative's Signature

Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

RECEIVED

MAY 15 1998

BLACK & VEATCH

GMS# 3049M06279

Sample Date: 11/09/95

Monitoring Well # 3049A17007

Well Type: ☒ Background

Well Name MW - 1

☐ Site Boundary

Classification of Groundwater G-II

☐ Intermediate

Well Purged Prior to Sample Collection Yes

☐ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		72.43	Feet		
00400	pH (FIELD)	Grab	150.1	5.62	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	.88	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	22	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	1.72	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	25	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	13.8	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	7	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	<0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

DEPARTMENT OF ENVIRONMENTAL REGULATION



Central Florida District

19 Maguire Boulevard
Box 222
Orlando, Florida 32803-3767

LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 A 17007

Date 10/15/95

DER Permit # IC49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period July 1, 1995 to Sept. 30, 1995
date date

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A. Sharma

Owner or Authorized Representative's Signature

10/16/95

Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Sample Date: 09/27/95

Monitoring Well # 3049A17009

Well Type: ☐ Background

Well Name MW - 6

☐ Site Boundary

Classification of Groundwater G-II

☐ Intermediate

Well Purged Prior to Sample Collection Yes

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVE ADDED
82545	GROUND WATER LEVEL	Grab		73.9	-1 ft MSL		
00400	pH (FIELD)	Grab	150.1	5.80	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	78	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	130	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	0.24	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	1.82	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	< 5	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

119 Maguire Boulevard
Suite 212
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700 (6) (k) 2.

GMS# 3049 A 17007

Date 10/15/95

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Fl. 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period July 1, 1995 to Sept. 30, 1995
date date

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Au Sharma 10/16/95
Owner or Authorized Representative's Signature Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279Sample Date: 09/27/95Monitoring Well # 3049A17008Well Type: ☐ BackgroundWell Name MW - 5☐ Site BoundaryClassification of Groundwater G-II☐ IntermediateWell Purged Prior to Sample Collection Yes☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVE ADDED
82545	GROUND WATER LEVEL	Grab		74.4	ft/MSL		
00400	pH (FIELD)	Grab	150.1	6.13	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	46	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	39	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	0.13	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	1.92	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	< 5	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

319 Maguire Boulevard
Suite 212
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 A 17007

Date 10/15/95

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848 Osceola
Address City State Zip County

A. K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period July 1, 1995 to Sept. 30, 1995
date date

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A. K. Sharma
Owner or Authorized Representative's Signature

10/16/95
Date

3rd QUARTER 1995

KUA / CANE ISLAND
Osceola County
PARAMETER MONITORING REPORT
 (Rule 17-3.402, 17-3.404 - 17-3.406)

RECEIVED
 MAY 15 1998

GMS# 3049M06279
 Monitoring Well # 3049A17007
 Well Name MW - 1
 Classification of Groundwater G-II
 Well Purged Prior to Sample Collection Yes

BLACK & VEATCH

Sample Date: 09/27/95

Well Type: ☒ Background
☐ Site Boundary
☐ Intermediate
☐ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATT ADDED
82545	GROUND WATER LEVEL	Grab		73.3	1 ft MSL		
00400	pH (FIELD)	Grab	150.1	5.29	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	62	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	15	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	1.87	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	19	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	8.5	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	< 5	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

3319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 A 17007

Date 7/10/95

DER Permit # IC49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848
Address City State Zip County Osceola

Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period April 1, 1995 to June 30, 1995
date date

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Owner or Authorized Representative's Signature

Date

KUA/CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT (Rule 17-3.402, 17-3.404 - 17-3.406)

GMS # 3049M06279

Sample Date 6-22-95

Monitoring Well # 3049A17009

Well Type: ☐ Background
☐ Site Boundary
☐ Intermediate
☒ Compliance

Well Name MW-6

Classification of Groundwater GII

Well Purged* Prior to Sample Collection (Yes) No

Storet Code	Parameter Monitored	Sampling Method	Analysis Method	Analysis Result	Units	Filtered/Unfiltered	Preservatives Added
82545	Ground Water Level			69.8 ft	ft		
400	pH (field)	Grab	150.1	7.35	s.u.	Unfiltered	None
70304	TDS	Grab	160.1	100	mg/l	Unfiltered	None
82079	Turbidity	Grab	180.1	50	NTU	Unfiltered	None
620	Nitrate	Grab	NOX-NO ₂	.14	mg/l	Unfiltered	None
945	Sulfate	Grab	375.4	5	mg/l	Unfiltered	None
929	Sodium	Grab	200.7	1.7	mg/l	Unfiltered	H ₂ NO ₃
940	Chloride	Grab	329.3	8.61	mg/l	Unfiltered	None
31666	TRPH	Grab	418.1	<.25 BDL	mg/l	Unfiltered	HCl

*Well development is the process of pumping the well prior to sampling in order to obtain a representative ground water sample.

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District
3319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 A 17007

Date 7/10/95

DER Permit # 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Fl. 33848 Osceola
Address City State Zip County

Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period April 1, 1995 to June 30, 1995
date date

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Owner or Authorized Representative's Signature Date

KUA/CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT (Rule 17-3.402, 17-3.404 - 17-3.406)

GMS # 3049M06279

Sample Date 6-22-95

Monitoring Well # 3049A17008

Well Type: ☐ Background
☐ Site Boundary
☐ Intermediate
☒ Compliance

Well Name MW-5

Classification of Groundwater GII

Well Purged* Prior to Sample Collection (Yes/No)

Storet Code	Parameter Monitored	Sampling Method	Analysis Method	Analysis Result	Units	Filtered/Unfiltered	Preservatives Added
82545	Ground Water Level	Grab		70.1'	ft ± (MSL or NGVD)		
400	pH (field)	Grab	150.1	6.30	s.u.	Unfiltered	None
70304	TDS	Grab	160.1	52	mg/l	Unfiltered	None
82079	Turbidity	Grab	180.1	16	NTU	Unfiltered	None
620	Nitrate	Grab	NOX-NO ₂	.09	mg/l	Unfiltered	None
945	Sulfate	Grab	375.4	6	mg/l	Unfiltered	None
929	Sodium	Grab	200.7	1.4	mg/l	Unfiltered	H ₂ NO ₃
940	Chloride	Grab	329.3	6.89	mg/l	Unfiltered	None
31666	TRPH	Grab	418.1	.26	mg/l	Unfiltered	HCl

*Well development is the process of pumping the well prior to sampling in order to obtain a representative ground water sample.

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

7319 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 A 17007

Date 7/10/95

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy, Florida 33848 Osceola
Address City State Zip County

Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period April 1, 1995 to June 30, 1995
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

Note: Pursuant to Rule 17-28.700(6)(k)3., at any time there is a change in the permitted volume, location or chemical, physical or microbiological composition of the discharge plume, the permittee shall notify the department and, if required by the department, submit a new report stating the volume and chemical, physical and microbiological compositions of the discharge at the point of release or contact with the ground water at the site boundary.

CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

Owner or Authorized Representative's Signature Date

KUA/CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT
(Rule 17-3.402, 17-3.404 - 17-3.406)2nd QUARTER 1995
RECEIVED

MAY 15 1998

GMS # 3049M06279

Sample Date

BLACK & VEATCH
6-22-95Monitoring Well # 3049A17007Well Type: ☒ Background
☐ Site Boundary
☐ Intermediate
☐ ComplianceWell Name MW-1Classification of Groundwater GIIWell Purged* Prior to Sample Collection ☒ Yes ☐ No

Storet Code	Parameter Monitored	Sampling Method	Analysis Method	Analysis Result	Units	Filtered/Unfiltered	Preservatives Added
82545	Ground Water Level			69.9 ft.	GL & (MSL or NGVD)		
400	pH (field)	Grab	150.1	6.8	s.u.	Unfiltered	None
70304	TDS	Grab	160.1	140	mg/l	Unfiltered	None
82079	Turbidity	Grab	180.1	.10	NTU	Unfiltered	None
620	Nitrate	Grab	NOX-NO ₂	1.4	mg/l	Unfiltered	None
945	Sulfate	Grab	375.4	45	mg/l	Unfiltered	None
929	Sodium	Grab	200.7	27	mg/l	Unfiltered	H ₂ NO ₃
940	Chloride	Grab	329.3	8.61	mg/l	Unfiltered	None
31666	TRPH	Grab	418.1	<.25 BVL	mg/l	Unfiltered	HCl

*Well development is the process of pumping the well prior to sampling in order to obtain a representative ground water sample.

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

1719 Maguire Boulevard
Suite 232
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 6-10-96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 4-1-96 to 6-30-96
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

Note: Pursuant to Rule 17-28.700(6)(k)3., at any time there is a change in the permitted volume, location or chemical, physical or microbiological composition of the discharge plume, the permittee shall notify the department and, if required by the department, submit a new report stating the volume and chemical, physical and microbiological compositions of the discharge at the point of release or contact with the ground water at the site boundary.

CERTIFICATION

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A. K. Sharma
Owner or Authorized Representative's Signature Date 5/28/96

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Monitoring Well # 3049A17009

Well Name MW - 6

Classification of Groundwater G-II

Well Purged Prior to Sample Collection Yes

Sample Date: 04/25/96

Well Type: ☐ Background

☐ Site Boundary

☐ Intermediate

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVE ADDED
82545	GROUND WATER LEVEL	Grab		72.1	Feet		
00400	pH (FIELD)	Grab	150.1	5.24	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	98	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	20	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	1.34	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	3	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	9.04	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	51	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

19 Maguire Boulevard
Suite 232
Tampa, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 8/20/96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 7/1/96 to 9/30/96
date date

Attach monitoring data as approved in monitoring plan using parameter monitoring report forms. When applicable, attach additional sheets describing any changes in the background water quality and the discharge plume since the last reported description. Include any changes in size, direction of movement, rate of movement, and concentration changes of plume constituents in violation of the applicable standards.

Note: Pursuant to Rule 17-28.700(6)(k)3., at any time there is a change in the permitted volume, location or chemical, physical or microbiological composition of the discharge plume, the permittee shall notify the department and, if required by the department, submit a new report stating the volume and chemical, physical and microbiological compositions of the discharge at the point of release or contact with the ground water at the site boundary.

CERTIFICATION

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Ak Sharma
Owner or Authorized Representative's Signature

8/18/96
Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

RECEIVED

MAY 15 1998

GMS# 3049M06279

BLACK & VEATCH
Sample Date: 07/25/96

Monitoring Well # 3049A17007

Well Type: [X] Background

Well Name MW-1

[] Site Boundary

Classification of Groundwater G-II

[] Intermediate

Well Purged Prior to Sample Collection Yes

[] Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		71.35	FEET		
00400	pH (FIELD)	Grab	150.1	4.86	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	186	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	7.4	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	17.4	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	6	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	9.6	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	6	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

Maguire Boulevard
222
Orlando, Florida 32803-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 8/20/96

DER Permit # IC 49-212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 7/1/96 to 9/30/96
date date

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Ak Sharma
Owner or Authorized Representative's Signature

8/18/96
Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Sample Date: 07/25/96

Monitoring Well # 3049A17008

Well Type: ☐ Background

Well Name MW-5

☐ Site Boundary

Classification of Groundwater G-II

☐ Intermediate

Well Purged Prior to Sample Collection Yes

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		71.48	FEET		
00400	pH (FIELD)	Grab	150.1	6.10	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	190	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	6.2	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	3.04	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	< 1	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	28.5	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	57	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

STATE OF FLORIDA
Department of Environmental Regulation

Central Florida District

3319 Maguire Boulevard
Tallahassee, Florida 32303-3767



LAWTON CHILES
GOVERNOR

ALEX ALEXANDER
DISTRICT MANAGER

Quarterly Report on Ground Water Monitoring
Rule 17-28.700(6)(k)2.

GMS# 3049 MO6279

Date 20 36

DER Permit # IC 212248

Kissimmee Utility Authority/Cane Island Power Park
Installation Name

6075 Old Tampa Hwy Florida 33848 Osceola
Address City State Zip County

A.K. Sharma Director of Power Supply
Owner or Authorized Representative's Name Title

Method of Discharge Percolation Pond

Type of Industry Electric Power Generation

Report for Period 7/1/96 to 9/30/96
date date

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A. Sharma 8/18/96
Owner or Authorized Representative's Signature Date

KUA / CANE ISLAND

Osceola County

PARAMETER MONITORING REPORT

(Rule 17-3.402, 17-3.404 - 17-3.406)

GMS# 3049M06279

Monitoring Well # 3049A17009

Well Name MW -6

Classification of Groundwater G-II

Well Purged Prior to Sample Collection Yes

Sample Date: 07/25/96

Well Type: ☐ Background

☐ Site Boundary

☐ Intermediate

☒ Compliance

STORET CODE	PARAMETER MONITORED	SAMPLING METHOD	ANALYSIS METHOD	ANALYSIS RESULT	UNITS	FILTERED/ UNFILTERED	PRESERVATIVES ADDED
82545	GROUND WATER LEVEL	Grab		71.01	FEET		
00400	pH (FIELD)	Grab	150.1	5.41	S.U.	Unfiltered	None
70304	TOTAL DISSOLVED SOLIDS	Grab	160.1	166	mg/L	Unfiltered	None
82079	TURBIDITY	Grab	180.1	24	NTU	Unfiltered	None
00620	NITRATE	Grab	353.1	3.60	mg/L	Unfiltered	None
00945	SULFATE	Grab	375.4	2.0	mg/L	Unfiltered	None
00929	SODIUM	Grab	200.7	23.9	mg/L	Unfiltered	H2NO3
00940	CHLORIDE	Grab	325.3	48	mg/L	Unfiltered	None
31666	TRPH	Grab	418.1	< 0.5	mg/L	Unfiltered	H2SO4

GROUNDWATER MONITORING REPORT - PART D
KUA/Cane Island

RECEIVED

MAY 10 1998

FACILITY ID: FLA010961

Month/Year: January 1997

Date Sample Obtained: 11/14/96

Was the well pumped before sampling? Yes.

Test Site ID: 6240

Well Name/ID: B-11 Background

Ground Water Class: G-II

BLACK & VEATCH

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		71.54 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.65 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	EPA 160.1	140 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	20 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	13.7 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 375.4	6 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	9.81 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 325.3	6 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

4 L
C. WARTEN 1996

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: January 1997

Date Sample Obtained: 11/14/96

Was the well pumped before sampling? Yes.

Test Site ID: 6239

Well Name/Type: MW-5/Compliance

Ground Water Class: G-II

Parameter	Storet Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82345	Grab	N/A	N/A		70.89 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	4.89 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	EPA 160.1	273 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	4.8 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	5.77 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 375.4	< 1.0 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	34.3 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 325.3	83 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961
Month/Year: January 1997
Date Sample Obtained: 11/14/96
Was the well pumped before sampling? Yes.

Test Site ID: 6238
Well Name/Type: MW-6/Compliance
Ground Water Class: G-II

Parameter	Storet Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		74.82 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	6.33 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	EPA 160.1	140 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	18 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	3.07 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 375.4	2 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	17.8 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 325.3	46 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT - PART D
KUA/Cane Island

RECEIVED

MAY 15 1998

1st QUARTER 1997

FACILITY ID: FLA010961

Month/Year: April 1997

Date Sample Obtained: 2/21/97

Was the well pumped before sampling? Yes.

Test Site ID: 6240

Well Name/Type: MW-1/Background

Ground Water Class: G-II

BLACK & VEATCH

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82343	Grab	N/A	N/A		69.92 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.92 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	EPA 160.1	128 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	16 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	12.0 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	10 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	11.6 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	5 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: April 1997

Date Sample Obtained: 2/21/97

Was the well pumped before sampling? Yes.

Test Site ID: 6219

Well Name/Type: MW-5/Compliance

Ground Water Class: G-II

Parameter	Storet Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		69.24 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	6.50 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	EPA 160.1	264 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	7.9 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	4.58 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	7 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	38.3 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	11 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961
Month/Year: April 1997
Date Sample Obtained: 2/21/97
Was the well pumped before sampling? Yes.

Test Site ID: 6238
Well Name/Type: MW-6/Compliance
Ground Water Class: Q-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82543	Grab	N/A	N/A		69.12 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.72 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	EPA 160.1	112 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	6.5 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	2.05 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	2 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	23.8 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	44 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

RECEIVED

2ND QUARTER 1997GROUNDWATER MONITORING REPORT - PART D
KUA/Cane Island

MAY 15 1998

FACILITY ID: FLA010961

Month/Year: July 1997

Date Sample Obtained: 5/29/97

Was the well pumped before sampling? Yes.

Test Site ID: 6240

BLACK & VEATCH
Well Name/Type: MW-1/Background
Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82543	Grab	N/A	N/A		69.66 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	4.57 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	114 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	16 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	13.7 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	10 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	11.9 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	6 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: July 1997

Date Sample Obtained: 5/29/97

Was the well pumped before sampling? Yes.

Test Site ID: 6239

Well Name/Type: MW-5/Compliance

Ground Water Class: G-II

Parameter	Storet Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		69.15 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.92 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	110 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	9.6 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	0.72 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	15 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	22.9 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	16 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: July 1997

Date Sample Obtained: 5/29/97

Was the well pumped before sampling? Yes.

Test Site ID: 6238

Well Name/Type: MW-6/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82343	Grab	N/A	N/A		68.98 feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.73 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	112 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	5.2 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	2.87 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	1 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	23.8 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	51 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT - PART D
KUA/Cane Island

RECEIVED

MAY 15 1998

Test Site ID: 6240
Well Name/Type: MW-1/Background
Ground Water Class: G-II

FACILITY ID: FLA010961

Month/Year: October 1997

Date Sample Obtained: 8/28/97

Was the well pumped before sampling? Yes.

BLACK & VEATCH

Parameter	Storet Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		72.39	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	4.97 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	170 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	1.1 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	14.6 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	7 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	7.51 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	5 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: October 1997

Date Sample Obtained: 8/28/97

Was the well pumped before sampling? Yes.

Test Site ID: 6239

Well Name/Type: MW-5/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82343	Grab	N/A	N/A		72.39	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.96 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	62 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	6.8 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	0.32 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	11 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	12.7 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	11 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: October 1997

Date Sample Obtained: 8/28/97

Was the well pumped before sampling? Yes.

Test Site ID: 6238

Well Name/Type: MW-6/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82345	Grab	N/A	N/A		72.14	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	6.20 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	182 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	2.4 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	2.68 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	2 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	21.4 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	54 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

RECEIVED

MAY 15 1998

FACILITY ID: FLA010961

Month/Year: January 1998

Date Sample Obtained: 11/19/97

Was the well pumped before sampling? Yes.

Test Site ID: 6240

Well Name/Type: MW-1/Background

Ground Water Class: G-II

BLACK & VEATCH

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		72.44 Feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.38 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	162 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	4.2 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	11.6 mg/l	.002 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	10 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	5.64 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	< 5 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: January 1998

Date Sample Obtained: 11/26/97

Was the well pumped before sampling? Yes.

Test Site ID: 6239

Well Name/Type: MW-5/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82343	Grab	N/A	N/A		72.17 Feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.69 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	108 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	17 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	0.33 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	11 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	14.1 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	8 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: January 1998

Date Sample Obtained: 11/19/97

Was the well pumped before sampling? Yes.

Test Site ID: 6238

Well Name/Type: MW-6/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82345	Grab	N/A	N/A		72.05 Feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	7.19 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	216 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	23 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	3.03 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	6 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	23.1 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	52 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

RECEIVED

MAY 12 1998

Test Site ID: 6240
Well Name/Type: MW-1/Background
Ground Water Class: G-II

FACILITY ID: FLA010961

Month/Year: April 1998

Date Sample Obtained: 2/18/98

Was the well pumped before sampling? Yes.

BLACK & VEATCH

Parameter	Storet Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82343	Grab	N/A	N/A		73.79 Feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	5.4 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	150 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	45 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	7.03 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	7 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	2.3 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	< 5 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: April 1998

Date Sample Obtained: 2/18/98

Was the well pumped before sampling? Yes.

Test Site ID: 6239

Well Name/Type: MW-5/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y/N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82543	Grab	N/A	N/A		73.34 Feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	7.14 S.U.	0.01 S.U.
TDS	70390	Grab	N	None	SM 2540 B	90 mg/l	5 mg/l
Turbidity	82879	Grab	N	None	EPA 180.1	12 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	0.19 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	10 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	12.4 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	< 5 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations

GROUNDWATER MONITORING REPORT _ PART D
KUA/Cane Island

FACILITY ID: FLA010961

Month/Year: April 1998

Date Sample Obtained: 2/18/98

Was the well pumped before sampling? Yes.

Test Site ID: 6238

Well Name/Type: MW-6/Compliance

Ground Water Class: G-II

Parameter	Store Code	Sampling Method	Samples Filtered (Y?N)	Preservatives Added	Analysis Method	Analysis Results/Units	Detection Limits/Units
Water Level	82545	Grab	N/A	N/A		73.34 Feet	.01 ft.
pH	00406	Grab	N	None	EPA 150.1	7.1 S.U.	0.01 S.U.
TDS	70300	Grab	N	None	SM 2540 B	102 mg/l	5 mg/l
Turbidity	82079	Grab	N	None	EPA 180.1	26 N.T.U.	0.10 N.T.U.
Nitrate Nitrogen	00620	Grab	N	H ₂ SO ₄	EPA 353.1	0.57 mg/l	0.02 mg/l
Sulfate	00946	Grab	N	None	EPA 300.0A	11 mg/l	1 mg/l
Sodium	00929	Grab	N	HNO ₃	EPA 200.7	14.6 mg/l	0.50 mg/l
Chloride	00940	Grab	N	None	EPA 300.0A	12 mg/l	5 mg/l
TRPH	31666	Grab	N	H ₂ SO ₄	EPA 418.1	< 0.5 mg/l	0.5 mg/l

Comments and Explanations



10.10 Cane Island Vascular Plant List

Table 10.10-1 is a list of vascular plant species observed at the Cane Island Power Park and related offsite facility areas. The observations were made during the preliminary site investigations (1991) and mitigation monitoring efforts (1993-1997).



Table 10.10-1
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
TREES	
<i>Acer rubrum</i> L.	red maple
<i>Asimina triloba</i> (L.) Dunal	pawpaw
<i>Carya glabra</i> (Mill.) Sweet	pignut hickory
<i>Carya floridana</i> Sarg.	scrub hickory
<i>Diospyros virginiana</i> L.	common persimmon
<i>Fraxinus caroliniana</i> Mill.	carolina ash
<i>Gordonia lasianthus</i> (L.) Ellis	loblolly bay
<i>Liquidambar styraciflua</i> L.	sweet gum
<i>Magnolia grandiflora</i> L.	southern magnolia
<i>Magnolia virginiana</i> L.	sweet bay
<i>Nyssa sylvatica</i> Marsh.	swamp black gum
<i>Osmanthus americanus</i> (L.) Benth. & Hook. F. ex A. Gray	wild olive
<i>Persea borbonia</i> (L.) Spreng	red bay
<i>Pinus clausa</i> (Chapm. ex Engelm.) Vasey ex Sarg.	sand pine
<i>Pinus elliottii</i> Engelm.	slash pine
<i>Pinus serotina</i> Dougl.	pond pine
<i>Prunus serotina</i> EHRH.	black cherry
<i>Quercus chapmanii</i> Sarg.	Chapman's oak
<i>Quercus geminata</i> Small	scrub live oak
<i>Quercus inopina</i> Ashe.	scrub oak
<i>Quercus laurifolia</i> Michx.	laurel oak
<i>Quercus myrtifolia</i> Willd.	myrtle oak
<i>Quercus nigra</i> L.	water oak
<i>Quercus virginiana</i> Mill.	Virginia live oak
<i>Sabal palmetto</i> (Walt.) Lodd ex Schultes	cabbage palm
<i>Taxodium distichum</i> (L.) L.C. Rich.	bald cypress
<i>Tilia americana</i> L.	American basswood
<i>Ulmus americana</i> L.	American elm



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
SHRUBS	
<i>Asimina pygmaea</i> (Bartr.) Dunal	dwarf pawpaw
<i>Baccharis glomeruliflora</i> Pers.	groundsel tree
<i>Baccharis halimifolia</i> L.	groundsel tree
<i>Befaria racemosa</i> Ventenat	tarflower
<i>Bumelia tenax</i> (L.) Willd.	tough bumelia
<i>Ceratiola ericoides</i> Michx.	rosemary
<i>Euonymus americanus</i> L.	strawberry bush
<i>Gelsemium sempervirens</i> (L.) W.T. Ait.	yellow jasmine
<i>Hypericum hypercoides</i> (L.) Crantz	St. Andrew's-cross
<i>Hypericum reductum</i> P. Adams	Atlantic St. John's-wort
<i>Hypericum tetrapetalum</i> Lam.	four-petal St. John's-wort
<i>Hyptis alata</i> (Raf.) Shinnars	musky mint
<i>Ilex cassine</i> L.	dahoon holly
<i>Ilex glabra</i> (L.) Gray	inkberry
<i>Leucothoe racemosa</i> (L.) A. Gray	fetterbush
<i>Lyonia ferruginea</i> (Walt.) Nutt.	rusty lyonia
<i>Lyonia fruticosa</i> (Michx.) Torr.	staggerbush
<i>Lyonia ligustrina</i> (L.) DC.	maleberry
<i>Lyonia lucida</i> (Lam.) K. Koch	fetterbush
<i>Myrica cerifera</i> L.	wax myrtle
<i>Osmanthus americanus</i> (L.) Benth. & Hook. ex Gray	devil wood
<i>Quercus pumila</i> Walt.	running oak
<i>Rhododendron viscosum</i> (L.) Torr.	swamp honeysuckle
<i>Rhus copallina</i> L.	winged sumac
<i>Serenoa repens</i> (Bartr.) Small	saw palmetto
<i>Vaccinium arboreum</i> Marsh	sparkleberry
<i>Vaccinium cf. corymbosum</i> L.	highbush blueberry
<i>Vaccinium myrsinites</i> L.	shiny blueberry
<i>Viburnum obovatum</i> Walt.	small viburnum



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name¹</u>	<u>Common Name²</u>
HERBACEOUS PLANTS AND WOODY VINES	
<i>Ampelopsis arborea</i> (L.) Koehne	pepper-vine
<i>Amphicarpum muhlenbergianum</i> (J.A. Schultes) A. Hitchc.	perennial goobergrass
<i>Andropogon brachystachys</i> Chapm.	shortspike bluestem
<i>Andropogon virginicus</i> L.	broomsedge bluestem
<i>Apios americana</i> Medic.	groundnut
<i>Aristida spiciformis</i> Ell.	bottlebrush threeawn
<i>Aristida stricta</i> Michx.	wiregrass
<i>Aronia arbutifolia</i> (L.) Elliott	red chokeberry
<i>Arundinaria gigantea</i> (Walter) ex Muhl.	giant cane
<i>Asclepias pedicellata</i> Walter	savannah milkweed
<i>Aster dumosus</i> L.	no common name
<i>Aster reticulatus</i> Pursh	pine barren white-top aster
<i>Axonopus furcatus</i> (Fluegge) A. Hitchc.	big carpet grass
<i>Balduina angustifolia</i> (Pursh) Robins.	yellowbuttons
<i>Blechnum serrulatum</i> L.C. Rich	toothed mid-sorus fern
<i>Bulbostylis</i> sp.	hairsedge
<i>Botrychium binernatum</i> (Sav.) Underw.	southern grape fern
<i>Callitriche</i> sp.	water-starwort
<i>Campanula floridana</i> S. Wats. ex Gray	Florida bellflower
<i>Canna flaccida</i> Salisb.	bandana-of-the-everglades
<i>Carex alata</i> Torr. & Gray	no common name
<i>Carphephorus odoratissimus</i> (J.F. Gmel.) Herbert	vanilla plant
<i>Cassia chamaecrista</i> L.	partridge-pea
<i>Cassia fasciculata</i> Michx.	partridge-pea
<i>Cassia nictans</i> L.	sensitive partridge pea
<i>Centella asiatica</i> (L.) Urban	Asian coinleaf
<i>Chapmania floridana</i> Torr. & Gray	alicia
<i>Chaptalia tomentosa</i> Vent.	pineland daisy
<i>Chasmanthium sessilifolium</i> (Poir.) Yates	longleaf chasmanthium



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name¹</u>	<u>Common Name²</u>
<i>Chloris gayana</i> Kunth.	rhodesgrass
<i>Chloris glauca</i> (Chapm.) Wood	no common name
<i>Chrysopsis subulata</i> Small	goldenaster
<i>Conyza canadensis</i> (L.) Cronq.	Canada horseweed
<i>Crotolaria rotundifolia</i> Walter ex. J.F. Gmel.	prostrate rattle-box
<i>Crotonopsis</i> cf. <i>linearis</i> Michx.	rushfoil
<i>Cuthbertia ornata</i> Small	no common name
<i>Cynodon dactylon</i> (L.) Pers.	bermuda grass
<i>Cyperus articulatus</i> L.	jointed flatsedge
<i>Cyperus ligularis</i> L.	Alabama swamp flatsedge
<i>Cyperus globulosus</i> Aubl.	no common name
<i>Cyperus polystachyos</i> Rottb.	many-spike flatsedge
<i>Cyperus retrorsus</i> Chapm.	no common name
<i>Cyperus tetragonus</i> Elliott	four-angle flatsedge
<i>Dalea pinnata</i> (Walt. ex J. F. Gmel) Barneby	no common name
<i>Dichanthelium aciculare</i> (Desv. ex Poir.) Gould & Clark	needle-leaf witchgrass
<i>Dichanthelium acuminatum</i> (Swartz) Gould & C.A. Clark	panic grass
<i>Dichanthelium dichotomum</i> (L.) Gould	cypress witchgrass
<i>Digitaria</i> sp.	crabgrass
<i>Diodia virginiana</i> L.	Virginia buttonweed
<i>Drosera brevifolia</i> Pursh	dwarf sundew
<i>Dryopteris ludoviciana</i> (Kunze) Small	Florida shield fern
<i>Eclipta alba</i> (L.) Hassk.	yerba de tajo
<i>Eichornia crassipes</i> (Mart.) Solms	water hyacinth
<i>Eleocharis nigrescens</i> (Nees) Steud.	small-flower spikerush
<i>Elephantopus elatus</i> Bertol.	Florida elephant's-foot
<i>Erechtites hieracifolia</i> (L.) Raf. ex DC.	American burn
<i>Eupatorium capillifolium</i> (Lam.) Small	dog fennel
<i>Eupatorium mohrii</i> Greene	no common name
<i>Eupatorium rotundifolium</i> L.	false hoarhound



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
<i>Eupatorium serotinum</i> Michx.	thorough-wort
<i>Euthamia minor</i> (Michx.) Greene	slender fragrant-golden-rod
<i>Eryngium baldwinii</i> Spreng.	Baldwin's coyote-thistle
<i>Eryngium yuccifolium</i> Michx.	button snakeroot
<i>Fimbristylis caroliniana</i> (Lam.) Fernald	carolina fimbry
<i>Froelichia floridana</i> (Nutt.) Moq.	cottonweed
<i>Fuirena scirpoidea</i> Michx.	southern umbrella sedge
<i>Galactia elliotii</i> Nutt.	Elliott's milkpea
<i>Galactia volubilis</i> (L.) Britt.	no common name
<i>Galium hispidulum</i> Michx.	bedstraw
<i>Gaylussacia dumosa</i> (Andr.) Torr. & Gray	dwarf huckleberry
<i>Gaylussacia tomentosa</i> (Gray) Small	dangleberry
<i>Gelsemium sempervirens</i> (L.) J. St. Hil.	yellow jessamine
<i>Gnaphalium purpureum</i> L.	purple cudweed
<i>Gratiola virginiana</i> L.	no common name
<i>Habenaria odontopetala</i> Reichb. F.	an orchid
<i>Hedyotis uniflora</i> (L.) Lam.	no common name
<i>Heterotheca graminifolia</i> (Michx.) Shinnars	golden aster
<i>Hieraceum gronovii</i> L.	hawkweed
<i>Hydrocotyle umbellata</i> L.	many-flowered penny-wort
<i>Hypoxis juncea</i> L.	yellow-star grass
<i>Hypoxis leptocarpa</i> (Engelm. & Gray) Small	club-pod goldstar
<i>Indigofera</i> cf. <i>caroliniana</i> P. Mill.	Carolina indigo
<i>Indigofera hirsuta</i> Harv.	hairy indigo
<i>Iris hexagona</i> Walt.	prairie iris
<i>Juncus dichotomus</i> Ell.	forked rush
<i>Juncus effusus</i> L.	soft rush
<i>Juncus marginatus</i> Rostk.	grass-leaf rush
<i>Juncus scirpoides</i> Lam.	needle-pod rush
<i>Kosteletzkya virginica</i> (L.) Presl ex Gray	saltmarsh mallow



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
<i>Krigia virginica</i> (L.) Willd.	Virginia dwarf-dandelion
<i>Lachnocaulon anceps</i> (Walt.) Morong	white-head bogbuttons
<i>Lachnocaulon beyrichianum</i> Sporr. ex. Koern.	bog buttons
<i>Lacnanthes caroliniana</i> (Lam.) Dandy	carolina redroot
<i>Lechea cernua</i> Small	no common name
<i>Lechea sessiliflora</i> Raf.	no common name
<i>Lemna acuinotialis</i> Welw.	duckweed
<i>Lespedeza striata</i> (Thunb.) Hook. & Arn.	Japanese clover
<i>Liatris tenuifolia</i> Nutt.	no common name
<i>Linaria floridana</i> Chapman	no common name
<i>Ludwigia alternifolia</i> L.	bushy seedbox
<i>Ludwigia hirtella</i> Raf.	hairy seedbox
<i>Lycopus rubellus</i> Moench	water hoarhound
<i>Lygodesmia aphylla</i> (Nutt.) DC.	roserush
<i>Matelea carolinensis</i> (Jacq.) Woods.	no common name
<i>Mitchella repens</i> L.	partridge-berry
<i>Mitreola petiolata</i> (J.F. Gmel.) Torr. & Gray	miterwort
<i>Nerium oleander</i> L.	oleander
<i>Opuntia humifusa</i> (Raf.) Raf.	prickly-pear cactus
<i>Osmunda cinnamomea</i> L.	cinnamon fern
<i>Osmunda regalis</i> L.	royal fern
<i>Oxalis</i> sp.	woodsorrel
<i>Panicum repens</i> L.	topedo grass
<i>Panicum rigidulum</i> Bosc ex Nees	redtop panicum
<i>Parthenocissus quinquefolia</i> (L.) Planch.	Virginia creeper
<i>Paspalum notatum</i> Fluegge	bahiagrass
<i>Paspalum setaceum</i> Michx.	thin paspalum
<i>Phoebanthus grandiflora</i> (Torr. & Gray) Blake	no common name
<i>Piloblephis rigida</i> (Bartr. ex Beath.) Raf.	pennyroyal
<i>Pityopsis graminifolia</i> (Michx.) Nutt.	no common name



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
<i>Pluchea foetida</i> (L.) DC.	stinking camphor-weed
<i>Polygala rugelii</i> Shuttlew.	yellow batchelor's button
<i>Polygala setacea</i> Michx.	coastal plain milkwort
<i>Polygonum hydropiperoides</i> Michx.	swamp smartweed
<i>Polypodium aureum</i> L.	golden polypody
<i>Polypodium polypodioides</i> (L.) Watt.	resurrection fern
<i>Polypremum procumbens</i> L.	rustweed
<i>Pontederia cordata</i> L.	pickerel weed
<i>Ponthieva racemosa</i> (Walt.) Mohr.	shadow witch
<i>Pteridium aquilinum</i> (L.) Kuhn	bracken
<i>Pterocaulon virgatum</i> (L.) DC.	wand blackroot
<i>Rhexia mariana</i> L.	Maryland meadow beauty
<i>Rhexia nuttallii</i> C.W. James	Nuttal's meadow beauty
<i>Rhynchelytrum repens</i> (Willd.) C. E. Hubb.	natalgrass
<i>Rhynchospora cephalantha</i> Gray	clustered beakrush
<i>Rhynchospora chapmanii</i> M. A. Curt	Chapman's beakrush
<i>Rhynchospora corniculata</i> (Lam.) Gray	short-bristle beakrush
<i>Rhynchospora fascicularis</i> (Michx.) Vahl	fasciculate beakrush
<i>Rhynchospora megalocarpa</i> Gray	no common name
<i>Rhynchospora microcarpa</i> Baldwin ex Gray	southern beakrush
<i>Rhynchospora microcephala</i> (Britton) Britton	capitate beakrush
<i>Rhynchospora miliacea</i> (Lam.) Gray	millet beakrush
<i>Rhynchospora plumosa</i> Ell.	plumed beakrush
<i>Rhynchospora rariflora</i> (Michx.) Elliott	few-flower beakrush
<i>Rhynchospora wrightiana</i> Boeckl.	Wright's beakrush
<i>Rubus cuneifolius</i> Pursh.	sand blackberry
<i>Rudbeckia hirta</i> L.	black-eyed susan
<i>Ruellia caroliniensis</i> (J.F. Gmel.) Steud.	wild petunia
<i>Sabatia brevifolia</i> Raf.	short-leaf rose-gentian
<i>Salvinia minima</i> Baker	water spangles



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
<i>Saururus cernuus</i> L.	lizard's-tail
<i>Schrankia uncinata</i> Willd.	sensitive briar
<i>Scleria ciliata</i> Michx.	fringed nutrush
<i>Scleria triglomerata</i> Michx.	tall nutgrass
<i>Scleria verticillata</i> Muhl. ex Willd.	low nutrush
<i>Scoparia dulcis</i> L.	sweet broom
<i>Secale cereale</i> L.	rye
<i>Selaginella arenicola</i> Underw.	sand spikemoss
<i>Smilax bona-nox</i> L.	greenbrier
<i>Smilax laurifolia</i> L.	catbrier
<i>Solidago fistulosa</i> Mill.	pine barren goldenrod
<i>Solidago odora</i> Ait.	no common name
<i>Sphagnum</i> sp.	no common name
<i>Sporobolus indicus</i> (L.) R. Br.	smutgrass
<i>Stipa avenacea</i> L.	blackseed needlegrass
<i>Stipulicida setacea</i> Michx.	no common name
<i>Stylosanthes biflora</i> (L.) BSP.	pencil flower
<i>Thelypteris kunthii</i> (Desv.) Morton	widespread maiden fern
<i>Thelypteris palustris</i> Schott.	marsh fern
<i>Tillandsia</i> cf. <i>recurvata</i> (L.) L.	ball moss
<i>Tillandsia setacea</i> Sw.	wild pine
<i>Tillandsia</i> sp.	no common name
<i>Tillandsia usneoides</i> (L.) L.	Spanish moss
<i>Toxicodendron radicans</i> (L.) Kuntze	poison ivy
<i>Trichostema dichotomum</i> L.	forked blue-curls
<i>Trifolium</i> sp.	clover
<i>Typha latifolia</i> L.	broad-leaf cattail
<i>Utricularia</i> sp.	bladderwort
<i>Viola affinis</i> LeConte	a violet
<i>Vitis aestivalis</i> Michx.	summer grape



Table 10.10-1 (Continued)
Vascular Plants Observed at Cane Island Power Park

<u>Scientific Name</u> ¹	<u>Common Name</u> ²
<i>Vitis munsoniana</i> Simpson	southern fox grape
<i>Vitis rotundifolia</i> Michx.	muscadine grape
<i>Vittaria lineata</i> (L.) J. G. Smith	shoestring fern
<i>Woodwardia aereolata</i> (L.) Moore	netted chain fern
<i>Woodwardia virginica</i> (L.) J.E. Smith	Virginia chainfern
<i>Xyris brevifolia</i> Michx.	yellow-eyed grass
<i>Xyris caroliniana</i> Walter	carolina yellow-eyed grass
<i>Yucca filamentosa</i> L.	Adam's needle

¹Scientific names follow the nomenclature of Kartesz, J.T., and R. Kartesz, *A Synonymized Checklist of the Vascular Flora of the United States, Canada, and Greenland, Volume II, The Biota of North America*, The North Carolina Press, Chapel Hill, NC, 1980.

²Common names follow Wunderlin, R.P., *Guide to the Vascular Plants of Central Florida*, University Presses of Florida, Gainesville, FL, 1982. Common names were used from P.B. Buck, Jr. *National List of Plant Species That Occur In Wetlands: Southeast (Region 2)*, US Fish and Wildlife Service Biological Report, Volume 88, 124 pages, 1988, when none were found in Wunderlin (1982).



10.11 Cane Island Wildlife List

Table 10.11-1 is a list of the animal species observed at the Cane Island Power Park and related offsite facility areas. The observations were made during the preliminary site investigations (1991) and mitigation monitoring efforts (1993-1997).



Table 10.11-1
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Birds						
Cattle egret (<i>Bubulcus ibis</i>)				X		
Great egret (<i>Casmerodius albus</i>)			X			
Snowy egret (<i>Egretta thula</i>)			X			
White ibis (<i>Eudocimus albus</i>)			X X			X
Great blue heron (<i>Ardea herodias</i>)			X			
Green heron (<i>Butorides striatus</i>)						X
Tricolored heron (<i>Egretta tricolor</i>)			X			
Turkey vulture (<i>Cathartes aura</i>)	X X X	X X X		X		
Black vulture (<i>Coragyps atratus</i>)	X	X X X		X		
Sharp-shinned hawk (<i>Accipiter striatus</i>)	X	X		X		



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Red-tailed hawk (<i>Buteo jamaicensis</i>)	X	X	X	X		
Red-shouldered hawk (<i>Buteo lineatus</i>)	X	X X X		X X	X X	
American kestrel (<i>Falco sparverius</i>)	X	X		X		
Bobwhite quail (<i>Colinus virginianus</i>)	X X X	X		X X		
Wild turkey (<i>Meleagris gallopavo</i>)	X	X X	X X X	X X	X X	
American woodcock (<i>Scolopax minor</i>)			X	X	X	
Killdeer (<i>Charadrius vociferus</i>)				X		X
Mourning dove (<i>Zenaida macroura</i>)	X X X	X X		X X X		
Ground dove (<i>Columbina passerina</i>)	X			X		
Yellow-billed cuckoo (<i>Coccyzus americanus</i>)		X			X X X	
Screech owl (<i>Otus asio</i>)	X	X		X		
Great horned owl (<i>Bubo virginianus</i>)	X	X	X	X	X	X



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Barred owl (<i>Strix varia</i>)		X	X		X X X	
Whip-poor-will (<i>Caprimulgus vociferus</i>)	X	X				
Common nighthawk (<i>Chordeiles minor</i>)	X X X	X		X X		
Belted kingfisher (<i>Ceryle alcyon</i>)						X X
Ruby-throated hummingbird (<i>Archilochus colubris</i>)	X				X	
Common flicker (<i>Colaptes auratus</i>)	X	X		X		
Downy woodpecker (<i>Picoides pubescens</i>)		X	X		X	
Hairy woodpecker (<i>Picoides villosus</i>)	X	X			X X	
Pileated woodpecker (<i>Dryocopus pileatus</i>)	X	X				
Red-bellied woodpecker (<i>Melanerpes carolinus</i>)	X X X	X X	X X	X X	X X	



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Red-headed woodpecker (<i>Melanerpes erythrocephalus</i>)	X			X		
Yellow-bellied sapsucker (<i>Sphyrapicus varius</i>)		X				
Eastern phoebe (<i>Sayornis phoebe</i>)		X				
Tree swallow (<i>Tachycineta bicolor</i>)	X	X		X		
Purple martin (<i>Progne subis</i>)	X	X		X		
Blue jay (<i>Cyanocitta cristata</i>)	X	X X			X X X	
Tufted titmouse (<i>Parus bicolor</i>)	X	X	X X	X	X X	
Carolina wren (<i>Thryothorus ludovicianus</i>)	X	X X X	X	X	X X	
Blue-gray gnatcatcher (<i>Poliophtila caerulea</i>)	X	X X	X	X	X	
Northern mockingbird (<i>Mimus polyglottos</i>)	X X X	X X		X	X	



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Gray catbird (<i>Dumetella carolinensis</i>)			X			
Brown thrasher (<i>Toxostoma rufum</i>)	X X	X		X		
Loggerhead shrike (<i>Lanius ludovicianus</i>)		X X		X		
European starling (<i>Sturnus vulgaris</i>)				X		
Yellow-throated vireo (<i>Vireo flavifrons</i>)	X	X	X			
White-eyed vireo (<i>Vireo griseus</i>)	X				X	
Red-eyed vireo (<i>Vireo olivaceus</i>)			X		X	
Palm warbler (<i>Dendroica palmarum</i>)	X	X	X	X	X	X
Prairie warbler (<i>Dendroica discolor</i>)	X X	X X		X		
Pine warbler (<i>Dendroica pinus</i>)	X	X X			X	
Black-and-white warbler (<i>Mniotilta varia</i>)	X X				X X	
Yellow-rumped warbler (<i>Dendroica coronata</i>)	X	X		X		



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Yellow-throated warbler (<i>Dendroica dominica</i>)				X	X	
Common yellowthroat (<i>Geothlypis trichas</i>)	X	X		X		
Northern cardinal (<i>Cardinalis cardinalis</i>)	X X X	X		X	X X X	
Rufous-sided towhee (<i>Pipilo erythrophthalmus</i>)	X X	X		X	X	
Boat-tailed grackle (<i>Quiscalus quiscula</i>)				X		
Common grackle (<i>Quiscalus major</i>)	X		X		X	
Ruby-crowned kinglet (<i>Regulus calendula</i>)	X					
Eastern meadowlark (<i>Sturnella magna</i>)	X			X		
Red-winged blackbird (<i>Agelaius phoeniceus</i>)				X		
American goldfinch (<i>Carduelis tristis</i>)	X					



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Veery (<i>Catharus fuscescens</i>)					X	
Hermit thrush (<i>Catharus guttatus</i>)					X	
Northern parula (<i>Parula americana</i>)				X		
Mammals						
Virginia opossum (<i>Didelphis virginiana</i>)	X	X	X	X	X	X
Least Shrew (<i>Cryptotis parva</i>)	X	X		X	X	
Eastern mole (<i>Scalopus aquaticus</i>)	X	X				
Spotted skunk (<i>Spilogale putoris</i>)	X	X	X	X	X	X
White-tailed deer (<i>Odocoileus virginianus</i>)	X X X	X X X	X X X	X X X	X X X	X X
Nine-banded armadillo (<i>Dasypus novemcinctus</i>)	X X X	X X X	X X	X X X	X X X	X
Raccoon (<i>Procyon lotor</i>)	X X	X X	X X	X X	X X X	X



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Gray squirrel (<i>Sciurus carolinensis</i>)		X X X	X X X	X X	X X X	X
Florida mouse (<i>Peromyscus floridanus</i>)	X X	X				
Hispid cotton rat (<i>Sigmodon hispidus</i>)	X X	X X X				
Cotton mouse (<i>Peromyscus gossypinus</i>)	X X	X X	X			
Eastern cottontail (<i>Sylvilagus floridanus</i>)	X	X X X		X	X	
Marsh rabbit (<i>Sylvilagus palustris</i>)		X				
Gray fox (<i>Urocyon cinereoargenteus</i>)	X	X X	X	X	X X	X
Bobcat (<i>Felis rufus</i>)	X	X	X	X	X	X
Reptiles						
Green anole (<i>Anolis carolinensis</i>)	X	X X	X X		X X X	
Corn snake (<i>Elaphe guttata</i>)					X	
Box turtle (<i>Terrapene carolina</i>)	X				X X	
Gopher tortoise (<i>Gopherus polyphemus</i>)	X X X	X X		X X X		



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Ground skink (<i>Leiopisma laterale</i>)	X X X	X X	X	X	X X X	X
Six-lined racerunner (<i>Cnemidophorus sexlineatus</i>)	X X X			X		
Brown anole (<i>Anolis sagrei</i>)		X		X	X	
Yellow rat snake (<i>Elaphe obsoleta quadrivittata</i>)	X					
Florida cottonmouth (<i>Agkistrodon piscivorus conanti</i>)			X			
Crowned snake (<i>Tantilla sp.</i>)				X		
Southern fence lizard (<i>Sceloporus undulatus</i>)	X	X			X	
Southern black racer (<i>Coluber constrictor priapus</i>)	X	X	X	X	X	X
Eastern diamondback rattlesnake (<i>Crotalus adamanteus</i>)					X	



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Dusky pigmy rattlesnake (<i>Sistrurus miliaris barbouri</i>)	X	X		X		
Peninsula ribbon snake (<i>Thamnophis sauritus sackenii</i>)					X	
Amphibians						
Pine woods treefrog (<i>Hyla femoralis</i>)	X	X				
Squirrel treefrog (<i>Hyla squirella</i>)			X		X X	
Southern leopard frog (<i>Rana spheocephala</i>)			X			
Eastern spadefoot toad (<i>Scaphiopus holbrookii</i>)	X X					
Southern toad (<i>Bufo terrestris</i>)	X X				X X	
Oak toad (<i>Bufo quercicus</i>)	X X	X		X	X	
Eastern narrowmouth toad (<i>Gastrophryne carolinensis</i>)	X X	X	X	X	X	X



Table 10.11-1 (Continued)
Wildlife Observed at the Cane Island Power Park and Related Facility Areas

Species	SPS/OS	PF/F	MHS/CP/CS	OF/G	PMO/HH	Wetland Creation Site
	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97	'91'93'97
Green treefrog (<i>Hyla cinerea</i>)			X		X	

Legend

SPS/OS= Sand pine scrub

MHS/CP/CS: Mixed Hardwood Swamp/Cypress Pond/Cypress Strand

PF/F= Pine Flatwoods/Flatwoods

PMO/HH: Pine Mesic Oak/Hydric Hammock

OF/G: Old Field/Grassland

**SITE CERTIFICATION
APPLICATION**

**Appendix 10.7
PSD Application**

Kissimmee Utility Authority
Florida Municipal Power Agency
Cane Island – Units 1 - 3

 **BLACK & VEATCH^{LLP}**

SITE CERTIFICATION APPLICATION

Appendix 10.7 – PSD Application

Kissimmee Utility Authority
Florida Municipal Power Agency



Cane Island
Units 1 - 3



BLACK & VEATCH_{LLP}

Cane Island Power Park

Site Certification Application

APPENDIX 10.7

Manual Number KUA/FMPA- 60

Issued to _____

Location _____

Appendix 10.7

**PREVENTION OF SIGNIFICANT DETERIORATION
AIR PERMIT APPLICATION
FOR
CANE ISLAND UNIT 3**

Submitted by:

**Kissimmee Utility Authority
and the
Florida Municipal Power Agency**

Prepared by:

Black & Veatch

**July 31, 1998
Project No. 59140**



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1.0 Introduction

Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) propose to develop a new electrical power generating unit at the Cane Island Power Park near Intercession City. The Cane Island Power Park currently includes a nominal 40 megawatt (MW) simple cycle combustion turbine (SCCT) unit (Unit 1) and a nominal 120 MW combined cycle combustion turbine (CCCT) with heat recovery steam generator (HRSG) and steam turbine (Unit 2).

The proposed unit (Unit 3), will be a CCCT unit rated at approximately 250 MW, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a backup fuel. Unit 3 will occupy approximately 5 acres adjacent to and north of Unit 2. New major support facilities for Unit 3 will include a cooling tower, water and wastewater treatment facilities, water storage tanks, storm water detention pond, 230 kV transmission line, and a fuel oil storage tank.

This report is technical support document for the Prevention of Significant Deterioration Air Permit Application. The following sections contain a project characterization, Best Available Control Technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's preparation of an air construction permit for Unit 3.



2.0 Project Characterization

The following sections briefly characterize Unit 3 including a general description of the location, facility, and emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

Unit 3 will be located on the Cane Island Power Park (Power Park) in rural northwest Osceola County, Florida. Figure 2-1 shows the general location of the Power Park which is approximately 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The nearest Federal PSD Class I Area is the Chassahowitzka National Wildlife Refuge located approximately 105 kilometers northwest of the Power Park.

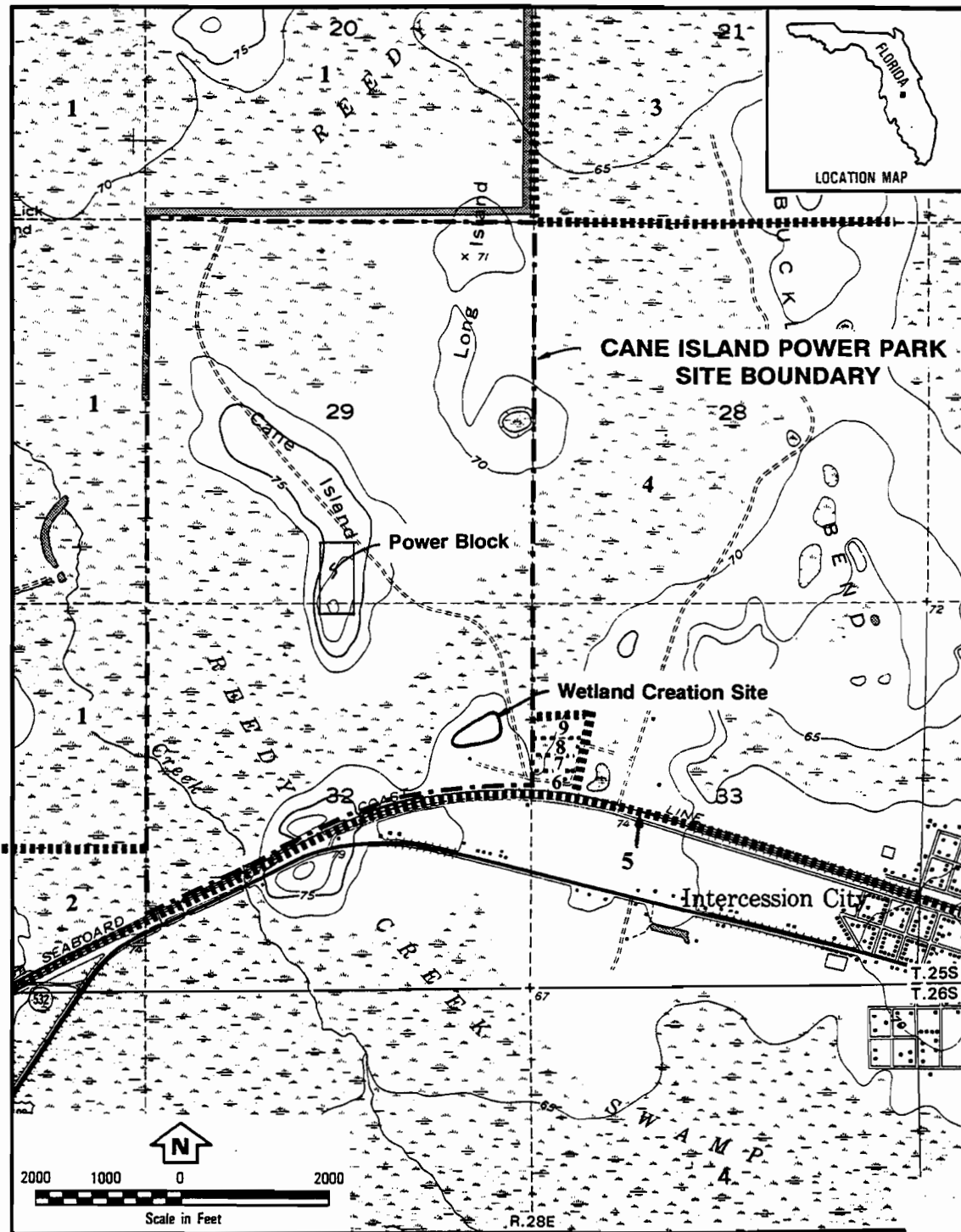
The Power Park is situated on a slightly elevated ridge of dry sand surrounded by the wetlands of the Reedy Creek Swamp. The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

Unit 3 will be located at the Power Park which currently includes two existing units (Units 1 and 2) and related support facilities. Unit 1 is a nominal 40 MW simple cycle combustion turbine (SCCT). Unit 2 is a nominal 120 MW combined cycle combustion turbine (CCCT). Both existing units fire natural gas as the primary fuel, with distillate fuel as backup.

The addition of Unit 3 will constitute a modification to the Power Park. Unit 3 will be an approximately 250 MW CCCT generating unit firing natural gas and the primary fuel and distillate oil as backup for up to 720 hours per year. Unit 3 will occupy approximately 5 acres north of the existing Units 1 and 2. Major equipment associated with Unit 3 will consist of a combustion turbine generator, heat recovery steam generator (HRSG) with supplemental firing, steam generator, cooling tower, and a fuel oil storage tank.

The CCCT/HRSG will use evaporative coolers as necessary to cool the compressor inlet air prior to its combining with fuel in the combustor of the CCCT. The thermal energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy



Base Map Source: USGS,
Intercession City, FL quad.

Figure 2-1
Site Location

Poor Original



as these gases expand through the turbine sections of the CCCTs. The rotating mechanical energy will be converted into electrical energy via a shaft on the CCCT connected to an electrical generator. The remaining usable thermal energy in the combustion gases will be exchanged with water/steam in the HRSG. The HRSG will be equipped with a bypass stack and guillotine damper to permit simple cycle operation prior to HRSG installation or while the HRSG is out of service.

While operating in combined cycle mode, supplemental (duct) firing with natural gas will be used to increase the thermal energy of the combustion gases exhausting from the CCCT. The resulting high pressure steam produced in the HRSG will be expanded through a single steam turbine. The rotating mechanical energy generated by the steam turbine will be converted into electrical energy via a shaft connected to an electrical generator. The exhaust gases will exit to the atmosphere after leaving the HRSG stack or bypass stack when operating in simple cycle mode.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from Unit 3. Emissions from Unit 3 will be generated from the following sources:

- Unit 3: One CCCT/HRSG with supplemental firing, or as a SCCT while operating in simple cycle mode with the bypass stack.
- Tank: One approximately 1,000,000 gallon No. 2 distillate fuel oil storage tank.

2.3.1 Unit 3 Emissions

Performance data for the CCCT/HRSG, based on vendor data from GE and Westinghouse at design loads of 50, 70, and 100 percent, natural gas and distillate fuel firing, and ambient air temperatures of 19° F, 72° F, and 102° F are provided in Attachment 1. Performance data for simple cycle operation at base load, natural gas and distillate fuel oil firing, and ambient air temperatures of 19° F, 72° F, and 102° F are also included in Attachment 1 for each turbine vendor.

Ambient temperature data were selected based on meteorological data from Orlando, FL. An ambient temperature of 19° F represents the lowest anticipated site temperature and maximum power generation. An ambient temperature of 72° F represents the average annual site temperature which is representative of the average heat input rate. An ambient temperature of 102° F represents the highest anticipated site temperature which corresponds



to the lowest heat input rate for the combustion turbine and results in the maximum required duct firing and evaporative cooling rates to maintain the desired plant electrical output.

The maximum pound per hour emission rates considering all ambient temperatures, both turbine vendors, combined and simple cycle operation, and partial load operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

2.3.2 No. 2 Distillate Fuel Oil Storage Tank

The fuel oil storage tank will have a capacity of 1,000,000 gallons. Emissions of VOCs from the fuel oil storage tank were estimated using the EPA's TANKS (Ver. 3.1) program. Results of the TANKS emission modeling are included in Attachment 2. The VOC emissions from the fuel oil storage tank are approximately 0.32 tpy and are included in the total PTE calculations.

2.4 Maximum Potential to Emit

At the time of this application, a turbine vendor had not yet been selected. As such, the potential to emit was estimated from the maximum hourly emission rate for each pollutant at an ambient temperature of 72° F (average annual) considering two turbine vendors, combined and simple cycle operation, 50 to 100 percent load, and 720 hours of distillate fuel oil firing (0.05 percent sulfur) with the remainder of the year on natural gas. The Unit 3 potential to emit for each pollutant is summarized in Table 2-2. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included in Attachment 3.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs: the PSD program outlined in 40 CFR 52.21; and, the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment area with respect to all pollutants. As such, the PSD program will apply to Unit 3, as administered by the State of Florida under 62-212.400, FAC, Stationary Sources - Preconstruction Review, Prevention of Significant Deterioration.



Table 2-1
Unit 3 Maximum Emission Rates (lb/h)*

Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NO _x	195.80	328.50
SO ₂	1.03	102.67
CO	790.60	2,908.20
PM/PM ₁₀	18.60	112.60
VOC	30.20	195.30

*Maximum pound per hour emission rates considering all ambient temperatures, two turbine vendors, combined and simple cycle operation, and partial load operation for natural gas and distillate fuel oil firing.



Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO _x	823.3 ^a	40	yes
SO ₂	38.1 ^{a,b}	40	no
CO	3,818.4 ^a	100	yes
PM/PM ₁₀	109.1 ^{a,c}	25/15	yes
VOC	173.3 ^a	40	yes
Sulfuric Acid Mist	4.7 ^{a,d}	7	no
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Vinyl Chloride	negl.	1	no
Total Fluorides	negl.	3	no
Mercury	0.00067 ^e	0.1	no
Beryllium	0.00024 ^e	0.0004	no
Lead	0.043 ^e	0.6	no

^aBased on maximum lb/h emission rate at 72° F conditions for all loads and operating scenarios; assuming 8,040 and 720 hours per year of natural gas and distillate fuel oil firing, respectively.

^bBased on 0.05% sulfur distillate fuel oil and 0.2 gr/100 scf sulfur natural gas.

^cAssumes front and back half PM/PM₁₀ emissions.

^dConservatively assuming a 10 percent conversion of SO₂ to SO₃, and a molecular ratio of 1.22 from SO₃ to H₂SO₄.

^eBased on AP-42 emission factors, a maximum heat input of 2,039.4 MBtu/h (considering both vendors and all operating scenarios), and distillate fuel oil firing for 720 hours per year.

Note: PTE calculations are provided in a spreadsheet included in Attachment 3.



2.5.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the ambient air quality standards (AAQS) while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The Power Park is one of the 28 major source categories (i.e., fossil fuel fired steam electric plant) which has a PTE greater than 100 tpy for at least one regulated pollutant. Additionally, the estimated emission increases of NO_x, CO, VOCs, and PM/PM₁₀ resulting from the proposed modification (i.e., addition of Unit 3), exceed the PSD significant emissions levels of 40, 100, 40, 25/15 tpy, respectively. Therefore, the Unit 3 emissions of NO_x, CO, VOC, and PM/PM₁₀ are subject to PSD review as a modification to an existing major source. The PSD review includes a BACT analysis, air quality impact analysis, and an assessment of the total project's (Units 1-3) impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis.





3.0 Best Available Control Technology

The 1977 Clean Air Act (CAA) established revised conditions for the approval of preconstruction permit applications under the PSD program. One of these requirements is that the Best Available Control Technology (BACT) be installed for all pollutants regulated under the Act which are emitted in significant amounts from new major sources or modifications located in an attainment area. BACT is defined as an emission limitation based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

To bring consistency to the BACT process, the EPA has authorized the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. Technologies required under lowest achievable emission rate (LAER) determinations must be considered. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. As stated above, in no event can BACT be less restrictive than NSPS.

3.1 Basis of Analysis

This section presents the project configuration, requirements and assumptions, and economic basis.

3.1.1 Project Configuration

As previously noted elsewhere in this permit application document, Unit 3 will consist of one combustion turbine which can be operated in either simple cycle or combined cycle mode. The combustion turbine will fire primarily natural gas with No. 2 fuel oil as a backup fuel. Unit 3 will be limited to operating on this backup fuel for a maximum of 720 hours per



year. Emissions are currently based on a General Electric (GE) Frame 7 FA size combustion turbine or a Westinghouse 501F combustion turbine.

An HRSG will recover energy from the high temperature flue gas exiting the combustion turbine (CT). A steam turbine will be used to generate electricity from the steam produced in the HRSG. The total unit output will be nominally rated at 250 MW.

The proposed operating scenarios for the CT include natural gas firing at loads from 50 to 100 percent of capacity. The CT may operate up to 8,760 hours per year in either simple cycle or combined cycle mode.

3.1.2 Requirements and Assumptions

The following is a summary of the requirements and assumptions that this BACT analysis is based upon:

- Federal ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal NSPS for combustion turbines with heat input greater than 10 MBtu/h (40 CFR 60 Subpart GG) establish limiting criteria for SO₂ and NO_x emissions only. No NSPS criteria have been established for limiting CO, SO₃, volatile organic compounds (VOC), and PM/PM₁₀ emissions. The following flue gas emission limits are established by NSPS for Subpart GG units:
 - NO_x: 75 ppmdv at 15 percent O₂, corrected for fuel nitrogen content and turbine heat rate.
 - SO₂: 150 ppmdv at 15 percent O₂ or any fuel that contains less than 0.8 percent sulfur by weight.
- The emissions estimates and BACT costs presented in this analysis are based on operating the CT for 8,760 hrs/yr. All annual emissions are based on operation at full load in combined cycle mode while firing natural gas at the yearly average ambient temperature of 72 F. The emissions for this case are as follows:

NO _x , ppmdv @ 15% O ₂ :	15.0	(0.06 lb/MBtu)
CO, ppmdv @ 15% O ₂ :	25.0	(0.061 lb/MBtu)
VOC, ppmdv @ 15% O ₂ :	4	(0.006 lb/MBtu)
PM/PM ₁₀ , lb/hr:	16.1	(0.01 lb/MBtu)
- As discussed elsewhere in the application, the Power Park is located in an EPA designated attainment area for all criteria air pollutants.



3.1.3 Economic Basis

Table 3-1 lists the economic criteria used in the analysis of BACT alternatives. Economic analysis used to determine the capital and annual costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA BACT Guidelines, The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fourth Edition), and vendor budgetary cost quotes.

3.2 NO_x BACT Analysis

The objective of this analysis is to determine BACT for NO_x emissions from the Unit 3 combustion turbine. Unless otherwise noted, the emission concentrations described in this section are corrected to 15 percent oxygen.

3.2.1 BACT/LAER Clearinghouse Reviews

A review of the EPA BACT/LAER Clearinghouse Bulletin Board and the California Air Resource Board (BACT/LAER) indicates that the most stringent NO_x permitted emissions limit for a gas fired CT is 3.5 ppm_{dv} for the Brooklyn Navy Yard Cogeneration Project located in New York. The emissions from that unit are controlled through the use of dry low NO_x burners and SCR. This CT emission limit is noted in the Clearinghouse as being representative of LAER at the time of the permit (1995).

Black & Veatch spoke with Alan Dominitz of the New York State Department of Environmental Conservation, Region 2, regarding the NO_x compliance status of the Brooklyn Navy Yard unit. Mr. Dominitz indicated that startup stack testing demonstrated compliance with the 3.5 ppm limit. Since that time, the unit emissions have typically been in the 2.9 to 3.3 ppm range. However, there have been occasional exceedances of the 3.5 ppm limit as shown in the facility quarterly reports.

It should also be noted that recently the South Coast Management District in California has officially declared LAER for NO_x as 2.5 ppm. This emission rate is based on the results of operation by the Federal Plant in Vernon, CA. This unit is a 32 MW natural gas fired combined cycle facility which utilizes a new technology called SCONO_x for NO_x control.

Table 3-2 lists representative BACT determinations for NO_x control.



Table 3-1
Unit 3 Economic Evaluation Criteria

Economic Parameters	Value
Present Worth Discount Rate, percent	5.5
Capital Recovery Factor (EPA Method)	0.0745
Economic Life, years	20
Labor Cost, \$/h	26
Aqueous Ammonia Cost, \$/ton	350
Energy Cost, \$/kWh	0.023
Lost Power Generation Cost, \$/kWh	0.10
Natural Gas Cost, \$/MBtu	3.20



Table 3-2
Summary of NO_x BACT Determinations

Facility	Description	Permit Limit ppm@15% O ₂	BACT
Cataula, GA	1200 MW, Simple Cycle Unit	25--Natural Gas 42--Fuel Oil	Dry Low NO _x Burners Water Injection
Tiger Bay, FL	270 MW Combined Cycle	15/10--Natural Gas 42--Fuel Oil	Dry Low NO _x Burners Water Injection
Hines Polk, FL	485 MW Combined Cycle	12--Natural Gas	Dry Low NO _x Burners Water Injection
Tallahassee, FL	260 MW Combined Cycle	12--Natural Gas	Dry Low NO _x Burners Water Injection
Mcintosh, AL	100 MW Combined Cycle	15--Natural Gas	Dry Low NO _x Burners
Perryman, MD	280 MW Combined Cycle	15--Natural Gas	Dry Low NO _x Burners Water Injection
Comstock, MI		15--Natural Gas	Dry Low NO _x Burners Water Injection
Sithe/IPP, NY	1012 MW Combined Cycle	4.5--Natural Gas	Selective Catalytic Reduction
Hermiston, OR	474 MW Combined Cycle	4.5--Natural Gas	Selective Catalytic Reduction
Brooklyn, NY	240 MW Combined Cycle	3.5--Natural Gas (LAER) 10--Fuel Oil	Selective Catalytic Reduction Selective Catalytic Reduction
Berkshire, MA	272 MW Combined Cycle	3.5--Natural Gas (LAER) 9--Fuel Oil	Selective Catalytic Reduction Selective Catalytic Reduction
Gainesville, FL	74 MW Simple Cycle	15--Natural Gas 42--Fuel Oil	Dry Low NO _x Burners Water Injection



3.2.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. Emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature.

Nitrogen oxides control methods may be divided into two categories: in-combustor NO_x formation control, and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process. For combustion turbines, NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). Post-combustion NO_x control systems can subsequently reduce a portion of the NO_x exiting the CT. Selective non-catalytic reduction (SNCR) is one method of post-combustion control. However, the exhaust temperature at the exit of a CT, which is typically less than 1,100° F, is too low to meet the 1,500-1,900° F temperature range required for this technology. Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in combustion turbine projects for the past several years. In addition to SCR, the SCONO_x technology has had limited commercial operation at the Federal Plant. In-combustor control technology along with both of these methods of post-combustion control will be discussed and considered further in this BACT analysis as stand alone technologies and in combination with other systems and configurations.

CT Combustor NO_x Control. The reduction of thermal NO_x formation in CT combustors has been a major design focus over the last twenty years. The formation of thermal NO_x is a function of flame temperature and time. By limiting the flame temperatures and the amount of time which the combustion gases spend at elevated temperatures, CT designers have achieved substantial reductions in thermal NO_x formation. Until recently, diluent injection (e.g. water or steam) has been the primary means of controlling flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water or steam injected into the CT. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved CT tolerances to the water necessary to control NO_x emissions below the current NSPS level of 75 ppmdv at 15 percent O₂. However, there is a point at which the amount of water injected into the CT seriously degrades its reliability and operational life.



Diluent injection systems have several operational drawbacks one of which is that even the most sophisticated arrangements have not been able to achieve better than 25 ppm_{dv} NO_x.

Although water injection is an effective means of lowering NO_x emissions, it can be counterproductive with regard to carbon monoxide (CO) and volatile organic compounds (VOC) emissions that are formed as a result of incomplete combustion. NO_x control methods of lowering the combustion temperature result in higher CO and VOC emissions. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion will minimize CO and VOC emissions.

As an alternative to water injection, dry low NO_x (DLN) combustors have been developed. This burner design does not need water to be injected into the combustion chamber to achieve low NO_x emissions. The DLN combustors control the actual fuel-air ratio so that combustion occurs in the lean region, thus limiting flame temperature. The new designs have also altered the combustion gas flow path so that compressor discharge air bypasses the combustor and reenters the flow path immediately after combustion, thus limiting the amount of time that the gases spend at elevated temperatures.

Also, as with the standard combustor with water or steam injection, the DLN combustors can also be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures will result in higher CO and VOC emissions.

Both GE and Westinghouse are currently willing to guarantee 15 ppm using dry low NO_x technology. Emissions achieved by DLN are as low as 9 ppm. GE has recently met a 9 ppm guarantee with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA. Westinghouse and GE continue to develop further advancements and refinements on the DLN technology. Both companies are partners with the Department of Energy (DOE) in the Advanced Turbine Systems (ATS) Program. Among the goals of the Program is to develop 60 percent combined cycle efficiencies while achieving NO_x emissions of 9 ppm or less.

Selective Catalytic Reduction. SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the CT exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades, ammonia slip will increase to a level that requires catalyst replacement.



The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. The optimum flue gas temperature range for SCR operation using a conventional vanadia/titania catalyst is approximately 600° to 750° F. At temperatures above 800° F permanent damage to the vanadia/titania catalyst occurs. For a combined cycle project, this temperature window occurs at an intermediate point inside the HRSG.

In order to control NO_x during simple cycle operation, the only location for the catalyst is in the path of the high temperature flue gas directly exiting the CT where temperatures typically range from 1,000° to 1,150° F. To control NO_x emissions during this operation, a more expensive zeolite catalyst must be used to prevent rapid degradation of the catalyst by the high temperatures.

SCONO_x System. SCONO_x is a new system produced by Goal Line Environmental Technologies that began commercial operation on a LM2500 combustion turbine (approximately 32 MW) in December 1996. This system uses a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. Based on the operational experience of this plant, the South Coast Management District (SCAQMD) in California has recently declared LAER for NO_x as 2.5 ppm.

The system consists of a catalyst which is installed in the flue gas at a point where the temperature is between 280° F and 650° F. For a new unit, where the facility can be designed to place the catalyst in the optimum location, the catalyst can be placed in an area of the HRSG where the temperature is between 550° F and 650° F. CO emissions are reduced by the oxidation of CO to CO₂. The NO emissions are reduced by a two step process. First, NO emissions are oxidized to NO₂ and then absorbed onto the catalyst. In the second step, a proprietary regenerative gas is then passed through the catalyst. This gas de-absorbs the NO₂ from the catalyst and reduces it to N₂.

The regenerative gas is produced from natural gas. For systems where the SCONO_x catalyst is located in an area with low flue gas temperatures, the gas is produced by processing a small stream of natural gas through a separate, skid mounted processing unit. The resulting regenerative gas is approximately 3 percent nitrogen, 1.5 percent CO₂ and 4 percent H₂, with steam making up the balance. For systems where the SCONO_x catalyst is located in an area with flue gas temperatures above 500° F, the regeneration gas can be



produced in the flue gas before it regenerates the catalyst. In the high temperature case, a separate processing unit is not required.

Dampers are used to isolate a portion of the catalyst for regeneration. The regenerative gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the dampers open, the next set of dampers close, and the next portion of the catalyst is isolated and regenerated. This cycle repeats continuously. As a result, each section of the catalyst is regenerated about once every 15 minutes.

The catalyst is very susceptible to fouling by sulfur in the flue gas. Sulfur causes the catalyst to lose activity. The impact of sulfur can be minimized by a sulfur absorption catalyst, called SCOSO_x, located upstream of the SCONO_x catalyst. The SO₂ is oxidized to SO₃ by the catalyst. The SO₃ is then deposited on the catalyst and removed from the catalyst when it is regenerated with the SCONO_x catalyst. The resulting byproduct of the regeneration is either H₂S (for systems with flue gas below 450° F at the SCONO_x catalyst) or SO₂ (for systems with flue gas above 450° F). As of the writing of this document, the SCOSO_x portion of the system has not yet been implemented at any facility. Because the SCOSO_x system is not installed, the sulfur is being removed from the natural gas before combustion to protect the SCONO_x catalyst from excessive sulfur contamination.

The existing system at the Federal Plant has not been exposed to the levels of sulfur found in flue gas during fuel oil firing. Since this system has shown to be highly susceptible to even natural gas-fired levels of sulfur, there is concern about the application of this system on a unit with fuel oil fired operation. Because of these concerns, this technology is not considered further for use on Unit 3.

3.2.3 Evaluation of Feasible Technologies

The NO_x control technologies that can be considered for use on Unit 3 to comply with NSPS restrictions include water/steam injection, dry low NO_x combustor technology, and SCR control technology. The following control technologies will be evaluated in this BACT analysis:

- The addition of a low temperature SCR system to reduce outlet NO_x emissions from the dry low NO_x burners to 3.5 ppm_{dv}. This system would not reduce NO_x emissions from the dry low NO_x burners during simple cycle operation.



However, this is not reflected in the BACT analysis since it has been performed for combined cycle operation.

- The addition of a high temperature SCR system to reduce outlet NO_x emissions from the dry low NO_x burners to 3.5 ppm_{dv}. This system will reduce NO_x emissions during simple cycle operation.
- Advanced combustion controls (dry low NO_x burners) to limit outlet NO_x emissions to 15 ppm_{dv}.

The following evaluation considers energy, environmental, and economic impacts for the potential BACT scenarios evaluated. Table 3-3 lists estimated NO_x emissions from the CT for the alternative control technologies.

Energy Impacts. The SCR systems impacts the energy requirements of Unit 3. SCRs require vaporizers and blowers to vaporize and dilute the aqueous ammonia reagent for injection. In addition, both systems will increase the backpressure on the CT. The low temperature SCR system will add 2 inches water gauge (in. w.g.) backpressure. The high temperature SCR system will add 2.5 in. w.g. Decreased energy sales are included in the annual cost estimate.

Environmental Impacts. The feasibility of reducing NO_x emissions to 3.5 ppm or even less is highly dependent on the ability to measure this low level of emissions. Because the SCR system requires the regulation of ammonia injection based on the emission monitors, the accuracy of the emission reading directly influences the amount of actual error in the ammonia injection rate. Therefore, erroneous emission readings can result in excess ammonia levels even when the actual NO_x values is below the permitted values. This may result in excessive ammonia "slip" being discharged to the atmosphere with little or no improvement in NO_x emissions. Limitations to accurate measurements of emissions at this level include sampling methods, analyzer limitations, and calibration gas error. Current EPA procedures and standards recognize such limitations. Currently, 40 CFR Part 75 allows emission monitors with span ranges of less than 200 ppm have calibrations that deviate by up to 10 ppm and can still be considered "in control."



Table 3-3
NO_x Reduction by Control Technology Alternatives

Control Technology	Uncontrolled Emissions (ppmdv)	Emissions Reduction (percent)	Emissions Achievable (ppmdv)	Annual Emissions (tons per year)
High Temperature SCR	15	77	3.5	101
Low Temperature SCR	15	77	3.5	101
Dry Low NO _x Burners	15	N/A	15	433
Note: All listed emissions are based on full load operation in combined cycle mode at an ambient temperature of 72 F. Annual emissions are based on 8,760 hours of operation.				



The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA) and Section 112(r) of the Accidental Release Provisions. According to Committee on Toxicology of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

<u>Human Response</u>	<u>Concentration (ppm)</u>
Immediate throat irritation	equal to or greater than 400
Eye irritation	equal to or greater than 700
Coughing	equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

Some ammonia slip from the HRSG stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppm_{dv} (uncorrected), unless that limit is shown to be inappropriate. Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst size and life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates associated catalyst replacement. A design value of 10 ppm_{dv} (uncorrected) is appropriate for a clean fuel facility such as Unit 3.

The vanadium content of the low temperature SCR catalyst may contribute to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. Because of this, recycling of SCR catalysts for vanadium has become common.

The SCR catalyst will oxidize approximately 1 to 3 percent of the SO₂ in the flue gas to SO₃. The ammonia present in the flue gas will react with the SO₃ to form ammonium sulfate and bisulfate salts. Ammonium bisulfate will condense on the downstream HRSG tubes as a sticky white substance. This will need to be periodically washed off to avoid corrosion of boiler tubes or reduced HRSG efficiency. Ammonium sulfate will exit the stack as a vapor and condense into a particulate form downstream. This is primarily of concern during fuel oil fired operation.



Economic Impacts. Table 3-4 presents the capital cost for installing each of the control alternatives. The cost of the systems include: catalyst; ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor; HRSG modifications; and, balance of plant equipment. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. The high temperature SCR costs are significantly greater than low temperature SCR system costs due to the greater costs of high temperature zeolite catalyst.

Table 3-5 presents the annual operating costs and emission rates for each control technologies applied to Unit 3. Annual operating costs include catalyst replacement, energy impacts, operating personnel, maintenance, and reagent consumption.

Throughout the life of Unit 3, catalyst elements will require periodic replacement. Currently, SCR catalyst manufacturers are willing to guarantee a catalyst life of three years.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.05 for the low temperature catalyst and 1.5 for the high temperature catalyst. The use of each of these systems increases the energy requirements for Unit 3. The SCR system requires vaporizers and blowers to vaporize and dilute the aqueous ammonia reagent for injection. Maintenance costs consist of routine system maintenance. The replacement materials are assumed to be two percent of the original cost for moving equipment. Labor for operation and maintenance of the SCR systems is assumed to be 2 hours per day.

3.2.4 Conclusions

The cost effectiveness of a low temperature SCR system is \$3,481 per ton of NO_x removed. However, this system does not reduce NO_x emissions during simple cycle operation. The cost effectiveness for a high temperature SCR is \$10,376 per ton of NO_x removed. Both of these systems result in environmental impacts such as ammonia storage, ammonia slip, and higher particulate emissions. In addition, each consumes energy and reduces the output of the combustion turbines.

Dry low NO_x burners are being continually improved by both GE and Westinghouse. Emissions of less than 9 ppm are expected to be easily achieved in the year 2002. In addition, these DLN combustors do not have the environmental impacts of SCR. Because of these benefits, the proposed BACT for Unit 3 is dry low NO_x combustors to achieve 15 ppmdv during the first two years of operation and less than 9 ppmdv after the first 2 years. If the dry



Table 3-4
Capital Cost of NO_x Control Alternatives

	Dry Low NO _x Burners	Low Temp SCR	High Temp SCR	Remarks
Direct Capital Cost				
Catalyst	Not Applicable	480,000	3,520,000	Provided by vendors, scaled to this unit
Catalyst Reactor	Not Applicable	186,000	279,000	Calculated based on catalyst size
Control/Instrumentation	Base	140,000	140,000	
Ammonia Storage and Injection	Not Applicable	250,000	350,000	Scaled from previous project
Balance of Plant	<u>Base</u>	<u>345,000</u>	<u>1,458,000</u>	32 % of equipment costs
Total Direct Capital Cost	Base	1,361,000	5,747,000	
Indirect Capital Costs				
Contingency	Base	340,000	1,437,000	25% of Direct Capital Cost
Engineering and Supervision	Base	136,000	575,000	10% of Direct Capital Cost
Construction & Field Expense	Base	68,000	287,000	5% of Direct Capital Cost
Construction Fees	Base	136,000	575,000	10% of Direct Capital Cost
Start-Up Assistance	Base	27,000	115,000	2% of Direct Capital Cost
Performance Test	<u>Base</u>	<u>27,000</u>	<u>27,000</u>	
Total Indirect Capital Cost	Base	734,000	3,016,000	
Total Installed Cost	Base	2,095,000	8,763,000	



Table 3-5
Annual Cost of NO_x Control Alternatives

	Dry Low NO _x Burners	Low Temp SCR	High Temp SCR	Remarks
Direct Annual Cost				
Catalyst Replacement	Not Applicable	183,000	1,467,000	3 year catalyst life
O&M	Base	27,000	29,000	See text for description
Reagent Feed	Not Applicable	216,000	281,000	See text for description
Power Consumption	Base	58,000	75,000	Vaporizers and dilution blowers
Lost Power Generation	Not Applicable	388,000	485,000	Based on backpressure on turbine
Annual Distribution Check	<u>Not Applicable</u>	<u>14,000</u>	<u>15,000</u>	
Total Direct Annual Cost	Not Applicable	886,000	2,351,000	
Indirect Annual Costs				
Overhead	Base	11,000	11,000	60 % of O&M labor
Administrative Charges	Base	42,000	175,000	2 % of Total Installed Cost (TIC)
Property Taxes	Base	21,000	88,000	1 % of Total Installed Cost (TIC)
Insurance	Base	21,000	88,000	1 % of Total Installed Cost (TIC)
Capital Recovery	<u>Base</u>	<u>175,000</u>	<u>733,000</u>	Capital Recover Factor * TIC
Total Indirect Annual Cost	Base	270,000	1,095,000	
Total Annual Cost	Base	1,156,000	3,446,000	
Annual Emissions, tpy	433	101	101	Emission from Table 3-2
Emissions Reduction, tpy	Base	332	332	
Total Cost Effectiveness, \$/ton	Base	3,481	10,376	Annual Cost/Emission Reduction



low NO_x burners are not capable of meeting this value within 2 years of commercial operation, the unit will be equipped with a low temperature SCR to reduce emissions to 7 ppm_{dv}. This proposed BACT is consistent with the permitting strategy of the City of Lakeland project.

3.3 CO and VOC BACT Analysis

The objective of this analysis is to determine BACT for CO and VOC emissions from the Unit 3 combustion turbine. Unless otherwise noted the emission rates described in this section are corrected to 15 percent oxygen.

3.3.1 BACT/LAER Clearinghouse Reviews

A review of the EPA BACT/LAER Clearinghouse Bulletin Board indicates that the most stringent CO emission level for a CT is 1.8 ppm_{dv} for the Newark Bay Cogeneration L.P. project located in New Jersey. These emissions are achieved by reducing CO emissions by 80 percent (from 9 ppm_{dv} to 1.8) through the use of an oxidation catalyst. It should be noted that the Newark Bay project is located in non-attainment areas for CO and ozone.

The BACT/LAER Clearinghouse documents indicate that the most stringent VOC emission level for a CT is 1.5 ppm_{dv} at 15 percent O₂ for the Lakewood Cogeneration L.P. project located in New Jersey. These emissions are achieved by combustion controls and is for a unit which is approximately half the size of the unit proposed for this project.

Table 3-6 lists representative BACT determinations for CO and VOC control.

3.3.2 Alternative CO and VOC Emission Reduction Systems

CO and VOCs are formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO and VOC formation is limited by ensuring complete and efficient combustion of the fuel in the CT. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. Lowering combustion temperatures through steam/water injection or staged combustion, which is used to reduce combustor based NO_x formation, can be counterproductive with regard to CO and VOC emissions.



Table 3-6
Summary of CO and VOC BACT Determinations

Facility	Description	CO Permit Limit ppm@15% O ₂	VOC Permit Limit ppm@15% O ₂	BACT
Hines Polk, FL	485 MW Combined Cycle	25--Natural Gas 30--Fuel Oil	7--Natural Gas 7--Fuel Oil	Clean fuel and good combustion Clean fuel and good combustion
Tallahassee, FL	260 MW Combined Cycle	25--Natural Gas 90--Fuel Oil		Clean fuel and good combustion Clean fuel and good combustion
Perryman, MD	280 MW Combined Cycle	20--Natural Gas		Clean fuel and good combustion
Comstock, MI		20--Natural Gas		Clean fuel and good combustion
Plattsburgh, NY		3--Natural Gas	0.0045 lb/MBtu, Natural Gas	Oxidation Catalyst
Sithe/TPP, NY	1012 MW Combined Cycle	13--Natural Gas		Clean fuel and good combustion Clean fuel and good combustion
Hermiston, OR	474 MW Combined Cycle	15--Natural Gas		Clean fuel and good combustion Clean fuel and good combustion
Brooklyn, NY	240 MW Combined Cycle	4--Natural Gas 5--Fuel Oil	3.5--Natural Gas 10--Fuel Oil	Clean fuel and good combustion CO Catalyst
Berkshire, MA	272 MW Combined Cycle	4--Natural Gas 5--Fuel Oil	4--Natural Gas 16--Fuel Oil	Clean fuel and good combustion Clean fuel and good combustion
Newark Bay, NJ	136 MW Cogeneration	1.8--Natural Gas 2.6--Kerosene	4--Natural Gas 6.1--Kerosene	Oxidation catalyst for CO, Turbine design for VOC
Lakewood, NJ		12--Natural Gas 25--Fuel Oil	1.5--Natural Gas 3--Fuel Oil	Clean fuel and good combustion Clean fuel and good combustion



An alternative is catalytic oxidation, which is a post-combustion method for reduction of CO and VOC emissions. The process uses a catalyst located in an appropriate temperature zone to promote the oxidation of CO to CO₂ and VOCs to CO₂ and water. Higher temperatures promote better oxidation of CO. No reagent injection is necessary and oxidizing catalysts are capable of reducing CO emissions by 80 percent and VOC emissions by 20 percent. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic.

3.3.3 Evaluation of Feasible Technologies

Good combustion practice is considered as the baseline control technology for CO emissions. The addition of an oxidation catalyst to reduce outlet CO emissions to 5 ppmvd at full load will be evaluated in this BACT analysis. This is an 80 percent reduction in CO emissions. The following evaluation considers energy, environmental, and economic impacts for the potential BACT scenarios evaluated. Table 3-7 lists estimated CO emissions from the CT for the alternate control technologies.

Energy Impacts. The oxidation catalyst system impacts the energy requirements of Unit 3. The system will increase the backpressure on the CT of 1.2 in. w.g. Decreased energy sales are included in the annual cost estimate.

Environmental Impacts. The spent catalyst is made up of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of the precious metal content of the catalyst, the oxidation catalyst can also be recycled to recover the precious metals.

An oxidation catalyst will oxidize 20 to 80 percent of the SO₂ to SO₃, depending on the flue gas temperature at the catalyst location and catalyst formulation. This SO₃ will react with moisture in the flue gas to form sulfuric acid. Sulfuric acid will exit the stack in either vapor form (sulfuric acid mist) or in particulate form, depending on the flue gas temperature at the stack and the concentration of sulfuric acid in the flue gas. This is primarily a concern during oil firing.

Economic Impacts. Table 3-8 presents the capital cost for installing an oxidation catalyst on Unit 3. The cost of the oxidation catalyst system includes: catalyst; catalytic reactor;



Table 3-7
CO and VOC Reduction by Control Technology Alternatives

Control Technology	Uncontrolled Emissions (ppmdv)	Emissions Reduction (percent)	Emissions Achievable (ppmdv)	Annual Emissions (tons per year)
Oxidation Catalyst				
CO	25	80	5	87
VOC	4	20	3.2	32
Combustion Controls				
CO	25	N/A	25	435
VOC	4	N/A	4	40

Note: All listed emissions are based on full load operation in combined cycle mode at an ambient temperature of 72° F. Annual emissions are based on 8,760 hours of operation.



Table 3-8
Capital Cost of CO and VOC Control Alternatives

	Combustion Controls	Oxidation Catalyst	Remarks
Direct Capital Cost			
Catalyst	Not Applicable	600,000	Scaled from previous project vendor quote
Catalyst Reactor	Not Applicable	60,000	Based on catalyst size
Control and Instrumentation	Base	40,000	
Balance of Plant	<u>Not Applicable</u>	<u>105,000</u>	15% of equipment costs
Total Direct Capital Cost	Base	805,000	
Indirect Capital Costs			
Contingency	Base	201,000	25% of Direct capital cost
Engineering and Supervision	Base	40,000	5% of Direct capital cost
Construction & Field Expense	Base	16,000	2% of Direct capital cost
Construction Fees	Base	8,000	1% of Direct capital cost
Start-Up Assistance	Base	8,000	1 % of Direct capital cost
Performance Test	<u>Base</u>	<u>4,000</u>	
Total Indirect Capital Cost	Base	277,000	
Total Installed Cost	Base	1,082,000	



HRSG modifications; and balance of plant equipment. Capital costs were based on scaled estimates of previous budgetary quotations from equipment manufacturers and other engineering estimates.

Table 3-9 present the annual operating costs and emission rates for applying the oxidation catalyst technology to Unit 3. Annual operating costs include catalyst replacement, energy impacts, operating personnel, and maintenance.

Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, oxidation catalyst manufacturers are willing to guarantee a catalyst life of 3 years.

3.3.4 Conclusions

The cost effectiveness of an oxidation catalyst is \$1,680 per ton of emissions removed. This value is high for CO and VOC reduction. In addition, the environmental impact of high SO₂ to SO₃ oxidation by the catalyst makes it an unattractive option on units that fire fuel oil. Therefore, the proposed BACT for Unit 3 CO and VOC emissions is combustion controls to maintain CO emissions at 25 ppm_{dv} and VOC emissions at 4 ppm_{dv} at the full load, natural gas fired condition.

3.4 PM/PM₁₀ BACT Analysis

The emission of particulate matter from Unit 3 will be controlled by ensuring as complete combustion of the fuel as possible and by minimizing SO₂ to SO₃ oxidation. The NSPS for combustion turbines do not establish an emission limit for particulate.

Natural gas and fuel oil contain only small quantities of non-combustible material. The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations, the use of combustion controls is the proposed BACT for particulate matter.

3.5 Summary

Table 3-10 provides a listing of the selected BACT technologies for Unit 3. The associated emission rates are also summarized in various units for comparison to the various applicable standards.



Table 3-9
Annual Cost of CO and VOC Control Alternatives

	Combustion Controls	Oxidation Catalyst	Remarks
Direct Annual Cost			
Catalyst Replacement	Not Applicable	230,000	3 year catalyst life
Lost Power Generation	<u>Not Applicable</u>	<u>233,000</u>	Based on backpressure on the turbine
Total Direct Annual Cost	Base	463,000	
Indirect Annual Costs			
Administrative Charges	Base	22,000	2% of Total Installed Cost (TIC)
Property Taxes	Base	11,000	1% of TIC
Insurance	Base	11,000	1% of TIC
Capital Recovery	<u>Base</u>	<u>91,000</u>	Capital Recovery Factor TIC
Total Indirect Annual Cost	Base	135,000	
Total Annual Cost	Base	598,000	
Annual Emissions, tpy	475	119	Emissions from Table 3-5
Emissions Reduction, tpy	Base	356	
Total Cost Effectiveness, \$/ton	Base	1,680	Annual Cost/Emissions Reduction



Table 3-10
Summary of BACT Determinations

Pollutant	BACT	Emission Rate (lb/hr)	Annual Emissions (tons/year)
NO_x	Dry Low NO_x Burners	99	433
CO	Combustion Controls	99	435
VOC	Combustion Controls	9.1	40
PM	Low Ash Fuels	16	71

Notes: Emissions are based on full load operation firing natural gas and an ambient temperature of 72° F.





4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those PSD pollutants which will have a PTE greater than the PSD significant emission rate (i.e., NO_x, CO, and PM/PM₁₀). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of KUA in a letter from Black & Veatch dated May 26, 1998 (Attachment 4).

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 97363) air dispersion model was used to predict maximum ground level concentrations associated with Unit 3 emissions. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to access pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with EPA guidance.

4.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

4.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios (i.e., combined or simple cycle operation), fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing Unit 3's proposed operating load range (i.e., 50, 70, and 100 percent loads) with a representative set of stack parameters and pollutant emission rates that were conservatively selected from multiple vendor performance data to produce the worst-case plume dispersion



conditions and highest model predicted concentrations (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as enveloping.

The representative stack parameters and emission rates for each load, fuel type, and operating scenario considered in the analysis are presented in Table 4-1. A Lotus spreadsheet used in determining the load based representative emissions and stack parameters from the vendor performance data is included in Attachment 3.

4.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer 1 and use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the Power Park location, it was concluded that over 50 percent of the area surrounding the Power Park is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

4.2.3 GEP Stack Height Determination

Existing (Units 1 and 2) and proposed (Unit 3) buildings and structures were analyzed to determine the potential to influence the dispersion of stack emissions. EPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document was followed in this evaluation. Structure dimensions and relative locations were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for Unit 3 is 45.72 m (150 ft).

4.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.



Table 4-1
Representative (*Enveloped*) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis

							Pollutant Emission Rate (g/s)		
Operating Scenario/Fuel	ISCST3 Source ID*	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	NO _x ***	PM/PM ₁₀	CO
CCCT/HRSG Natural Gas	#SCC1NG	100	39.62	5.49	17.86	356.48	12.91	2.34	12.79
	#SCC7NG	70	39.62	5.49	14.60	352.59	10.71	2.27	85.91
	#SCC5NG	50	39.62	5.49	12.68	351.48	24.67	2.27	99.61
CCCT/HRSG Distillate Fuel Oil	#SCC1FO	100	39.62	5.49	20.60	408.15	41.39	10.75	350.56
	#SCC7FO	70	39.62	5.49	16.86	398.15	32.29	12.59	366.43
	#SCC5FO	50	39.62	5.49	14.66	398.15	26.31	14.19	360.03
CCCT/HRSG Annualized**	#ACC1	100	39.62	5.49	17.86	356.48	15.26	3.03	n/a
	#ACC7	70	39.62	5.49	14.60	352.59	12.48	3.12	n/a
	#ACC5	50	39.62	5.49	12.68	351.48	24.81	3.25	n/a
SCCT - Natural Gas	#SSC1NG	100	30.48	5.49	44.32	851.48	12.90	2.27	12.70
SCCT - Fuel Oil	#SSC1FO	100	30.48	5.49	43.86	802.59	41.38	10.80	48.17
SCCT- Annualized**	#ASC1	100	30.48	5.49	44.32	851.48	15.24	2.97	n/a

*The "#" character in the ISCST3 Source ID name refers to either N, P, or C, which denote NO_x, PM/PM₁₀, and CO; S or A refer to short or annualized emission rate; CC or SC refer to combined or simple cycle; 1, 7, or 5 refer to 100, 70, or 50 percent load; and NG or FO refer to natural gas or distillate fuel oil fired.

** Annualized emission rate based on 720 hours of distillate fuel oil firing.

*** Short-term NO_x emission rates are used in the region haze analysis modeling presented in Subsection 5.4.2.2.



- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 15 km from the center of Unit 3 was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 1,000 m, 500 m spacing out to 5 km, and then 1,000 m spacing from 5 to 15 km. Receptor spacing of 25 m intervals was used along the Power Park fenceline, and a 100 m fine grid was used at the maximum impact receptors. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures. The flat terrain option was used for all receptor points.

4.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1987-1991) of surface and upper air meteorological data from Orlando and Tampa, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

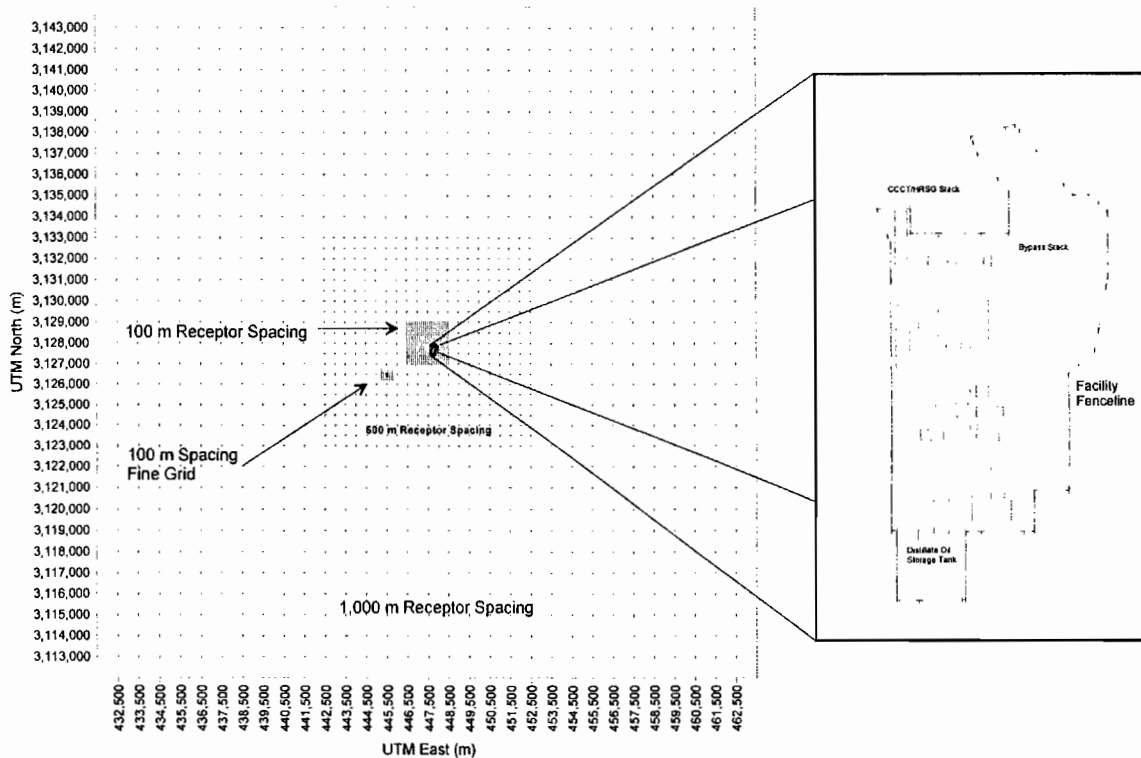
4.3 Model Results

As presented in Section 2.0, the Unit 3 PTE exceeds the PSD significant emission thresholds for NO_x , CO, and PM/PM_{10} . In accordance with the approved modeling protocol,

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.

Receptor Location Plot
Figure 4-1



Receptor and Emission Source Locations



ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, CO, and PM/PM₁₀ for each applicable averaging period.

Tables 4-2 through 4-6 present the results for the 5 year refined modeling period (1987-1991) for each pollutant and applicable averaging period. The shaded concentrations in each table represent the maximum modeled predicted impacts in each case.

4.3.1 Comparison to PSD Significant Impact Levels and Preconstruction Monitoring Requirements

Table 4-7 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels and the preconstruction monitoring requirements. As Table 4-7 indicates, the Unit 3 maximum predicted concentrations are less than the PSD Class II significant impact levels (SILs) for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the preconstruction monitoring de minus levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD preconstruction monitoring requirements.



Table 4-2
ISCST3 Model Predicted Maximum Annual Concentrations of NO_x

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	UTM Location	
					East (m)	North (m)
NACC1	Annual	100	1987	0.17	444,500.0	3,125,500.0
NACC7		70		0.18	444,500.0	3,126,000.0
NACC5		50		0.41	444,500.0	3,126,000.0
NACC1		100	1988	0.16	444,500.0	3,126,000.0
NACC7		70		0.16	445,500.0	3,126,000.0
NACC5		50		0.38	445,500.0	3,126,000.0
NACC1		100	1989	0.16	448,000.0	3,130,500.0
NACC7		70		0.17	448,000.0	3,130,500.0
NACC5		50		0.38	448,000.0	3,130,000.0
NACC1		100	1990	0.19	444,000.0	3,125,500.0
NACC7		70		0.20	445,000.0	3,126,000.0
NACC5		50		0.42	445,350.0	3,126,350.0
NACC1		100	1991	0.17	447,500.0	3,131,000.0
NACC7		70		0.18	447,500.0	3,130,500.0
NACC5		50		0.42	447,500.0	3,130,500.0
NASC1	Annual	100	1987	0.018	433,500.0	3,120,000.0
NASC1		100	1988	0.018	433,500.0	3,119,000.0
NASC1		100	1989	0.016	448,500.0	3,140,000.0
NASC1		100	1990	0.020	435,500.0	3,120,000.0
NASC1		100	1991	0.016	447,500.0	3,139,000.0



Table 4-3
ISCST3 Model Predicted Maximum 1-Hour Concentrations of CO

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	UTM Location	
					East (m)	North (m)
CSCC1NG	1-Hour	100	1987	20.17	447,800.0	3,128,700.0
CSCC7NG		70		153.32	447,900.0	3,127,000.0
CSCC5NG		50		183.12	447,900.0	3,127,000.0
CSCC1NG		100	1988	13.83	448,000.0	3,128,800.0
CSCC7NG		70		392.15	447,891.2	3,127,873.0
CSCC5NG		50		549.61	447,891.2	3,127,873.0
CSCC1NG		100	1989	14.85	447,000.0	3,127,300.0
CSCC7NG		70		107.35	447,000.0	3,127,300.0
CSCC5NG		50		155.00	448,500.0	3,126,500.0
CSCC1NG		100	1990	15.22	448,500.0	3,129,500.0
CSCC7NG		70		118.14	448,500.0	3,126,500.0
CSCC5NG		50		420.63	447,700.0	3,128,000.0
CSCC1NG		100	1991	27.54	447,600.0	3,128,100.0
CSCC7NG		70		444.50	447,858.8	3,127,911.0
CSCC5NG		50		621.26	447,858.8	3,127,911.0
CSCC1FO	1-Hour	100	1987	250.78	448,800.0	3,127,200.0
CSCC7FO		70		288.09	448,500.0	3,127,200.0
CSCC5FO		50		299.37	448,500.0	3,127,300.0
CSCC1FO		100	1988	257.86	449,000.0	3,127,500.0
CSCC7FO		70		371.82	448,000.0	3,128,800.0
CSCC5FO		50		1,278.43	447,891.2	3,127,873.0
CSCC1FO		100	1989	229.45	446,900.0	3,128,700.0
CSCC7FO		70		406.33	446,900.0	3,127,200.0
CSCC5FO		50		403.98	446,900.0	3,127,200.0
CSCC1FO		100	1990	259.69	448,500.0	3,130,000.0
CSCC7FO		70		273.70	448,500.0	3,130,000.0
CSCC5FO		50		277.96	448,200.0	3,128,500.0
CSCC1FO		100	1991	286.34	448,500.0	3,127,100.0
CSCC7FO		70		680.95	447,600.0	3,128,100.0
CSCC5FO		50		1,421.39	447,858.8	3,127,911.0
CSSC1NG	1-Hour	100	1987	2.72	449,500.0	3,128,000.0
CSSC1NG		100	1988	2.78	446,700.0	3,129,000.0
CSSC1NG		100	1989	2.75	446,000.0	3,128,000.0
CSSC1NG		100	1990	2.72	449,000.0	3,129,000.0
CSSC1NG		100	1991	9.72	447,700.0	3,128,000.0
CSSC1FO	1-Hour	100	1987	10.38	449,500.0	3,128,000.0
CSSC1FO		100	1988	10.61	446,700.0	3,129,000.0
CSSC1FO		100	1989	11.21	449,000.0	3,127,000.0
CSSC1FO		100	1990	10.38	449,000.0	3,129,000.0
CSSC1FO		100	1991	38.47	447,700.0	3,128,000.0



Table 4-4
ISCST3 Model Predicted Maximum 8-Hour Concentrations of CO

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	UTM Location	
					East (m)	North (m)
CSCC1NG	8-Hour	100	1987	4.72	448,500.0	3,126,600.0
CSCC7NG		70		38.68	450,000.0	3,127,000.0
CSCC5NG		50		53.29	448,500.0	3,127,200.0
CSCC1NG		100	1988	4.42	446,500.0	3,128,800.0
CSCC7NG		70		49.02	447,891.2	3,127,873.0
CSCC5NG		50		135.64	447,826.6	3,127,864.0
CSCC1NG		100	1989	5.05	445,500.0	3,127,500.0
CSCC7NG		70		42.55	445,500.0	3,127,500.0
CSCC5NG		50		55.39	448,500.0	3,128,800.0
CSCC1NG		100	1990	4.63	449,500.0	3,127,000.0
CSCC7NG		70		38.58	449,000.0	3,127,000.0
CSCC5NG		50		57.69	447,700.0	3,128,000.0
CSCC1NG		100	1991	4.30	447,000.0	3,129,500.0
CSCC7NG		70		55.56	447,858.8	3,127,911.0
CSCC5NG		50		166.68	447,858.8	3,127,911.0
CSCC1FO	8-Hour	100	1987	67.24	451,500.0	3,126,500.0
CSCC7FO		70		91.69	448,500.0	3,126,000.0
CSCC5FO		50		103.04	448,500.0	3,126,000.0
CSCC1FO		100	1988	73.19	448,100.0	3,129,000.0
CSCC7FO		70		88.90	448,000.0	3,128,800.0
CSCC5FO		50		159.80	447,891.2	3,127,873.0
CSCC1FO		100	1989	69.77	449,500.0	3,130,000.0
CSCC7FO		70		97.77	445,000.0	3,127,500.0
CSCC5FO		50		109.77	445,000.0	3,127,500.0
CSCC1FO		100	1990	61.41	450,000.0	3,126,500.0
CSCC7FO		70		81.27	445,500.0	3,128,000.0
CSCC5FO		50		92.64	445,500.0	3,128,000.0
CSCC1FO		100	1991	62.52	448,000.0	3,130,500.0
CSCC7FO		70		85.22	448,000.0	3,130,000.0
CSCC5FO		50		177.67	447,858.8	3,127,911.0
CSSC1NG	8-Hour	100	1987	0.52	446,000.0	3,127,000.0
CSSC1NG		100	1988	0.54	446,500.0	3,128,800.0
CSSC1NG		100	1989	0.56	447,000.0	3,129,500.0
CSSC1NG		100	1990	0.45	446,500.0	3,126,500.0
CSSC1NG		100	1991	1.23	447,700.0	3,128,000.0
CSSC1FO	8-Hour	100	1987	2.00	446,000.0	3,127,000.0
CSSC1FO		100	1988	2.08	446,500.0	3,128,800.0
CSSC1FO		100	1989	2.14	447,000.0	3,129,500.0
CSSC1FO		100	1990	2.40	446,500.0	3,126,500.0
CSSC1FO		100	1991	4.86	447,700.0	3,128,000.0
CSSC1FO		100				



Table 4-5
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM₁₀

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	UTM Location	
					East (m)	North (m)
PACC1	Annual	100	1987	0.03	444,500.0	3,126,000.0
PACC7		70		0.04	444,500.0	3,126,000.0
PACC5		50		0.05	444,500.0	3,126,000.0
PACC1		100	1988	0.03	444,500.0	3,126,000.0
PACC7		70		0.04	445,500.0	3,126,500.0
PACC5		50		0.05	445,500.0	3,126,500.0
PACC1		100	1989	0.03	448,000.0	3,130,500.0
PACC7		70		0.04	448,000.0	3,130,500.0
PACC5		50		0.05	448,000.0	3,130,000.0
PACC1		100	1990	0.04	444,000.0	3,125,500.0
PACC7		70		0.05	445,000.0	3,126,000.0
PACC5		50		0.05	445,350.0	3,126,350.0
PACC1		100	1991	0.04	447,500.0	3,131,000.0
PACC7		70		0.04	447,500.0	3,130,500.0
PACC5		50		0.05	447,500.0	3,130,500.0
PASC1	Annual	100	1987	0.003	433,500.0	3,120,000.0
PASC1		100	1988	0.004	433,500.0	3,119,000.0
PASC1		100	1989	0.003	448,500.0	3,140,000.0
PASC1		100	1990	0.004	435,500.0	3,120,000.0
PASC1		100	1991	0.003	447,500.0	3,139,000.0



Table 4-6
ISCST3 Model Predicted Maximum 24-Hour Concentrations of PM/PM₁₀

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m³)	UTM Location	
					East (m)	North (m)
PSCC1NG	24-Hour	100	1987	0.29	447,900.0	3,128,800.0
PSCC7NG		70		0.35	451,000.0	3,126,500.0
PSCC5NG		50		0.42	451,000.0	3,126,500.0
PSCC1NG		100	1988	0.31	446,000.0	3,125,500.0
PSCC7NG		70		0.43	447,891.2	3,127,873.0
PSCC5NG		50		1.39	447,891.2	3,127,873.0
PSCC1NG		100	1989	0.33	445,500.0	3,126,500.0
PSCC7NG		70		0.40	446,500.0	3,127,100.0
PSCC5NG		50		0.47	446,500.0	3,127,100.0
PSCC1NG		100	1990	0.31	444,000.0	3,125,500.0
PSCC7NG		70		0.39	444,000.0	3,125,500.0
PSCC5NG		50		0.45	448,100.0	3,129,000.0
PSCC1NG		100	1991	0.33	449,500.0	3,127,000.0
PSCC7NG		70		0.49	447,858.8	3,127,911.0
PSCC5NG		50		1.27	447,858.8	3,127,911.0
PSCC1FO	24-Hour	100	1987	0.70	445,000.0	3,129,000.0
PSCC7FO		70		1.08	452,000.0	3,126,000.0
PSCC5FO		50		1.44	452,000.0	3,126,000.0
PSCC1FO		100	1988	0.80	448,100.0	3,129,000.0
PSCC7FO		70		1.21	445,500.0	3,125,000.0
PSCC5FO		50		2.10	447,891.2	3,127,873.0
PSCC1FO		100	1989	0.83	445,500.0	3,126,500.0
PSCC7FO		70		1.22	445,500.0	3,126,500.0
PSCC5FO		50		1.53	445,500.0	3,126,500.0
PSCC1FO		100	1990	0.74	441,500.0	3,124,000.0
PSCC7FO		70		1.15	443,000.0	3,125,000.0
PSCC5FO		50		1.48	443,000.0	3,125,000.0
PSCC1FO		100	1991	0.73	447,500.0	3,131,500.0
PSCC7FO		70		1.24	450,000.0	3,127,000.0
PSCC5FO		50		2.33	447,858.5	3,127,911.0
PSSC1NG	24-Hour	100	1987	0.03	452,500.0	3,114,000.0
PSSC1NG		100	1988	0.04	446,500.0	3,128,800.0
PSSC1NG		100	1989	0.04	447,000.0	3,129,500.0
PSSC1NG		100	1990	0.04	433,500.0	3,137,000.0
PSSC1NG		100	1991	0.07	447,700.0	3,128,000.0
PSSC1FO	24-Hour	100	1987	0.19	461,500.0	3,121,000.0
PSSC1FO		100	1988	0.18	446,500.0	3,128,800.0
PSSC1FO		100	1989	0.21	447,000.0	3,129,500.0
PSSC1FO		100	1990	0.22	446,500.0	3,126,500.0
PSSC1FO		100	1991	0.36	447,700.0	3,128,000.0
PSSC1FO		100				



Table 4-7
Comparison of Maximum Predicted Impacts with the PSD Class II
Significant Impact Levels and the PSD De Minimis Monitoring Levels

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu\text{g}/\text{m}^3$)	PSD Class II Significant Impact Level	PSD De Minimis Monitoring Level
NO _x	Annual	0.47	1	14
CO	1-Hour	1,421.39	2,000	-
	8-Hour	177.67	500	575
PM/PM ₁₀	Annual	0.06	1	-
	24-Hour	2.33	5	10
VOC (Ozone)	N/A	45.2 tpy*	N/A	100 tpy

*Ozone preconstruction monitoring applicability based on an annualized Unit 3 emission rate assuming 720 hours of distillate fuel oil firing and 8,040 hours of natural gas firing during base load (100 percent) conditions at 72° F ambient temperature, as well as emissions from the distillate fuel oil storage tank.



5.0 Additional and Class I Area Impact Analyses

The following sections discuss the Unit 3 impacts on commercial, residential, and industrial growth, vegetation and soils, visibility, and nearby Class I areas.

5.1 Commercial, Residential, and Industrial Growth

Unit 3 is within the Cane Island Power Park (Power Park) which is located within an unincorporated area of Osceola County. There will be a increase in the local labor force during the construction phase of Unit 3, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the Power Park vicinity.

It is anticipated that most of the labor force during the construction phase will commute from nearby communities. The electrical generating capacity created by Unit 3 will not have a significant effect upon the industrial growth in the immediate area considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. The net number of new, permanent jobs which will be created by the Project is estimated to be two. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of Unit 3 will be very small, compared to the overall population size of the surrounding area.

5.2 Vegetation and Soils

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the Unit 3 impacts on soils and vegetation will be minimal.

The National Ambient Air Quality Standards (NAAQS) were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public



welfare also encompasses vegetation and soils. Specifically, ambient concentrations of NO_x , CO, and PM/PM_{10} below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutants which triggered an additional impact analysis include NO_x , CO, and PM/PM_{10} . The modeled impacts were compared to the secondary NAAQS as the basis for assessing cumulative impacts. The modeling in Section 4.0 showed that the NO_x , CO, and PM/PM_{10} impacts are below the NAAQS. The impacts are even less than the much lower significant impact level thresholds. Because Unit 3 emissions do not even significantly impact the NAAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Visibility Impairment Analysis

The additional impact analysis requirements of a PSD permit application are concerned with visibility impairment within the Unit 3 impact area. The general components of a visibility impairment analysis include:

- Determine the visual quality of the area.
- Determine the potential for visibility impairment with a screening level assessment.
- If warranted, conduct a more in-depth analysis of the visibility impairment potential.

5.3.1 Visual Quality of the Area

The Power Park is located in the central section of the Florida peninsula, immediately surrounded by lakes and swamp land. The climate is characterized as nearly tropical with warm temperatures and abundant moisture. The high relative humidity and coastal influence generally result in moderate visibility with relatively low background visual ranges.

5.3.2 Visual Impairment Screening Assessment

A visibility impairment screening analysis was conducted for the nearest Class I Area to the Power Park to provide a conservative indication of the perceptibility of plumes from the proposed emission source. The nearest Class I Area is the Chassahowitzka National Wildlife Refuge located approximately 105 km northwest of the Power Park.

The analysis was performed in accordance with EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015, September 1988, hereinafter referred to as the Workbook), using the VISCREEN model. In accordance with Workbook visual



screening procedures, the VISCREEN plume visual impact screening model was used with default worst-case Level-1 visual screening parameters using the maximum estimated emission rates of NO_x and PM/PM_{10} for distillate oil firing as presented in Table 2-1.

The report output of the VISCREEN model is included in Attachment 5. Results of the Level-1 visual screening analysis indicate that the conservative screening criteria are not exceeded. Therefore, further analyses to quantify the extent of any reductions in visibility due to Unit 3 emissions are not warranted based on the results of the Level-1 visual impairment screening analysis.

5.4 Class I Area Impact Analysis

Class I areas are afforded special attention based on the value of natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine the potential for deteriorating the particular properties that make these areas worthy of a Class I designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Power Park is located approximately 105 km southeast from the closest boundary of the Chassahowitzka Wilderness Area. The area is designated as mandatory Class I area, under the jurisdiction of the Fish and Wildlife Service as the Federal Land Manager (FLM). The FLM typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing a project's impact on air the quality and visibility/regional haze.

5.4.1 Class I Air Quality Impact Analysis

Air dispersion modeling was performed to determine the Unit 3 maximum predicted impact at the Class I area. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted impacts of NO_x and PM/PM_{10} at a receptor placed at the closest boundary point of the Power Park. The 5 year meteorological data set, model options, and operating scenarios used in the refined modeling analysis presented in Section 4.0, were also used in the Class I air quality impact analyses.

5.4.1.1 Class I Significant Impact Level Modeling Results. Tables 5-1 through 5-3 present the results of the Class I area air dispersion modeling for each pollutant and applicable averaging period. The maximum predicted concentrations are presented for each



Table 5-1
ISCST3 Model Predicted Maximum Annual Concentrations
of NO_x at Chassahowitzka

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m ³)	Class I Increment (µg/m ³)	Class I SIL* (µg/m ³)
NACC1	Annual	100	1987	0.009	2.5	0.1
NACC7		70		0.008	2.5	0.1
NACC5		50		0.016	2.5	0.1
NACC1		100	1988	0.009	2.5	0.1
NACC7		70		0.008	2.5	0.1
NACC5		50		0.017	2.5	0.1
NACC1		100	1989	0.012	2.5	0.1
NACC7		70		0.011	2.5	0.1
NACC5		50		0.022	2.5	0.1
NACC1		100	1990	0.011	2.5	0.1
NACC7		70		0.009	2.5	0.1
NACC5		50		0.019	2.5	0.1
NACC1		100	1991	0.010	2.5	0.1
NACC7		70		0.009	2.5	0.1
NACC5		50		0.018	2.5	0.1
NASC1	Annual	100	1987	0.004	2.5	0.1
NASC1		100	1988	0.004	2.5	0.1
NASC1		100	1989	0.005	2.5	0.1
NASC1		100	1990	0.005	2.5	0.1
NASC1		100	1991	0.004	2.5	0.1

*Calculated as 4 percent of the PSD Class I Increment.



Table 5-2
ISCST3 Model Predicted Maximum Annual Concentrations
of PM/PM₁₀ at Chassahowitzka

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)	Class I Increment ($\mu\text{g}/\text{m}^3$)	Class I SIL* ($\mu\text{g}/\text{m}^3$)
PACC1	Annual	100	1987	0.002	4	0.16
PACC7		70		0.002	4	0.16
PACC5		50		0.002	4	0.16
PACC1		100	1988	0.002	4	0.16
PACC7		70		0.002	4	0.16
PACC5		50		0.002	4	0.16
PACC1		100	1989	0.002	4	0.16
PACC7		70		0.003	4	0.16
PACC5		50		0.003	4	0.16
PACC1		100	1990	0.002	4	0.16
PACC7		70		0.002	4	0.16
PACC5		50		0.003	4	0.16
PACC1		100	1991	0.002	4	0.16
PACC7		70		0.002	4	0.16
PACC5		50		0.002	4	0.16
PASC1	Annual	100	1987	0.001	4	0.16
PASC1		100	1988	0.001	4	0.16
PASC1		100	1989	0.001	4	0.16
PASC1		100	1990	0.001	4	0.16
PASC1		100	1991	0.001	4	0.16

*Calculated as 4 percent of the PSD Class I Increment.



Table 5-3
ISCST3 Model Predicted Maximum 24-Hour Concentrations
of PM/PM₁₀ at Chassahowitzka

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m ³)	Class I Increment (µg/m ³)	Class I SIL* (µg/m ³)
PSCC1NG	24-Hour	100	1987	0.024	8	0.32
PSCC7NG		70		0.026	8	0.32
PSCC5NG		50		0.027	8	0.32
PSCC1NG		100	1988	0.021	8	0.32
PSCC7NG		70		0.021	8	0.32
PSCC5NG		50		0.022	8	0.32
PSCC1NG		100	1989	0.025	8	0.32
PSCC7NG		70		0.029	8	0.32
PSCC5NG		50		0.030	8	0.32
PSCC1NG		100	1990	0.033	8	0.32
PSCC7NG		70		0.035	8	0.32
PSCC5NG		50		0.036	8	0.32
PSCC1NG		100	1991	0.029	8	0.32
PSCC7NG		70		0.030	8	0.32
PSCC5NG		50		0.031	8	0.32
PSCC1FO	24-Hour	100	1987	0.083	8	0.32
PSCC7FO		70		0.112	8	0.32
PSCC5FO		50		0.134	8	0.32
PSCC1FO		100	1988	0.085	8	0.32
PSCC7FO		70		0.106	8	0.32
PSCC5FO		50		0.123	8	0.32
PSCC1FO		100	1989	0.086	8	0.32
PSCC7FO		70		0.115	8	0.32
PSCC5FO		50		0.138	8	0.32
PSCC1FO		100	1990	0.120	8	0.32
PSCC7FO		70		0.157	8	0.32
PSCC5FO		50		0.186	8	0.32
PSCC1FO		100	1991	0.110	8	0.32
PSCC7FO		70		0.141	8	0.32
PSCC5FO		50		0.167	8	0.32
PSSC1NG	24-Hour	100	1987	0.008	8	0.32
PSSC1NG		100	1988	0.010	8	0.32
PSSC1NG		100	1989	0.010	8	0.32
PSSC1NG		100	1990	0.011	8	0.32
PSSC1NG		100	1991	0.012	8	0.32
PSSC1FO	24-Hour	100	1987	0.039	8	0.32
PSSC1FO		100	1988	0.050	8	0.32
PSSC1FO		100	1989	0.046	8	0.32
PSSC1FO		100	1990	0.054	8	0.32
PSSC1FO		100	1991	0.058	8	0.32

*Calculated as 4 percent of the PSD Class I Increment.



year and compared with the Class I SILs. The Class I SILs were calculated as 4 percent of the PSD Class I increments. As the results indicated, the maximum predicted concentrations of NO_x and PM/PM₁₀ are considerably less than the applicable Class I SILs.

5.4.2 Regional Haze Analysis

A regional haze analysis was performed to evaluate the potential for a visibility impairment (significant increase in uniform haze) at the Chassahowitzka Class I area. Visibility impairment occurs as a result of the scattering and absorption of light due to particles and gasses in the atmosphere. On a local-scale, visual impairment is generally defined as a plume or layered haze from a single source or small group of sources. This phenomena, known as regional haze, impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen.

The regional haze analysis was performed in accordance with guidance published in the Interagency Workgroup on Air Quality Modeling (IWAQM) (EPA-454/R-93-015) document, as well as technical guidance and an example provide by the NPS. The methodology, input, and results are described in the following subsections.

5.4.2.1 Analysis Methodology and Input. The reduction of image forming light per unit distance in the atmosphere due to the sum of scattering (light redirected away from the sight path) and adsorption (light captured by aerosols and turned into heat energy) is represented by a term known as the extinction coefficient (b_{ext}). Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level (usually set at 2% difference between target and sky), a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere. With the aforementioned assumptions, extinction can be related to visual range with the following equation:

$$b_{ext} = \frac{3.912}{vr}$$

Where: b_{ext} = extinction coefficient, 1/km



vr = visual range, km

A uniform incremental change in b_{ext} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a change in b_{ext} or, percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, the Level I screening analysis is satisfied, and no further analysis is required. The percent change in extinction is calculated as follows:

$$= \frac{b_{exts}}{b_{extb}} (100\%)$$

Where: b_{exts} = source extinction coefficient
 b_{extb} = background extinction coefficient

The source extinction coefficient is calculated as a function of the source's NO_x , SO_2 , and fine PM model predicted concentration levels at the Class I area, as well as the ambient relative humidity. Although relative humidity does not by itself cause visibility to be degraded, some particles in the atmosphere accumulate water and grow to just the right size to be very efficient at scattering light. Based on guidance from the IWAQM document and NPS, the source extinction coefficient may be calculated as follows:

$$b_{exts} = (0.003)(RH_f)[(NH_4)_2SO_4 + NH_4NO_3] + (0.003)(PM_{fine})$$

Where: RH_f = relative humidity correction factor to adjust for the effects of ambient humidity on light extinction calculations.

$(NH_4)_2SO_4$ = concentration of ammonium sulfate in units of $\mu g/m^3$, calculated as $(SO_2 \text{ 24-h concentration, } \mu g/m^3)(1.5)(1.375)$, assuming all SO_2 converts to ammonium sulfate.



NH_4NO_3 = concentration of ammonium nitrate in units of $\mu\text{g}/\text{m}^3$, calculated as $(\text{NO}_x \text{ 24-h concentration, } \mu\text{g}/\text{m}^3)(1.35)(1.29)$, assuming all NO_x converts to ammonium nitrate.

PM_{fine} = concentration of primary fine particulate in units of $\mu\text{g}/\text{m}^3$, calculated as $(\text{PM}/\text{PM}_{10} \text{ 24-h concentration, } \mu\text{g}/\text{m}^3)(1.0)$, assuming all PM/PM_{10} is primary fine particulate.

The background extinction coefficient is calculated as a function of the estimated visual range as follows:

$$b_{\text{extb}} = \frac{3.912}{vr}$$

Where: b_{extb} = background extinction coefficient, 1/km
 vr = background visual range, km

5.4.2.2 Regional Haze Calculations and Results. Based on the aforementioned methodology, the percent change in extinction was calculated for each of the operating scenarios and 5 years of meteorological data assessed in the refined modeling analysis presented in Section 4.0. The results of the analysis are presented in a spreadsheet included as Attachment 6. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predict 24-hour impacts of NO_x and PM/PM_{10} at a receptor placed at the closest boundary point of the Power Park. Actual relative humidity data corresponding to the date of the maximum predicted NO_x impacts for each scenario were used in the regional haze calculations.

As the results in Attachment 6 indicate, the percent change in extinction for each year and operating scenario is less than screening threshold for Level I analyses of 5 percent. Therefore, further analysis of potential visibility impairment is not warranted.

Attachments

Attachment 1
(Turbine Vendor Data)

KUA Cane Island Unit 3
WEC 501F 1x1 Combined Cycle

* 100 Percent Load - Natural Gas*					
Case Name	Case 1	Case 2	Case 3	Case 4	Case 5
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off
Ambient Temperature	19	72	72	102	102
Ambient Relative Humidity	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	66.7	72	84.7	102
CTG Compr. Inlet Relative Humidity, %	55	96	74	92	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75
Inlet Loss, in. H2O	3.9	4.0	4.0	3.8	3.7
Exhaust Loss, in. H2O	14.0	13.5	13.2	12.4	11.7
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	Base	Base
Number of CTGs	1	1	1	1	1
Gross CTG Output, kW	185,000	177,100	173,750	166,650	156,090
Gross CTG Heat Rate, Btu/kWh (LHV)	9,040	9,235	9,270	9,395	9,540
CTG Heat Input, MBtu/h (LHV)	1,672.40	1,635.52	1,610.66	1,565.68	1,489.10
CTG Heat Input, MBtu/h (HHV)	1,855.50	1,814.59	1,787.00	1,737.10	1,652.13
CTG Fuel Flow, lb/h	79,710	77,960	76,770	74,630	70,980
CTG Water Injection Flow, lb/h	0	0	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0	0	0
Injection Ratio	0.000	0.000	0.000	0.000	0.000
CTG Exhaust Flow, lb/h	3,604,762	3,505,556	3,469,805	3,350,992	3,236,818
CTG Exhaust Temperature, F	1,077	1,120	1,123	1,138	1,148
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0
Stack Exit Temperature, F	182	188	187	189	187
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	64.9	64.2	63.4	61.8	59.4

* 100 Percent Load - Natural Gas*					
Case Name	Case 1	Case 2	Case 3	Case 4	Case 5
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRS G Duct Firing On/Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)					
O2	12.50%	12.12%	12.20%	11.84%	12.07%
CO2	3.88%	3.88%	3.86%	3.86%	3.81%
H2O	7.75%	9.61%	9.41%	11.09%	10.40%
N2	74.93%	73.47%	73.61%	72.30%	72.80%
Ar	0.94%	0.92%	0.92%	0.91%	0.91%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)					
NOx, ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0
NOx, lb/h as NO2	101.1	98.9	97.4	94.7	90.1
CO, ppmvd	31.0	31.6	31.4	32.0	31.4
CO, ppmvw	28.6	28.6	28.5	28.5	28.1
CO, ppmvd @ 15% O2	25.0	25.0	25.0	25.0	25.0
CO, lb/h	101.5	99.3	97.8	95.1	90.4
UHC, ppmvd	6.61	6.75	6.70	6.83	6.69
UHC, ppmvw	6.10	6.10	6.07	6.07	5.99
UHC, ppmvd @ 15% O2	5.33	5.33	5.33	5.33	5.33
UHC, lb/h as CH4	12.39	12.14	11.94	11.61	11.04
VOC, ppmvd	4.97	5.06	5.03	5.12	5.02
VOC, ppmvw	4.58	4.57	4.55	4.55	4.50
VOC, ppmvd @ 15% O2	4.00	4.00	4.00	4.00	4.00
VOC, lb/h as CH4	9.30	9.10	8.96	8.71	8.28
SO2, ppmvd	0.14	0.14	0.14	0.14	0.14
SO2, ppmvw	0.13	0.13	0.12	0.12	0.12
SO2, lb/h	1.02	1.00	0.98	0.95	0.91
Particulates (TSP = PM10), lb/h (dry filterables only)	16.80	16.10	16.00	15.00	15.00
CTG Fuel LHV, Btu/lb					
	20,980	20,980	20,980	20,980	20,980
CTG Fuel HHV, Btu/lb					
	23,277	23,277	23,277	23,277	23,277
HHV/LHV Ratio					
	1.1095	1.1095	1.1095	1.1095	1.1095
CTG Fuel Composition (Ultimate Analysis by Weight)					
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	74.043570%	74.043570%	74.043570%
H2	24.256660%	24.256660%	24.256660%	24.256660%	24.256660%
N2	0.575950%	0.575950%	0.575950%	0.575950%	0.575950%
O2	1.123180%	1.123180%	1.123180%	1.123180%	1.123180%
S	0.000640%	0.000640%	0.000640%	0.000640%	0.000640%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis					
Molecular Wt, lb/mol	28.47	28.27	28.29	28.10	28.17
Gas Constant, ft-lbf/lbm-R	54.262	54.655	54.616	54.974	54.836
Specific Volume, ft ³ /lb	38.19	39.59	39.67	40.38	40.60
Exhaust Gas Flow, acfm	2,294,431	2,313,083	2,294,119	2,255,218	2,190,247
Specific Volume, scf/lb	13.32	13.42	13.41	13.50	13.47
Exhaust Gas Flow, scfm	800,257	784,076	775,501	753,973	726,666
Exhaust Gas Flow, lb/h	3,604,762	3,505,556	3,469,805	3,350,992	3,236,818

KUA Cane Island Unit 3
WEC 501F 1x1 Combined Cycle

* 100 Percent Load - Natural Gas*					
Case Name	Case 1	Case 2	Case 3	Case 4	Case 5
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSO Duct Firing On/Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)					
Ar	0.94%	0.92%	0.92%	0.91%	0.91%
CO2	3.88%	3.88%	3.86%	3.86%	3.81%
H2O	7.75%	9.61%	9.41%	11.09%	10.40%
N2	74.93%	73.47%	73.61%	72.30%	72.80%
O2	12.50%	12.12%	12.20%	11.84%	12.07%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)					
Molecular Wt, lb/mol	28.47	28.27	28.29	28.10	28.17
Gas Constant, ft-lb/lbm-R	54.262	54.655	54.616	54.974	54.836
Specific Volume, ft ³ /lb	16.50	16.77	16.73	16.90	16.80
Exhaust Gas Flow, acfm	991,310	979,803	967,497	943,863	906,309
Specific Volume, scf/lb	13.32	13.42	13.41	13.50	13.47
Exhaust Gas Flow, scfm	800,257	784,076	775,501	753,973	726,666
Exhaust Gas Flow, lb/h	3,604,762	3,505,556	3,469,805	3,350,992	3,236,818
Emissions (at Stack exit)					
NOx, ppmvd @15% O2 without SCR	15.0	15.0	15.0	15.0	15.0
NOx, lb/h as NO2 without SCR	101.1	98.9	97.4	94.7	90.1
NOx, ppmvd @15% O2 with SCR	4.0	4.0	4.0	4.0	4.0
NOx, lb/h as NO2 with SCR	26.7	26.1	25.7	25.0	23.8
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	24.7	24.2	23.8	23.1	22.0
CO, ppmvd without Catalyst	31.0	31.6	31.4	32.0	31.4
CO, lb/h without Catalyst	101.5	99.3	97.8	95.1	90.4
CO, ppmvd @ 15% O2 without Catalyst	25.0	25.0	25.0	25.0	25.0
CO, ppmvd with Catalyst	31.0	31.6	31.4	32.0	31.4
CO, lb/h with Catalyst	101.5	99.3	97.8	95.1	90.4
CO, ppmvd @ 15% O2 with Catalyst	25.0	25.0	25.0	25.0	25.0
SO2, ppmvd	0.14	0.14	0.14	0.14	0.14
SO2, ppmvw	0.13	0.13	0.12	0.12	0.12
SO2, lb/h	1.02	1.00	0.98	0.95	0.91
UHC, ppmvd	6.6	6.7	6.7	6.8	6.7
UHC, ppmvw	6.1	6.1	6.1	6.1	6.0
UHC, ppmvd @ 15% O2	5.3	5.3	5.3	5.3	5.3
UHC, lb/h as CH4	12.4	12.1	11.9	11.6	11.0
VOC, ppmvd	5.0	5.1	5.0	5.1	5.0
VOC, ppmvw	4.6	4.6	4.6	4.6	4.5
VOC, ppmvd @ 15% O2	4.0	4.0	4.0	4.0	4.0
VOC, lb/h as CH4	9.3	9.1	9.0	8.7	8.3
Particulates (TSP = PM10), lb/h (dry filterables only)	16.8	16.1	16.0	15.0	15.0

Notes:

1. Values shown above are for one combustion turbine/HRSO unit only.
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100scf for illustration purposes only.
3. 73% effective SCR and no CO catalyst.
4. Particulates are per EPA Method 201A/202 (front and back half) and include H2SO4 mist.
5. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA.

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KUA Cane Island Unit 3
WEC 501F 1x1 Combined Cycle

Case Name	* 70 & 50 Percent Load - Natural Gas *					
	Case 6 WEC 501F DLN/15 ppm Natural Gas 70 Percent WEC 05/27/98 Off Off	Case 7 WEC 501F DLN/45 ppm Natural Gas 50 Percent WEC 05/27/98 Off Off	Case 8 WEC 501F DLN/15 ppm Natural Gas 70 Percent WEC 05/27/98 Off Off	Case 9 WEC 501F DLN/45 ppm Natural Gas 50 Percent WEC 05/27/98 Off Off	Case 10 WEC 501F DLN/15 ppm Natural Gas 70 Percent WEC 05/27/98 Off Off	Case 11 WEC 501F DLN/45 ppm Natural Gas 50 Percent WEC 05/27/98 Off Off
Ambient Temperature	19	19	72	72	102	102
Ambient Relative Humidity	55	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	19	72	72	102	102
CTG Compr. Inlet Relative Humidity, %	55	55	74	74	45	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75	75
Inlet Loss, in. H2O	2.5	2.4	2.5	2.3	2.4	2.2
Exhaust Loss, in. H2O	9.6	8.0	8.5	7.0	7.8	6.4
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
Number of CTGs	1	1	1	1	1	1
Gross CTG Output, kW	143,390	102,030	121,270	86,190	108,860	77,310
Gross CTG Heat Rate, Btu/kWh (LHV)	9,790	10,638	10,351	11,421	10,731	11,908
CTG Heat Input, MBtu/h (LHV)	1,403.79	1,085.40	1,255.27	984.38	1,168.18	920.61
CTG Heat Input, MBtu/h (HHV)	1,557.48	1,204.24	1,392.70	1,092.16	1,296.08	1,021.40
CTG Fuel Flow, lb/h	66,910	51,730	59,830	46,920	55,680	43,880
CTG Water Injection Flow, lb/h	0	0	0	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
Injection Ratio	0.000	0.000	0.000	0.000	0.000	0.000
CTG Exhaust Flow, lb/h	2,890,793	2,814,086	2,725,887	2,597,939	2,623,298	2,476,057
CTG Exhaust Temperature, F	1,156	977	1,156	1,023	1,156	1,041
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0	0
Stack Exit Temperature, F	175	185	181	186	185	188
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	51.5	50.8	49.3	47.2	47.9	45.4

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSG Duct Firing On/Off	* 70 & 50 Percent Load - Natural Gas *					
	Case 6 WEC 501F DLN/15 ppm Natural Gas 70 Percent WEC 05/27/98 Off Off	Case 7 WEC 501F DLN/45 ppm Natural Gas 50 Percent WEC 05/27/98 Off Off	Case 8 WEC 501F DLN/15 ppm Natural Gas 70 Percent WEC 05/27/98 Off Off	Case 9 WEC 501F DLN/45 ppm Natural Gas 50 Percent WEC 05/27/98 Off Off	Case 10 WEC 501F DLN/15 ppm Natural Gas 70 Percent WEC 05/27/98 Off Off	Case 11 WEC 501F DLN/45 ppm Natural Gas 50 Percent WEC 05/27/98 Off Off
CTG Exhaust Analysis (Volume Basis - Wet)						
O2	12.12%	13.91%	12.26%	13.72%	12.34%	13.64%
CO2	4.06%	3.24%	3.83%	3.16%	3.69%	3.09%
H2O	8.09%	6.49%	9.35%	8.06%	10.17%	9.02%
N2	74.79%	75.42%	73.63%	74.13%	72.89%	73.33%
Ar	0.94%	0.95%	0.92%	0.93%	0.92%	0.92%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)						
NOx, ppmvd @ 15% O2	15.0	45.0	15.0	45.0	15.0	45.0
NOx, lb/h as NO2	85.0	195.8	76.1	177.7	70.9	168.2
CO, ppmvd	260.6	306.3	249.2	304.1	242.3	300.4
CO, ppmvw	239.6	288.4	225.9	279.6	217.7	273.3
CO, ppmvd @ 15% O2	200.0	300.0	200.0	300.0	200.0	300.0
CO, lb/h	681.8	790.6	609.6	717.1	567.3	670.7
UHC, ppmvd	6.95	27.23	6.64	27.03	6.48	26.70
UHC, ppmvw	6.39	25.46	6.02	24.85	5.80	24.30
UHC, ppmvd @ 15% O2	5.33	26.67	5.33	26.67	5.33	26.67
UHC, lb/h as CH4	10.42	40.26	9.30	36.51	8.66	34.15
VOC, ppmvd	5.21	20.42	4.98	20.28	4.85	20.02
VOC, ppmvw	4.79	19.09	4.52	18.64	4.35	18.22
VOC, ppmvd @ 15% O2	4.00	20.00	4.00	20.00	4.00	20.00
VOC, lb/h as CH4	7.81	30.19	6.98	27.38	6.50	25.61
SO2, ppmvd	0.14	0.11	0.14	0.11	0.13	0.11
SO2, ppmvw	0.13	0.10	0.12	0.10	0.12	0.10
SO2, lb/h	0.88	0.66	0.77	0.60	0.71	0.56
Particulates (TSP = PM10), lb/h (dry filterables only)	15.00	15.00	15.00	15.00	15.00	15.00
CTG Fuel LHV, Btu/lb	20,980	20,980	20,980	20,980	20,980	20,980
CTG Fuel HHV, Btu/lb	23,277	23,277	23,277	23,277	23,277	23,277
HHV/LHV Ratio	1.1095	1.1095	1.1095	1.1095	1.1095	1.1095
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	74.043570%	74.043570%	74.043570%	74.043570%
H2	24.256680%	24.256680%	24.256680%	24.256680%	24.256680%	24.256680%
N2	0.575950%	0.575950%	0.575950%	0.575950%	0.575950%	0.575950%
O2	1.123180%	1.123180%	1.123180%	1.123180%	1.123180%	1.123180%
S	0.000640%	0.000640%	0.000640%	0.000640%	0.000640%	0.000640%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.45	28.55	28.29	28.37	28.19	28.26
Gas Constant, ft-lb/lbm-R	54.304	54.112	54.609	54.454	54.808	54.668
Specific Volume, ft³/lb	40.61	36.12	40.95	37.61	41.17	38.27
Exhaust Gas Flow, acfm	1,956,585	1,694,080	1,860,418	1,628,475	1,800,020	1,579,312
Specific Volume, scf/lb	13.34	13.29	13.41	13.37	13.48	13.42
Exhaust Gas Flow, scfm	642,720	623,320	609,236	578,907	588,493	553,811
Exhaust Gas Flow, lb/h	2,890,793	2,814,086	2,725,887	2,597,939	2,623,298	2,476,057

* 70 & 50 Percent Load - Natural Gas *						
Case Name	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/45 ppm	DLN/15 ppm	DLN/45 ppm	DLN/15 ppm	DLN/45 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
CTG Performance Reference	WEC 05/27/98	WEC 05/27/98	WEC 05/27/98	WEC 05/27/98	WEC 05/27/98	WEC 05/27/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.94%	0.95%	0.92%	0.93%	0.92%	0.92%
CO2	4.06%	3.24%	3.83%	3.16%	3.69%	3.09%
H2O	8.09%	6.49%	9.35%	8.06%	10.17%	9.02%
N2	74.79%	75.42%	73.83%	74.13%	72.89%	73.33%
O2	12.12%	13.91%	12.28%	13.72%	12.34%	13.64%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)						
Molecular Wt, lb/mol	28.45	28.55	28.29	28.37	28.19	28.26
Gas Constant, ft-lb/lbm-R	54.304	54.112	54.609	54.454	54.808	54.668
Specific Volume, ft ³ /lb	16.33	16.53	16.58	16.66	16.74	16.78
Exhaust Gas Flow, acfm	786,777	775,281	753,253	721,361	731,900	692,471
Specific Volume, scf/lb	13.34	13.29	13.41	13.37	13.46	13.42
Exhaust Gas Flow, scfm	642,720	623,320	608,236	578,907	588,493	553,811
Exhaust Gas Flow, lb/h	2,890,793	2,814,086	2,725,887	2,597,939	2,623,298	2,476,057
Emissions (at Stack exit)						
NOx, ppmvd @15% O2 without SCR	15.0	45.0	15.0	45.0	15.0	45.0
NOx, lb/h as NO2 without SCR	85.0	195.8	76.1	177.7	70.9	166.2
NOx, ppmvd @15% O2 with SCR	4.0	12.0	4.0	12.0	4.0	12.0
NOx, lb/h as NO2 with SCR	22.4	51.9	20.0	47.1	18.6	44.1
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	20.7	16.0	18.5	14.5	17.2	13.8
CO, ppmvd without Catalyst	260.6	306.3	249.2	304.1	242.3	300.4
CO, lb/h without Catalyst	681.8	790.6	609.6	717.1	567.3	670.7
CO, ppmvd @ 15% O2 without Catalyst	200.0	300.0	200.0	300.0	200.0	300.0
CO, ppmvd with Catalyst	260.6	306.3	249.2	304.1	242.3	300.4
CO, lb/h with Catalyst	681.8	790.6	609.6	717.1	567.3	670.7
CO, ppmvd @ 15% O2 with Catalyst	200.0	300.0	200.0	300.0	200.0	300.0
SO2, ppmvd	0.14	0.11	0.14	0.11	0.13	0.11
SO2, ppmw	0.13	0.10	0.12	0.10	0.12	0.10
SO2, lb/h	0.86	0.66	0.77	0.60	0.71	0.56
UHC, ppmvd	7.0	27.2	6.6	27.0	6.5	26.7
UHC, ppmw	6.4	25.5	6.0	24.9	5.8	24.3
UHC, ppmvd @ 15% O2	5.3	26.7	5.3	26.7	5.3	26.7
UHC, lb/h as CH4	10.4	40.3	9.3	36.5	8.7	34.1
VOC, ppmvd	5.2	20.4	5.0	20.3	4.8	20.0
VOC, ppmw	4.8	19.1	4.5	18.6	4.4	18.2
VOC, ppmvd @ 15% O2	4.0	20.0	4.0	20.0	4.0	20.0
VOC, lb/h as CH4	7.8	30.2	7.0	27.4	6.5	25.6
Particulates (TSP = PM10), lb/h (dry filterables only)	15.0	15.0	15.0	15.0	15.0	15.0
Notes:						
1. Values shown above are for one combustion turbine/HRSG unit only.						
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100scf for illustration purposes only.						
3. 73% effective SCR and no CO catalyst.						
4. Particulates are per EPA Method 201A/202 (front and back half) and include H2SO4 mist.						
5. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA.						
B&V Project 59140.0031						
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* 100 Percent Load - Duct Fired - NG & DO *

Case Name	Case 23	Case 24	Case 25	Case 26
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	On	Off	On	Off
HRS G Duct Firing On/Off	On	On	On	On
Ambient Temperature	102	102	102	102
Ambient Relative Humidity	45	45	45	45
CTG Compressor Inlet Temperature, F	84.7	102	84.7	102
CTG Compr. Inlet Relative Humidity, %	92	45	92	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75
Inlet Loss, in. H2O	3.8	3.7	3.8	3.7
Exhaust Loss, in. H2O	12.4	11.7	12.2	11.4
CTG Load Level (percent of Base Load)	Base	Base	Base	Base
Number of CTGs	1	1	1	1
Gross CTG Output, kW	166,650	156,090	160,210	149,700
Gross CTG Heat Rate, Btu/kWh (LHV)	9,395	9,540	9,720	9,890
CTG Heat Input, MBtu/h (LHV)	1,565.68	1,489.10	1,557.24	1,480.53
CTG Heat Input, MBtu/h (HHV)	1,737.10	1,652.13	1,662.73	1,580.82
CTG Fuel Flow, lb/h	74,630	70,980	83,790	79,660
CTG Water Injection Flow, lb/h	0	0	33,516	31,864
CTG Steam Injection Flow, lb/h	0	0	0	0
Injection Ratio	0.000	0.000	0.400	0.400
CTG Exhaust Flow, lb/h	3,350,992	3,236,818	3,393,166	3,276,886
CTG Exhaust Temperature, F	1,138	1,148	1,101	1,112
Duct Burner Heat Input, MBtu/h (LHV)	40.07	55.6	55.2	62.63
Duct Burner Heat Input, MBtu/h (HHV)	44.46	61.69	58.94	66.87
Stack Exit Temperature, F	187	184	279	275
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	61.7	59.2	70.5	67.6

* 100 Percent Load - Duct Fired - NG & DO *				
Case Name	Case 23	Case 24	Case 25	Case 26
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	On	Off	On	Off
HRSR Duct Firing On/Off	On	On	On	On
CTG Exhaust Analysis (Volume Basis - Wet)				
O2	11.84%	12.07%	11.98%	12.21%
CO2	3.86%	3.81%	5.03%	4.97%
H2O	11.09%	10.40%	9.92%	9.24%
N2	72.30%	72.80%	72.17%	72.67%
Ar	0.91%	0.91%	0.91%	0.91%
SO2	0.00001%	0.00001%	0.00109%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)				
NOx, ppmvd @ 15% O2	15.0	15.0	42.0	42.0
NOx, lb/h as NO2	94.7	90.1	268.0	254.8
CO, ppmvd	32.0	31.4	115.6	113.2
CO, ppmvw	28.5	28.1	104.1	102.8
CO, ppmvd @ 15% O2	25.0	25.0	90.0	90.0
CO, lb/h	95.1	90.4	348.3	331.2
UHC, ppmvd	6.83	6.69	12.84	12.58
UHC, ppmvw	6.07	5.99	11.57	11.42
UHC, ppmvd @ 15% O2	5.33	5.33	10.00	10.00
UHC, lb/h as CH4	11.61	11.04	22.17	21.07
VOC, ppmvd	5.12	5.02	12.84	12.58
VOC, ppmvw	4.55	4.50	11.57	11.42
VOC, ppmvd @ 15% O2	4.00	4.00	10.00	10.00
VOC, lb/h as CH4	8.71	8.28	22.17	21.07
SO2, ppmvd	0.14	0.14	12.15	11.90
SO2, ppmvw	0.12	0.12	10.94	10.80
SO2, lb/h	0.95	0.91	83.71	79.59
Particulates (TSP = PM10), lb/h (dry filterables only)	15.00	15.00	69.20	66.90
CTG Fuel LHV, Btu/lb				
	20,980	20,980	18,586	18,586
CTG Fuel HHV, Btu/lb				
	23,277	23,277	19,845	19,845
HHV/LHV Ratio				
	1.1095	1.1095	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)				
Ar	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	86.135000%	86.135000%
H2	24.256660%	24.256660%	13.800000%	13.800000%
N2	0.575950%	0.575950%	0.015000%	0.015000%
O2	1.123180%	1.123180%	0.000000%	0.000000%
S	0.000640%	0.000640%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis				
Molecular Wt, lb/mol	28.10	28.17	28.42	28.48
Gas Constant, ft-lbf/lbm-R	54.974	54.836	54.373	54.245
Specific Volume, ft³/lb	40.38	40.60	39.03	39.29
Exhaust Gas Flow, acfm	2,255,218	2,190,247	2,207,254	2,145,814
Specific Volume, scf/lb	13.50	13.47	13.35	13.32
Exhaust Gas Flow, scfm	753,973	726,666	754,979	727,469
Exhaust Gas Flow, lb/h	3,350,992	3,236,818	3,393,166	3,276,886

* 100 Percent Load - Duct Fired - NG & DO *				
Case Name	Case 23	Case 24	Case 25	Case 26
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	On	Off	On	Off
HRSR Duct Firing On/Off	On	On	On	On
Stack Exhaust Analysis (Volume Basis - Wet)				
Ar	0.91%	0.91%	0.91%	0.91%
CO2	3.95%	3.95%	5.21%	5.17%
H2O	11.27%	10.67%	10.08%	9.43%
N2	72.23%	72.70%	72.11%	72.60%
O2	11.64%	11.78%	11.70%	11.89%
SO2	0.00001%	0.00001%	0.00113%	0.00112%
Total	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)				
Molecular Wt, lb/mol	28.09	28.16	28.42	28.48
Gas Constant, ft-lbf/lbm-R	54.996	54.868	54.371	54.244
Specific Volume, ft ³ /lb	16.85	16.73	19.03	18.88
Exhaust Gas Flow, acfm	941,607	903,272	1,077,141	1,032,187
Specific Volume, scf/lb	13.51	13.47	13.35	13.32
Exhaust Gas Flow, scfm	754,962	727,261	755,640	728,217
Exhaust Gas Flow, lb/h	3,352,902	3,239,468	3,396,136	3,280,256
Emissions (at Stack exit)				
NOx, ppmvd @15% O2 without SCR	15.2	15.3	41.3	41.1
NOx, lb/h as NO2 without SCR	98.2	95.0	272.7	260.2
NOx, ppmvd @15% O2 with SCR	4.0	4.1	11.0	11.0
NOx, lb/h as NO2 with SCR	25.9	25.1	72.5	69.1
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	23.7	22.8	24.4	23.3
CO, ppmvd without Catalyst	33.5	33.5	117.7	115.6
CO, lb/h without Catalyst	99.5	96.6	354.2	337.8
CO, ppmvd @ 15% O2 without Catalyst	25.5	25.7	88.4	88.1
CO, ppmvd with Catalyst	33.5	33.5	117.7	115.6
CO, lb/h with Catalyst	99.5	96.6	354.2	337.8
CO, ppmvd @ 15% O2 with Catalyst	25.5	25.7	88.4	88.1
SO2, ppmvd	0.14	0.14	12.59	12.41
SO2, ppmvw	0.13	0.13	11.32	11.24
SO2, lb/h	0.98	0.94	86.68	82.95
UHC, ppmvd	8.4	8.9	14.9	15.0
UHC, ppmvw	7.5	8.0	13.4	13.6
UHC, ppmvd @ 15% O2	6.4	6.9	11.2	11.4
UHC, lb/h as CH4	14.3	14.7	25.7	25.1
VOC, ppmvd	5.4	5.5	13.3	13.1
VOC, ppmvw	4.8	4.9	11.9	11.8
VOC, ppmvd @ 15% O2	4.1	4.2	10.0	10.0
VOC, lb/h as CH4	9.2	9.0	22.9	21.9
Particulates (TSP = PM10), lb/h (dry filterables only)	15.7	15.9	70.1	67.9
Notes:				
1. Values shown above are for one combustion turbine/HRSR unit only. 2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100scf for illustration purposes only. 3. 73% effective SCR and no CO catalyst. 4. Particulates are per EPA Method 201A/202 (front and back half) and include H2SO4 mist. 5. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA. 6. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA. 7. Duct Burner NOx, lb/MBtu (HHV) is 0.0800 8. Duct Burner CO, lb/MBtu (HHV) is 0.1000 9. Duct Burner Particulate, lb/MBtu (HHV) is 0.0150 10. Duct Burner UHC (CH4), lb/MBtu (HHV) is 0.0600 11. Duct Burner VOC (CH4), lb/MBtu (HHV) is 0.0120				
B&V Project 59140.0031 File: d:\proj\kua\cc\westing501f_ex.wk4 06/11/98				

KUA Cane Island Unit 3
WEC 501F 1x1 Combined Cycle

Case Name	* 100 Percent Load - Distillate Oil*				
	Case 12	Case 13	Case 14	Case 15	Case 16
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	Water/42 ppm	Water/42 ppm	Water/42 ppm	Water/42 ppm	Water/42 ppm
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	93 Percent	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off
Ambient Temperature	19	72	72	102	102
Ambient Relative Humidity	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	66.7	72	84.7	102
CTG Compr. Inlet Relative Humidity, %	55	96	74	92	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75
Inlet Loss, in. H2O	4.5	4.0	4.0	3.8	3.7
Exhaust Loss, in. H2O	15.2	13.2	13.0	12.2	11.4
CTG Load Level (percent of Base Load)	93 Percent	Base	Base	Base	Base
Number of CTGs	1	1	1	1	1
Gross CTG Output, kW	185,000	170,310	167,040	160,210	149,700
Gross CTG Heat Rate, Btu/kWh (LHV)	9,310	9,555	9,595	9,720	9,890
CTG Heat Input, MBtu/h (LHV)	1,722.35	1,627.31	1,602.75	1,557.24	1,480.53
CTG Heat Input, MBtu/h (HHV)	1,839.02	1,737.54	1,711.32	1,662.73	1,580.82
CTG Fuel Flow, lb/h	92,670	87,560	86,230	83,790	79,660
CTG Water Injection Flow, lb/h	37,068	35,024	34,492	33,516	31,864
CTG Steam Injection Flow, lb/h	0	0	0	0	0
Injection Ratio	0.400	0.400	0.400	0.400	0.400
CTG Exhaust Flow, lb/h	3,909,771	3,549,621	3,513,227	3,393,166	3,276,886
CTG Exhaust Temperature, F	996	1,085	1,087	1,101	1,112
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0
Stack Exit Temperature, F	290	283	282	285	281
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	81.3	73.7	72.8	71.1	68.1

	* 100 Percent Load - Distillate Oil*				
Case Name	Case 12	Case 13	Case 14	Case 15	Case 16
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	Water/42 ppm	Water/42 ppm	Water/42 ppm	Water/42 ppm	Water/42 ppm
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	93 Percent	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)					
O2	12.92%	12.26%	12.33%	11.98%	12.21%
CO2	4.89%	5.06%	5.03%	5.03%	4.97%
H2O	6.36%	8.43%	8.24%	9.92%	9.24%
N2	74.89%	73.33%	73.47%	72.17%	72.67%
Ar	0.94%	0.92%	0.92%	0.91%	0.91%
SO2	0.00106%	0.00110%	0.00109%	0.00109%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)					
NOx, ppmvd @ 15% O2	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2	296.3	280.0	275.8	268.0	254.8
CO, ppmvd	781.1	114.3	113.5	115.6	113.2
CO, ppmvw	731.4	104.6	104.2	104.1	102.8
CO, ppmvd @ 15% O2	650.0	90.0	90.0	90.0	90.0
CO, lb/h	2,782.3	364.0	358.5	348.3	331.2
UHC, ppmvd	19.22	12.70	12.61	12.84	12.58
UHC, ppmvw	18.00	11.63	11.58	11.57	11.42
UHC, ppmvd @ 15% O2	16.00	10.00	10.00	10.00	10.00
UHC, lb/h as CH4	39.21	23.16	22.81	22.17	21.07
VOC, ppmvd	19.23	12.70	12.61	12.84	12.58
VOC, ppmvw	18.01	11.63	11.58	11.57	11.42
VOC, ppmvd @ 15% O2	16.00	10.00	10.00	10.00	10.00
VOC, lb/h as CH4	39.22	23.16	22.81	22.17	21.07
SO2, ppmvd	11.36	12.01	11.93	12.15	11.90
SO2, ppmvw	10.64	10.99	10.95	10.94	10.80
SO2, lb/h	92.58	87.48	86.15	83.71	79.59
Particulates (TSP = PM10), lb/h (dry filterables only)	85.30	73.00	72.30	69.20	66.90
CTG Fuel LHV, Btu/lb	18,586	18,586	18,586	18,586	18,586
CTG Fuel HHV, Btu/lb	19,845	19,845	19,845	19,845	19,845
HHV/LHV Ratio	1.0677	1.0677	1.0677	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)					
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	86.135000%	86.135000%	86.135000%	86.135000%	86.135000%
H2	13.800000%	13.800000%	13.800000%	13.800000%	13.800000%
N2	0.015000%	0.015000%	0.015000%	0.015000%	0.015000%
O2	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
S	0.050000%	0.050000%	0.050000%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis					
Molecular Wt, lb/mol	28.79	28.58	28.60	28.42	28.48
Gas Constant, ft-lbf/lbm-R	53.664	54.059	54.024	54.373	54.245
Specific Volume, ft³/lb	35.68	38.32	38.36	39.03	39.29
Exhaust Gas Flow, acfm	2,325,010	2,267,025	2,246,123	2,207,254	2,145,814
Specific Volume, scf/lb	13.18	13.27	13.27	13.35	13.32
Exhaust Gas Flow, scfm	858,846	785,058	777,009	754,979	727,469
Exhaust Gas Flow, lb/h	3,909,771	3,549,621	3,513,227	3,393,166	3,276,886

KUA Cane Island Unit 3
WEC 501F 1x1 Combined Cycle

* 100 Percent Load - Distillate Oil*					
Case Name	Case 12	Case 13	Case 14	Case 15	Case 16
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	Water/42 ppm	Water/42 ppm	Water/42 ppm	Water/42 ppm	Water/42 ppm
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	93 Percent	Base	Base	Base	Base
CTG Performance Reference	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98	WEC 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSR Duct Firing On/Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)					
Ar	0.94%	0.92%	0.92%	0.91%	0.91%
CO2	4.89%	5.06%	5.03%	5.03%	4.97%
H2O	6.36%	8.43%	8.24%	9.92%	9.24%
N2	74.89%	73.33%	73.47%	72.17%	72.67%
O2	12.92%	12.26%	12.33%	11.98%	12.21%
SO2	0.00106%	0.00110%	0.00109%	0.00109%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)					
Molecular Wt, lb/mol	28.79	28.58	28.60	28.42	28.48
Gas Constant, ft-lbf/lbm-R	53.664	54.059	54.024	54.373	54.245
Specific Volume, ft ³ /lb	19.06	19.02	18.99	19.19	19.04
Exhaust Gas Flow, acfm	1,242,004	1,125,230	1,111,936	1,085,248	1,039,865
Specific Volume, scf/lb	13.18	13.27	13.27	13.35	13.32
Exhaust Gas Flow, scfm	858,846	785,058	777,009	754,979	727,469
Exhaust Gas Flow, lb/h	3,909,771	3,549,621	3,513,227	3,393,166	3,276,886
Emissions (at Stack exit)					
NOx, ppmvd @15% O2 without SCR	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2 without SCR	296.3	280.0	275.8	268.0	254.8
NOx, ppmvd @15% O2 with SCR	11.2	11.2	11.2	11.2	11.2
NOx, lb/h as NO2 with SCR	78.7	74.4	73.3	71.2	67.7
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	26.0	24.6	24.2	23.5	22.4
CO, ppmvd without Catalyst	781.1	114.3	113.5	115.6	113.2
CO, lb/h without Catalyst	2,782.3	364.0	358.5	348.3	331.2
CO, ppmvd @ 15% O2 without Catalyst	650.0	90.0	90.0	90.0	90.0
CO, ppmvd with Catalyst	781.1	114.3	113.5	115.6	113.2
CO, lb/h with Catalyst	2,782.3	364.0	358.5	348.3	331.2
CO, ppmvd @ 15% O2 with Catalyst	650.0	90.0	90.0	90.0	90.0
SO2, ppmvd	11.36	12.01	11.93	12.15	11.90
SO2, ppmw	10.64	10.99	10.95	10.94	10.80
SO2, lb/h	92.58	87.48	86.15	83.71	79.59
UHC, ppmvd	19.2	12.7	12.6	12.8	12.6
UHC, ppmw	18.0	11.6	11.6	11.6	11.4
UHC, ppmvd @ 15% O2	16.0	10.0	10.0	10.0	10.0
UHC, lb/h as CH4	39.2	23.2	22.8	22.2	21.1
VOC, ppmvd	19.2	12.7	12.6	12.8	12.6
VOC, ppmw	18.0	11.6	11.6	11.6	11.4
VOC, ppmvd @ 15% O2	16.0	10.0	10.0	10.0	10.0
VOC, lb/h as CH4	39.2	23.2	22.8	22.2	21.1
Particulates (TSP = PM10), lb/h (dry filterables only)	85.3	73.0	72.3	69.2	66.9
Notes: 1. Values shown above are for one combustion turbine/HRSR unit only. 2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100scf for illustration purposes only. 3. 73% effective SCR and no CO catalyst. 4. Particulates are per EPA Method 201A/202 (front and back half) and include H2SO4 mist. 5. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA.					
B&V Project 59140.0031 File: d:\proj\kua\ccw\westing\501f_ex.wrk4 06/11/98					

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSG Duct Firing On/Off	* 70 & 50 Percent Load - Distillate Oil*					
	Case 17 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98 Off Off	Case 18 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98 Off Off	Case 19 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98 Off Off	Case 20 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98 Off Off	Case 21 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98 Off Off	Case 22 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98 Off Off
Ambient Temperature	19	19	72	72	102	102
Ambient Relative Humidity	55	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	19	72	72	102	102
CTG Compr. Inlet Relative Humidity, %	55	55	74	74	45	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75	75
Inlet Loss, in. H2O	3.9	2.8	3.6	2.6	3.3	2.5
Exhaust Loss, in. H2O	12.1	8.6	10.2	7.5	9.2	6.8
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
Number of CTGs	1	1	1	1	1	1
Gross CTG Output, kW	138,350	98,420	116,560	82,820	104,380	74,110
Gross CTG Heat Rate, Btu/kWh (LHV)	9,722	10,908	10,324	11,755	10,789	12,282
CTG Heat Input, MBtu/h (LHV)	1,345.04	1,073.57	1,203.37	973.55	1,126.16	910.22
CTG Heat Input, MBtu/h (HHV)	1,436.15	1,146.29	1,284.89	1,039.50	1,202.45	971.88
CTG Fuel Flow, lb/h	72,370	57,760	64,750	52,380	60,590	48,970
CTG Water Injection Flow, lb/h	18,093	11,552	16,188	10,476	15,148	9,794
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
Injection Ratio	0.250	0.200	0.250	0.200	0.250	0.200
CTG Exhaust Flow, lb/h	3,639,112	3,041,793	3,284,857	2,789,277	3,074,954	2,643,062
CTG Exhaust Temperature, F	877	899	932	952	969	973
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0	0
Stack Exit Temperature, F	291	280	289	277	288	277
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	75.6	62.2	68.5	57.2	64.3	54.4

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSRG Duct Firing On/Off	* 70 & 50 Percent Load - Distillate Oil*					
	Case 17 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98 Off Off	Case 18 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98 Off Off	Case 19 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98 Off Off	Case 20 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98 Off Off	Case 21 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98 Off Off	Case 22 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98 Off Off
CTG Exhaust Analysis (Volume Basis - Wet)						
O2	14.29%	14.62%	14.03%	14.37%	13.83%	14.24%
CO2	4.12%	3.93%	4.05%	3.87%	4.04%	3.80%
H2O	4.90%	4.54%	6.58%	6.19%	7.64%	7.22%
N2	75.74%	75.86%	74.42%	74.64%	73.58%	73.81%
Ar	0.95%	0.95%	0.93%	0.94%	0.92%	0.93%
SO2	0.00090%	0.00086%	0.00088%	0.00084%	0.00088%	0.00083%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)						
NOx, ppmvd @ 15% O2	42.0	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2	231.6	185.1	207.3	167.9	194.1	157.0
CO, ppmvd	866.0	1,014.9	867.0	1,015.7	866.1	1,017.4
CO, ppmw	823.6	968.8	810.1	952.7	799.9	943.9
CO, ppmvd @ 15% O2	870.0	1,071.0	869.0	1,072.0	862.0	1,081.0
CO, lb/h	2,908.2	2,857.4	2,599.0	2,593.6	2,412.4	2,445.1
UHC, ppmvd	101.54	101.39	101.76	101.38	101.48	101.65
UHC, ppmw	96.56	96.79	95.09	95.10	93.73	94.31
UHC, ppmvd @ 15% O2	102.00	107.00	102.00	107.00	101.00	108.00
UHC, lb/h as CH4	195.28	163.49	174.72	148.27	161.89	139.91
VOC, ppmvd	101.54	101.39	101.76	101.38	101.48	101.65
VOC, ppmw	96.56	96.79	95.09	95.10	93.73	94.31
VOC, ppmvd @ 15% O2	102.00	107.00	102.00	107.00	101.00	108.00
VOC, lb/h as CH4	195.28	163.49	174.72	148.27	161.89	139.91
SO2, ppmvd	9.41	8.96	9.44	8.96	9.50	8.90
SO2, ppmw	8.95	8.56	8.82	8.41	8.78	8.26
SO2, lb/h	72.30	57.71	64.69	52.33	60.53	48.92
Particulates (TSP = PM10), lb/h (dry filterables only)	99.90	112.80	89.20	102.10	82.90	96.00
CTG Fuel LHV, Btu/lb	18,586	18,586	18,586	18,586	18,586	18,586
CTG Fuel HHV, Btu/lb	19,845	19,845	19,845	19,845	19,845	19,845
HHV/LHV Ratio	1.0677	1.0677	1.0677	1.0677	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	86.135000%	86.135000%	86.135000%	86.135000%	86.135000%	86.135000%
H2	13.800000%	13.800000%	13.800000%	13.800000%	13.800000%	13.800000%
N2	0.015000%	0.015000%	0.015000%	0.015000%	0.015000%	0.015000%
O2	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
S	0.050000%	0.050000%	0.050000%	0.050000%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.87	28.89	28.68	28.70	28.56	28.58
Gas Constant, ft-lbf/lbm-R	53.520	53.482	53.871	53.834	54.098	54.060
Specific Volume, ft³/lb	32.92	33.72	34.65	35.36	35.81	36.09
Exhaust Gas Flow, acfm	1,996,659	1,709,488	1,897,005	1,643,814	1,835,235	1,589,802
Specific Volume, scf/lb	13.14	13.13	13.23	13.22	13.28	13.28
Exhaust Gas Flow, scfm	796,966	665,646	724,311	614,571	680,590	584,998
Exhaust Gas Flow, lb/h	3,639,112	3,041,793	3,284,857	2,789,277	3,074,954	2,643,062

* 70 & 50 Percent Load - Distillate Oil*						
Case Name	Case 17 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98	Case 18 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98	Case 19 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98	Case 20 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98	Case 21 WEC 501F DLN/42 ppm Distillate 70 Percent WEC 06/03/98	Case 22 WEC 501F DLN/42 ppm Distillate 50 Percent WEC 06/03/98
CTG Model						
Combustor/NOx Emission Rate						
CTG Fuel Type						
CTG Load Level (percent of Base Load)						
CTG Performance Reference						
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.95%	0.95%	0.93%	0.94%	0.92%	0.93%
CO2	4.12%	3.93%	4.05%	3.87%	4.04%	3.80%
H2O	4.90%	4.54%	6.56%	6.19%	7.64%	7.22%
N2	75.74%	75.96%	74.42%	74.64%	73.58%	73.81%
O2	14.29%	14.62%	14.03%	14.37%	13.83%	14.24%
SO2	0.00090%	0.00086%	0.00088%	0.00084%	0.00088%	0.00083%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)						
Molecular Wt, lb/mol	28.87	28.89	28.68	28.70	28.56	28.58
Gas Constant, ft-lb/lbm-R	53.520	53.482	53.871	53.834	54.068	54.060
Specific Volume, ft ³ /lb	19.04	18.74	19.11	18.79	19.17	18.87
Exhaust Gas Flow, scfm	1,154,812	950,053	1,046,227	873,509	982,448	831,243
Specific Volume, scf/lb	13.14	13.13	13.23	13.22	13.28	13.28
Exhaust Gas Flow, scfm	796,966	665,646	724,311	614,571	680,590	584,998
Exhaust Gas Flow, lb/h	3,639,112	3,041,793	3,284,857	2,789,277	3,074,954	2,643,062
Emissions (at Stack exit)						
NOx, ppmvd @15% O2 without SCR	42.0	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2 without SCR	231.8	185.1	207.3	167.9	194.1	157.0
NOx, ppmvd @15% O2 with SCR	11.2	11.2	11.2	11.2	11.2	11.2
NOx, lb/h as NO2 with SCR	61.5	49.1	55.0	44.5	51.5	41.6
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	20.3	16.2	18.2	14.7	17.0	13.8
CO, ppmvd without Catalyst	866.0	1,014.9	867.0	1,015.7	866.1	1,017.4
CO, lb/h without Catalyst	2,908.2	2,857.4	2,599.0	2,593.6	2,412.4	2,445.1
CO, ppmvd @ 15% O2 without Catalyst	870.0	1,071.0	869.0	1,072.0	862.0	1,081.0
CO, ppmvd with Catalyst	866.0	1,014.9	867.0	1,015.7	866.1	1,017.4
CO, lb/h with Catalyst	2,908.2	2,857.4	2,599.0	2,593.6	2,412.4	2,445.1
CO, ppmvd @ 15% O2 with Catalyst	870.0	1,071.0	869.0	1,072.0	862.0	1,081.0
SO2, ppmvd	9.41	8.96	9.44	8.96	9.50	8.90
SO2, ppmvw	8.95	8.56	8.82	8.41	8.76	8.28
SO2, lb/h	72.30	57.71	64.69	52.33	60.53	48.92
UHC, ppmvd	101.5	101.4	101.8	101.4	101.5	101.6
UHC, ppmvw	96.8	96.8	95.1	95.1	93.7	94.3
UHC, ppmvd @ 15% O2	102.0	107.0	102.0	107.0	101.0	108.0
UHC, lb/h as CH4	195.3	163.5	174.7	148.3	161.9	139.9
VOC, ppmvd	101.5	101.4	101.8	101.4	101.5	101.6
VOC, ppmvw	96.8	96.8	95.1	95.1	93.7	94.3
VOC, ppmvd @ 15% O2	102.0	107.0	102.0	107.0	101.0	108.0
VOC, lb/h as CH4	195.3	163.5	174.7	148.3	161.9	139.9
Particulates (TSP = PM10), lb/h (dry filterables only)	99.9	112.6	89.2	102.1	82.9	96.0

Notes:

1. Values shown above are for one combustion turbine/HRSG unit only.
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100scf for illustration purposes only.
3. 73% effective SCR and no CO catalyst.
4. Particulates are per EPA Method 201A/202 (front and back half) and include H2SO4 mist.
5. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA.

KUA Cane Island Unit 3
WEC 501F 1x1 Combined Cycle

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSG Duct Firing On/Off	* Simple Cycle - 100 Percent Load - NG & DO *					
	Case 1 WEC 501F DLN/15 ppm Natural Gas 90 Percent WEC 05/22/98 Off Off	Case 3 WEC 501F DLN/15 ppm Natural Gas Base WEC 05/22/98 Off Off	Case 5 WEC 501F DLN/15 ppm Natural Gas Base WEC 05/22/98 Off Off	Case 12 WEC 501F DLN/42 ppm Distillate 93Percent WEC 05/22/98 Off Off	Case 14 WEC 501F DLN/42 ppm Distillate Base WEC 05/22/98 Off Off	Case 16 WEC 501F DLN/42 ppm Distillate Base WEC 05/22/98 Off Off
Ambient Temperature	19	72	102	19	72	102
Ambient Relative Humidity	55	74	45	55	74	45
CTG Compressor Inlet Temperature, F	19	72	102	19	72	102
CTG Compr. Inlet Relative Humidity, %	55	74	45	55	74	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75	75
Inlet Loss, in. H2O	3.8	4.0	3.7	4.5	4.0	3.7
Exhaust Loss, in. H2O	4.9	4.7	4.1	5.4	4.7	4.0
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	93Percent	Base	Base
Number of CTGs	1	1	1	1	1	1
Gross CTG Output, kW	185,000	175,310	157,520	185,000	168,520	151,180
Gross CTG Heat Rate, Btu/kWh (LHV)	8,975	9,190	9,455	9,240	9,510	9,795
CTG Heat Input, MBtu/h (LHV)	1,860.38	1,611.10	1,489.35	1,709.40	1,602.63	1,480.81
CTG Heat Input, MBtu/h (HHV)	1,842.17	1,787.49	1,652.41	1,825.19	1,711.19	1,581.12
CTG Fuel Flow, lb/h	79,140	76,790	70,990	91,970	86,230	79,670
CTG Water Injection Flow, lb/h	0	0	0	36,788	34,492	31,868
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
Injection Ratio	0.000	0.000	0.000	0.400	0.400	0.400
CTG Exhaust Flow, lb/h	3,576,914	3,469,805	3,236,818	3,909,057	3,513,227	3,276,886
CTG Exhaust Temperature, F	1,073	1,118	1,143	985	1,082	1,106
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0	0
Stack Exit Temperature, F	1073	1118	1143	985	1082	1106
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	153.9	154.6	147.1	156.7	151.3	143.9

* Simple Cycle - 100 Percent Load - NG & DO *						
Case Name	Case 1	Case 3	Case 5	Case 12	Case 14	Case 16
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	93Percent	Base	Base
CTG Performance Reference	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)						
O2	12.50%	12.19%	12.07%	12.97%	12.33%	12.21%
CO2	3.88%	3.86%	3.81%	4.86%	5.03%	4.97%
H2O	7.75%	9.41%	10.40%	6.31%	8.24%	9.24%
N2	74.93%	73.61%	72.80%	74.91%	73.47%	72.67%
Ar	0.94%	0.92%	0.91%	0.94%	0.92%	0.91%
SO2	0.00001%	0.00001%	0.00001%	0.00106%	0.00109%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)						
NOx, ppmvd @ 15% O2	15.0	15.0	15.0	42.0	42.0	42.0
NOx, lb/h as NO2	100.3	97.4	90.1	294.1	275.8	254.9
CO, ppmvd	31.1	31.4	31.4	107.3	113.5	113.2
CO, ppmvw	28.6	28.5	28.1	100.5	104.2	102.8
CO, ppmvd @ 15% O2	25.0	25.0	25.0	90.0	90.0	90.0
CO, lb/h	100.8	97.8	90.4	382.3	358.5	331.2
UHC, ppmvd	4.97	5.03	5.02	20.27	12.61	12.58
UHC, ppmvw	4.58	4.55	4.50	18.99	11.58	11.42
UHC, ppmvd @ 15% O2	4.00	4.00	4.00	17.00	10.00	10.00
UHC, lb/h as CH4	9.24	8.96	8.29	41.36	22.81	21.08
VOC, ppmvd	3.73	3.77	3.76	20.27	12.61	12.58
VOC, ppmvw	3.44	3.42	3.37	18.99	11.58	11.42
VOC, ppmvd @ 15% O2	3.00	3.00	3.00	17.00	10.00	10.00
VOC, lb/h as CH4	6.93	6.72	6.21	41.36	22.81	21.08
SO2, ppmvd	0.14	0.14	0.14	11.28	11.93	11.90
SO2, ppmvw	0.13	0.12	0.12	10.56	10.95	10.80
SO2, lb/h	1.01	0.98	0.91	91.88	86.15	79.60
Particulates (TSP = PM10), lb/h (dry filterables only)	16.70	16.00	15.00	85.70	72.30	66.90
CTG Fuel LHV, Btu/lb						
CTG Fuel LHV, Btu/lb	20,980	20,980	20,980	18,586	18,586	18,586
CTG Fuel HHV, Btu/lb	23,277	23,277	23,277	19,845	19,845	19,845
HHV/LHV Ratio	1.1095	1.1095	1.1095	1.0677	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	74.043570%	86.135000%	86.135000%	86.135000%
H2	24.256660%	24.256660%	24.256660%	13.800000%	13.800000%	13.800000%
N2	0.575950%	0.575950%	0.575950%	0.015000%	0.015000%	0.015000%
O2	1.123180%	1.123180%	1.123180%	0.000000%	0.000000%	0.000000%
S	0.000640%	0.000640%	0.000640%	0.050000%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.47	28.29	28.17	28.79	28.60	28.48
Gas Constant, ft-lbf/lbm-R	54.263	54.617	54.836	53.662	54.024	54.245
Specific Volume, ft³/lb	38.94	40.36	41.23	36.25	39.01	39.85
Exhaust Gas Flow, acfm	2,321,417	2,334,022	2,224,233	2,361,722	2,284,183	2,176,398
Specific Volume, scf/lb	13.33	13.41	13.47	13.18	13.27	13.32
Exhaust Gas Flow, scfm	794,671	775,501	726,866	858,690	777,009	727,469
Exhaust Gas Flow, lb/h	3,576,914	3,468,805	3,236,818	3,908,057	3,513,227	3,276,886

* Simple Cycle - 100 Percent Load - NG & DO *						
Case Name	Case 1	Case 3	Case 5	Case 12	Case 14	Case 16
CTG Model	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F	WEC 501F
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	90 Percent	Base	Base	93Percent	Base	Base
CTG Performance Reference	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98	WEC 05/22/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRS G Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.94%	0.92%	0.91%	0.94%	0.92%	0.91%
CO2	3.88%	3.86%	3.81%	4.86%	5.03%	4.97%
H2O	7.75%	9.41%	10.40%	6.31%	8.24%	9.24%
N2	74.93%	73.61%	72.80%	74.91%	73.47%	72.87%
O2	12.50%	12.19%	12.07%	12.97%	12.33%	12.21%
SO2	0.00001%	0.00001%	0.00001%	0.00106%	0.00106%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)						
Molecular Wt, lb/mol	28.47	28.29	28.17	28.79	28.60	28.48
Gas Constant, ft-lbf/lbm-R	54.263	54.617	54.836	53.662	54.024	54.245
Specific Volume, ft³/lb	39.41	40.83	41.64	36.73	39.46	40.24
Exhaust Gas Flow, acfm	2,349,436	2,361,202	2,246,352	2,392,994	2,310,532	2,197,698
Specific Volume, scf/lb	13.33	13.41	13.47	13.18	13.27	13.32
Exhaust Gas Flow, scfm	794,671	775,501	726,666	858,690	777,009	727,469
Exhaust Gas Flow, lb/h	3,576,914	3,469,805	3,236,818	3,909,057	3,513,227	3,276,886
Emissions (at Stack exit)						
NOx, ppmvd @15% O2 without SCR	15.0	15.0	15.0	42.0	42.0	42.0
NOx, lb/h as NO2 without SCR	100.3	97.4	90.1	294.1	275.8	254.9
NOx, ppmvd @15% O2 with SCR	4.0	4.0	4.0	11.2	11.2	11.2
NOx, lb/h as NO2 with SCR	26.5	25.7	23.8	78.2	73.3	67.7
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	24.5	23.8	22.0	25.8	24.2	22.4
CO, ppmvd without Catalyst	31.1	31.4	31.4	107.3	113.5	113.2
CO, lb/h without Catalyst	100.8	97.8	90.4	382.3	358.5	331.2
CO, ppmvd @ 15% O2 without Catalyst	25.0	25.0	25.0	90.0	90.0	90.0
CO, ppmvd with Catalyst	31.1	31.4	31.4	107.3	113.5	113.2
CO, lb/h with Catalyst	100.8	97.8	90.4	382.3	358.5	331.2
CO, ppmvd @ 15% O2 with Catalyst	25.0	25.0	25.0	90.0	90.0	90.0
SO2, ppmvd	0.14	0.14	0.14	11.28	11.93	11.90
SO2, ppmvw	0.13	0.12	0.12	10.56	10.85	10.80
SO2, lb/h	1.01	0.98	0.91	91.88	86.15	79.60
UHC, ppmvd	5.0	5.0	5.0	20.3	12.6	12.6
UHC, ppmvw	4.8	4.8	4.5	19.0	11.8	11.4
UHC, ppmvd @ 15% O2	4.0	4.0	4.0	17.0	10.0	10.0
UHC, lb/h as CH4	9.2	9.0	8.3	41.4	22.8	21.1
VOC, ppmvd	3.7	3.8	3.8	20.3	12.6	12.6
VOC, ppmvw	3.4	3.4	3.4	19.0	11.8	11.4
VOC, ppmvd @ 15% O2	3.0	3.0	3.0	17.0	10.0	10.0
VOC, lb/h as CH4	6.9	6.7	6.2	41.4	22.8	21.1
Particulates (TSP = PM10), lb/h (dry filterables only)	16.7	16.0	15.0	85.7	72.3	66.9
Notes:						
1. Values shown above are for one combustion turbine/HRS G unit only.						
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100scf for illustration purposes only.						
3. 73% effective SCR and no CO catalyst.						
4. Particulates are per EPA Method 201A/202 (front and back half) and include H2SO4 mist.						
5. CTG performance from Westinghouse data received 05/21/98, 05/22/98 and 05/27/98 for KUA.						
B&V Project 59140.0031						
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KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* 100 Percent Load - Natural Gas *					
Case Name	Case 1	Case 2	Case 3	Case 4	Case 5
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	Base	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSO Duct Firing On/Off	Off	Off	Off	Off	Off
Ambient Temperature, F	19	72	72	102	102
Ambient Relative Humidity, %	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	66.7	72	84.7	102
CTG Compr. Inlet Relative Humidity, %	55	96	74	92	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75
Inlet Loss, in. H ₂ O	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H ₂ O	14.0	14.0	14.0	14.0	14.0
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Number of CTGs	1	1	1	1	1
Gross CTG Output, kW	183,000	164,200	161,100	152,900	141,500
Gross CTG Heat Rate, Btu/kWh (LHV)	9,270	9,460	9,490	9,680	9,900
CTG Heat Input, MBtu/h (LHV)	1,696.41	1,553.33	1,528.84	1,480.07	1,400.85
CTG Heat Input, MBtu/h (HHV)	1,862.14	1,723.40	1,696.23	1,642.12	1,554.22
CTG Fuel Flow, lb/h	80,860	74,040	72,870	70,550	66,770
CTG Water Injection Flow, lb/h	0	0	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0	0	0
Injection Ratio	0.000	0.000	0.000	0.000	0.000
CTG Exhaust Flow, lb/h	3,785,000	3,454,000	3,429,000	3,307,000	3,184,000
CTG Exhaust Temperature, F	1,083	1,128	1,131	1,143	1,157
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0
Stack Exit Temperature, F	190	192	192	194	192
Stack Exhaust Pressure, in. H ₂ O above Patm	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	69.0	63.6	63.1	61.4	58.8

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* 100 Percent Load - Natural Gas *					
Case Name	Case 1	Case 2	Case 3	Case 4	Case 5
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	Base	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)					
O2	12.79%	12.42%	12.52%	12.19%	12.43%
CO2	3.75%	3.74%	3.71%	3.70%	3.65%
H2O	7.49%	9.34%	9.12%	10.78%	10.09%
N2	75.03%	73.57%	73.72%	72.42%	72.92%
Ar	0.94%	0.92%	0.93%	0.91%	0.92%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)					
NOx, ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0
NOx, lb/h as NO2	102.5	93.9	92.5	89.6	84.8
CO, ppmvd	15.0	15.0	15.0	15.0	15.0
CO, ppmvw	13.9	13.6	13.6	13.4	13.5
CO, ppmvd @ 15% O2	12.5	12.3	12.5	12.3	12.5
CO, lb/h	51.6	46.5	46.3	44.1	42.7
UHC, ppmvd	7.57	7.72	7.70	7.85	7.79
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00
UHC, ppmvd @ 15% O2	6.32	6.35	6.40	6.41	6.51
UHC, lb/h as CH4	14.92	13.71	13.60	13.20	12.68
VOC, ppmvd	1.51	1.54	1.54	1.57	1.56
VOC, ppmvw	1.40	1.40	1.40	1.40	1.40
VOC, ppmvd @ 15% O2	1.26	1.27	1.28	1.28	1.30
VOC, lb/h as CH4	2.98	2.74	2.72	2.64	2.54
SO2, ppmvd	0.13	0.13	0.13	0.13	0.13
SO2, ppmvw	0.12	0.12	0.12	0.12	0.12
SO2, lb/h	1.03	0.95	0.93	0.90	0.85
Particulates (TSP = PM10), lb/h (dry filterables only)	18.00	18.00	18.00	18.00	18.00
CTG Fuel LHV, Btu/lb					
CTG Fuel LHV, Btu/lb	20,980	20,980	20,980	20,980	20,980
CTG Fuel HHV, Btu/lb					
CTG Fuel HHV, Btu/lb	23,277	23,277	23,277	23,277	23,277
HHV/LHV Ratio					
HHV/LHV Ratio	1.1095	1.1095	1.1095	1.1095	1.1095
CTG Fuel Composition (Ultimate Analysis by Weight)					
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	74.043570%	74.043570%	74.043570%
H2	24.256660%	24.256660%	24.256660%	24.256660%	24.256660%
N2	0.575950%	0.575950%	0.575950%	0.575950%	0.575950%
O2	1.123180%	1.123180%	1.123180%	1.123180%	1.123180%
S	0.000640%	0.000640%	0.000640%	0.000640%	0.000640%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis					
Molecular Wt, lb/mol	28.49	28.28	28.31	28.12	28.19
Gas Constant, ft-lbf/lbm-R	54.232	54.623	54.581	54.937	54.798
Specific Volume, ft ³ /lb	38.32	39.72	39.77	40.33	40.58
Exhaust Gas Flow, acfm	2,417,353	2,286,548	2,272,856	2,222,855	2,153,445
Specific Volume, scf/lb	13.32	13.41	13.40	13.49	13.46
Exhaust Gas Flow, scfm	840,270	771,969	765,810	743,524	714,277
Exhaust Gas Flow, lb/h	3,785,000	3,454,000	3,429,000	3,307,000	3,184,000

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* 100 Percent Load - Natural Gas *					
Case Name	Case 1	Case 2	Case 3	Case 4	Case 5
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	Base	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)					
Ar	0.94%	0.92%	0.93%	0.91%	0.92%
CO2	3.75%	3.74%	3.71%	3.70%	3.65%
H2O	7.49%	9.34%	9.12%	10.78%	10.09%
N2	75.03%	73.57%	73.72%	72.42%	72.92%
O2	12.79%	12.42%	12.52%	12.19%	12.43%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)					
Molecular Wt, lb/mol	28.49	28.28	28.31	28.12	28.19
Gas Constant, ft-lbf/lbm-R	54.232	54.623	54.581	54.937	54.798
Specific Volume, ft ³ /lb	16.69	16.87	16.85	17.02	16.92
Exhaust Gas Flow, acfm	1,052,861	971,150	962,978	938,086	897,888
Specific Volume, scf/lb	13.32	13.41	13.40	13.49	13.46
Exhaust Gas Flow, scfm	840,270	771,969	765,810	743,524	714,277
Exhaust Gas Flow, lb/h	3,785,000	3,454,000	3,429,000	3,307,000	3,184,000
Emissions (at Stack exit)					
NOx, ppmvd @15% O2 without SCR	15.0	15.0	15.0	15.0	15.0
NOx, lb/h as NO2 without SCR	102.5	93.9	92.5	89.8	84.8
NOx, ppmvd @15% O2 with SCR	4.0	4.0	4.0	4.0	4.0
NOx, lb/h as NO2 with SCR	27.1	24.8	24.4	23.6	22.3
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	25.0	22.9	22.6	21.9	20.7
CO, ppmvd without Catalyst	15.0	15.0	15.0	15.0	15.0
CO, lb/h without Catalyst	51.6	46.5	46.3	44.1	42.7
CO, ppmvd @ 15% O2 without Catalyst	12.5	12.3	12.5	12.3	12.5
CO, ppmvd with Catalyst	15.0	15.0	15.0	15.0	15.0
CO, lb/h with Catalyst	51.6	46.5	46.3	44.1	42.7
CO, ppmvd @ 15% O2 with Catalyst	12.5	12.3	12.5	12.3	12.5
SO2, ppmvd	0.13	0.13	0.13	0.13	0.13
SO2, ppmvw	0.12	0.12	0.12	0.12	0.12
SO2, lb/h	1.03	0.95	0.93	0.90	0.85
UHC, ppmvd	7.6	7.7	7.7	7.8	7.8
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0
UHC, ppmvd @ 15% O2	6.3	6.3	6.4	6.4	6.5
UHC, lb/h as CH4	14.9	13.7	13.6	13.2	12.7
VOC, ppmvd	1.5	1.5	1.5	1.6	1.6
VOC, ppmvw	1.4	1.4	1.4	1.4	1.4
VOC, ppmvd @ 15% O2	1.3	1.3	1.3	1.3	1.3
VOC, lb/h as CH4	3.0	2.7	2.7	2.6	2.5
Particulates (TSP = PM10), lb/h (dry filterables only)	18.0	18.0	18.0	18.0	18.0
Notes:					
1. Values shown above are for one combustion turbine/HRSG unit only.					
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100 scf added for illustration purposes only.					
3. 73% effective SCR and no CO catalyst.					
4. Particulates are front and back half.					
5. CTG performance from General Electric data received 5/21/98 for KUA.					
B&V Project 59140.0031					
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06/08/98					

Case Name	* 70 & 50 Percent Load - Natural Gas *					
	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Ambient Temperature, F	19	19	72	72	102	102
Ambient Relative Humidity, %	55	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	19	72	72	102	102
CTG Compr. Inlet Relative Humidity, %	55	55	74	74	45	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75	75
Inlet Loss, in. H ₂ O	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H ₂ O	14.0	14.0	14.0	14.0	14.0	14.0
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Number of CTGs	1	1	1	1	1	1
Gross CTG Output, kW	128,100	91,500	114,900	82,100	107,100	76,500
Gross CTG Heat Rate, Btu/kWh (LHV)	10,220	11,920	10,580	12,380	10,880	12,700
CTG Heat Input, MBtu/h (LHV)	1,309.18	1,090.68	1,215.64	1,016.40	1,165.25	971.55
CTG Heat Input, MBtu/h (HHV)	1,452.52	1,210.09	1,348.73	1,127.68	1,292.83	1,077.92
CTG Fuel Flow, lb/h	62,400	51,990	57,940	48,450	55,540	46,310
CTG Water Injection Flow, lb/h	0	0	0	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
Injection Ratio	0.000	0.000	0.000	0.000	0.000	0.000
CTG Exhaust Flow, lb/h	2,904,000	2,485,000	2,745,000	2,355,000	2,668,000	2,309,000
CTG Exhaust Temperature, F	1,126	1,163	1,162	1,197	1,180	1,200
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0	0
Stack Exit Temperature, F	178	180	180	173	183	177
Stack Exhaust Pressure, in. H ₂ O above Patm	0	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	52.0	44.6	49.6	42.0	48.6	41.6

* 70 & 50 Percent Load - Natural Gas *						
Case Name	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRS/SG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)						
O2	12.74%	12.95%	12.58%	12.77%	12.49%	12.77%
CO2	3.77%	3.68%	3.68%	3.59%	3.62%	3.49%
H2O	7.53%	7.34%	9.07%	8.90%	10.04%	9.79%
N2	75.01%	75.08%	73.74%	73.81%	72.94%	73.04%
Ar	0.94%	0.94%	0.93%	0.93%	0.92%	0.92%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)						
NOx, ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0
NOx, lb/h as NO2	79.3	66.3	73.7	61.8	70.7	59.1
CO, ppmvd	15.0	15.0	15.0	15.0	15.0	15.0
CO, ppmvw	13.9	13.9	13.6	13.7	13.5	13.5
CO, ppmvd @ 15% O2	12.5	12.8	12.5	12.9	12.6	13.1
CO, lb/h	39.6	33.9	37.0	31.8	35.8	31.0
UHC, ppmvd	7.57	7.55	7.70	7.68	7.78	7.76
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00	7.00
UHC, ppmvd @ 15% O2	6.29	6.45	6.44	6.61	6.56	6.80
UHC, lb/h as CH4	11.45	9.79	10.89	9.34	10.62	9.19
VOC, ppmvd	1.51	1.51	1.54	1.54	1.56	1.55
VOC, ppmvw	1.40	1.40	1.40	1.40	1.40	1.40
VOC, ppmvd @ 15% O2	1.26	1.29	1.29	1.32	1.31	1.36
VOC, lb/h as CH4	2.29	1.96	2.18	1.87	2.12	1.84
SO2, ppmvd	0.13	0.13	0.13	0.13	0.13	0.13
SO2, ppmvw	0.12	0.12	0.12	0.12	0.12	0.11
SO2, lb/h	0.80	0.66	0.74	0.62	0.71	0.59
Particulates (TSP = PM10), lb/h (dry filterables only)	18.00	18.00	18.00	18.00	18.00	18.00
CTG Fuel LHV, Btu/lb						
CTG Fuel LHV, Btu/lb	20,980	20,980	20,980	20,980	20,980	20,980
CTG Fuel HHV, Btu/lb						
CTG Fuel HHV, Btu/lb	23,277	23,277	23,277	23,277	23,277	23,277
HHV/LHV Ratio						
HHV/LHV Ratio	1.1095	1.1095	1.1095	1.1095	1.1095	1.1095
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	74.043570%	74.043570%	74.043570%	74.043570%
H2	24.256660%	24.256660%	24.256660%	24.256660%	24.256660%	24.256660%
N2	0.575950%	0.575950%	0.575950%	0.575950%	0.575950%	0.575950%
O2	1.123180%	1.123180%	1.123180%	1.123180%	1.123180%	1.123180%
S	0.000640%	0.000640%	0.000640%	0.000640%	0.000640%	0.000640%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.49	28.50	28.31	28.32	28.20	28.21
Gas Constant, ft-lbf/lbm-R	54.237	54.214	54.576	54.554	54.792	54.761
Specific Volume, ft ³ /lb	39.39	40.29	40.54	41.40	41.15	41.63
Exhaust Gas Flow, acfm	1,906,476	1,668,678	1,854,705	1,624,950	1,829,803	1,602,061
Specific Volume, scf/lb	13.32	13.31	13.40	13.40	13.45	13.45
Exhaust Gas Flow, scfm	644,688	551,256	613,050	525,950	598,077	517,601
Exhaust Gas Flow, lb/h	2,904,000	2,485,000	2,745,000	2,355,000	2,668,000	2,309,000

* 70 & 50 Percent Load - Natural Gas *						
Case Name	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.94%	0.94%	0.93%	0.93%	0.92%	0.92%
CO2	3.77%	3.68%	3.68%	3.59%	3.62%	3.49%
H2O	7.53%	7.34%	9.07%	8.90%	10.04%	9.79%
N2	75.01%	75.08%	73.74%	73.81%	72.94%	73.04%
O2	12.74%	12.95%	12.58%	12.77%	12.49%	12.77%
SO2	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)						
Molecular Wt, lb/mol	28.49	28.50	28.31	28.32	28.20	28.21
Gas Constant, ft-lbf/lbm-R	54.237	54.214	54.576	54.554	54.792	54.761
Specific Volume, ft ³ /lb	16.39	16.43	16.54	16.35	16.69	16.52
Exhaust Gas Flow, acfm	793,276	680,476	756,705	641,738	742,149	635,745
Specific Volume, scf/lb	13.32	13.31	13.40	13.40	13.45	13.45
Exhaust Gas Flow, scfm	644,688	551,256	613,050	525,950	598,077	517,601
Exhaust Gas Flow, lb/h	2,904,000	2,485,000	2,745,000	2,355,000	2,668,000	2,309,000
Emissions (at Stack exit)						
NOx, ppmvd @15% O2 without SCR	15.0	15.0	15.0	15.0	15.0	15.0
NOx, lb/h as NO2 without SCR	79.3	66.3	73.7	61.8	70.7	59.1
NOx, ppmvd @15% O2 with SCR	4.0	4.0	4.0	4.0	4.0	4.0
NOx, lb/h as NO2 with SCR	20.9	17.4	19.4	16.2	18.6	15.5
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	19.3	16.1	17.9	15.0	17.2	14.3
CO, ppmvd without Catalyst	15.0	15.0	15.0	15.0	15.0	15.0
CO, lb/h without Catalyst	39.6	33.9	37.0	31.8	35.8	31.0
CO, ppmvd @ 15% O2 without Catalyst	12.5	12.8	12.5	12.9	12.6	13.1
CO, ppmvd with Catalyst	15.0	15.0	15.0	15.0	15.0	15.0
CO, lb/h with Catalyst	39.6	33.9	37.0	31.8	35.8	31.0
CO, ppmvd @ 15% O2 with Catalyst	12.5	12.8	12.5	12.9	12.6	13.1
SO2, ppmvd	0.13	0.13	0.13	0.13	0.13	0.13
SO2, ppmvw	0.12	0.12	0.12	0.12	0.12	0.11
SO2, lb/h	0.80	0.66	0.74	0.62	0.71	0.59
UHC, ppmvd	7.6	7.6	7.7	7.7	7.8	7.8
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0
UHC, ppmvd @ 15% O2	6.3	6.5	6.4	6.6	6.6	6.8
UHC, lb/h as CH4	11.4	9.8	10.9	9.3	10.6	9.2
VOC, ppmvd	1.5	1.5	1.5	1.5	1.6	1.6
VOC, ppmvw	1.4	1.4	1.4	1.4	1.4	1.4
VOC, ppmvd @ 15% O2	1.3	1.3	1.3	1.3	1.3	1.4
VOC, lb/h as CH4	2.3	2.0	2.2	1.9	2.1	1.8
Particulates (TSP = PM10), lb/h (dry filterables only)	18.0	18.0	18.0	18.0	18.0	18.0
Notes:						
1. Values shown above are for one combustion turbine/HRSG unit only.						
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100 scf added for illustration purposes only.						
3. 73% effective SCR and no CO catalyst.						
4. Particulates are front and back half.						
5. CTG performance from General Electric data received 5/21/98 for KUA.						
B&V Project 59140.0031						
File: d:\proj\kua\cc\ge\7fa_exh.wk4						
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KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* 100 Percent Load - Duct Firing - NG & DO *				
Case Name	Case 23	Case 24	Case 25	Case 26
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	On	Off	On	Off
HRSR Duct Firing On/Off	On	On	On	On
Ambient Temperature, F	102	102	102	102
Ambient Relative Humidity, %	45	45	45	45
CTG Compressor Inlet Temperature, F	84.7	102	84.7	102
CTG Compr. Inlet Relative Humidity, %	92	45	92	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	14.0	14.0	14.0	14.0
CTG Fuel Type	Natural Gas	Natural Gas	Distillate	Distillate
Number of CTGs	1	1	1	1
Gross CTG Output, kW	152,900	141,500	161,500	151,300
Gross CTG Heat Rate, Btu/kWh (LHV)	9,680	9,900	10,260	10,480
CTG Heat Input, MBtu/h (LHV)	1,480.07	1,400.85	1,656.99	1,585.62
CTG Heat Input, MBtu/h (HHV)	1,642.12	1,554.22	1,769.23	1,693.03
CTG Fuel Flow, lb/h	70,550	66,770	89,150	85,310
CTG Water Injection Flow, lb/h	0	0	94,100	93,960
CTG Steam Injection Flow, lb/h	0	0	0	0
Injection Ratio	0.000	0.000	1.056	1.101
CTG Exhaust Flow, lb/h	3,307,000	3,184,000	3,416,600	3,296,660
CTG Exhaust Temperature, F	1,143	1,157	1,131	1,145
Duct Burner Heat Input, MBtu/h (LHV)	39.02	36.72	16.91	32.53
Duct Burner Heat Input, MBtu/h (HHV)	43.29	40.74	18.06	34.73
Stack Exit Temperature, F	192	189	282	278
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	61.3	58.6	72.0	69.0

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* 100 Percent Load - Duct Firing - NG & DO *				
Case Name	Case 23	Case 24	Case 25	Case 26
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	On	Off	On	Off
HRS G Duct Firing On/Off	On	On	On	On
CTG Exhaust Analysis (Volume Basis - Wet)				
O2	12.19%	12.43%	11.06%	11.20%
CO2	3.70%	3.65%	5.26%	5.23%
H2O	10.78%	10.09%	12.77%	12.32%
N2	72.42%	72.92%	70.02%	70.37%
Ar	0.91%	0.92%	0.88%	0.88%
SO2	0.00001%	0.00001%	0.00114%	0.00114%
Total	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)				
NOx, ppmvd @ 15% O2	15.0	15.0	42.0	42.0
NOx, lb/h as NO2	89.6	84.8	285.1	272.8
CO, ppmvd	15.0	15.0	20.0	20.0
CO, ppmvw	13.4	13.5	17.4	17.5
CO, ppmvd @ 15% O2	12.3	12.5	14.4	14.6
CO, lb/h	44.1	42.7	59.4	57.5
UHC, ppmvd	7.85	7.79	8.02	7.98
UHC, ppmvw	7.00	7.00	7.00	7.00
UHC, ppmvd @ 15% O2	6.41	6.51	5.78	5.82
UHC, lb/h as CH4	13.20	12.68	13.64	13.14
VOC, ppmvd	1.57	1.56	4.01	3.99
VOC, ppmvw	1.40	1.40	3.50	3.50
VOC, ppmvd @ 15% O2	1.28	1.30	2.89	2.91
VOC, lb/h as CH4	2.64	2.54	6.82	6.57
SO2, ppmvd	0.13	0.13	13.12	12.97
SO2, ppmvw	0.12	0.12	11.45	11.37
SO2, lb/h	0.90	0.85	89.07	85.23
Particulates (TSP = PM10), lb/h (dry filterables only)	18.00	18.00	43.00	43.00
CTG Fuel LHV, Btu/lb				
CTG Fuel LHV, Btu/lb	20,980	20,980	18,586	18,586
CTG Fuel HHV, Btu/lb	23,277	23,277	19,845	19,845
HHV/LHV Ratio	1.1095	1.1095	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)				
Ar	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	86.135000%	86.135000%
H2	24.256660%	24.256660%	13.800000%	13.800000%
N2	0.575950%	0.575950%	0.015000%	0.015000%
O2	1.123180%	1.123180%	0.000000%	0.000000%
S	0.000640%	0.000640%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis				
Molecular Wt, lb/mol	28.12	28.19	28.13	28.17
Gas Constant, ft-lb/lbm-R	54.937	54.798	54.930	54.841
Specific Volume, ft ³ /lb	40.33	40.58	40.02	40.31
Exhaust Gas Flow, acfm	2,222,855	2,153,445	2,278,872	2,214,806
Specific Volume, scf/lb	13.49	13.46	13.49	13.47
Exhaust Gas Flow, scfm	743,524	714,277	768,166	740,100
Exhaust Gas Flow, lb/h	3,307,000	3,184,000	3,416,600	3,296,660

*** 100 Percent Load - Duct Firing - NG & DO ***

Case Name	Case 23 GE 7241FA DLN/15 ppm Natural Gas Base GE 05/21/98 On On	Case 24 GE 7241FA DLN/15 ppm Natural Gas Base GE 05/21/98 Off On	Case 25 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 On On	Case 26 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off On
CTG Model				
Combustor/NOx Emission Rate				
CTG Fuel Type				
CTG Load Level (percent of Base Load)				
CTG Performance Reference				
Evaporative Cooler On/Off				
HRSG Duct Firing On/Off				
Stack Exhaust Analysis (Volume Basis - Wet)				
Ar	0.91%	0.91%	0.88%	0.88%
CO2	3.79%	3.74%	5.32%	5.33%
H2O	10.96%	10.27%	12.82%	12.41%
N2	72.35%	72.85%	70.01%	70.33%
O2	11.99%	12.23%	10.98%	11.04%
SO2	0.00001%	0.00001%	0.00116%	0.00116%
Total	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)				
Molecular Wt, lb/mol	28.11	28.18	28.13	28.17
Gas Constant, ft-lbf/lbm-R	54.959	54.819	54.930	54.840
Specific Volume, ft ³ /lb	16.97	16.85	19.30	19.17
Exhaust Gas Flow, acfm	935,856	894,665	1,099,299	1,053,842
Specific Volume, scf/lb	13.50	13.46	13.49	13.47
Exhaust Gas Flow, scfm	744,494	714,670	768,370	740,493
Exhaust Gas Flow, lb/h	3,308,860	3,185,750	3,417,510	3,298,410
Emissions (at Stack exit)				
NOx, ppmvd @15% O2 without SCR	15.2	15.2	41.8	41.6
NOx, lb/h as NO2 without SCR	93.0	88.1	286.5	275.6
NOx, ppmvd @15% O2 with SCR	4.0	4.0	11.1	11.1
NOx, lb/h as NO2 with SCR	24.5	23.2	76.1	73.2
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	22.4	21.2	25.3	24.5
CO, ppmvd without Catalyst	16.5	16.4	20.6	21.2
CO, lb/h without Catalyst	48.4	46.7	61.2	61.0
CO, ppmvd @ 15% O2 without Catalyst	13.1	13.4	14.7	15.2
CO, ppmvd with Catalyst	16.5	16.4	20.6	21.2
CO, lb/h with Catalyst	48.4	46.7	61.2	61.0
CO, ppmvd @ 15% O2 with Catalyst	13.1	13.4	14.7	15.2
SO2, ppmvd	0.14	0.13	13.26	13.24
SO2, ppmvw	0.12	0.12	11.56	11.60
SO2, lb/h	0.93	0.88	89.98	86.98
UHC, ppmvd	9.4	9.3	8.7	9.3
UHC, ppmvw	8.4	8.3	7.6	8.1
UHC, ppmvd @ 15% O2	7.5	7.6	6.2	6.6
UHC, lb/h as CH4	15.8	15.1	14.7	15.2
VOC, ppmvd	1.9	1.9	4.1	4.2
VOC, ppmvw	1.7	1.7	3.6	3.7
VOC, ppmvd @ 15% O2	1.5	1.5	3.0	3.0
VOC, lb/h as CH4	3.2	3.0	7.0	7.0
Particulates (TSP = PM10), lb/h (dry filterables only)	18.6	18.6	43.3	43.5

Notes:

1. Values shown above are for one combustion turbine/HRSG unit only.
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100 scf added for illustration purposes only.
3. 73% effective SCR and no CO catalyst.
4. Particulates are front and back half.
5. CTG performance from General Electric data received 5/21/98 for KUA.
6. Duct Burner NOx, lb/MBtu (HHV) is 0.0800
7. Duct Burner CO, lb/MBtu (HHV) is 0.1000
8. Duct Burner Particulate, lb/MBtu (HHV) is 0.0150
9. Duct Burner UHC (CH4), lb/MBtu (HHV) is 0.0600
10. Duct Burner VOC (CH4), lb/MBtu (HHV) is 0.0120

B&V Project 59140.0031

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06/05/98

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSG Duct Firing On/Off	* 100 Percent Load - Distillate Oil *				
	Case 12 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off	Case 13 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 On Off	Case 14 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off	Case 15 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 On Off	Case 16 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off
Ambinet Temperature, F	19	72	72	102	102
Ambient Relative Humidity, %	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	66.7	72	84.7	102
CTG Compr. Inlet Relative Humidity, %	55	96	74	92	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	14.0	14.0	14.0	14.0	14.0
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate
Number of CTGs	1	1	1	1	1
Gross CTG Output, kW	189,300	174,000	171,500	161,500	151,300
Gross CTG Heat Rate, Btu/kWh (LHV)	10,090	10,110	10,150	10,260	10,480
CTG Heat Input, MBtu/h (LHV)	1,910.04	1,759.14	1,740.73	1,656.99	1,585.62
CTG Heat Input, MBtu/h (HHV)	2,039.42	1,878.30	1,858.65	1,769.23	1,693.03
CTG Fuel Flow, lb/h	102,770	94,650	93,660	89,150	85,310
CTG Water Injection Flow, lb/h	131,760	110,720	111,020	94,100	93,960
CTG Steam Injection Flow, lb/h	0	0	0	0	0
Injection Ratio	1.282	1.170	1.185	1.056	1.101
CTG Exhaust Flow, lb/h	3,901,400	3,586,520	3,552,540	3,416,600	3,296,660
CTG Exhaust Temperature, F	1,068	1,112	1,116	1,131	1,145
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0
Stack Exit Temperature, F	281	282	281	284	281
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	81.4	75.3	74.5	72.2	69.3

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* 100 Percent Load - Distillate Oil *					
Case Name	Case 12	Case 13	Case 14	Case 15	Case 16
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	On	Off	On	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)					
O2	11.38%	11.13%	11.16%	11.06%	11.20%
CO2	5.36%	5.34%	5.34%	5.26%	5.23%
H2O	10.60%	11.90%	11.80%	12.77%	12.32%
N2	71.76%	70.73%	70.81%	70.02%	70.37%
Ar	0.90%	0.89%	0.89%	0.88%	0.88%
SO2	0.00117%	0.00116%	0.00116%	0.00114%	0.00114%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)					
NOx, ppmvd @ 15% O2	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2	328.5	302.6	299.4	285.1	272.8
CO, ppmvd	20.0	20.0	20.0	20.0	20.0
CO, ppmvw	17.9	17.6	17.6	17.4	17.5
CO, ppmvd @ 15% O2	14.5	14.3	14.4	14.4	14.6
CO, lb/h	68.9	62.7	62.2	59.4	57.5
UHC, ppmvd	7.83	7.95	7.94	8.02	7.98
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00
UHC, ppmvd @ 15% O2	5.68	5.70	5.70	5.78	5.82
UHC, lb/h as CH4	15.44	14.27	14.13	13.64	13.14
VOC, ppmvd	3.91	3.97	3.97	4.01	3.99
VOC, ppmvw	3.50	3.50	3.50	3.50	3.50
VOC, ppmvd @ 15% O2	2.84	2.85	2.85	2.89	2.91
VOC, lb/h as CH4	7.72	7.13	7.06	6.82	6.57
SO2, ppmvd	13.04	13.19	13.17	13.12	12.97
SO2, ppmvw	11.66	11.62	11.61	11.45	11.37
SO2, lb/h	102.67	94.56	93.57	89.07	85.23
Particulates (TSP = PM10), lb/h (dry filterables only)	44.00	44.00	44.00	43.00	43.00
CTG Fuel LHV, Btu/lb					
CTG Fuel LHV, Btu/lb	18,586	18,586	18,586	18,586	18,586
CTG Fuel HHV, Btu/lb	19,845	19,845	19,845	19,845	19,845
HHV/LHV Ratio	1.0677	1.0677	1.0677	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)					
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	86.135000%	86.135000%	86.135000%	86.135000%	86.135000%
H2	13.800000%	13.800000%	13.800000%	13.800000%	13.800000%
N2	0.015000%	0.015000%	0.015000%	0.015000%	0.015000%
O2	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
S	0.050000%	0.050000%	0.050000%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis					
Molecular Wt, lb/mol	28.37	28.23	28.24	28.13	28.17
Gas Constant, ft-lb/lbm-R	54.449	54.729	54.708	54.930	54.841
Specific Volume, ft ³ /lb	38.10	39.40	39.48	40.02	40.31
Exhaust Gas Flow, acfm	2,477,389	2,355,148	2,337,571	2,278,872	2,214,806
Specific Volume, scf/lb	13.37	13.44	13.43	13.49	13.47
Exhaust Gas Flow, scfm	869,362	803,380	795,177	768,166	740,100
Exhaust Gas Flow, lb/h	3,901,400	3,586,520	3,552,540	3,416,600	3,296,660

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSG Duct Firing On/Off	* 100 Percent Load - Distillate Oil *				
	Case 12 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off	Case 13 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 On Off	Case 14 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off	Case 15 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 On Off	Case 16 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off
Stack Exhaust Analysis (Volume Basis - Wet)					
Ar	0.90%	0.89%	0.89%	0.88%	0.88%
CO2	5.36%	5.34%	5.34%	5.26%	5.23%
H2O	10.60%	11.90%	11.80%	12.77%	12.32%
N2	71.76%	70.73%	70.81%	70.02%	70.37%
O2	11.38%	11.13%	11.16%	11.06%	11.20%
SO2	0.00117%	0.00116%	0.00116%	0.00114%	0.00114%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)					
Molecular Wt, lb/mol	28.37	28.23	28.24	28.13	28.17
Gas Constant, ft-lbf/lbm-R	54.449	54.729	54.708	54.930	54.841
Specific Volume, ft ³ /lb	19.11	19.23	19.20	19.36	19.25
Exhaust Gas Flow, acfm	1,242,596	1,149,480	1,136,813	1,102,423	1,057,678
Specific Volume, scf/lb	13.37	13.44	13.43	13.49	13.47
Exhaust Gas Flow, scfm	869,362	803,380	795,177	768,166	740,100
Exhaust Gas Flow, lb/h	3,901,400	3,586,520	3,552,540	3,416,600	3,296,660
Emissions (at Stack exit)					
NOx, ppmvd @15% O2 without SCR	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2 without SCR	328.5	302.6	299.4	285.1	272.8
NOx, ppmvd @15% O2 with SCR	11.2	11.2	11.2	11.2	11.2
NOx, lb/h as NO2 with SCR	87.3	80.4	79.6	75.8	72.5
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	28.9	26.6	26.3	25.0	24.0
CO, ppmvd without Catalyst	20.0	20.0	20.0	20.0	20.0
CO, lb/h without Catalyst	68.9	62.7	62.2	59.4	57.5
CO, ppmvd @ 15% O2 without Catalyst	14.5	14.3	14.4	14.4	14.6
CO, ppmvd with Catalyst	20.0	20.0	20.0	20.0	20.0
CO, lb/h with Catalyst	68.9	62.7	62.2	59.4	57.5
CO, ppmvd @ 15% O2 with Catalyst	14.5	14.3	14.4	14.4	14.6
SO2, ppmvd	13.04	13.19	13.17	13.12	12.97
SO2, ppmvw	11.66	11.62	11.61	11.45	11.37
SO2, lb/h	102.67	94.56	93.57	89.07	85.23
UHC, ppmvd	7.8	7.9	7.9	8.0	8.0
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0
UHC, ppmvd @ 15% O2	5.7	5.7	5.7	5.8	5.8
UHC, lb/h as CH4	15.4	14.3	14.1	13.6	13.1
VOC, ppmvd	3.9	4.0	4.0	4.0	4.0
VOC, ppmvw	3.5	3.5	3.5	3.5	3.5
VOC, ppmvd @ 15% O2	2.8	2.8	2.9	2.9	2.9
VOC, lb/h as CH4	7.7	7.1	7.1	6.8	6.6
Particulates (TSP = PM10), lb/h (dry filterables only)	44.0	44.0	44.0	43.0	43.0
Notes: 1. Values shown above are for one combustion turbine/HRSG unit only. 2. 73% effective SCR and no CO catalyst. 3. Particulates are front and back half. 4. CTG performance from General Electric data received 5/21/98 for KUA.					
B&V Project 59140.0031 File: d:\proj\kualcc\gel7fa_exh.wk4 06/05/98					

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

Case Name	* 70 & 50 Percent Load - Distillate Oil *					
	Case 17 GE 7241FA DLN/42 ppm Distillate 70 Percent GE 05/21/98 Off Off	Case 18 GE 7241FA DLN/42 ppm Distillate 50 Percent GE 05/21/98 Off Off	Case 19 GE 7241FA DLN/42 ppm Distillate 70 Percent GE 05/21/98 Off Off	Case 20 GE 7241FA DLN/42 ppm Distillate 50 Percent GE 05/21/98 Off Off	Case 21 GE 7241FA DLN/42 ppm Distillate 70 Percent GE 05/21/98 Off Off	Case 22 GE 7241FA DLN/15 ppm Distillate 50 Percent GE 05/21/98 Off Off
Ambinet Temperature, F	19	19	72	72	102	102
Ambient Relative Humidity, %	55	55	74	74	45	45
CTG Compressor Inlet Temperature, F	19	19	72	72	102	102
CTG Compr. Inlet Relative Humidity, %	55	55	74	74	45	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75	75
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	14.0	14.0	14.0	14.0	14.0	14.0
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
Number of CTGs	1	1	1	1	1	1
Gross CTG Output, kW	132,500	94,600	121,800	87,000	113,100	80,800
Gross CTG Heat Rate, Btu/kWh (LHV)	11,240	12,810	11,260	12,970	11,510	13,260
CTG Heat Input, MBtu/h (LHV)	1,489.30	1,211.83	1,371.47	1,128.39	1,301.78	1,071.41
CTG Heat Input, MBtu/h (HHV)	1,590.18	1,293.92	1,464.37	1,204.83	1,389.96	1,143.99
CTG Fuel Flow, lb/h	80,130	65,200	73,790	60,710	70,040	57,650
CTG Water Injection Flow, lb/h	96,600	69,650	78,790	57,160	68,770	49,220
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
Injection Ratio	1.206	1.068	1.068	0.942	0.982	0.854
CTG Exhaust Flow, lb/h	2,806,750	2,446,980	2,715,850	2,398,050	2,676,900	2,357,100
CTG Exhaust Temperature, F	1,200	1,200	1,200	1,200	1,200	1,200
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0	0
Stack Exit Temperature, F	257	264	264	257	270	263
Stack Exhaust Pressure, in. H2O above Patm	0	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	56.7	49.7	55.5	48.4	55.3	48.1

* 70 & 50 Percent Load - Distillate Oil *						
Case Name	Case 17	Case 18	Case 19	Case 20	Case 21	Case 22
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/15 ppm
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
CTG Exhaust Analysis (Volume Basis - Wet)						
O2	10.66%	11.43%	10.96%	11.69%	11.19%	11.86%
CO2	5.81%	5.44%	5.51%	5.15%	5.30%	4.96%
H2O	11.12%	9.85%	11.63%	10.50%	11.96%	10.93%
N2	71.51%	72.37%	71.01%	71.75%	70.67%	71.35%
Ar	0.90%	0.91%	0.89%	0.90%	0.89%	0.90%
SO2	0.00126%	0.00118%	0.00120%	0.00112%	0.00115%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)						
NOx, ppmvd @ 15% O2	42.0	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2	256.3	208.8	236.1	194.5	224.2	184.7
CO, ppmvd	20.0	27.0	20.0	32.0	21.0	36.0
CO, ppmvw	17.8	24.3	17.7	28.6	18.5	32.1
CO, ppmvd @ 15% O2	13.3	19.5	13.9	24.2	15.2	28.1
CO, lb/h	49.3	58.6	47.5	67.8	49.1	74.8
UHC, ppmvd	7.88	7.77	7.92	7.82	7.95	7.86
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00	7.00
UHC, ppmvd @ 15% O2	5.24	5.60	5.52	5.91	5.75	6.13
UHC, lb/h as CH4	11.11	9.65	10.78	9.49	10.65	9.35
VOC, ppmvd	3.94	3.88	3.96	3.91	3.98	3.93
VOC, ppmvw	3.50	3.50	3.50	3.50	3.50	3.50
VOC, ppmvd @ 15% O2	2.62	2.80	2.76	2.96	2.87	3.07
VOC, lb/h as CH4	5.56	4.83	5.39	4.75	5.33	4.68
SO2, ppmvd	14.21	13.12	13.56	12.51	13.08	12.12
SO2, ppmvw	12.63	11.83	11.98	11.20	11.51	10.79
SO2, lb/h	80.06	65.14	73.72	60.65	69.97	57.60
Particulates (TSP = PM10), lb/h (dry filterables only)	42.00	41.00	41.00	40.00	41.00	40.00
CTG Fuel LHV, Btu/lb	18,586	18,586	18,586	18,586	18,586	18,586
CTG Fuel HHV, Btu/lb	19,845	19,845	19,845	19,845	19,845	19,845
HHV/LHV Ratio	1.0677	1.0677	1.0677	1.0677	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	86.135000%	86.135000%	86.135000%	86.135000%	86.135000%	86.135000%
H2	13.800000%	13.800000%	13.800000%	13.800000%	13.800000%	13.800000%
N2	0.015000%	0.015000%	0.015000%	0.015000%	0.015000%	0.015000%
O2	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
S	0.050000%	0.050000%	0.050000%	0.050000%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.36	28.46	28.28	28.36	28.22	28.30
Gas Constant, ft-lbf/lbm-R	54.469	54.277	54.636	54.472	54.751	54.600
Specific Volume, ft ³ /lb	41.41	41.26	41.53	41.41	41.62	41.51
Exhaust Gas Flow, acfm	1,937,125	1,682,707	1,879,821	1,655,054	1,856,876	1,630,720
Specific Volume, scf/lb	13.38	13.33	13.42	13.38	13.44	13.41
Exhaust Gas Flow, scfm	625,905	543,637	607,445	534,765	599,626	526,812
Exhaust Gas Flow, lb/h	2,806,750	2,446,980	2,715,850	2,398,050	2,676,900	2,357,100

* 70 & 50 Percent Load - Distillate Oil *						
Case Name	Case 17	Case 18	Case 19	Case 20	Case 21	Case 22
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm	DLN/15 ppm
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	70 Percent	50 Percent	70 Percent	50 Percent	70 Percent	50 Percent
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.90%	0.91%	0.89%	0.90%	0.89%	0.90%
CO2	5.81%	5.44%	5.51%	5.15%	5.30%	4.96%
H2O	11.12%	9.85%	11.63%	10.50%	11.96%	10.93%
N2	71.51%	72.37%	71.01%	71.75%	70.67%	71.35%
O2	10.66%	11.43%	10.96%	11.69%	11.19%	11.86%
SO2	0.00126%	0.00118%	0.00120%	0.00112%	0.00115%	0.00108%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)						
Molecular Wt, lb/mol	28.36	28.46	28.28	28.36	28.22	28.30
Gas Constant, ft-lbf/lbm-R	54.469	54.277	54.636	54.472	54.751	54.600
Specific Volume, ft ³ /lb	18.50	18.61	18.73	18.50	18.93	18.70
Exhaust Gas Flow, acfm	865,415	758,972	847,798	739,399	844,562	734,630
Specific Volume, scf/lb	13.38	13.33	13.42	13.38	13.44	13.41
Exhaust Gas Flow, scfm	625,905	543,637	607,445	534,765	599,626	526,812
Exhaust Gas Flow, lb/h	2,806,750	2,446,980	2,715,850	2,398,050	2,676,900	2,357,100
Emissions (at Stack exit)						
NOx, ppmvd @15% O2 without SCR	42.0	42.0	42.0	42.0	42.0	42.0
NOx, lb/h as NO2 without SCR	256.3	208.8	236.1	194.5	224.2	184.7
NOx, ppmvd @15% O2 with SCR	11.2	11.2	11.2	11.2	11.2	11.2
NOx, lb/h as NO2 with SCR	68.1	55.4	62.7	51.6	59.5	49.0
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	22.5	18.3	20.7	17.1	19.7	16.2
CO, ppmvd without Catalyst	20.0	27.0	20.0	32.0	21.0	36.0
CO, lb/h without Catalyst	49.3	58.6	47.5	67.8	49.1	74.8
CO, ppmvd @ 15% O2 without Catalyst	13.3	19.5	13.9	24.2	15.2	28.1
CO, ppmvd with Catalyst	20.0	27.0	20.0	32.0	21.0	36.0
CO, lb/h with Catalyst	49.3	58.6	47.5	67.8	49.1	74.8
CO, ppmvd @ 15% O2 with Catalyst	13.3	19.5	13.9	24.2	15.2	28.1
SO2, ppmvd	14.21	13.12	13.56	12.51	13.08	12.12
SO2, ppmvw	12.63	11.83	11.98	11.20	11.51	10.79
SO2, lb/h	80.06	65.14	73.72	60.65	69.97	57.60
UHC, ppmvd	7.9	7.8	7.9	7.8	8.0	7.9
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0
UHC, ppmvd @ 15% O2	5.2	5.6	5.5	5.9	5.7	6.1
UHC, lb/h as CH4	11.1	9.7	10.8	9.5	10.7	9.4
VOC, ppmvd	3.9	3.9	4.0	3.9	4.0	3.9
VOC, ppmvw	3.5	3.5	3.5	3.5	3.5	3.5
VOC, ppmvd @ 15% O2	2.6	2.8	2.8	3.0	2.9	3.1
VOC, lb/h as CH4	5.6	4.8	5.4	4.7	5.3	4.7
Particulates (TSP = PM10), lb/h (dry filterables only)	42.0	41.0	41.0	40.0	41.0	40.0
Notes:						
1. Values shown above are for one combustion turbine/HRSG unit only.						
2. 73% effective SCR and no CO catalyst.						
3. Particulates are front and back half.						
4. CTG performance from General Electric data received 5/21/98 for KUA.						
B&V Project 59140.0031						
File: d:\proj\kua\cc\ge\7fa_exh.wk4						
06/05/98						

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

Case Name	* Simple Cycle - 100 Percent Load - NG & DO *					
	Case 1	Case 3	Case 5	Case 12	Case 14	Case 16
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Ambient Temperature, F	19	72	102	19	72	102
Ambient Relative Humidity, %	55	74	45	55	74	45
CTG Compressor Inlet Temperature, F	19	72	102	19	72	102
CTG Compr. Inlet Relative Humidity, %	55	74	45	55	74	45
Atmospheric Pressure, psia	14.656	14.656	14.656	14.656	14.656	14.656
Site Elevation, ft	75	75	75	75	75	75
Inlet Loss, in. H ₂ O	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H ₂ O	5.5	5.5	5.5	5.5	5.5	5.5
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
Number of CTGs	1	1	1	1	1	1
Gross CTG Output, kW	183,700	162,800	143,000	189,800	172,500	152,800
Gross CTG Heat Rate, Btu/kWh (LHV)	9,230	9,410	9,800	10,060	10,080	10,370
CTG Heat Input, MBtu/h (LHV)	1,695.55	1,531.95	1,401.40	1,909.39	1,738.80	1,584.54
CTG Heat Input, MBtu/h (HHV)	1,881.19	1,699.68	1,554.83	2,038.73	1,856.58	1,691.88
CTG Fuel Flow, lb/h	80,820	73,020	66,800	102,730	93,550	85,250
CTG Water Injection Flow, lb/h	0	0	0	131,790	110,950	93,940
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
Injection Ratio	0.000	0.000	0.000	1.283	1.186	1.102
CTG Exhaust Flow, lb/h	3,785,000	3,420,000	3,184,000	3,903,000	3,554,000	3,298,000
CTG Exhaust Temperature, F	1,080	1,127	1,151	1,067	1,112	1,139
Duct Burner Heat Input, MBtu/h (LHV)	0	0	0	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	0	0	0	0	0	0
Stack Exit Temperature, F	1080	1127	1151	1067	1112	1139
Stack Exhaust Pressure, in. H ₂ O above Patm	0	0	0	0	0	0
Stack Diameter, ft	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	163.4	153.2	145.4	167.8	158.1	149.5

Case Name CTG Model Combustor/NOx Emission Rate CTG Fuel Type CTG Load Level (percent of Base Load) CTG Performance Reference Evaporative Cooler On/Off HRSG Duct Firing On/Off	* Simple Cycle - 100 Percent Load - NG & DO *					
	Case 1 GE 7241FA DLN/15 ppm Natural Gas Base GE 05/21/98 Off Off	Case 3 GE 7241FA DLN/15 ppm Natural Gas Base GE 05/21/98 Off Off	Case 5 GE 7241FA DLN/15 ppm Natural Gas Base GE 05/21/98 Off Off	Case 12 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off	Case 14 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off	Case 16 GE 7241FA DLN/42 ppm Distillate Base GE 05/21/98 Off Off
CTG Exhaust Analysis (Volume Basis - Wet)						
O2	12.79%	12.48%	12.43%	11.39%	11.17%	11.21%
CO2	3.75%	3.73%	3.65%	5.36%	5.33%	5.22%
H2O	7.49%	9.15%	10.09%	10.59%	11.79%	12.31%
N2	75.03%	73.71%	72.92%	71.76%	70.81%	70.37%
Ar	0.94%	0.93%	0.92%	0.90%	0.89%	0.88%
SO2	0.00001%	0.00001%	0.00001%	0.00116%	0.00116%	0.00114%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (at CTG exhaust flange)						
NOx, ppmvd @ 15% O2	15.0	15.0	15.0	42.0	42.0	42.0
NOx, lb/h as NO2	102.4	92.7	84.8	328.4	299.1	272.7
CO, ppmvd	15.0	15.0	15.0	20.0	20.0	20.0
CO, ppmvw	13.9	13.6	13.5	17.9	17.6	17.5
CO, ppmvd @ 15% O2	12.5	12.4	12.5	14.5	14.4	14.6
CO, lb/h	51.6	46.1	42.7	68.9	62.2	57.5
UHC, ppmvd	7.57	7.71	7.79	7.83	7.94	7.98
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00	7.00
UHC, ppmvd @ 15% O2	6.33	6.37	6.51	5.68	5.71	5.83
UHC, lb/h as CH4	14.92	13.57	12.68	15.45	14.13	13.15
VOC, ppmvd	1.51	1.54	1.56	3.91	3.97	3.99
VOC, ppmvw	1.40	1.40	1.40	3.50	3.50	3.50
VOC, ppmvd @ 15% O2	1.27	1.27	1.30	2.84	2.86	2.91
VOC, lb/h as CH4	2.98	2.71	2.54	7.72	7.07	6.57
SO2, ppmvd	0.13	0.13	0.13	13.03	13.14	12.95
SO2, ppmvw	0.12	0.12	0.12	11.65	11.59	11.36
SO2, lb/h	1.03	0.93	0.85	102.63	93.46	85.17
Particulates (TSP = PM10), lb/h (dry filterables only)	18.00	18.00	18.00	44.00	44.00	43.00
CTG Fuel LHV, Btu/lb	20,980	20,980	20,980	18,586	18,586	18,586
CTG Fuel HHV, Btu/lb	23,277	23,277	23,277	19,845	19,845	19,845
HHV/LHV Ratio	1.1095	1.1095	1.1095	1.0677	1.0677	1.0677
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
C	74.043570%	74.043570%	74.043570%	86.135000%	86.135000%	86.135000%
H2	24.256660%	24.256660%	24.256660%	13.800000%	13.800000%	13.800000%
N2	0.575950%	0.575950%	0.575950%	0.015000%	0.015000%	0.015000%
O2	1.123180%	1.123180%	1.123180%	0.000000%	0.000000%	0.000000%
S	0.000640%	0.000640%	0.000640%	0.050000%	0.050000%	0.050000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.49	28.30	28.19	28.38	28.24	28.17
Gas Constant, ft-lbf/lbm-R	54.232	54.585	54.798	54.449	54.707	54.840
Specific Volume, ft ³ /lb	39.04	40.49	41.26	38.86	40.20	40.99
Exhaust Gas Flow, acfm	2,462,773	2,307,930	2,189,531	2,527,843	2,381,180	2,253,084
Specific Volume, scf/lb	13.32	13.40	13.46	13.37	13.43	13.47
Exhaust Gas Flow, scfm	840,270	763,800	714,277	869,719	795,504	740,401
Exhaust Gas Flow, lb/h	3,785,000	3,420,000	3,184,000	3,903,000	3,554,000	3,298,000

KUA Cane Island Unit 3
GE 7FA 1x1 Combined Cycle

* Simple Cycle - 100 Percent Load - NG & DO *						
Case Name	Case 1	Case 3	Case 5	Case 12	Case 14	Case 16
CTG Model	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA	GE 7241FA
Combustor/NOx Emission Rate	DLN/15 ppm	DLN/15 ppm	DLN/15 ppm	DLN/42 ppm	DLN/42 ppm	DLN/42 ppm
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level (percent of Base Load)	Base	Base	Base	Base	Base	Base
CTG Performance Reference	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98	GE 05/21/98
Evaporative Cooler On/Off	Off	Off	Off	Off	Off	Off
HRSG Duct Firing On/Off	Off	Off	Off	Off	Off	Off
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.94%	0.93%	0.92%	0.90%	0.89%	0.88%
CO2	3.75%	3.73%	3.65%	5.36%	5.33%	5.22%
H2O	7.49%	9.15%	10.09%	10.59%	11.79%	12.31%
N2	75.03%	73.71%	72.92%	71.76%	70.81%	70.37%
O2	12.79%	12.48%	12.43%	11.39%	11.17%	11.21%
SO2	0.00001%	0.00001%	0.00001%	0.00116%	0.00116%	0.00114%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Stack Exhaust Gas Analysis (Wet)						
Molecular Wt, lb/mol	28.49	28.30	28.19	28.38	28.24	28.17
Gas Constant, ft-lb/lbm-R	54.232	54.585	54.798	54.449	54.707	54.840
Specific Volume, ft ³ /lb	39.56	41.04	41.82	39.39	40.74	41.54
Exhaust Gas Flow, acfm	2,495,577	2,339,280	2,219,248	2,562,320	2,413,166	2,283,315
Specific Volume, scf/lb	13.32	13.40	13.46	13.37	13.43	13.47
Exhaust Gas Flow, scfm	840,270	763,800	714,277	869,719	795,504	740,401
Exhaust Gas Flow, lb/h	3,785,000	3,420,000	3,184,000	3,903,000	3,554,000	3,298,000
Emissions (at Stack exit)						
NOx, ppmvd @15% O2 without SCR	15.0	15.0	15.0	42.0	42.0	42.0
NOx, lb/h as NO2 without SCR	102.4	92.7	84.8	328.4	299.1	272.7
NOx, ppmvd @15% O2 with SCR	4.0	4.0	4.0	11.2	11.2	11.2
NOx, lb/h as NO2 with SCR	27.1	24.4	22.4	87.3	79.5	72.4
NH3 slip, ppmvd @15% O2 with SCR	10.0	10.0	10.0	10.0	10.0	10.0
NH3 slip, lb/h with SCR	25.0	22.6	20.7	28.9	26.3	23.9
CO, ppmvd without Catalyst	15.0	15.0	15.0	20.0	20.0	20.0
CO, lb/h without Catalyst	51.6	46.1	42.7	68.9	62.2	57.5
CO, ppmvd @ 15% O2 without Catalyst	12.5	12.4	12.5	14.5	14.4	14.6
CO, ppmvd with Catalyst	15.0	15.0	15.0	20.0	20.0	20.0
CO, lb/h with Catalyst	51.6	46.1	42.7	68.9	62.2	57.5
CO, ppmvd @ 15% O2 with Catalyst	12.5	12.4	12.5	14.5	14.4	14.6
SO2, ppmvd	0.13	0.13	0.13	13.03	13.14	12.95
SO2, ppmvw	0.12	0.12	0.12	11.65	11.59	11.36
SO2, lb/h	1.03	0.93	0.85	102.63	93.46	85.17
UHC, ppmvd	7.6	7.7	7.8	7.8	7.9	8.0
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0
UHC, ppmvd @ 15% O2	6.3	6.4	6.5	5.7	5.7	5.8
UHC, lb/h as CH4	14.9	13.6	12.7	15.4	14.1	13.1
VOC, ppmvd	1.5	1.5	1.6	3.9	4.0	4.0
VOC, ppmvw	1.4	1.4	1.4	3.5	3.5	3.5
VOC, ppmvd @ 15% O2	1.3	1.3	1.3	2.8	2.9	2.9
VOC, lb/h as CH4	3.0	2.7	2.5	7.7	7.1	6.6
Particulates (TSP = PM10), lb/h (dry filterables only)	18.0	18.0	18.0	44.0	44.0	43.0
Notes:						
1. Values shown above are for one combustion turbine/HRSG unit only.						
2. Sample analysis for natural gas fuel received from KUA, sulfur at 0.2 gr/100 scf added for illustration purposes only.						
3. 73% effective SCR and no CO catalyst.						
4. Particulates are front and back half.						
5. CTG performance from General Electric data received 5/21/98 for KUA.						
Rev. 1						
B&V Project 59140.0031						
File: d:\project\kua\7fa_exh.wk4						
07/14/98						

Attachment 2
(Tanks Model Output)

IMAGE QUALITY

AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

06/25/98
PAGE 1

Identification

Identification No.: 67
City: Cane Island
State: FL
Company: KUA
Type of Tank: Vertical Fixed Roof
Description: Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft): 35.0
Diameter (ft): 70.0
Liquid Height (ft): 34.8
Avg. Liquid Height (ft): 17.0
Volume (gallons): 1000000
Turnovers: 10.5
Net Throughput (gal/yr): 10495660

Paint Characteristics

Shell Color/Shade: White/White
Shell Condition: Good
Roof Color/Shade: White/White
Roof Condition: Good

Roof Characteristics

Type: Dome
Height (ft): 0.00
Radius (ft) (Dome Roof): 56.00
Slope (ft/ft) (Cone Roof): 0.0000

Breather Vent Settings

Vacuum Setting (psig): -0.03
Pressure Setting (psig): 0.03

Meteorological Data Used in Emission Calculations: Orlando, Florida

(Avg Atmospheric Pressure = 14.7 psia)

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
LIQUID CONTENTS OF STORAGE TANK

06/25/98
PAGE 2

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Distillate fuel oil no. 2	All	74.41	68.90	79.92	72.42	0.0103	0.0087	0.0122	130.000				188.00 Option 3: A=12.1010, B=8907.0

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
DETAIL CALCULATIONS (AP-42)

06/25/98
PAGE 3

Annual Emission Calculations

Standing Losses (lb):	295.6338
Vapor Space Volume (cu ft):	93882.05
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.037443
Vented Vapor Saturation Factor:	0.986867

Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	93882.05
Tank Diameter (ft):	70.0
Vapor Space Outage (ft):	24.39
Tank Shell Height (ft):	35.0
Average Liquid Height (ft):	17.0
Roof Outage (ft):	6.39

Roof Outage (Dome Roof)	
Roof Outage (ft):	6.39
Dome Radius (ft):	56
Shell Radius (ft):	35.0

Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	0.010293
Daily Avg. Liquid Surface Temp. (deg. R):	534.08
Daily Average Ambient Temp. (deg. R):	532.07
Ideal Gas Constant R	
(psia cuft / (lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.09
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation	
Factor (Btu/sqftday):	1487.00

Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.037443
Daily Vapor Temperature Range (deg.R):	22.05
Daily Vapor Pressure Range (psia):	0.003554
Breather Vent Press. Setting Range (psia):	0.06
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	0.010293
Vapor Pressure at Daily Minimum Liquid	
Surface Temperature (psia):	0.008651
Vapor Pressure at Daily Maximum Liquid	
Surface Temperature (psia):	0.012204
Daily Avg. Liquid Surface Temp. (deg R):	534.08
Daily Min. Liquid Surface Temp. (deg R):	528.57
Daily Max. Liquid Surface Temp. (deg R):	539.59
Daily Ambient Temp. Range (deg.R):	20.80

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
DETAIL CALCULATIONS (AP-42)

06/25/98
PAGE 4

Annual Emission Calculations

Vented Vapor Saturation Factor

Vented Vapor Saturation Factor: 0.986867

Vapor Pressure at Daily Average Liquid

Surface Temperature (psia): 0.010293

Vapor Space Outage (ft): 24.39

Working Losses (lb): 334.3891

Vapor Molecular Weight (lb/lb-mole): 130.000000

Vapor Pressure at Daily Average Liquid

Surface Temperature (psia): 0.010293

Annual Net Throughput (gal/yr): 10495660

Turnover Factor: 1.0000

Maximum Liquid Volume (cuft): 133926

Maximum Liquid Height (ft): 34.8

Tank Diameter (ft): 70.0

Working Loss Product Factor: 1.00

Total Losses (lb): 630.02

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
INDIVIDUAL TANK EMISSION TOTALS

06/25/98
PAGE 5

Annual Emissions Report

Liquid Contents	Losses (lbs.):		Total
	Standing	Working	
Distillate fuel oil no. 2	295.63	334.39	630.02
Total:	295.63	334.39	630.02

Attachment 3
(Emission Calculation Spreadsheet)

[illegible]

Attachment 4
(Dispersion Modeling Protocol)

BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 458-2000

Kissimmee Utility Authority
Cane Island Unit 3

B&V Project 59140
B&V File 15.0203
May 26, 1998

Via FEDEX and Fax

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Twin Towers Office Building, MS #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Pre-Application Meeting-
Air Dispersion Modeling
Methodology

Attention: Cleave Holladay

Gentlemen:

Thank-you for the opportunity to meet with you last Wednesday, May 20, 1998, regarding PSD pre-application issues for the proposed Cane Island Power Park modifications. As you recall, the purpose of the meeting was to review and agree on the proposed methodology and content of the Cane Island Unit 3 PSD air permit application and air dispersion modeling workplan. Throughout the course of the meeting, several air dispersion modeling issues pertaining to the PSD air quality impact analysis were discussed. The purpose of this letter is to summarize the proposed air dispersion modeling methodology in order that it may serve as a workplan for conducting the forthcoming PSD air quality impact analysis.

The following decisions regarding the air dispersion modeling analysis were made during the course of the meeting:

- Air Dispersion Model: ISCST3 (Ver. 97363).
- Model Options: EPA default and flat terrain.
- Screening Modeling: Envelope worst-case emission and stack parameter data across multiple vendor and ambient temperature data for each of 3 load points. *The term envelope refers to selecting the highest emission rate, lowest exit velocity, and lowest exit temperature*

Florida Department of Environmental Protection
Cleave Holladay

B&V Project 59140
May 26, 1998

from a range of operating conditions. Model each "enveloped" representative load data set to determine which results in the highest impact on a 1-hour basis using SCREEN3 worst-case meteorological data in ISC on a pollutant by pollutant basis.

- Refined Modeling: The enveloped load data resulting in the highest ground-level impact for each pollutant in the screening analysis will be used in the refined modeling analysis with sequential meteorological data.
- GEP & Downwash: EPA's BPIP program will be used to determine GEP stack height and direction specific building downwash for the HRSB stack and bypass stack.
- Receptor Grids: The modeling analysis will use a 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 500 m spacing from 1 to 5 km, and 1,000 m spacing from 5 to 10 km. Additionally, fence-line receptors at 50 m spacing and 100 m fine grids at the maximum impact locations will be used.
- Dispersion Coefficients: Rural; based on a visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.
- Meteorological Data: For screening level modeling, a matrix of worst-case meteorological parameters based on the SCREEN3 model will be used. Refined level modeling will use sequential meteorological data consisting of the most recent 5 years of surface and upper air data available for Orlando and Tampa/Ruskin, respectively.
- Modeled Impacts: It is anticipated that the maximum model predicted impacts will be less than the PSD significant impact levels (SILs) for all applicable pollutants and averaging times. If this is not the case, additional agency consultation regarding increment and ambient air quality impact analyses will be

Florida Department of Environmental Protection
Cleave Holladay

B&V Project 59140
May 26, 1998

initiated.

- Class I Analysis: A regional haze visibility study and Class I SIL analysis will be performed for the Chassahowitzka NWR located approximately 105 km northwest of the site.
- Toxics: A toxic modeling analysis is not required.

If you have any questions or comments regarding the aforementioned air dispersion modeling methodology, please do not hesitate to call me at 913-458-7928.

Very truly yours,

BLACK & VEATCH


T. M. Hillman
Air Quality Scientist

tmh

cc: Al Linero (FDEP/DARM/BAR)
Ben Sharma (KUA)
Jeff Ling (KUA)
Tasha Buford (YVV)

BLACK & EATCH

TELEPHONE MEMORANDUM

KUA
KUA Unit 3
Alternate Meteorological Data
for Air Dispersion Modeling

B&V Project 591490.0030
B&V File 32.0000
June 11, 1998
3 p.m.

To: Cleve Holiday
Company: FDEP
Phone No.: 850-921-9530

Recorded by: K. J. Lucas

Tim Hillman contacted Mr. Cleve Holiday at the FDEP on June 10, 1998 to discuss NCDC's current meteorological data processing and availability problems and to request the alternate use of meteorological data from the USEPA SCRAM bulletin board for the years 1987 through 1991. This alternate meteorological data (Orlando surface data and Tampa upper air data) would be used for KUA's proposed Unit 3 AQIA. Mr. Holiday was unavailable, but returned the phone call later in the day stating the alternate choice of meteorological data would be acceptable.

kjl

Attachment 5
(VISCREEN Model Output)

Visual Effects Screening Analysis for
Source: Unit 3
Class I Area: Chassahowitzka

*** Level-1 Screening ***

Input Emissions for

Particulates	112.60	LB /HR
NOx (as NO2)	328.50	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	105.00 km
Min. Source-Class I Distance:	105.00 km
Max. Source-Class I Distance:	125.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	84.	105.0	84.	2.00	.089	.05	.000
SKY	140.	84.	105.0	84.	2.00	.015	.05	-.001
TERRAIN	10.	84.	105.0	84.	2.00	.006	.05	.000
TERRAIN	140.	84.	105.0	84.	2.00	.002	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	75.	101.6	94.	2.00	.093	.05	.000
SKY	140.	75.	101.6	94.	2.00	.016	.05	-.001
TERRAIN	10.	60.	96.0	109.	2.00	.008	.05	.000
TERRAIN	140.	60.	96.0	109.	2.00	.002	.05	.000

Attachment 6
(Regional Haze Calculation Spreadsheet)

Calculation of Extinction per Year Maximum Impact

Background Visibility
Background Extinction

25.0 km
0.15648 km⁻¹

Scenario Name	Actual 24-hr Impact (ug/m ³)	Date (y/m/d/y)	X Coordinate	Y Coordinate	NO2 Impact (ug/m ³)	NO3 Impact (ug/m ³)	NH4NO3 (ug/m ³)	Minimum Daily Relative Humidity (%)	Maximum Daily Relative Humidity (%)	Average Daily Relative Humidity (%)	Estimated Relative Humidity Factor	NH4NO3 Source Extinction (km ⁻¹)	Scenario Name	Actual 24-hr Impact (ug/m ³)	X Coordinate	Y Coordinate	PM Source Extinction (km ⁻¹)	Source Change in Extinction (%)	Pass/Fail 5.0% Change
NOx																			
1987 NSCC1NG	0.1338	87070224	348451.5	3165401.0	0.13380	0.18063	0.23301	51	97	74.0	2.8	0.00182	PSCC1NG	0.0243	348451.5	3165401.0	0.00007	1.21	PASS
NSCC7NG	0.1221	87070224	348451.5	3165401.0	0.12210	0.16484	0.21264	51	97	74.0	2.8	0.00166	PSCC7NG	0.0259	348451.5	3165401.0	0.00008	1.11	PASS
NSCC5NG	0.2965	87070224	348451.5	3165401.0	0.29650	0.40028	0.51635	51	97	74.0	2.8	0.00403	PSCC5NG	0.0273	348451.5	3165401.0	0.00008	2.83	PASS
NSCC1FO	0.3214	87070224	348451.5	3165401.0	0.32140	0.43389	0.55972	51	97	74.0	2.8	0.00437	PSCC1FO	0.0835	348451.5	3165401.0	0.00025	2.95	PASS
NSCC7FO	0.2860	87070224	348451.5	3165401.0	0.28600	0.38610	0.49807	51	97	74.0	2.8	0.00388	PSCC7FO	0.1115	348451.5	3165401.0	0.00033	2.70	PASS
NSCC5FO	0.2480	87070224	348451.5	3165401.0	0.24800	0.33480	0.43189	51	97	74.0	2.8	0.00337	PSCC5FO	0.1338	348451.5	3165401.0	0.00040	2.41	PASS
NSCC1NG	0.0482	87061824	348451.5	3165401.0	0.04820	0.06237	0.08046	40	91	65.5	1.9	0.00046	PSCC1NG	0.0081	348451.5	3165401.0	0.00002	0.31	PASS
NSCC1FO	0.1511	87061824	348451.5	3165401.0	0.15110	0.20369	0.26314	40	91	65.5	1.9	0.00150	PSCC1FO	0.0354	348451.5	3165401.0	0.00011	1.03	PASS
NOx																			
1988 NSCC1NG	0.1163	88020124	348451.5	3165401.0	0.11625	0.15694	0.20245	49	100	74.5	2.6	0.00158	PSCC1NG	0.0211	348451.5	3165401.0	0.00006	1.05	PASS
NSCC7NG	0.1009	88020124	348451.5	3165401.0	0.10090	0.13622	0.17572	49	100	74.5	2.6	0.00137	PSCC7NG	0.0214	348451.5	3165401.0	0.00006	0.92	PASS
NSCC5NG	0.2386	88020124	348451.5	3165401.0	0.23860	0.32211	0.41552	49	100	74.5	2.6	0.00324	PSCC5NG	0.0220	348451.5	3165401.0	0.00007	2.11	PASS
NSCC1FO	0.3282	88020124	348451.5	3165401.0	0.32820	0.44037	0.56808	49	100	74.5	2.6	0.00443	PSCC1FO	0.0847	348451.5	3165401.0	0.00025	2.99	PASS
NSCC7FO	0.2714	88020124	348451.5	3165401.0	0.27140	0.36039	0.47264	49	100	74.5	2.6	0.00389	PSCC7FO	0.1058	348451.5	3165401.0	0.00032	2.56	PASS
NSCC5FO	0.2280	88020124	348451.5	3165401.0	0.22800	0.30780	0.38706	49	100	74.5	2.6	0.00310	PSCC5FO	0.1230	348451.5	3165401.0	0.00037	2.22	PASS
NSCC1NG	0.0592	88020124	348451.5	3165401.0	0.05920	0.07992	0.10310	49	100	74.5	2.6	0.00080	PSCC1NG	0.0104	348451.5	3165401.0	0.00003	0.53	PASS
NSCC1FO	0.1934	88020124	348451.5	3165401.0	0.19340	0.26109	0.33681	49	100	74.5	2.6	0.00263	PSCC1FO	0.0505	348451.5	3165401.0	0.00015	1.76	PASS
NOx																			
1989 NSCC1NG	0.1386	89091524	348451.5	3165401.0	0.13860	0.18711	0.24137	52	97	74.5	2.6	0.00188	PSCC1NG	0.0251	348451.5	3165401.0	0.00008	1.25	PASS
NSCC7NG	0.1355	89082724	348451.5	3165401.0	0.13550	0.18293	0.23587	52	97	74.5	2.6	0.00184	PSCC7NG	0.0287	348451.5	3165401.0	0.00009	1.23	PASS
NSCC5NG	0.3232	89082724	348451.5	3165401.0	0.32325	0.43639	0.56294	52	97	74.5	2.6	0.00439	PSCC5NG	0.0297	348451.5	3165401.0	0.00009	2.86	PASS
NSCC1FO	0.3314	89091524	348451.5	3165401.0	0.33140	0.44739	0.57713	52	97	74.5	2.6	0.00450	PSCC1FO	0.0861	348451.5	3165401.0	0.00026	3.04	PASS
NSCC7FO	0.2952	89091524	348451.5	3165401.0	0.29520	0.39852	0.51409	52	97	74.5	2.6	0.00401	PSCC7FO	0.1151	348451.5	3165401.0	0.00035	2.78	PASS
NSCC5FO	0.2583	89091524	348451.5	3165401.0	0.25830	0.34850	0.44535	52	97	74.5	2.6	0.00348	PSCC5FO	0.1382	348451.5	3165401.0	0.00041	2.48	PASS
NSCC1NG	0.0540	89101724	348451.5	3165401.0	0.05400	0.07290	0.09454	44	97	70.5	2.4	0.00068	PSCC1NG	0.0285	348451.5	3165401.0	0.00003	0.45	PASS
NSCC1FO	0.1781	89101724	348451.5	3165401.0	0.17810	0.23774	0.30668	44	97	70.5	2.4	0.00221	PSCC1FO	0.0460	348451.5	3165401.0	0.00014	1.50	PASS
NOx																			
1990 NSCC1NG	0.1816	90020124	348451.5	3165401.0	0.18160	0.24543	0.31690	53	100	76.5	2.8	0.00296	PSCC1NG	0.0330	348451.5	3165401.0	0.00010	1.76	PASS
NSCC7NG	0.1631	90020124	348451.5	3165401.0	0.16310	0.22016	0.28404	53	100	76.5	2.8	0.00239	PSCC7NG	0.0346	348451.5	3165401.0	0.00010	1.59	PASS
NSCC5NG	0.3924	90020124	348451.5	3165401.0	0.39240	0.52974	0.68336	53	100	76.5	2.8	0.00574	PSCC5NG	0.0361	348451.5	3165401.0	0.00011	3.74	PASS
NSCC1FO	0.4819	90020124	348451.5	3165401.0	0.48190	0.62356	0.80440	53	100	76.5	2.8	0.00676	PSCC1FO	0.1200	348451.5	3165401.0	0.00036	4.55	PASS
NSCC7FO	0.4018	90020124	348451.5	3165401.0	0.40180	0.54218	0.69839	53	100	76.5	2.8	0.00587	PSCC7FO	0.1586	348451.5	3165401.0	0.00047	4.05	PASS
NSCC5FO	0.3446	90020124	348451.5	3165401.0	0.34460	0.46521	0.60012	53	100	76.5	2.8	0.00504	PSCC5FO	0.1859	348451.5	3165401.0	0.00056	3.58	PASS
NSCC1NG	0.0630	90020124	348451.5	3165401.0	0.06300	0.08505	0.10971	53	100	76.5	2.8	0.00092	PSCC1NG	0.0111	348451.5	3165401.0	0.00003	0.61	PASS
NSCC1FO	0.2073	90020124	348451.5	3165401.0	0.20730	0.27986	0.36101	53	100	76.5	2.8	0.00303	PSCC1FO	0.0541	348451.5	3165401.0	0.00016	2.04	PASS
NOx																			
1991 NSCC1NG	0.1602	91020624	348451.5	3165401.0	0.16020	0.21627	0.27899	35	93	64.0	1.8	0.00151	PSCC1NG	0.0382	348451.5	3165401.0	0.00009	1.02	PASS
NSCC7NG	0.1424	91020624	348451.5	3165401.0	0.14240	0.19224	0.24799	35	93	64.0	1.8	0.00134	PSCC7NG	0.0302	348451.5	3165401.0	0.00009	0.91	PASS
NSCC5NG	0.3413	91020624	348451.5	3165401.0	0.34130	0.48075	0.59437	35	93	64.0	1.8	0.00321	PSCC5NG	0.0314	348451.5	3165401.0	0.00009	2.11	PASS
NSCC1FO	0.4245	91020624	348451.5	3165401.0	0.42450	0.57308	0.73927	35	93	64.0	1.8	0.00399	PSCC1FO	0.1103	348451.5	3165401.0	0.00033	2.76	PASS
NSCC7FO	0.3629	91020624	348451.5	3165401.0	0.36290	0.48992	0.63199	35	93	64.0	1.6	0.00341	PSCC7FO	0.1415	348451.5	3165401.0	0.00042	2.45	PASS
NSCC5FO	0.3092	91020624	348451.5	3165401.0	0.30920	0.41742	0.53547	35	93	64.0	1.8	0.00291	PSCC5FO	0.1666	348451.5	3165401.0	0.00050	2.18	PASS
NSCC1NG	0.0683	91020624	348451.5	3165401.0	0.06830	0.09221	0.11694	35	93	64.0	1.8	0.00064	PSCC1NG	0.0120	348451.5	3165401.0	0.00004	0.43	PASS
NSCC1FO	0.2235	91020624	348451.5	3165401.0	0.22350	0.30173	0.38623	35	93	64.0	1.8	0.00210	PSCC1FO	0.0583	348451.5	3165401.0	0.00017	1.45	PASS

Kissimmee Utility Authority Cane Island Power Park

Construction Permit Application

July 1998



BLACK & VEATCH

Contents

- I. Applicable Information
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Attachments

Facility

- | | |
|--------------|------------------------------------|
| Attachment A | Area Map Showing Facility Location |
| Attachment B | Facility Plot Plan |
| Attachment C | Process Flow Diagrams |
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Combustion Turbine

- | | |
|--------------|---|
| Attachment E | Unit Specific Applicable Requirements |
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| Attachment H | Detailed Description of Control Equipment |
| Attachment I | Description of Stack Sampling Facilities |
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| Attachment L | Operation and Maintenance Plan |

Fuel Storage Tank

- | | |
|--------------|---------------------------------------|
| Attachment M | Unit Specific Applicable Requirements |
| Attachment N | Process Flow Diagram |
| Attachment O | Emission Source Calculations |

I. Application Information

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Kissimmee Utility Authority	
2. Site Name : Cane Island Power Park	
3. Facility Identification Number :	0970043 [] Unknown
4. Facility Location : Kissimmee Utility Authority Cane Island Power Park Located 10 km west fo Kissimmee, near Intrecession City, Osceola County, Florida	
Street Address or Other Locator :	6075 Old Tampa Highway
City : Intercession City	County : Osceola Zip Code : 33848-9999
5. Relocatable Facility? [] Yes [X] No	6. Existing Permitted Facility? [X] Yes [] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : A. K. Sharma

Title : Director of Power Supply

2. Owner or Authorized Representative or Responsible Official Mailing Address :

Organization/Firm : Kissimmee Utility Authority

Street Address : 1701 West Carroll Street

City : Kissimmee

State : FL Zip Code : 34741-6804

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (407)933-7777

Fax : (407)847-0787

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*

A. K. Sharma
Signature

7/28/98
Date

* Attach letter of authorization if not currently on file.

I. Part 2 - 1

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
005	Unit 3 - 250 MW Combined Cycle Combustion Turbine	NA
006	Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3	NA

Purpose of Application and Category

Category I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain :

- ☐ Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

- ☐ Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number :

- ☐ Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

- ☐ Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number :

Operation permit to be revised :

- ☐ Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

I. Part 4 - 1

- ☐ Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

Category II : All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

- ☐ Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

- ☐ Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

- ☐ Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

I. Part 4 - 2

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

- ☒ Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :

- ☐ Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s) :

- ☐ Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one :

☐ Attached - Amount : \$0.00

☒ Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations :	
See project description in SCA Appendix 10.7	
2. Projected or Actual Date of Commencement of Construction :	01-Oct-1999
3. Projected Date of Completion of Construction :	01-Jun- 01

Professional Engineer Certification

1. Professional Engineer Name : D. D. Schultz Registration Number : 30304	
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Street Address : 8400 Ward Parkway City : Kansas City State : MO Zip Code : 64114-2031	
3. Professional Engineer Telephone Numbers : Telephone : (913)458-2028 Fax : (913)458-2934	

4. Professional Engineer Statement :

I, the undersigned, hereby certify, except as particularly noted herein, that :*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

DD Schultz

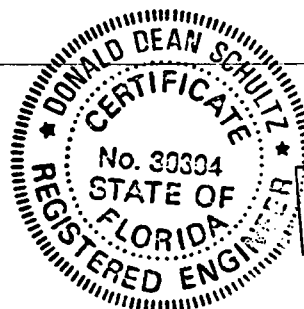
Signature
(seal)

8/6/98

Date

I. Part 6 - 1

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96



Poor Original

* Attach any exception to certification statement.

I. Part 6 - 2

DEP Form No. 62-210.900(1) - Form

Effective : 3-21-96

Application Contact

1. Name and Title of Application Contact :

Name : A. K. Sharma

Title : Director of Power Supply

2. Application Contact Mailing Address :

Organization/Firm : Kissimmee Utility Authority

Street Address : 1701 West Carol Street

City : Kissimmee

State : FL **Zip Code :** 34741-6804

3. Application Contact Telephone Numbers :

Telephone : (407)933-7777

Fax : (407)847-0787

Application Comment

The facility has submitted an intital operating permit application. This applicaiton is for a construction permit for a new combustion turbine and a fuel oil storage tank.

II. Facility Information

General Facility Information

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

2

1. Facility UTM Coordinates : Zone : 17 East (km) : 447.72 North (km) : 3127.68			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 28 16 32 Longitude (DD/MM/SS) : 81 31 59			
3. Governmental Facility Code :	4. Facility Status Code : A	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) :
7. Facility Comment : Construction of new emission sources at an existing facility which will not be permanently shut down.			

Facility Contact

1. Name and Title of Facility Contact : Jeff Ling Plant Manager	
2. Facility Contact Mailing Address : Organization/Firm : KUA Cane Island Power Plant Street Address : 6075 Old Tampa Highway City : Intercession City State : FL Zip Code : 33848-9999	
3. Facility Contact Telephone Numbers : Telephone : (417)846-7070 Fax : (407)846-6485	

II. Part 1 - 1

DEP Form No. 62-210.900(1) - Form

Effective : 3-21-96

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	Y
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment : Facility units currently exempt under NESHAPs. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used--the cooling tower is not a major source of HAPs.	

II. Part 2 - 1

Facility Regulations

B. FACILITY REGULATIONS

Rule Applicability Analysis

N/A - Facility is a Title V Source.
See Attachment D for Facility applicable requirements.

B. FACILITY REGULATIONS

List of Applicable Regulations

FDEP Title V Core List (effective 3/25/95) incorporated by reference

40 CFR Part 60, Subpart A - Standards of Performance for New Stationary Sources

40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 61, Subpart A - National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 61, Subpart M - National Emissions Standard for Asbestos

Part 70 - State Operating Permit Programs

Section 70.1 - Program Overview

Section 70.2 - Definitions

Section 70.3 - Applicability

Section 70.4 - State Program Submittals and Transition

Section 70.5 - Permit Applications

Section 70.6 - Permit Content

Section 70.7 - Permit Issuance, Renewal, Reopenings, and Revisions

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 70.8 - Permit Review by the EPA and Affected States

Section 70.9 - Fee Determination and Certification

Section 70.10 - Federal Oversight and Sanctions

Section 70.11 - Requirements for Enforcement Authority

Part 72 - Regulations on Permits

Subpart A - Acid Rain Program General Provisions

Section 72.1 Purpose and Scope

Section 72.2 - Definitions

Section 72.3 - Measurements, Abbreviations, and Acronyms

Section 72.4 - Federal Authority

Section 72.5 - State Authority

Section 72.6 - Applicability

Section 72.9 - Standard Requirements

Section 72.10 - Availability of Information

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.11 - Computation of Time

Section 72.12 - Administrative Appeals

Section 72.13 - Incorporation by Reference

Subpart B - Designated Representative

Section 72.20 - Authorization and Responsibilities of the Designated

Section 72.21 - Submissions

Section 72.22 - Alternate Designated Representative

Section 72.23 - Changing the Designated Representative, Alternate Designated

Section 72.24 - Certificate of Representation

Section 72.25 - Objections

Subpart C- Acid Rain Application

Section 72.30 - Requirements to Apply

Section 72.31 - Information Requirements for Acid Rain Permit

Section 72.32 - Permit Application Shield and Binding Effect of Permit

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B. FACILITY REGULATIONS

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Section 72.33 - Identification of Dispatch System

Subpart D - Acid Rain Compliance Plan and Compliance Options

Section 72.40 - General

Subpart E - Acid Rain Permit Conditions

Section 72.50 - General

Section 72.51 - Permit Shield

Subpart F - Federal Acid Rain Permit Issuance Procedure

Section 72.60 - General

Section 72.61 - Completeness

Section 72.62 - Draft Permit

Section 72.63 - Administrative Record

Section 72.64 - Statement of Basis

Section 72.65 - Public Notice of Opportunities for Public Comment

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.66 - Public Comments

Section 72.67 - Opportunity for Public Hearing

Section 72.68 - Response to Comments

Section 72.69 - Issuance and Effective Date of Acid Rain Permits

Subpart G - Acid Rain Phase II Implementation

Section 72.70 - Relationship to Title V Operating Permit Program

Section 71.71 - Approval of State Programs--General

Section 72.72 - State Permit Program Approval Criteria

Section 72.73 - State Issuance of Phase II Permits

Section 72.74 - Federal Issuance of Phase II Permits

Subpart H - Permit Revisions

Section 72.80 - General

Section 72.81 - Permit Modifications

Section 72.82 - Fast-Track Modifications

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.83 - Administrative Permit Amendment

Section 72.84 - Automatic permit Amendment

Section 72.85 - Permit Reopenings

Subpart I - Compliance Certification

Section 72.90 - Annual Compliance Certification Report

Section 72.95 - Allowance Deduction Formula

Section 72.96 - Administrator's Action on Compliance Certifications

Part 73 - Sulfr Dioxide Allowance Systems

Subpart A - Background and Summary

Section 73.1 - Purpose and Scope

Section 73.2 - Applicability

Section 73.3 - General

Subpart B - Allowance Allocations

Section 73.10 - Initial Allocations for Phase I and II

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B. FACILITY REGULATIONS

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Section 73.12 - Rounding Procedures

Section 73.13 - Procedures for Submittals

Section 73.26 - Conservation and Renewable Energy Reserve

Section 73.27 - Special Allowance Reserve

Subpart C - Allowance Tracking System

Section 73.30 - Allowance Tracking System Accounts

Section 73.31 - Establishment of Accounts

Section 73.32 - Allowance Accounts Contents

Section 73.33 - Authorized Account Representative

Section 73.34 - Recordation in Accounts

Section 73.35 - Compliance

Section 73.36 - Banking

Section 73.37 - Account Error and Dispute Resolution

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 73.38 - Closing of Accounts

Subpart D - Allowance Transfers

Section 73.50 - Scope and Submission of Transfers

Section 73.51 - Prohibition

Section 73.52 - EPA Recordation

Section 73.53 - Notification

Subpart E - Auctions, Direct Sales, and Independent Power Producers Written

Section 73.70 - Auctions

Section 73.71 - Bidding

Section 73.72 - Direct Sales

Section 73.73 - Selegation of Auctions and Sales and Termination of Auctions

Section 73.74 - Independent Power Producers Written Guarantee

Section 73.75 - Application for an IPP Written Guarantee

Section 73.76 - Approval and Exercise of the IPP Written Guarantee

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B. FACILITY REGULATIONS

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Section 73.77 - Relationship of Independent Power Producers Written Guarantee

Section 75.5 - Prohibitions

Section 75.6 - Incorporation by Reference

Section 76.7 - EPA Study

Section 76.8 [Reserved]

Subpart - Monitoring Provisions

Section 75.10 - General Operating Requirements

Section 75.11 - Specific Provisions for Monitoring SO₂ Emissions

Section 75.12 - Specific Provisions for Monitoring NO_x Emissions (NO_x and Flow)

Section 75.13 - Specific Provisions for Monitoring CO₂ Emissions

Section 75.14 - Specific Provisions for Monitoring Opacity

Section 75.15 - Specific Provisions for Monitoring SO₂ Emissions Removal by

Section 75.16 - Specific Provisions for Monitoring Emissions from Common, By-

Section 75.17 - Specific Provisions for Monitoring Emissions from Common, By

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.18 - Specific Provisions for Monitoring Emissions from Common and

Section 75.41 Precision Criteria

Section 75.42 - Reliability Criteria

Section 75.43 - Accessibility Criteria

Section 75.44 - Timelines Criteria

Section 75.45 - Daily Quality Assurance Criteria

Section 75.46 - Missing data Substitution Criteria

Section 75.47 - Criteria for a Class of Affected Units

Section 75.48 - Petition for an Alternative Monitoring System

Subpart F - Recordkeeping Requirements

Section 75.50 - General Recordkeeping Provisions

Section 75.51 - General Recordkeeping Provisions for Specific Situations

Section 75.52 - Certifications, Quality Assurance and Quality Control Record

Section 75.53 - Monitoring Plan

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B. FACILITY REGULATIONS

List of Applicable Regulations

Subpart G - Reporting Requirements

Section 75.60 - General Provisions

Section 75.61 - Notification and Recertification Test Dates

Section 75.62 - Monitoring Plan

Section 75.63 - Certification or Recertification Applications

Section 75.64 - Quarterly Reports

Section 75.65 - Opacity Reports

Section 75.66 - Petitions to the Administrator

Section 75.67 - Retired Units Petitions

Part 76 - EPA Regulations on Acid Rain Nitrogen Oxides

Section 76.1 - Applicability

Section 76.2 - Definitions

Section 76.3 - General Acid Rain Program Provisions

Section 76.4 - Incorporation by Reference

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 76.5 - NOx Emission Limitations for Group 1 Boilers

Section 76.6 - NOx Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 - Revised NOx Emission Limitations for Group 1, Phase II Boilers

Section 76.8 - Early Election for Group 1, Phase II Boilers

Section 76.9 - Permit Application and Compliance Plans

Section 76.10 - Alternative Emission Limitations

Section 76.11 - Emissions Averaging

Section 76.12 - Phase I NOx Compliance Extensions

Section 76.13 - Compliance and Excess Emissions

Section 76.14 - Monitoring, Recordkeeping, and Reporting

Section 76.15 - Test Methods and Procedures

Section 76.16 - [Reserved]

Part 77 - Excess Emissions

State Applicable Requirements

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B. FACILITY REGULATIONS

List of Applicable Regulations

Chapter 62-4, F.A.C.; PERMITS

62-4.055 - Permit Processing

Chapter 62-210, F.A.C.; STATIONARY SOURCES - GENERAL REQUIREMENTS

62-210.550 - Stack Height Policy

62-210.700 Excess Emissions

Chapter 62-212, F.A.C.; STATIONARY SOURCES - PRECONSTRUCTION REVIEW

62-212.300 - General Preconstruction Review Requirements

62-212.400 - Prevention of Significant Deterioration

62-212.410 - Best Available Control Technology

Chapter 62-213, F.A.C.; OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION

62-213.413 - Fast-Track Revisions of Acid Rain Parts

Chapter 62-214, F.A.C.; REQUIREMENTS FOR SOURCES SUBJECT TO THE FEDERAL ACID RAIN PR

62-214.300 - Applicability

62-214.320 - Applications

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B. FACILITY REGULATIONS

List of Applicable Regulations

62-214.330 - Acid Rain Compliance Plan and Compliance Options

62-214.350 - Certification

62-214.370 - Revisions and Administrative Corrections

62-214.420 - Acid Rain Part Content

62-214.430 - Implementation and Termination of Compliance Options

Chapter 62-272, F.A.C.; AMBIENT AIR QUALITY STANDARDS

62-272.500 - Maximum Allowable Increases

Chapter 62-273, F.A.C.; AIR POLLUTION EPISODES

62-273.300 - Air Pollution Episodes

62-273.400 - Air Alert

62-273.500 - Air Warning

62-273.600 - Air Emergency

Chapter 62-296, F.A.C.; STATIONARY SOURCES - EMISSION STANDARDS

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B. FACILITY REGULATIONS

List of Applicable Regulations

62-296.405 - Fossil Fuel Steam Generators

Chapter 62-297, F.A.C.; STATIONARY SOURCES - EMISSIONS MONITORING

62-297.401 - Compliance Test Methods

62-297.440 - Supplementary Test Procedures

62-297.520 - EPA Performance Specifications

62-297.620 - Exceptions and Approval of Alternate Procedures and Requirements

62-297.310 - General Test Requirements

Subpart F - Energy Conservation and Renewable Energy Reserve

Section 73.80 - Operation of Allowance Reserve Program for Conservation ..

Section 73.81 - Quantified Conservation Measures and Renewable Energy

Section 73.82 - Application for Allowances from Reserve Program

Section 73.83 - Secretary of Energy's Action on New Income Neutrality

Section 73.84 - Administrator's Action on Applications

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B. FACILITY REGULATIONS

List of Applicable Regulations

Section 73.85 - Administrator Review of the Reserve Program

Section 73.86 - State Regulatory Autonomy, Appendix A to Subpart F -- List of

Part 75 - Emission Monitoring

Subpart A - General

Section 75.1 - Purpose and Scope

Section 75.2 - Applicability

Section 75.3 - General Acid Rain Program Provisions

Section 75.4 - Compliance Dates

Subpart C - Operation and Maintenance Requirements

Section 75.20 - Certification and Recertification Procedures

Section 75.21 - Quality Assurance and Quality Control Requirements

Section 75.22 - Reference Test Methods

Section 75.23 - Alternatives to ASTM Methods

Section 75.24 - Out-of-Control Periods

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B. FACILITY REGULATIONS

List of Applicable Regulations

Subpart D - Missing Data Substitution Procedures

Section 75.30 - General Procedures

Section 75.31 - Initial Missing Data Procedures

Section 75.32 - Determinations of Monitor Data Availability for Standard Missing Data

Section 75.33 - Standard Missing Data Procedures

Section 75.34 - Units with Add-on Emission Controls

Subpart E - Alternative Monitoring Systems

Subaprt 75.40 - General Demonstration Requirementrs

Facility Pollutants

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
VOC	A
CO	A
NOX	A
PM	A
PM10	A
SO2	A
PB	B
H095	A
H021	B
H015	B
H114	B

II. Part 4 - 1

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Facility Pollutant Detail Information

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 1

1. Pollutant Emitted :	VOC	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 1

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 2

1. Pollutant Emitted :	CO	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 2

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 3

1. Pollutant Emitted :	NOX	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 3

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 4

1. Pollutant Emitted :	PM	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 4

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 5

1. Pollutant Emitted :	PM10	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 5

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 6

1. Pollutant Emitted :	SO2	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 6

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 7

1. Pollutant Emitted :	PB	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 7

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 8

1. Pollutant Emitted :	H095	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 8

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 9

1. Pollutant Emitted :	H021	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 9

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 10

1. Pollutant Emitted :	H015	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 10

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information

Pollutant 11

1. Pollutant Emitted :	H114	
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

II. Part 4b - 11

Facility Supplemental Information

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Attachment A
2. Facility Plot Plan :	Attachment B
3. Process Flow Diagram(s) :	Attachment C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	SCA Section 4.5
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Application :	SCA APPENDIX 10.7

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities :	NA
8. List of Equipment/Activities Regulated under Title VI :	NA
9. Alternative Methods of Operation :	NA
10. Alternative Modes of Operation (Emissions Trading) :	NA
11. Identification of Additional Applicable Requirements :	NA
12. Compliance Assurance Monitoring Plan :	NA
13. Risk Management Plan Verification :	Plan Submit
14. Compliance Report and Plan :	NA
15. Compliance Certification (Hard-copy Required) :	NA

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT (Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

- ☒ [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ [] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

- ☒ [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☐ [] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ [] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

III. Part 1 - 1

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B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 3 - 250 MW Combined Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 005 [] No Corresponding ID [] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The 250 MW combined cycle combustion turbine is comprised of one combustion turbine which exhausts through a heat recovery steam generator (HRSG) which is used to power a steam turbine. Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description :

A. Low NOx Burner Technology: For natural gas firing the use of dry low NOx burner technology to control NOx emissions. This technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage.

2. Control Device or Method Code : 25

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description :

B. Use of low sulfur fuel oil (0.05 percent) and the use of natural gas to control emissions of SO₂.

2. Control Device or Method Code : 30

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description :

C. Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This control will be used for fuel oil firing.

2. Control Device or Method Code : 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	01-Jun- 01	
2. Long-term Reserve Shutdown Date :		
3. Package Unit :		
Manufacturer : Unknown	Model Number : Unknown	
4. Generator Nameplate Rating : 250 MW		
5. Incinerator Information :		
Dwell Temperature :	Degrees Fahrenheit	
Dwell Time :	Seconds	
Incinerator Afterburner Temperature :	Degrees Fahrenheit	

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	1696	mmBtu/hr
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment :		
The maximum heat input (MBtu/h):		
Natural gas firing at 19 F@ 100 % = 1,696 LHV, 1,882 HHV		
No. 2 distillate fuel oil firing at 19 F@ 100 % = 1,910 LHV, 2,039 HHV		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :		
	24 hours/day	7 days/week

52 weeks/year

8,760 hours/year

III. Part 4 - 2

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D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Rule Applicability Analysis

N/A - Facility is a Title V Source.

III. Part 6a - 1

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Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

List of Applicable Regulations

See Attachment E for unit specific applicable requirements.

III. Part 6b - 1

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E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	S-6 HRSG/S-7 Bypass
2. Emission Point Type Code :	3
3. Descriptions of Emission Points Comprising this Emissions Unit :	Two emission points are associated with the combustion turbine - the Bypass and HRSG. (S-6 HRSG)
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common :	N/A
5. Discharge Type Code :	V
6. Stack Height :	130 feet
7. Exit Diameter :	18.00 feet
8. Exit Temperature :	173 °F
9. Actual Volumetric Flow Rate :	635,155 acfm
10. Percent Water Vapor :	%
11. Maximum Dry Standard Flow Rate :	dscfm
12. Nonstack Emission Point Height :	feet
13. Emission Point UTM Coordinates :	Zone : 17 East (km) : 447.722 North (km) : 3,127.785
14. Emission Point Comment :	Exit temperature and flow rate conservatively reflect worst-case combined cycle low load and natural gas operation.

III. Part 7b - 1

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E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	S-6 HRSG/S-7 Bypass
2. Emission Point Type Code :	3
3. Descriptions of Emission Points Comprising this Emissions Unit :	When the unit operates in simple cycle mode the exhaust gas exits through the Bypass (S-7 Bypass).
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common :	N/A
5. Discharge Type Code :	V
6. Stack Height :	100 feet
7. Exit Diameter :	18.00 feet
8. Exit Temperature :	1,073 °F
9. Actual Volumetric Flow Rate :	2,195,520 acfm
10. Percent Water Vapor :	%
11. Maximum Dry Standard Flow Rate :	dscfm
12. Nonstack Emission Point Height :	feet
13. Emission Point UTM Coordinates :	
Zone :	17
East (km) :	447.758
North (km) :	3,127.785
14. Emission Point Comment :	Exit temperature and flow rate conservatively reflect worst-case simple cycle low load and natural gas operation.

III. Part 7b - 3

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F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Combustion Turbine operating in either combined cycle or simple cycle mode on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e., 8,760 hours).	
2. Source Classification Code (SCC) : 2-01-002-01	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.92	5. Maximum Annual Rate : 16,819.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 978	
10. Segment Comment : (fuel flow)x(fuel density) = Maximum Hourly Rate (80,860 lb/h)x(23.8 scf/lb)x(Mscf/10 ⁶ scf) = 1.92 Mscf/h (1.92 Mscf/h)x(8,760 h/yr) = 16,819 mscf/yr (23,277 MBtu/lb)x(lb/23.8 scf) =978 MBtu/Mscf	

III. Part 8 - 1

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Combustion turbine operating in either combined or simple cycle mode on No. 2 distillate fuel oil. Unit 3 allowed to operate on No. 2 distillate fuel oil for 720 hours/yr.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.58	5. Maximum Annual Rate : 10,498.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 140	
10. Segment Comment : (fuel flow)x(fuel density)=Max Hrly Rate (102770 lb/h)/(7.05 lb/gal)/(1000 gal)=14.58 1000gal/h (14.58 gal/h)x(720 h/yr)=10498 1000gal/yr (19485 Btu/lb)x(7.05 lb/gal)/(1000 gal)=140 Btu/1000gal	

III. Part 8 - 2

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G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - PM			EL
2 - SO2	030		EL
3 - NOX	025	028	EL
4 - VOC			EL
5 - CO			EL
6 - H114			EL
7 - H015			EL
8 - H021			EL
9 - PB			EL
10 - H095			NS
11 - PM10			EL

III. Part 9a - 1

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H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : PM	
2. Total Percent Efficiency of Control :	%
3. Potential Emissions :	
102.1000000 lb/hour	109.1200000 tons/year
4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Reference : Manufacturer	Units :
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for either combined or simple cycle operation: Natural gas = 18 lb/h Fuel oil = 102.1 lb/h Potential hours of operation: Natural gas = 8,760 h/yr Fuel Oil = 720 h/yr Potential annual emissions: $[(18 \text{ lb/h} \times 8,040 \text{ h/yr}) + (102.1 \text{ lb/h} \times 720 \text{ h/yr})] / (2,000 \text{ lb/ton}) = 109.12 \text{ tons/yr}$	
9. Pollutant Potential/Estimated Emissions Comment :	

III. Part 9b - 1

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees. *Based on 72°F ambient conditions.*

III. Part 9b - 2

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				18.60	lb/h
4. Equivalent Allowable Emissions :					
				18.60	lb/hour
				81.50	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Natural gas firing for 8,760 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads,					

III. Part 9c - 1

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	112.60	lb/h	
4. Equivalent Allowable Emissions :	112.60	lb/hour	40.50 tons/year
5. Method of Compliance :			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	Oil firing 720 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.		

III. Part 9c - 2

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : SO2		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
94.5600000 lb/hour		38.0600000 tons/year
4. Synthetically Limited? ☐ Yes ☒ No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor Reference : Manufacturer		Units :
7. Emissions Method Code : 0		
8. Calculations of Emissions : Highest hourly emissions for either combined or simple cycle operation: Natural gas = 1.0 lb/h Fuel oil = 94.56 lb/h Potential hours of operation: Natural gas = 8,760 h/yr Fuel Oil = 720 h/yr Potential annual emissions: $[(1.0 \text{ lb/h} \times 8,040 \text{ h/yr}) + (94.56 \text{ lb/h} \times 720 \text{ h/yr})] / (2,000 \text{ lb/ton}) = 38.06 \text{ tons/yr}$		
9. Pollutant Potential/Estimated Emissions Comment :		

III. Part 9b - 3

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees. Based on 72°F Ambient conditions.

III. Part 9b - 4

DEP Form No. 62-210.900(1) - Form

Effective : 3-21-96

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				1.03	lb/h
4. Equivalent Allowable Emissions :					
		1.03	lb/hour	4.50	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Natural gas firing for 8,760 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :		OTHER			
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :		102.67	lb/h		
4. Equivalent Allowable Emissions :		102.67	lb/hour	37.00	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Oil firing 720 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

III. Part 9c - 4

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance :	NSPS 40 CFR 60.334(b) Subpart GG	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : NOX		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
302.6000000 lb/hour		823.2900000 tons/year
4. Synthetically Limited? [] Yes [X] No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor Reference : Manufacturer		Units :
7. Emissions Method Code : 0		
8. Calculations of Emissions : Highest hourly emissions for either combined or simple cycle operation: Natural gas = 177.7 lb/h Fuel oil = 302.6 lb/h Potential hours of operation: Natural gas = 8,760 h/yr Fuel Oil = 720 h/yr Potential annual emissions: [(177.7 lb/h x 8,040 h/yr) + (302.6 lb/h x 720 h/yr)] / (2,000 lb/ton) = 823.29 tons/y		
9. Pollutant Potential/Estimated Emissions Comment :		

III. Part 9b - 5

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees. Based on 72°F ambient conditions.

III. Part 9b - 6

DEP Form No. 62-210.900(1) - Form
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Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				15.00	ppm@15%O2
4. Equivalent Allowable Emissions :					
		195.80	lb/hour	857.60	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Natural gas firing for 8,760 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

III. Part 9c - 5

DEP Form No. 62-210.900(1) - Form
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Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				42.00	ppm@15%O2
4. Equivalent Allowable Emissions :					
		328.50	lb/hour	118.30	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Oil firing 720 h/yr Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 3

1. Basis for Allowable Emissions Code :			RULE
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :			75.00 ppm@15%O2
4. Equivalent Allowable Emissions :			
			lb/hour tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines. NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332 (a)(1)			

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : VOC		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
174.7000000 lb/hour	173.0400000 tons/year	
4. Synthetically Limited? ☐ Yes ☒ No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor Reference : Manufacturer		Units :
7. Emissions Method Code : 0		
8. Calculations of Emissions : Highest hourly emissions for either combined or simple cycle operation: Natural gas = 27.4 lb/h Fuel oil = 174.7 lb/h Potential hours of operation: Natural gas = 8,760 h/yr Fuel Oil = 720 h/yr Potential annual emissions: $[(27.4 \text{ lb/h} \times 8,040 \text{ h/yr}) + (174.7 \text{ lb/h} \times 720 \text{ h/yr})] / (2,000 \text{ lb/ton}) = 173.04 \text{ tons/y}$		
9. Pollutant Potential/Estimated Emissions Comment :		

III. Part 9b - 7

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees. Based on 72°F ambient conditions.

III. Part 9b - 8

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Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				30.20	lb/h
4. Equivalent Allowable Emissions :					
				30.20	lb/hour
				132.30	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Natural gas firing for 8,760 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

III. Part 9c - 7

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				195.30	lb/h
4. Equivalent Allowable Emissions :					
				195.30	lb/hour
				70.30	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Oil firing 720 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

III. Part 9c - 8

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : CO	
2. Total Percent Efficiency of Control :	%
3. Potential Emissions :	
2,599.0000000 lb/hour	3,818.3800000 tons/year
4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Reference : Manufacturer	Units :
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for either combined or simple cycle operation: Natural gas = 717.1 lb/h Fuel oil = 2599.0 lb/h Potential hours of operation: Natural gas = 8,760 h/yr Fuel Oil = 720 h/yr Potential annual emissions: $[(717.1 \text{ lb/h} \times 8,040 \text{ h/yr}) + (2599.0 \text{ lb/h} \times 720 \text{ h/yr})] / (2,000 \text{ lb/ton}) = 3818.38 \text{ tons/y}$	
9. Pollutant Potential/Estimated Emissions Comment :	

III. Part 9b - 9

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees. Based on 72°F ambient conditions.

III. Part 9b - 10

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Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER	
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :		25.00	ppm@15%O2
4. Equivalent Allowable Emissions :		760.60	lb/hour
		3,462.80	tons/year
5. Method of Compliance :			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :			
Natural gas firing for 8,760 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads,			

III. Part 9c - 9

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				90.00	ppm@15%O2
4. Equivalent Allowable Emissions :					
		2,908.20	lb/hour	1,047.00	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Oil firing 720 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads.					

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : H114		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
0.0019000 lb/hour		0.0007000 tons/year
4. Synthetically Limited?		
[] Yes [X] No		
5. Range of Estimated Fugitive/Other Emissions:		
		to tons/year
6. Emissions Factor 0 Units : lb/mmBtu		
Reference : AP-42		
7. Emissions Method Code : 0		
8. Calculations of Emissions :		
Heat input for oil firing = 2039.42 MBtu/h $(2039.42 \text{ MBtu/h}) \times (0.00000091 \text{ lb/MBtu}) \times (720 \text{ h/yr}) / (2,000 \text{ lb/ton}) = 0.0007 \text{ ton/yr}$ Ref: AP-42 (fifth edition) Ref: 2039.42 MBtu/h is the maximum heat input for fuel oil firing based on the higher heating value (HHV).		
9. Pollutant Potential/Estimated Emissions Comment :		
Mercury (Hg)		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 7

1. Pollutant Emitted : H015		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
0.0100000 lb/hour		0.0040000 tons/year
4. Synthetically Limited? [] Yes [X] No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor 0		Units : lb/MBtu
Reference : AP-42		
7. Emissions Method Code : 0		
8. Calculations of Emissions : Heat input for oil firing = 2039.42 MBtu/h (2039.42 MBtu/h)x(4.9E-6 lb/MBtu) = 0.01 lb/h (0.01 lb/h)x(720 h/yr)/(2,000 lb/ton) = 0.004 ton/yr Ref: AP-42 (fifth edition) Ref: 2039.42 MBtu/h is the maximum hear input for fuel oil firing based on the higher heating value (HHV).		
9. Pollutant Potential/Estimated Emissions Comment : Arsenic (As)		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : H021		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
0.0007000 lb/hour		0.0002500 tons/year
4. Synthetically Limited? ☐ Yes ☒ No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor 0		Units : lb/mmBtu
Reference : AP-42		
7. Emissions Method Code : 0		
8. Calculations of Emissions : Heat input for oil firing = 2039.42 MBtu/h (2039.42 MBtu/h)x(3.3E-7 lb/MBtu) = 0.0007 lb/h (0.0007 lb/h)x(720 h/yr)/(2,000 lb/ton) = 0.00025 ton/yr Ref: AP-42 (fifth edition) Ref: 2039.42 MBtu/h is the maximum hear input for fuel oil firing based on the higher heating value (HHV).		
9. Pollutant Potential/Estimated Emissions Comment : Beryllium		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION

Emissions Unit Information Section

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 9

1. Pollutant Emitted : PB	
2. Total Percent Efficiency of Control :	%
3. Potential Emissions :	0.1200000 lb/hour 0.0400000 tons/year
4. Synthetically Limited? [] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions:	to tons/year
6. Emissions Factor 0 Reference : AP-42	Units : lb/mmBtu
7. Emissions Method Code : 0	
8. Calculations of Emissions : Heat input for oil firing = 2039.42 MBtu/h (2039.42 MBtu/h)x(5.8E-5 lb/MBtu) = 0.12 lb/h (0.12 lb/h)x(720 h/yr)/(2,000 lb/ton) = 0.04 ton/yr Ref: AP-42 (fifth edition) Ref: 2039.42 MBtu/h is the maximum hear input for fuel oil firing based on the higher heating value (HHV).	
9. Pollutant Potential/Estimated Emissions Comment :	
Lead (Pb)	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 10

1. Pollutant Emitted : H095		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
lb/hour		tons/year
4. Synthetically Limited? [] Yes [X] No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor Reference :		Units :
7. Emissions Method Code :		
8. Calculations of Emissions :		
9. Pollutant Potential/Estimated Emissions Comment :		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 11

1. Pollutant Emitted : PM10		
2. Total Percent Efficiency of Control :		%
3. Potential Emissions :		
102.1000000 lb/hour		109.1200000 tons/year
4. Synthetically Limited? [] Yes [X] No		
5. Range of Estimated Fugitive/Other Emissions:		
	to	tons/year
6. Emissions Factor Reference : Manufacturer		Units :
7. Emissions Method Code : 0		
8. Calculations of Emissions : Highest hourly emissions for either combined or simple cycle operation: Natural gas = 18 lb/h Fuel oil = 102.1 lb/h Potential hours of operation: Natural gas = 8,760 h/yr Fuel Oil = 720 h/yr Potential annual emissions: [(18 lb/h x 8,040 h/yr) + (102.1 lb/h x 720 h/yr)] / (2,000 lb/ton) = 109.12 tons/y		
9. Pollutant Potential/Estimated Emissions Comment :		

III. Part 9b - 19

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees. *Based on 72°F ambient conditions.*

III. Part 9b - 20

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Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 11

Allowable Emissions 1

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				18.60	lb/h
4. Equivalent Allowable Emissions :					
		18.60	lb/hour	81.50	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Natural gas firing for 8,760 h/yr. Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads,					

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Pollutant Information Section 11

Allowable Emissions 2

1. Basis for Allowable Emissions Code :				OTHER	
2. Future Effective Date of Allowable Emissions :					
3. Requested Allowable Emissions and Units :				112.60	lb/h
4. Equivalent Allowable Emissions :					
				112.60	lb/hour
				40.50	tons/year
5. Method of Compliance :					
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :					
Oil firing 720 h/yr Expected lb/h operating limit for forthcoming air constr. permit. Max lb/h emission rate considering all temps, vendors, modes of operation, and loads,					

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : OTHER
3. Requested Allowable Opacity : Normal Conditions : 10 % Exceptional Conditions : 20 % Maximum Period of Excess Opacity Allowed : 6 min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment :

III. Part 10 - 1

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unkown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75. This CEM will be installed on the HSRG stack.	

Continuous Monitoring System Continuous Monitor 2

:

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of the emission unit. Required as a condition of 40 CFR 75. This CEM will be installed on the Bypass stack.	

III. Part 11 - 1

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of the emission source. Rule: New Source Performance Standards, 40 CFR 60, Subpart GG.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of the emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR Part 75.	

III. Part 11 - 2

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 3 - 250 MW Combined Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of the emission source. Natural Gas flow monitor installed pursuant to 40 CFR Part 75.	

Continuous Monitoring System Continuous Monitor 6

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of the emission source. This CEM will be installed on the HRSG stack. Required by 40 CFR Part 75.	

III. Part 11 - 3

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 7

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of the emission source. This CEM will be installed on the By-pass stack. Required by 40 CFR Part 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

- ☒ [X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.
- ☐ [] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ [] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ [] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ [] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

III. Part 12 - 1

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2. Increment Consuming for Nitrogen Dioxide?

- ☒ The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.
- ☐ The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :

PM : C

SO2 : C

NO2 : C

4. Baseline Emissions :

PM :

lb/hour

tons/year

SO2 :

lb/hour

tons/year

NO2 :

tons/year

5. PSD Comment :

Refer to the attached PSD Air Quality Analysis for further information regarding unit emissions and subsequent air quality impacts.

III. Part 12 - 2

DEP Form No. 62-210.900(1) - Form

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L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 3 - 250 MW Combined Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment F
2. Fuel Analysis or Specification :	Attachment G
3. Detailed Description of Control Equipment :	Attachment H
4. Description of Stack Sampling Facilities :	Attachment I
5. Compliance Test Report :	Attachment J
6. Procedures for Startup and Shutdown :	Attachment K
7. Operation and Maintenance Plan :	Attachment L
8. Supplemental Information for Construction Permit Application :	SCA Appnd. 10.7
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alternative Modes of Operation (Emissions Trading) :	NA

III. Part 13 - 1

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)	

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT (Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

- ☒ [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ [] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

- ☐ [] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☒ [X] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ [] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

III. Part 1 - 2

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**B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)****Emissions Unit Description and Status**

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3		
2. Emissions Unit Identification Number : 006 [] No Corresponding ID [] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a verticle fixed roof design.		

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Emissions Unit Control Equipment _____

1. Description :
2. Control Device or Method Code :

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Emissions Unit Details

1. Initial Startup Date :	01-Jun- 01
2. Long-term Reserve Shutdown Date :	
3. Package Unit :	
Manufacturer : Unknown	Model Number : Unknown
4. Generator Nameplate Rating :	MW
5. Incinerator Information :	
Dwell Temperature :	Degrees Fahrenheit
Dwell Time :	Seconds
Incinerator Afterburner Temperature :	Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	mmBtu/hr
2. Maximum Incinerator Rate :	lb/hr tons/day
3. Maximum Process or Throughput Rate :	10496 thousand gal/yr
4. Maximum Production Rate :	
5. Operating Capacity Comment :	
The maximum throughput rate corresponds to the use of No. 2 fuel oil for 720 hour/year	

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
hours/day	days/week
weeks/year	hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Rule Applicability Analysis

N/A

III. Part 6a - 2

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Emissions Unit Information Section

2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

List of Applicable Regulations

See Attachment M for list of applicable regulations.

III. Part 6b - 2

DEP Form No. 62-210.900(1) - Form

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E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	S-8
2. Emission Point Type Code :	1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emissions resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.	
5. Discharge Type Code :	P
6. Stack Height :	0 feet
7. Exit Diameter :	0.0 feet
8. Exit Temperature :	72 °F
9. Actual Volumetric Flow Rate :	0 acfm
10. Percent Water Vapor :	0.00 %
11. Maximum Dry Standard Flow Rate :	0 dscfm
12. Nonstack Emission Point Height :	35 feet

III. Part 7a - 1

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13. Emission Point UTM Coordinates :

Zone : 17

East (km) : 447.743

North (km) : 3127.475

14. Emission Point Comment :

III. Part 7a - 2

DEP Form No. 62-210.900(1) - Form

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F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Storage Loss: Emissions resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure (also known as standing loss or breathing loss).	
2. Source Classification Code (SCC) : 4-03-010-19	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1000000 gal stored)/(1000 gal) = 1000 capacity factor	

III. Part 8 - 4

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in the liquid level within the tank.	
2. Source Classification Code (SCC) : 4-03-010-21	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 10,496.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (10,495,660 gal of fuel oil consumed by the turbine/year)/(1,000 gal) = 10496.0 gal/yr	

III. Part 8 - 5

DEP Form No. 62-210.900(1) - Form
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G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2
Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

III. Part 9a - 2

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Emissions Unit Information Section 2
Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	
4. Equivalent Allowable Emissions :	
	lb/hour tons/year
5. Method of Compliance :	
	As specified in 40 CFR 60.116 (a) and (b), Subpart Kb
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	
	RULE: 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

- ☐ The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.
- ☐ The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☒ None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

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2. Increment Consuming for Nitrogen Dioxide?

- ☐ The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.
- ☐ The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☐ For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.
- ☒ None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

Distillate Fuel Oil Storage Tank (1,000,000 gal) No. 3

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment N
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	SCA Appnd. 10.7
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alternative Modes of Operation (Emissions Trading) :	NA

III. Part 13 - 1

DEP Form No. 62-210.900(1) - Form

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12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA
14. Acid Rain Application (Hard-copy Required) :	
NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

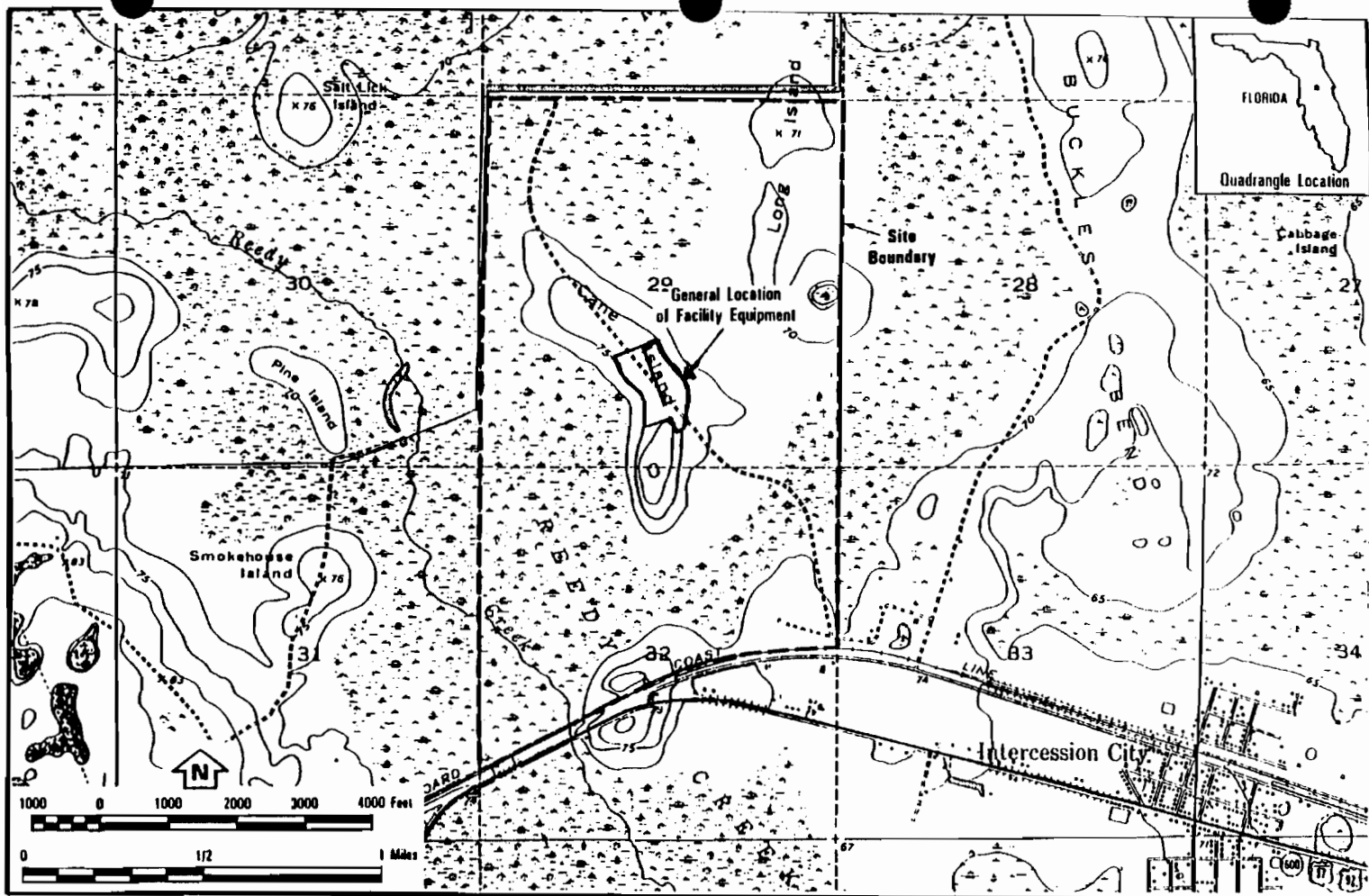
Attachment A

Attachment A

Area Map Showing Facility Location

IMAGE QUALITY

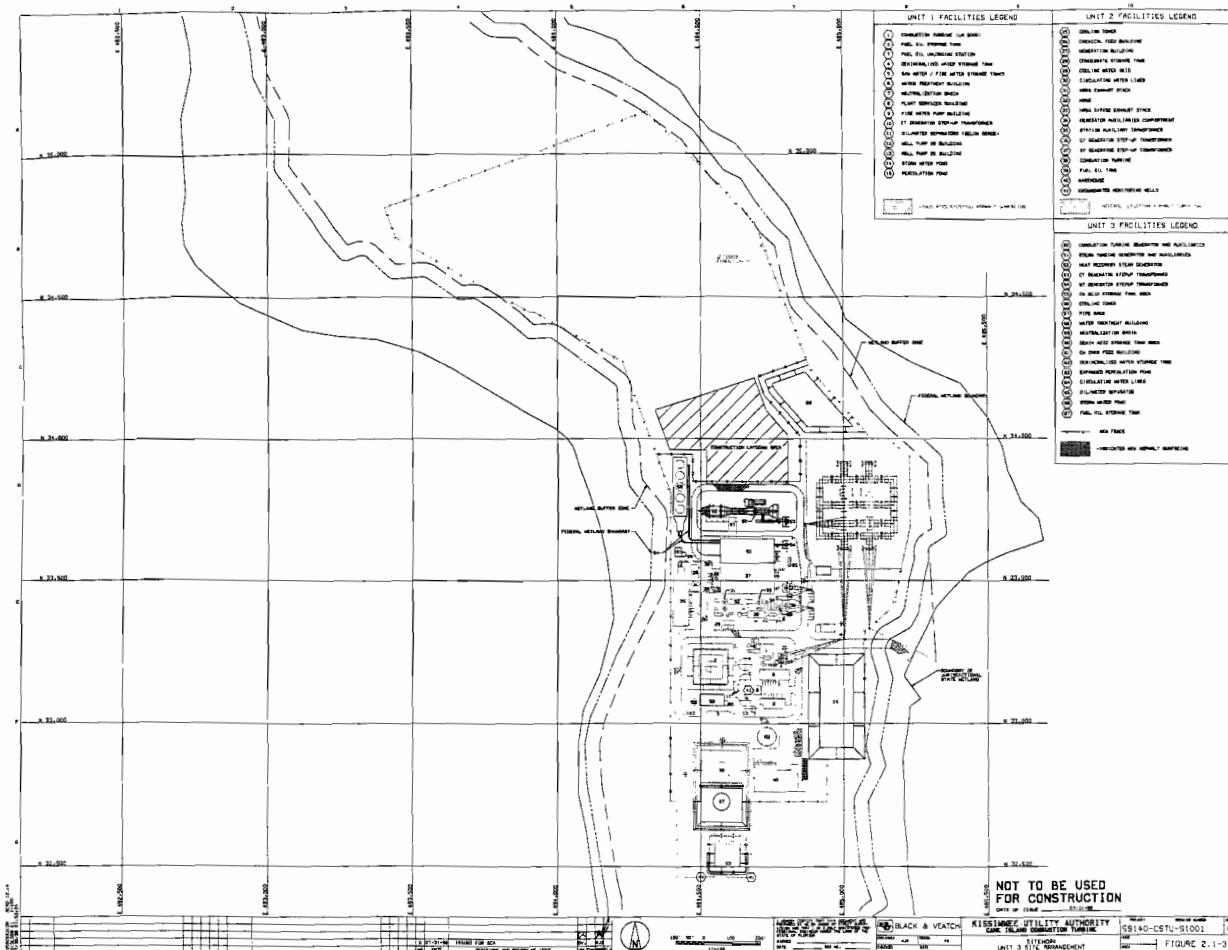
AS YOU REVIEW THE NEXT GROUP OF IMAGES, PLEASE NOTE THAT THE ORIGINAL DOCUMENTS WERE OF POOR QUALITY.



Base Map Source: USGS,
Intercession City, Fl. 1970, quad.

CANE ISLAND SITE LOCATION

Attachment B



Attachment C

Attachment C

Process Flow Diagrams

(See individual unit process flow diagrams, Attachments F, and N)

Attachment D

Attachment D
Facility Applicable Requirements

Facility Applicable Requirements

Applicable Regulation	Applicable Requirement
40 CFR 60.7, Notification and recordkeeping	Any physical or operational change to an existing facility which may increase the emission of any air pollutant requires notification pursuant to this rule, postmarked 60 days before the change is commenced.
	An excess emissions and monitoring systems performance report shall be submitted semiannually. The facility shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the facility; any malfunction of the air pollution control equipment; or any period the CEMS is inoperable.
	The owner or operator of an affected facility shall maintain a file of CEMS and performance test measurements, evaluations, and calibration checks for two years following the date of such activity.
40 CFR 60.8 (d), Testing	Notify the Administrator of any performance test at least 30 days prior to the test.
40 CFR 60.8 (e), Testing	Provide sampling ports, safe sampling platform, utilities and testing equipment prior to stack test.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 61.5, Prohibited activities	Ninety days after the effective date of any standard pursuant to this part, no owner or operator shall operate any existing source subject to that standard in violation of the standard.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain-program shall be submitted, signed, and certified by the designated representative.

Applicable Regulation	Applicable Requirement
40 CFR 72.90, Annual compliance certification report	Sixty days after the end of the calendar year, the designated representative shall submit an annual compliance certification report for each affected unit.
40 CFR 75.3, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO _x and CO ₂ CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
F.A.C. 62-4.030, General Prohibition	Any stationary installation which will be a source of air pollution shall not be operated, maintained, constructed, expanded, or modified without appropriate and valid permits issued by the DEP.
F.A.C. 62-4.090, Renewals	Submit an operating permit renewal application to the FDEP 180 days before the expiration of the operating permit.
F.A.C. 62-4.130, Plant Operation - Problems	If a facility is temporarily unable to comply with any of the conditions of a permit due to breakdown of equipment or destruction by hazard of fire, wind, or by other cause, the permittee shall immediately notify the DEP.
F.A.C. 62-4.160, Permit Conditions	The permittee shall allow authorized DEP personnel access to the facility where the permitted activity is located to have access to and copy any records that must be kept under conditions of the permit; inspect the facility, equipment, practices, or operations regulated or required under the permit; and sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with permit conditions.

Applicable Regulation	Applicable Requirement
	If the permittee does not comply with or will be unable to comply with any condition or limitation of permit number AC 49-205703, the permittee shall immediately provide the DEP with a description of and cause of noncompliance; the period of noncompliance including dates and times, or, if not corrected, the anticipated time the noncompliance is expected to continue; and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. Permits, or a copy thereof, shall be kept at the work site of the permitted activity.
	The permittee shall furnish all records and plans required under DEP rules; hold at the facility all monitoring information, reports, and records of data for at least three years from the date of the sample, measurement, report, or application.
F.A.C. 62-4.160, Permit Conditions (continued)	When requested by DEP, the permittee shall furnish, within a reasonable time, any information required by law which is needed to determine compliance with any permit.
F.A.C. 62-4.210, Construction Permits	No person shall construct any installation or facility which will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the DEP unless exempted by statute or DEP rule.
F.A.C. 62-210.300, Permits Required	An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification
F.A.C. 62-210.350, Public Notice and Comment	A notice of proposed agency action on a permit application as described in F.A. C. 62-210.350(1)(a), where the proposed agency action is to issue the permit, shall be published by the applicant.
F.A.C. 62-210.360, Administrative Permit Corrections	A facility owner shall notify the DEP by letter of minor corrections to information contained in a permit. For operating permits, a copy shall be provided to the EPA:

Applicable Regulation	Applicable Requirement
F.A.C. 62-210.370, Reports	An Annual Operating Report for Air Pollution Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for all Title V sources. The annual operating report shall be submitted by March 1 of the following year.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-213.205, Annual Emissions Fee	Each Title V source must pay an annual emissions fee between January 15 and March 1 based on the factors identified in this rule.
F.A.C. 62-213.420, Permit Applications	Each Title V Acid Rain source that commenced operation on or before October 25, 1995 shall submit an operating permit application by June 15, 1996.
F.A.C. 62-214.320, Applications	New acid rain sources must submit an Acid Rain Part application in accordance with the provisions of 40 CFR Part 72.
F.A.C. 62-273.400, Air Pollution Episodes	Upon a declaration that an air pollution episode level exists (alert, warning, or emergency), any person responsible for the operation or conduct of activities which result in emission of air pollutants shall take actions as required in F.A.C. 62-273.400, 62-273.500, and 62-273.600.
F.A.C. 62-273.400, Air Alert	Upon a declaration of an air alert, open burning will be prohibited and motor vehicle operation minimized.
F.A.C. 62-273.500, Air Warning	Upon a declaration of an air warning, open burning will be prohibited and motor vehicle operation minimized. In addition, unnecessary space heating/cooling is prohibited.
F.A.C. 62-273.600, Air Emergency	Upon a declaration of an air emergency, operations will be restricted as prescribed under 62-273.600.

Applicable Regulation	Applicable Requirement
F.A.C. 62-296.320, General Pollutant Emission Limiting Standards	No person shall store, pump, handle, process, load, unload, or use in any process or installation, VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary by the DEP.
	No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
	Open burning in connection with industrial, commercial, or municipal operations is prohibited except if an emergency exists which requires immediate action to protect human health and safety.
	No person shall cause, let, permit, suffer, or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions.

Applicable Regulation	Applicable Requirement
F.A.C. 62-296.405, Fossil Fuel Steam Generators with more than 250 MBtu/hour Heat Input	The test method for visible emissions shall be DEP Method 9 as incorporated in F.A.C. 62-297.
	The test method for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F as incorporated in F.A.C. 62-297.
F.A.C. 62-296.405, Fossil Fuel Steam Generators with more than 250 MBtu/hour Heat Input (continued)	The test method for sulfur dioxide emissions shall be DEP Methods 6, 6A, 6B, or 6C as incorporated in F.A.C. 62-297. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated in the operation permit for the emissions unit.
	Each owner or operator of an emission unit subject to this rule shall install, calibrate, operate, and maintain a continuous monitoring system according to the requirements of 40 CFR 51, Appendix P and 40 CFR 60, Appendix B.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment E

Attachment E

Unit Specific Applicable Requirements

**250 MW Combined Cycle Combustion Turbine
Unit Specific Applicable Requirements**

Applicable Regulations	Applicable Requirement
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).
40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NO _x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio of water to fuel.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. For natural gas (no bulk storage), the values shall be determined and recorded daily.

Applicable Regulations	Applicable Requirement
	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334(c)(1): Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO _x and CO ₂ CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibrations, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.

Applicable Regulations	Applicable Requirement
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5(f).
40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NO _x continuous emission monitoring system (NO _x pollutant monitor and an O ₂ or CO ₂ diluent gas monitor) with automated DAHS which records NO _x concentration, O ₂ or CO ₂ concentration, and NO _x emission rate.
	The owner or operator shall measure CO ₂ emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted according to the procedures in Appendix F of this subpart.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.
40 CFR 75.11, Specific provisions for monitoring SO ₂	Gas and oiled fired units shall measure and record SO ₂ emissions as specified in 40 CFR 75, Appendix D.
40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO ₂ systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20(b) and (c).
	The owner or operator of a by-pass stack CEMS shall comply with all the requirements of 40 CFR 75.20 (a), (b), and (c) except only one nine-run relative accuracy test audit for certification or recertification of the flow monitor needs to be performed.

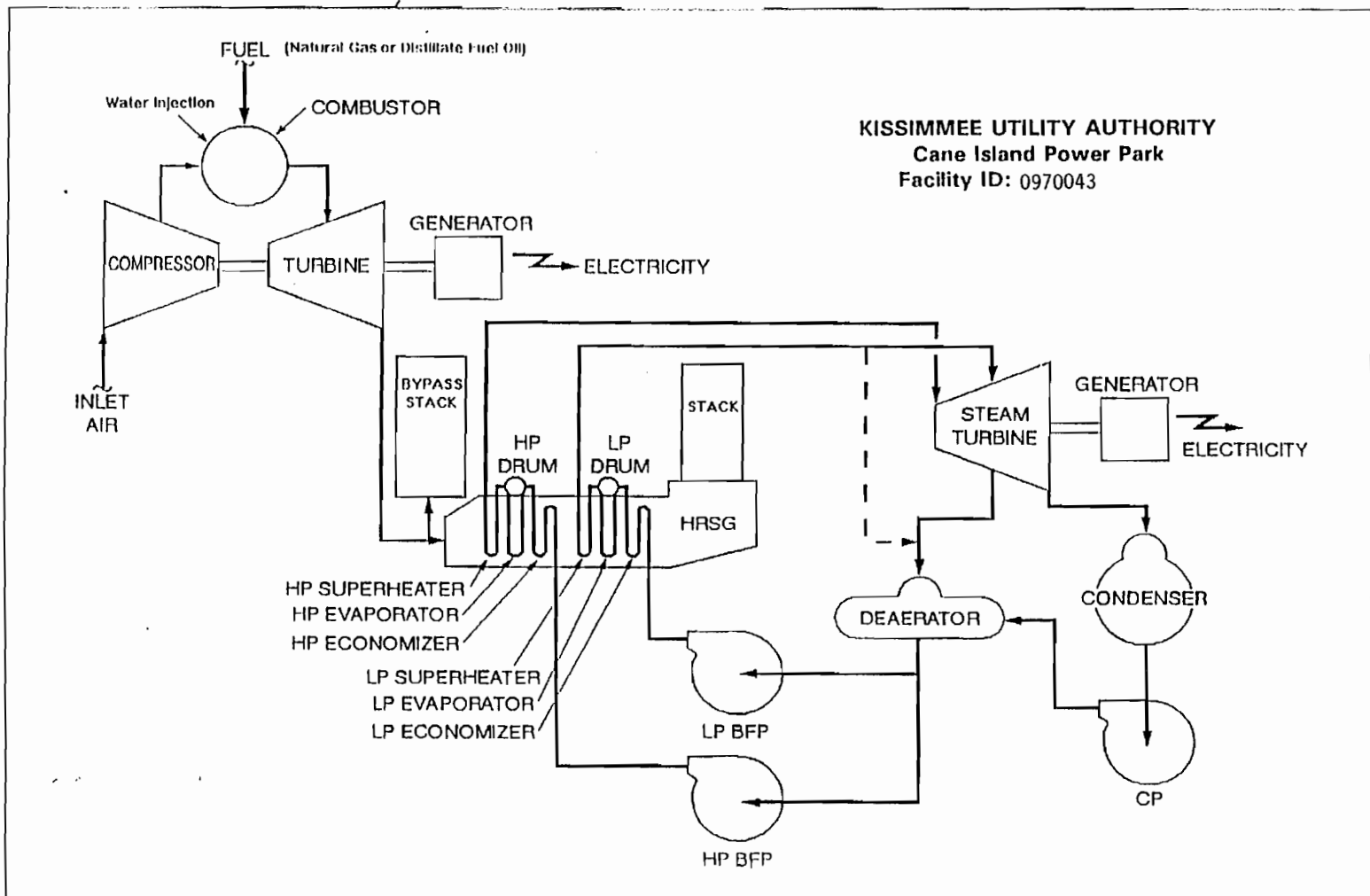
Applicable Regulations	Applicable Requirement
	The owner or operator using the optional SO ₂ monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20(g).
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24(c) through (e), and repeat tests applicable to the "out-of-control" parameter.
40 CFR 75.30, SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.
40 CFR 75.51, SUBPART F - Recordkeeping Requirements, General recordkeeping provisions for specific situations	The owner or operator shall comply with the recordkeeping requirements of 40 CFR 75.51(c)(1) through (3) when combusting natural gas and fuel oil.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52(a)(1) through (3) and 40 CFR 75.52(a)(5) through (7).
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO ₂ emission records, the owner or operator shall record information as required in 40 CFR 75.55(c) in lieu of the provisions of 40 CFR 75.54(c).
40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56(a)(1) through (3) and 40 CFR 75.56(a)(5) through (7).

Applicable Regulations	Applicable Requirement
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60(c) for any claims of confidential data.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this section.
40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO ₂ emissions monitoring, and adhere to all applicable requirements, as identified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.

Applicable Regulations	Applicable Requirement
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emissions rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment F

Attachment F
Process Flow Diagram



250 MW Combined Cycle Combustion Turbine
Process Flow Diagram

Attachment G

Attachment G

Fuel Analysis or Specification

IMAGE QUALITY

AS YOU REVIEW THE NEXT FEW PAGES,
PLEASE NOTE THAT THE ORIGINAL
DOCUMENT WAS OF POOR QUALITY.

3875 CORNERS NORTH COURT
NORCROSS, GEORGIA 30091-5808
(770) 448-5235
(800) 241-6315

KISSIMEE UTL AUTHORITY - CAPE ISLAND
SCOTT YELVINGTON
P O BOX 423219
KISSIMEE FL 34742-3219

Lab Number : 9568
Logged Date : 29-MAY-96
Sample Drawn : 28-MAY-96
Report Date : 31-MAY-96
Record Ref.# : 366310

Unit ID : UNIT 2
Sample ID : FUEL OIL #2
Worksite : CAPE ISLAND
Time On Fluid :

Mfg. : UNKNOWN
Model : -
PO No.: 10114
Time On System :

TESTING PERFORMED:

MEASURED

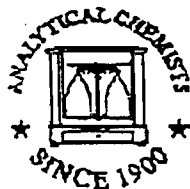
Heat of Combustion Calc (Fuel oil) D4868	
Ash Content, 2 wt. - D482	0.001
Sulfur Content by XRF, 2 wt - D4294	0.03
Water Content KF (ppm) D1744	77
Density, Kg/L @ 15°C - D1298	88.8450
Gross Heat Value, BTU/g - ASTM D4868	138064
Net Heat Value, BTU/g - ASTM D4868	129550
Gross Heat Value, BTU/lb - ASTM D4868	19615
Net Heat Value, BTU/lb - ASTM D4868	18405
Arsenic, ppm, EPA 7060	<0000.05
Beryllium, ppm, EPA 7091	<0000.05
Mercury, ppm, EPA 7471	<0000.05
Lead, ppm, EPA 7421	0000.07

RECOMMENDATIONS / COMMENTS:

SAMPLE SUBMITTED AND PROCESSED FOR THE TEST DATA (ONLY).

Respectfully Submitted,

Analysts, Inc.



NICHOLS LABORATORY, INC.

1924 Tennessee Avenue • Knoxville, Tennessee 37921 • (615) 523-6449

Certificate of Analysis

April 25, 1995

Power Generation Technologies
200 Tech Center Drive
Knoxville, TN 37912

Received: 4/20/95

Purchase Order No: ESC 05093

Lab ID # NF-2893

Sample ID # Kissimmee Utility Authority, Composite Sample
(50 ml each of ten samples)

	T =	60°F	70°F	100°F
1) Specific Gravity @ T		0.8475	0.8455	0.8412
2) Density @ T, g/cc		0.8467	0.8438	0.8412
3) Pounds Per U.S. Gallon @ T		7.0652	7.0408	6.9700
4) Gross Heating Value, Btu/lb		19505		
5) Btu Per Gallon		137,807		

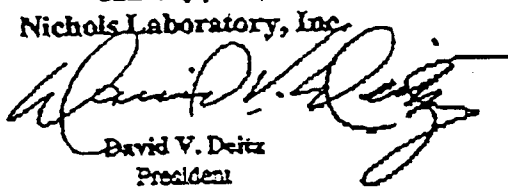
Ref: ASTM D 1250 (tables); D 1298; D 4809-90.

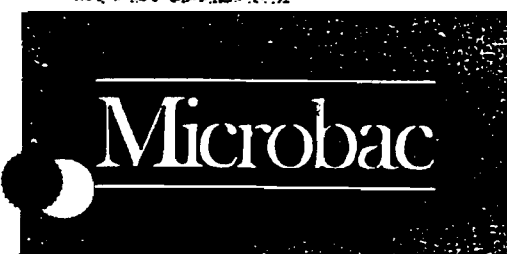
Ultimate Analysis

6) % Carbon	87.16
7) % Hydrogen	12.68
8) % Nitrogen	< 0.50
9) % Sulfur	0.0435
10) % Ash	< 0.001
11) % Oxygen by Difference	0.00

Ref: ASTM D 129; D 482; D 5291

Sincerely yours,
Nichols Laboratory, Inc.


David V. Deitz
President

MicrobacMicrobac Laboratories
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ERIE PA 16509
(814) 825-8533

Page 1

AIR • FUEL • WATER • OIL • GAS

CERTIFICATE OF ANALYSIS

ENVIRONMENTAL SYSTEMS CORP.

200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample IdPermit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
1	GAS 01, #1						
	LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			4/25/95	15:00	EVM
	ETHANE		0.32 %		4/25/95	15:00	EVM
	METHANE		95.33 %		4/25/95	15:00	EVM
	ETHANE		2.56 %		4/25/95	15:00	EVM
	PROPANE		0.67 %		4/25/95	15:00	EVM
	ISO-BUTANE		0.19 %		4/25/95	15:00	EVM
	N-BUTANE		0.15 %		4/25/95	15:00	EVM
	ISO-PENTANE		0.06 %		4/25/95	15:00	EVM
	N-PENTANE		0.03 %		4/25/95	15:00	EVM
	HEXANES		0.02 %		4/25/95	15:00	EVM
	CARBON DIOXIDE		0.68 %		4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1041.89	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1023.76	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		939.43	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		923.88	BTU/CU.FT.	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM
	ACTUAL NET BTU		939.43	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,906.10	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719717	G/ML	4/25/95	15:00	EVM
	DENSITY		0.04493573	LBS/CU.FT.	4/25/95	15:00	EVM
2	GAS 01, #2						
	LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			4/25/95	15:00	EVM
	NITROGEN		0.49 %		4/25/95	15:00	EVM
	METHANE		95.24 %		4/25/95	15:00	EVM
			2.54 %		4/25/95	15:00	EVM

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ENVIRONMENTAL SYSTEMS CORP.

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Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
2	GAS 01, #2						
	PROPANE		0.65	%	4/25/95	15:00	EVM
	BUTANE		0.19	%	4/25/95	15:00	EVM
	PENTANE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1839.41	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1821.32	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		937.17	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		928.86	BTU/CU.FT.	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5874		4/25/95	15:00	EVM
	ACTUAL NET BTU		937.17	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,857.83	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.800719646	G/ML	4/25/95	15:00	EVM
	DENSITY		0.844931297	LBS/CU.FT.	4/25/95	15:00	EVM

3 GAS 01-02, #3

LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			4/25/95	15:00	EVM
NITROGEN		0.35	%	4/25/95	15:00	EVM
METHANE		95.31	%	4/25/95	15:00	EVM
ETHANE		2.56	%	4/25/95	15:00	EVM
PROPANE		0.67	%	4/25/95	15:00	EVM
ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
N-BUTANE		0.14	%	4/25/95	15:00	EVM
PENTANE		0.06	%	4/25/95	15:00	EVM

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CERTIFICATE OF ANALYSIS

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Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample IdPermit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
3	GAS 01-02, #3						
	HEXANE		0.03 %		4/25/95	15:00	EVM
	ES		0.02 %		4/25/95	15:00	EVM
	CARBON DIOXIDE		0.60 %		4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1041.50	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1023.46	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		939.15	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		922.81	BTU/CU.FT.	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5876		4/25/95	15:00	EVM
	ACTUAL NET BTU		939.15	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,897.28	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.800719807	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044941301	LBS/CU.FT.	4/25/95	15:00	EVM
4	GAS 02, #4						
	LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			4/25/95	15:00	EVM
	NITROGEN		0.36 %		4/25/95	15:00	EVM
	METHANE		95.36 %		4/25/95	15:00	EVM
	ETHANE		2.55 %		4/25/95	15:00	EVM
	PROPANE		0.65 %		4/25/95	15:00	EVM
	ISO-BUTANE		0.19 %		4/25/95	15:00	EVM
	N-BUTANE		0.14 %		4/25/95	15:00	EVM
	ISO-PENTANE		0.05 %		4/25/95	15:00	EVM
	N-PENTANE		0.03 %		4/25/95	15:00	EVM
	HEXANES		0.02 %		4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67 %		4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1040.72	BTU/CU.FT.	4/25/95	15:00	EVM

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ENVIRONMENTAL SYSTEMS CORP.

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KNOXVILLE TN 37912

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Date Received 4/21/95

Order No 9504-01099

Invoice No 038527

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Sampled Date 4/12/95

Sampled Time 00:00

Sample Id

Permit No

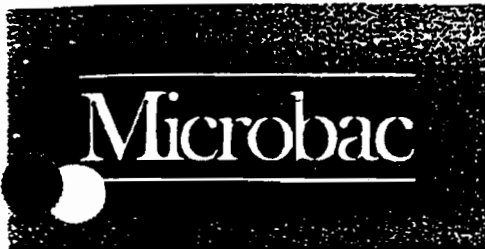
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
4	GAS 02, #4						
	BTU SAT. (HIGH HEAT VAL)		1022.61	BTU/CU.FT.	4/25/95	15:00	EVM
	DRY (LOW HEAT VAL)		938.35	BTU/CU.FT.	4/25/95	15:00	EVM
	NET D.V., SAT. (LOW HEAT VAL)		922.02	BTU/CU.FT.	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5869		4/25/95	15:00	EVM
	ACTUAL NET BTU		938.35	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,901.34	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719052	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044894187	LBS/CU.FT.	4/25/95	15:00	EVM
	GAS 02, #5						
	LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			4/25/95	15:00	EVM
	NITROGEN		0.53	%	4/25/95	15:00	EVM
	METHANE		95.21	%	4/25/95	15:00	EVM
	ETHANE		2.54	%	4/25/95	15:00	EVM
	PROPANE		0.65	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1038.90	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1020.83	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		920.41	BTU/CU.FT.	4/25/95	15:00	EVM
	SPECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM

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Order No 9504-01099
Invoice No 038527
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Sampled Date 4/12/95
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Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
5	GAS 02, #5						
	ACTUAL NET BTU		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU		20,844.55	BTU/LB.	4/25/95	15:00	EVM
	DEN		0.808719751	G/ML	4/25/95	15:00	EVM
	DENSITY		0.844937841	LBS/CU.FT.	4/25/95	15:00	EVM
7	GAS 03, #7						
	LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			4/25/95	15:00	EVM
	NITROGEN		0.58	%	4/25/95	15:00	EVM
	METHANE		95.35	%	4/25/95	15:00	EVM
	ETHANE		2.49	%	4/25/95	15:00	EVM
	PROPANE		0.65	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.20	%	4/25/95	15:00	EVM
	N-BUTANE		0.15	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.06	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.57	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1040.62	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1022.52	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		938.27	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		921.94	BTU/CU.FT.	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5867		4/25/95	15:00	EVM
	ACTUAL NET BTU		938.27	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,988.20	BTU/LB.	4/25/95	15:00	EVM
	DEN		0.808718756	G/ML	4/25/95	15:00	EVM
	DENSITY		0.844875676	LBS/CU.FT.	4/25/95	15:00	EVM

Certificate Of Analysis Continued On Next Page



Microbac

ERIE TESTING LAB

1962 WAGER ROAD

ERIE

PA 16503

(814) 825-8533

AIR • FUEL • WATER • FOOD • WASTES

CERTIFICATE OF ANALYSIS

Attn: James Sutton

ENVIRONMENTAL SYSTEMS CORP.

200 TECH CENTER DRIVE

KNOXVILLE TN 37912

Date Reported 5/15/95
 Date Received 5/11/95
 Order No 9505-00639
 Invoice No 039261
 Cust # 005186
 Sampled Date 8/08/00
 Sampled Time 00:00
 Sample Id

Permit No
 Cust P.O.

Subject: GAS SAMPLES (MILFORD PLANT, KISSIMMEE UTILITY), RECD. 5/11

TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
1 MILFORD PLANT, 5/5/95 @ 07:00						
LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-98			5/12/95	10:00	EVM
NITROGEN		1.82 %		5/12/95	10:00	EVM
METHANE		95.82 %		5/12/95	10:00	EVM
		2.16 %		5/12/95	10:00	EVM
		0.28 %		5/12/95	10:00	EVM
ISOBUTANE		0.00 %		5/12/95	10:00	EVM
N-BUTANE		0.04 %		5/12/95	10:00	EVM
ISO-PENTANE		0.02 %		5/12/95	10:00	EVM
N-PENTANE		0.02 %		5/12/95	10:00	EVM
HEXANES		0.02 %		5/12/95	10:00	EVM
CARBON DIOXIDE		0.51 %		5/12/95	10:00	EVM
BTU, DRY (HIGH HEAT VAL)		1021.15	BTU/CU.FT.	5/12/95	10:00	EVM
BTU, SAT. (HIGH HEAT VAL)		1002.75	BTU/CU.FT.	5/12/95	10:00	EVM
NET BTU, DRY (LOW HEAT VAL)		920.05	BTU/CU.FT.	5/12/95	10:00	EVM
NET BTU, SAT. (LOW HEAT VAL)		904.24	BTU/CU.FT.	5/12/95	10:00	EVM
REAL SPECIFIC GRAVITY		0.5787		5/12/95	10:00	EVM
ACTUAL NET BTU		920.05	BTU/CU.FT.	5/12/95	10:00	EVM
ACTUAL NET BTU		88,781.00	BTU/LB.	5/12/95	10:00	EVM
DENSITY		0.005704968	LB./L.	5/12/95	10:00	EVM
DENSITY		0.04264565	LB./CU.FT.	5/12/95	10:00	EVM

2 KISSIMMEE UTILITY, CANE ISLAND GAS REG. STATION, 5/9/95 @
 13:15 BY J. LOONEY

SULFUR, TOTAL (NATURAL GAS) ASTM D1872-90
 TOTAL SULFUR
 TOTAL SULFUR (% BY WEIGHT)

(1.9 02/1000)

(0.0031 %)

5/11/95 15:00 EVM
 5/11/95 15:00 EVM
 5/11/95 15:00 EVM

Certificate Of Analysis Continued On Next Page

< 0.0031%

The data and other information contained on this, and other accompanying documents, represent only the samples analyzed and is
 intended upon the condition that it is not to be reproduced wholly or in part for advertising or other purposes without written approval
 from the laboratory.

USDA-ERL-NIOSH Testing Food Sanitation Consulting Chemical and Microbiological Analysis and Research



Attachment H

Attachment H

Detailed Description of Control Equipment

Detailed Description of Control Equipment

- 1.) Low NO_x Burner: A technology that uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. this two-stage process ensures good mixing of the air and fuel, and minimizes the amount of air required which results in low NO_x emissions.
- 2.) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.
- 3.) Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used only during oil firing.

Attachment I

Attachment I
Description of Stack Sampling Facilities

Stack Sampling Facilities

Vendors for these items have not yet been identified. A detailed description of the stack sampling facilities will be included with the operating permit application.

Attachment J

Attachment J
Compliance Test Report

Compliance Test Report

A compliance test report will be included with the operating permit application after construction and initial testing has been completed.

Attachment K

Attachment K
Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

After a normal start up is initiated, the time is documented when the turbine starts firing. The turbine then continues with a normal start up and warm up. Time is documented again when the breaker closes. Upon the generator reaching 60 MW, the water injection pump is turned on (fuel oil only), and flow is established to the turbine. When the NO_x emissions are controlled and stable, the time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to 60 MW and the water injection pumps are taken out of service (fuel oil only-this time is documented). Time is again recorded when the turbine stops firing.

Attachment L

Attachment L

Operation and Maintenance Plan

Operation and Maintenance Plan

An operation and maintenance plan will be submitted if required by the construction permit.

Attachment M

Attachment M

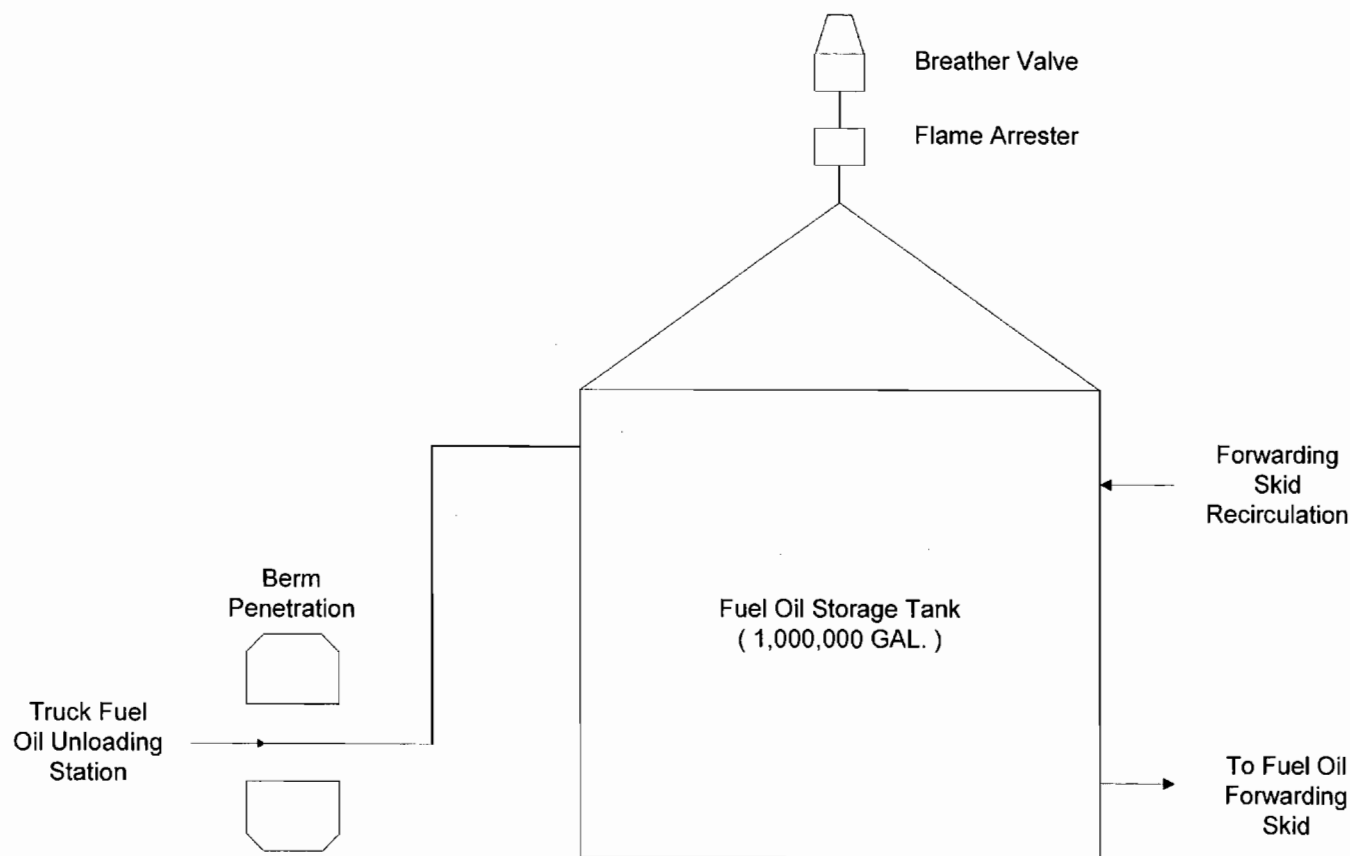
Unit Specific Applicable Requirements

**1,000,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements**

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.
40 CFR 60.116b, Monitoring of Operations	The owner / operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b) for a period of at least two (2) years.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of Excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.

Attachment N

Attachment N
Process Flow Diagram



Attachment O

Attachment 0

Emission Source Calculations

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

06/25/98
PAGE 1

Identification

Identification No.: 67
City: Cane Island
State: FL
Company: KUA
Type of Tank: Vertical Fixed Roof
Description: Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft): 35.0
Diameter (ft): 70.0
Liquid Height (ft): 34.8
Avg. Liquid Height (ft): 17.0
Volume (gallons): 1000000
Turnovers: 10.5
Net Throughput (gal/yr): 10495660

Paint Characteristics

Shell Color/Shade: White/White
Shell Condition: Good
Roof Color/Shade: White/White
Roof Condition: Good

Roof Characteristics

Type: Dome
Height (ft): 0.00
Radius (ft) (Dome Roof): 56.00
Slope (ft/ft) (Cone Roof): 0.0000

Breather Vent Settings

Vacuum Setting (psig): -0.03
Pressure Setting (psig): 0.03

Meteorological Data Used in Emission Calculations: Orlando, Florida

(Avg Atmospheric Pressure = 14.7 psia)

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
LIQUID CONTENTS OF STORAGE TANK

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PAGE 2

Mixture/Component	Month	Daily Liquid Surf.			Liquid Bulk			Vapor Pressures (psia)			Vapor	Liquid	Vapor	Mol. Weight	Basis for Vapor Pressure Calculations
		Temperatures (deg F)			Temp.				Mol.	Mass	Mass				
		Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight	Fract.	Fract.				
Distillate fuel oil no. 2	All	74.41	68.90	79.92	72.42	0.0103	0.0087	0.0122	130.000				188.00	Option 3: A=12.1010, B=8907.0	

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
DETAIL CALCULATIONS (AP-42)

06/25/98
PAGE 3

Annual Emission Calculations

Standing Losses (lb):	295.6338
Vapor Space Volume (cu ft):	93882.05
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.037443
Vented Vapor Saturation Factor:	0.986867

Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	93882.05
Tank Diameter (ft):	70.0
Vapor Space Outage (ft):	24.39
Tank Shell Height (ft):	35.0
Average Liquid Height (ft):	17.0
Roof Outage (ft):	6.39

Roof Outage (Dome Roof)	
Roof Outage (ft):	6.39
Dome Radius (ft):	56
Shell Radius (ft):	35.0

Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Daily Avg. Liquid Surface Temp. (deg. R):	534.08
Daily Average Ambient Temp. (deg. R):	532.07
Ideal Gas Constant R (psia cuft / (lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.09
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqftday):	1487.00

Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.037443
Daily Vapor Temperature Range (deg.R):	22.05
Daily Vapor Pressure Range (psia):	0.003554
Breather Vent Press. Setting Range (psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.008651
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.012204
Daily Avg. Liquid Surface Temp. (deg R):	534.08
Daily Min. Liquid Surface Temp. (deg R):	528.57
Daily Max. Liquid Surface Temp. (deg R):	539.59
Daily Ambient Temp. Range (deg.R):	20.80

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
DETAIL CALCULATIONS (AP-42)

06/25/98
PAGE 4

Annual Emission Calculations

Vented Vapor Saturation Factor
Vented Vapor Saturation Factor: 0.986867
Vapor Pressure at Daily Average Liquid
Surface Temperature (psia): 0.010293
Vapor Space Outage (ft): 24.39

Working Losses (lb): 334.3891
Vapor Molecular Weight (lb/lb-mole): 130.000000
Vapor Pressure at Daily Average Liquid
Surface Temperature (psia): 0.010293
Annual Net Throughput (gal/yr): 10495660
Turnover Factor: 1.0000
Maximum Liquid Volume (cuft): 133926
Maximum Liquid Height (ft): 34.8
Tank Diameter (ft): 70.0
Working Loss Product Factor: 1.00

Total Losses (lb): 630.02

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
INDIVIDUAL TANK EMISSION TOTALS

06/25/98
PAGE 5

Annual Emissions Report

Liquid Contents	Losses (lbs.):		Total
	Standing	Working	
Distillate fuel oil no. 2	295.63	334.39	630.02
Total:	295.63	334.39	630.02