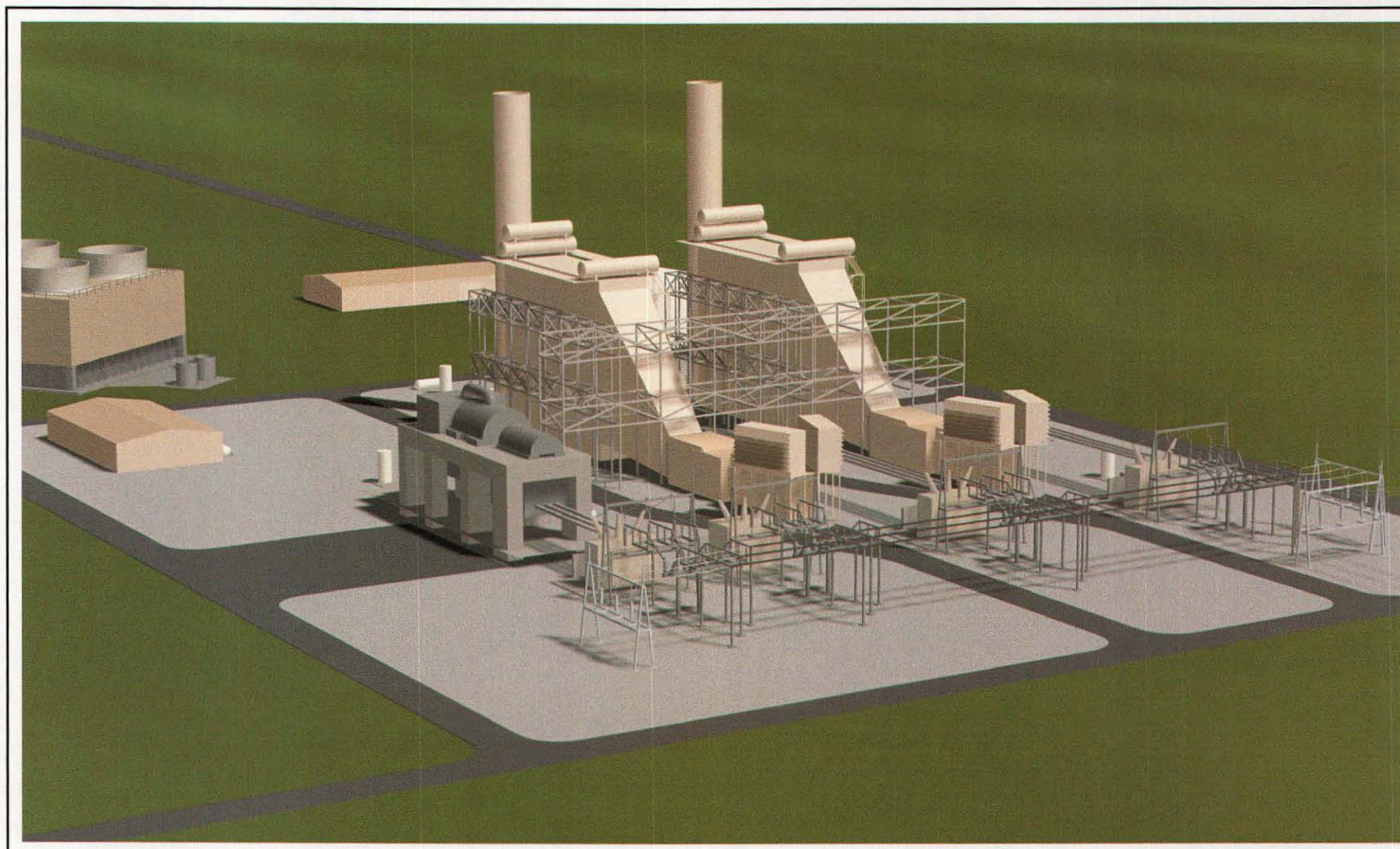


Supplemental Site Certification Application



Orlando Utilities Commission Curtis H. Stanton Energy Center Combined Cycle Unit A

B&V Project 98362

January 2001



**Curtis H. Stanton Energy Center
Combined Cycle Unit A**

Supplemental Site Certification Application

Manual Number CHSEC- 026

Issued to Stacey Anderson

Location _____

**Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A**

Supplemental Site Certification Application

B&V Project 98362

January 2001

SUPPLEMENTAL SITE CERTIFICATION APPLICATION

ENGINEERING CERTIFICATION STATEMENT

**CURTIS H. STANTON ENERGY CENTER
COMBINED CYCLE UNIT A**

I, the undersigned, hereby certify that:

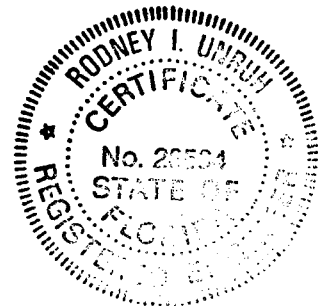
The engineering features of the Curtis H. Stanton Energy Center Combined Cycle Unit A project described in this application have been prepared, designed, or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles; and,

To the best of my knowledge, the information submitted in support of the application is true, accurate, and complete and is based upon reasonable techniques, estimates, materials, and information gathered and evaluated by qualified personnel; and,

To the best of my knowledge, there is reasonable assurance that combined cycle project described in this application, when properly operated and maintained, will comply with all applicable pollution control standards found in the Florida Statutes and rules of the Department of Environmental Protection.

 01/17/01

Rodney I. Unruh Date
Florida No. 28564
Black & Veatch
11401 Lamar
Overland Park, Kansas 66211



Preface

This Supplemental Site Certification Application (SSCA) is being submitted by the Orlando Utilities Commission (OUC), Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and the Southern Company-Florida, LLC (Southern-Florida) for certification of Curtis H. Stanton Energy Center Combined Cycle Unit A (Stanton A), a new 230 kV transmission line, and an associated natural gas pipeline. Stanton Units 1 and 2 are existing certified coal fired units at the site; Stanton A is proposed as a combined cycle combustion turbine unit with a 791 MVA nameplate rating and a 633 MW nominal rating. Units 1 and 2 operate under Certification Order PA 81-14 originally issued on December 15, 1982, and supplemented on December 17, 1991, for the addition of Unit 2. The Order has been subsequently modified in April 1993, July 1995, December 1997, and August 1998.

This document is intended to serve as the SSCA for Stanton A at the Stanton Energy Center, the Stanton A to Stanton switchyard transmission line, and an associated facility (natural gas pipeline), including all state and local permits for the construction and operation of the facilities. Following are the major section headings of this SSSC:

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.

Project Information

The Stanton Energy Center is located at 5100 South Alafaya Trail near Orlando, in Orange County, Florida, and includes two operating units at present. Stanton Units 1 and 2 are existing certified coal fired units at the site. Stanton Unit 1 has a net generation of 440 MW, and began commercial operation in June 1987. Stanton Unit 2 has a net generation of 446 MW, and began commercial operation in June 1996. Stanton A will be a combined cycle combustion turbine generating unit proposed for installation north of

Units 1 and 2, scheduled for commercial operation in October 2003. Stanton A will produce 633 MW (nominal) of electricity for distribution through the Stanton switchyard.

Stanton A will fire natural gas as the primary fuel; No. 2 fuel oil will be stored onsite as backup fuel. All new equipment will be installed with modern pollution control devices. Stanton A will be jointly owned by OUC, KUA, FMPA, and Southern-Florida. The new unit will be operated by Southern-Florida.

Project Impacts

Air

Units 1 and 2 are currently operating under Florida Department of Environmental Protection Title V Operating Permit 0950137-001-AV. Stanton A, 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 Stanton A potential to emit demonstrates that it will emit significant amounts of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM/PM₁₀), and sulfur dioxide (SO₂) with respect to the PSD program. 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.
- Additional Impact Analysis.

The technology proposed to control emissions from Stanton A include dry low NO_x burners and selective catalytic reduction (SCR) for the control of NO_x, the use of clean low sulfur, low ash fuels, and advanced combustion control technology to reduce CO, PM/PM₁₀, SO₂, and VOC emissions.

An air dispersion modeling analysis was performed to determine the Stanton A maximum NO_x, CO, PM/PM₁₀, and SO₂ 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 Stanton A 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 Stanton A PSD Class I pollutant

impacts, visual impacts, PSD Class I regional haze impacts, air quality impacts on vegetation and soils, air quality impacts due to growth, and a Hazardous Air Pollutant applicability Analysis, are inconsequential as the predicted levels are well below threshold levels.

Water Use

The Stanton A cooling tower requires an average of 2.9 million gallons per day of cooling tower makeup from the Orange County Eastern Water Reclamation Facility and other Stanton site reuse waters. A new pumping station will be required at the Stanton cooling water makeup lake to deliver effluent to the Stanton A cooling tower. At average load operation, approximately 369,000 gallons of cooling tower blowdown from Stanton A will be available for treatment and reuse at the Stanton site per day.

Under normal operation on natural gas, the units will require 0.316 million gallons of ground water per day from the Upper Floridan Aquifer for service and potable water supply. Under maximum operating conditions (power augmentation), Stanton A will require 0.895 million gallons per day. The majority of this amount is required for power cycle demineralized makeup water and evaporative cooler makeup water. Additional water is also required during oil firing for NO_x injection water to the combustion turbines. Modeling results indicate that ground water quality and quantity beyond the Stanton property will be unaffected by this withdrawal.

In addition to the normal service water demand, the applicants also request the use of 2.13 million gallons of ground water per day for emergency use as cooling tower makeup in the event of supply pipeline catastrophe or disruptions regarding the Orange County effluent pipeline or plant, or makeup pond shortages. The applicants request this ground water allocation on a temporary use (30 days per year) basis to continue operations until effluent supply is restored.

Land

The Stanton Energy Center property was approved for industrial use by the Orange County Board of Commissioners during the certification of Unit 1. Use of the property in an industrial capacity is consistent with the current and future elements of the Orange County, East Central Florida Regional Planning Council, and State of Florida comprehensive plans.

A biophysical assessment of the property concluded that the property is inhabited by several federally and state listed protected species. However, in consideration for previous impacts and approvals, OUC prepared and implemented the Joint Agency Mitigation Monitoring Plan in 1992 to mitigate and compensate for ultimate site

development. The applicants have taken measures to avoid and minimize ecological impacts as a result of Stanton A development, and in addition to continued implementation of the Joint Agency Mitigation Monitoring Plan, no significant impacts are anticipated.

There are no archaeological, historic, or cultural sites present on the Stanton property or in the utility corridor considered eligible for listing on the *National Register of Historic Places*. In March 1981 and August 1982, the State of Florida indicated 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 State approved the property for development.

Natural gas will be delivered to the site by an underground 16 inch pipeline with appurtenant metering facilities at the FGT and Stanton A connection points. The new pipeline will be installed in the existing OUC-owned utility corridor south of the Stanton site.

The new unit will require a new 0.6 mile long transmission line to connect to the existing Stanton switchyard. The route will use a disturbed maintenance road corridor for the majority of its length. The transmission line will be located entirely on Stanton Energy Center property.

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 tank has an automatic shutoff when full, and lined secondary containment.

Wastewater and Solid Waste

Process wastewaters will be treated and reused at the Stanton site in various processes. Stanton will remain a zero-discharge facility with the addition of Stanton A. Drainage from oil containment areas and other potential oil contaminated areas will be routed through an oil/water separator. Separator effluent will be directed to the Stanton recycle basin. Cooling tower blowdown will be collected and treated for additional reuse at the Stanton site. Sanitary wastewaters will be directed to a new onsite septic tank/tile field system for treatment and disposal. Uncontaminated storm waters will be directed to an existing storm water detention pond. All wastewaters will be treated to meet all applicable water quality standards appropriate for the intended use. No significant impacts on the existing Stanton systems will result from the treatment and reuse of these wastewaters. A licensed contractor will be responsible for treatment and disposal of boiler and combustion turbine cleaning wastewaters, and collected waste oil.

Trash and other solid waste will be disposed of at an approved facility by a licensed contractor. Solid waste from the cooling tower blowdown treatment system will be disposed onsite in the combustion waste landfill.

Socioeconomic

Operation of Units 1 and 2 has had only positive socioeconomic impacts in Orange County through tax revenues and employment. Construction and operation of Stanton A will incrementally increase these benefits. During the peak period of Stanton A construction, approximately 300 jobs will be created. The net direct employment effect will be the creation of 30 additional full-time operations positions for the operating life of the unit. The construction and operation of Stanton A at the Stanton Energy Center will not significantly impact the local or regional services or infrastructure based on the Units 1 and 2 experience, the level of existing local and regional services, and availability of a local construction workforce.

Need for Power

OUC, KUA, and FMPA have jointly filed a Need for Power petition for the addition of Stanton A to the Stanton Energy Center, in accordance with the Florida Electrical Power Plant Siting Act. Stanton A is a proposed combined cycle unit with a nominal rating of 633 MW. The determination of need for the proposed Stanton A 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 Stanton A will consist of two F-class combustion turbines, two heat recovery steam generators (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.

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 turbines. One new 1.68 million gallon fuel oil storage tank will be installed to provide backup fuel oil for Stanton A.

OUC was the project manager for licensing and construction of Units 1 and 2. OUC is also the operator for Units 1 and 2. However, Southern-Florida will be the project manager for construction of Stanton A and will be the operator; OUC is responsible for Stanton A licensing and certification.

Schedule

The Stanton A certification and major milestone schedule follows:

Need for Power Submittal	January 2001
Supplemental Site Certification Application Submittal	January 2001
Need for Power Approval	June 2001
Certification Hearing	July 2001
Supplemental Certification Issued	September 2001
Start of Construction	October 2001
Commercial Operation	October 2003

Applicant Information

Applicant's Official Names and Addresses

Orlando Utilities Commission (28% owner)
500 South Orange Avenue
Orlando, Florida 32802
(407) 423-9100

Florida Municipal Power Agency (3.5% owner)
8553 Commodity Circle
Orlando, Florida 32819-9002
(405) 355-7767

Kissimmee Utility Authority (3.5% owner)
1701 West Carroll Street
Kissimmee, Florida 32741
(407) 933-7777

Southern Company - Florida, LLC (65% owner)
270 Peachtree St., NW
Atlanta, Georgia 30303
(404) 506-5200

Business Entity

Orlando Utilities Commission (OUC) is a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC has the full authority over the management and control of the electric light and water works parts of the City of Orlando. It has the power to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission and distribution systems, and water production, transmission and distribution systems in order to meet the requirements of its customers.

Florida Municipal Power Agency (FMPA) is a joint agency formed pursuant to the Interlocal Cooperation Act and 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.

Kissimmee Utility Authority (KUA) is a public body, corporate and 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.

Southern Company-Florida, LLC (Southern-Florida) is a Delaware limited liability corporation authorized to transact business in Florida. Southern-Florida is a wholly-owned subsidiary of Southern Company which is one of the six operating subsidiaries of The Southern Company ("Southern Company"). Southern-Florida is the largest producer of electricity in the United States and one of the largest in the world, with a proven record of designing, owning and operating electric power plants. With 69 plants, comprised of 278 units, Southern Company generates more than 31,000 MW of capacity in the southeast United States. Southern Company also has more than 26,000 miles of transmission lines that interconnect with major utilities. Through its subsidiaries and affiliates, Southern Company develops, builds, owns, and operates power production and delivery facilities, conducts energy training and marketing activities, and provides other energy services in the United States and in international markets.

Names and Titles of Chief Executive Officers

Orlando Utilities Commission

Robert Haven

General Manager

Kissimmee Utility Authority

James Welsh

President and General Manager

Florida Municipal Power Agency

Claude L'Engle

General Manager

Southern Company - Florida, LLC

Charles D. McCrary

President

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

Fredrick Haddad, Jr.
Orlando Utilities Commission
500 South Orange Avenue
Orlando, FL 32802
(407) 244-8732

Site Location

Orange County

Nearest Incorporated City

Orlando, Florida

Latitude and Longitude

28° 29' 17" North Latitude
81° 10' 03" West Longitude

UTMs (Center of Site)

Northerly 1507528
Easterly 446825

Section, Township, Range

Sections 13 and 24 and the eastern half of Sections 14 and 23, R31E, T23S and Sections 18 and 19, R32E, T23S.

Location of any Directly Associated Transmission Facilities (counties)

Orange County

Nameplate Generating Capacity

Unit A: 791 MVA

Capacity of Proposed Additions and Ultimate Site Capacity

Proposed Unit A Addition: 633 MW at 70° F
Certified Ultimate Site Capacity: 2,000 MW

Contents

1.0	Need for Power and the Proposed Facilities	1-1
2.0	Site and Vicinity Characterization	2-1
2.1	Site and Associated Facilities Delineation.....	2-1
2.2	Sociopolitical Environment	2-7
2.3	Bio-Physical Environment	2-23
3.0	The Plant and Directly Associated Facilities	3-1
3.1	Background	3-1
3.2	Site Layout	3-1
3.3	Fuel	3-1
3.4	Air Emissions and Control.....	3-9
3.5	Plant Water Use	3-9
3.6	Chemical and Biocide Waste.....	3-13
3.7	Solid and Hazardous Waste	3-16
3.8	Onsite Drainage System.....	3-16
3.9	Construction Materials and Equipment Handling.....	3-20
3.10	Unit A Hydrologic Analysis	3-20
4.0	Effects of Site Preparation and Plant and Associated Facilities Construction....	4-1
4.1	Land Impact	4-1
4.2	Impact on Surface Water Bodies and Uses.....	4-2
4.3	Groundwater Impacts.....	4-2
4.4	Ecological Impacts.....	4-3
4.5	Air Impacts.....	4-3
4.6	Impact on Human Populations.....	4-10
4.7	Impact on Landmarks and Sensitive Areas.....	4-16
4.8	Impact on Archaeological and Historic Sites.....	4-16
4.9	Special Features	4-16
4.10	Benefits from Construction.....	4-17
4.11	Variances.....	4-17
5.0	Effects of Plant Operation.....	5-1
5.1	Effects of the Operation of the Heat Dissipation System	5-1
5.2	Effects of Chemical and Biocide Discharges.....	5-23

Contents (Continued)

5.3	Impacts on Water Supplies	5-24
5.4	Solid/Hazardous Waste Disposal Impacts	5-34
5.5	Sanitary and Other Waste Discharges.....	5-35
5.6	Air Quality Impacts.....	5-35
5.7	Operation Noise Impacts.....	5-35
5.8	Changes in Nonaquatic Species Populations	5-38
5.9	Other Plant Operation Effects.....	5-40
5.10	Landmarks, Sensitive Areas, and Archaeological Sites.....	5-40
5.11	Resources Committed	5-43
5.12	Variances.....	5-43
5.13	References.....	5-43
6.0	Transmission Lines and Other Linear Facilities	6-1
6.1	Transmission Line.....	6-1
6.2	Natural Gas Pipeline	6-12
7.0	Economic and Social Effects of Plant Construction and Operation	7-1
7.1	Socioeconomic Benefits.....	7-1
7.2	Socioeconomic Costs	7-4
7.3	References.....	7-10
8.0	Site and Design Alternatives.....	8-1
8.1	Alternative Sites.....	8-1
8.2	Proposed Site Design Alternatives.....	8-1
9.0	Coordination	9-1
9.1	Federal.....	9-1
9.2	State.....	9-1
9.3	Local	9-3
10.0	Appendices.....	10-1
10.1	Existing Federal Permits and Approvals.....	10-1
10.2	Federal Permit and Approval Applications.....	10-2
10.3	Existing State Permits	10-3
10.4	State Permit Applications	10-4

Contents (Continued)

10.5	Existing Local Permits.....	10-6
10.6	Local Permit Applications	10-7
10.7	Prevention of Significant Deterioration (PSD) Permit Application	10-8
10.8	Site Subsurface Data.....	10-9
10.9	Ground Water Quality Data.....	10-10

Tables

Table 2.2-1	Employment by Occupation Primary Impact Areas, 1990	2-12
Table 2.2-2	Employment by Industry, by County, with Percentage of Workforce (1998).....	2-13
Table 2.2-3	Occupational Employment Projections to 2007 - Orange County Aggregate Ranking by Openings, Wage, and Growth.....	2-14
Table 2.2-4	Occupational Employment Projections to 2007 - Florida Aggregate Ranking by Openings, Wage, and Growth.....	2-16
Table 2.2-5	Employment by Industry – Orange County (1998)	2-17
Table 2.2-6	Public Schools by Grade and School Enrollment, 1998-1999.....	2-19
Table 2.3-1	Generalized Regional Stratigraphic Section	2-24
Table 2.3-2	Chemical Analyses of Water from the Secondary Artesian Aquifer in Eastern Orange County	2-38
Table 2.3-3	Results of Pumping Tests in the Upper Floridan At and Near the Stanton Energy Center	2-40
Table 2.3-4	Supply Wells Within 1 Mile Boundary of SEC.....	2-50
Table 2.3-5	Total Water Demand for 1995 and 2020 in the St. Johns River Water Management District.....	2-51
Table 2.3-6	USGS Stream Data in the SEC Vicinity	2-52
Table 2.3-7	USGS Lake Stages in the SEC Vicinity	2-52
Table 2.3-8	Drainage Areas of Econlockhatchee River Tributaries Within the Project Vicinity of the Proposed Stanton A.....	2-56
Table 2.3-9	Plants and Animals Observed at the SEC	2-62
Table 2.3-10	State/Federally Listed Species On or Near the SEC.....	2-75
Table 2.3-11	State/Federally Listed Species On or Near the SEC.....	2-78
Table 2.3-12	Dry-Bulb Temperature Data for Orlando, Florida.....	2-85
Table 2.3-13	Wet-Bulb and Dry-Bulb Design Temperatures for Orlando, Florida	2-87
Table 2.3-14	Normal Relative Humidity Data for Orlando, Florida.....	2-88
Table 2.3-15	Heating and Cooling Degree-Day Data for Orlando, Florida.....	2-89

Contents (Continued)
Tables (Continued)

Table 2.3-16	Total Precipitation Data for Orlando, Florida.....	2-90
Table 2.3-17	Extreme Precipitation Data for Orlando, Florida.....	2-92
Table 2.3-18	Maximum Recorded Rainfall Data for Orlando, Florida.....	2-93
Table 2.3-19	Precipitation Amounts and Intensities for Selected Durations and Return Periods Expected in the Stanton Energy Center Area.....	2-94
Table 2.3-20	Annual Wind Rose Percent Frequency Distribution.....	2-108
Table 2.3-21	Estimated Average Mixing Heights and Average Wind Speeds Through the Mixed Layer Representative of the Stanton Energy Center Area	2-110
Table 2.3-22	Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--A Stability (Orlando, Florida, 1997).....	2-111
Table 2.3-23	Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--B Stability (Orlando, Florida, 1997).....	2-112
Table 2.3-24	Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--C Stability (Orlando, Florida, 1997).....	2-113
Table 2.3-25	Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--D Stability (Orlando, Florida, 1997).....	2-114
Table 2.3-26	Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--E Stability (Orlando, Florida, 1997)	2-115
Table 2.3-27	Distribution of Hours of Occurrence of Wind Speed, Wind Direction, and Stability--F Stability (Orlando, Florida, 1997)	2-116
Table 2.3-28	Ambient Air Quality Standards	2-117
Table 2.3-29	Background Ambient Air Quality	2-119
Table 3.3-1	Natural Gas Properties	3-5
Table 3.3-2	No. 2 Fuel Oil Properties	3-7
Table 3.5-1	Potable Water Analysis.....	3-12
Table 4.5-1	Available Fugitive Dust Control Methods for Disturbed Surface Areas	4-6
Table 4.5-2	Available Fugitive Dust Control Methods for Storage Piles	4-7
Table 4.5-3	Available Fugitive Dust Control Methods for Earth Moving.....	4-8
Table 4.5-4	Available Fugitive Dust Control Methods for Vehicular Traffic	4-9
Table 4.6-1	Typical Construction Equipment Noise Emissions	4-14
Table 5.1-1	SACTI Cooling Tower Modeling Input Parameters.....	5-5
Table 5.1-2	Total Hours of Predicted Plume Induced Fogging	5-8
Table 5.1-3	Average Monthly Predicted Cooling Tower Water Deposition	5-10
Table 5.1-4	Average Monthly Predicted Cooling Tower Salt Deposition	5-11

Contents (Continued)
Tables (Continued)

Table 5.1-5	Average Annual Predicted Plume Length Frequency of Occurrence	5-12
Table 5.3-1	Stanton Energy Center Water Usage	5-28
Table 5.7-1	Predicted Facility Noise Emissions versus Orange County Noise Criteria.	5-39
Table 6.1-1	Transmission Line Cost Estimate	6-5
Table 6.1-2	Substation Cost Estimate	6-6
Table 6.1-3	Wetland Impacts Within the SEC Electric Transmission Corridor	6-8
Table 6.2-1(a)	Cost for Gas Pipeline Construction.....	6-16
Table 6.2-1(b)	Cost for Gas Pipeline Construction.....	6-16
Table 6.2-2	Wetland Impacts Within the SEC Natural Gas Pipeline Corridor	6-18

Figures

Figure 2.1-1	Stanton Energy Center Property Location	2-2
Figure 2.1-2	Curtis H. Stanton Energy Center and Adjacent Terrain	2-3
Figure 2.1-3	Site Arrangement	2-5
Figure 2.2-1	Site Location	2-8
Figure 2.3-1	Major Depressions Within the SEC Boundary	2-26
Figure 2.3-2	Lineaments in the SEC Area.....	2-27
Figure 2.3-3	Sitework - Soil Boring Locations Plan and Description.....	2-29
Figure 2.3-4	Boring Location Plan	2-30
Figure 2.3-5	Stratigraphic Profile Beneath the SEC.....	2-32
Figure 2.3-6	Stratigraphic Profile Beneath the SEC.....	2-33
Figure 2.3-7	Piezometer and Monitoring Wells Location Plan.....	2-35
Figure 2.3-8	Upper Floridan Aquifer - Groundwater Levels Within Stanton Energy Center Site	2-41
Figure 2.3-9	Dissolved Solids Concentrations - Upper Floridan Aquifer.....	2-43
Figure 2.3-10	Chloride Concentrations - Upper Floridan Aquifer	2-44
Figure 2.3-11	Sulfate Concentrations - Upper Floridan Aquifer.....	2-45
Figure 2.3-12	Major Surface Hydrologic Features in SEC Vicinity	2-47
Figure 2.3-13	Water Supply Wells in the SEC Area	2-49
Figure 2.3-14	Historical Daily Streamflow Econlockhatchee River at Magnolia Ranch Station.....	2-54
Figure 2.3-15	Historical Daily Streamflow Econlockhatchee River Near Chuluota, Florida Station.....	2-55

Contents (Continued)

Figures (Continued)

Figure 2.3-16	Local Surface Hydrologic Features in SEC Vicinity	2-57
Figure 2.3-17	100 Year Flood-Prone Areas at the SEC	2-59
Figure 2.3-18	Vegetative Communities of the SEC	2-61
Figure 2.3-19	Red-Cockaded Woodpecker Colony Sites and Home Ranges on the SEC	2-80
Figure 2.3-20	Monthly Average Wind Speed and Prevailing Direction for Selected Florida Cities	2-82
Figure 2.3-21	Annual Average Wind Speed and Prevailing Direction for Selected Florida Cities	2-83
Figure 2.3-22	January Wind Rose for Orlando, Florida Period of Record: 1988- 1992.....	2-95
Figure 2.3-23	February Wind Rose for Orlando, Florida Period of Record: 1988-1992	2-96
Figure 2.3-24	March Wind Rose for Orlando, Florida Period of Record: 1988- 1992.....	2-97
Figure 2.3-25	April Wind Rose for Orlando, Florida Period of Record: 1988- 1992.....	2-98
Figure 2.3-26	May Wind Rose for Orlando, Florida Period: 1988-1992	2-99
Figure 2.3-27	June Wind Rose for Orlando, Florida Period: 1988-1992	2-100
Figure 2.3-28	July Wind Rose for Orlando, Florida Period: 1988-1992.....	2-101
Figure 2.3-29	August Wind Rose for Orlando, Florida Period: 1988-1992.....	2-102
Figure 2.3-30	September Wind Rose for Orlando, Florida Period: 1988-1992	2-103
Figure 2.3-31	October Wind Rose for Orlando, Florida Period: 1988-1992.....	2-104
Figure 2.3-32	November Wind Rose for Orlando, Florida Period: 1988-1992.....	2-105
Figure 2.3-33	December Wind Rose for Orlando, Florida Period: 1988-1992	2-106
Figure 2.3-34	Annual Wind Rose for Orlando, Florida Period: 1988-1992.....	2-107
Figure 6.1-1	Proposed Transmission Line Route	6-2
Figure 6.1-2	Typical Transmission Tower Structures	6-3

1.0 Need for Power and the Proposed Facilities

This Supplemental Site Certification Application (SSCA) is being submitted by the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA), the Orlando Utilities Commission (OUC), and Southern Company - Florida, LLC (Southern-Florida) as a non-need applicant, for the addition of a combined cycle unit (designated as Stanton A) and transmission line to the Curtis H. Stanton Energy Center and an associated offsite natural gas pipeline. Stanton Units 1 and 2 are existing certified coal fired units at the site. Stanton Unit 1 has a net generation of 440 MW, and began commercial operation in June 1987. Stanton Unit 2 has a net generation of 446 MW, and began commercial operation in June 1996. The electricity generated is stepped up in voltage for distribution to the power grid.

Stanton A is proposed as a nominal 633 MW at 70° F combined cycle combustion turbine unit with a nameplate rating of 791 MVA. The new unit will fire natural gas as the primary fuel. It, and support facilities, will occupy approximately 60 acres on the Stanton site. The 3,280 acre Stanton site was previously certified for an ultimate site development of 2,000 MW of coal and natural gas capacity in Order Pa-81-1431 and subsequent supplemental certifications. Unit 2 received supplemental certification on December 17, 1991. The conditions of certification were modified on April 5, 1993, July 24, 1995, December 24, 1997, and August 7, 1998. Stanton A has a proposed construction start date of fourth quarter 2001 and a proposed commercial operation date of October 2003.

In accordance with Section 403.519 of the Florida Statutes, OUC, KUA, and FMPA will file a Joint Petition to Determine Need for Electrical Power Plant for Stanton A to the Florida Public Service Commission (PSC) during the week of January 29, 2001.

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 Stanton Energy Center Combined Cycle Unit A (Stanton A).

2.1.1 Site Location

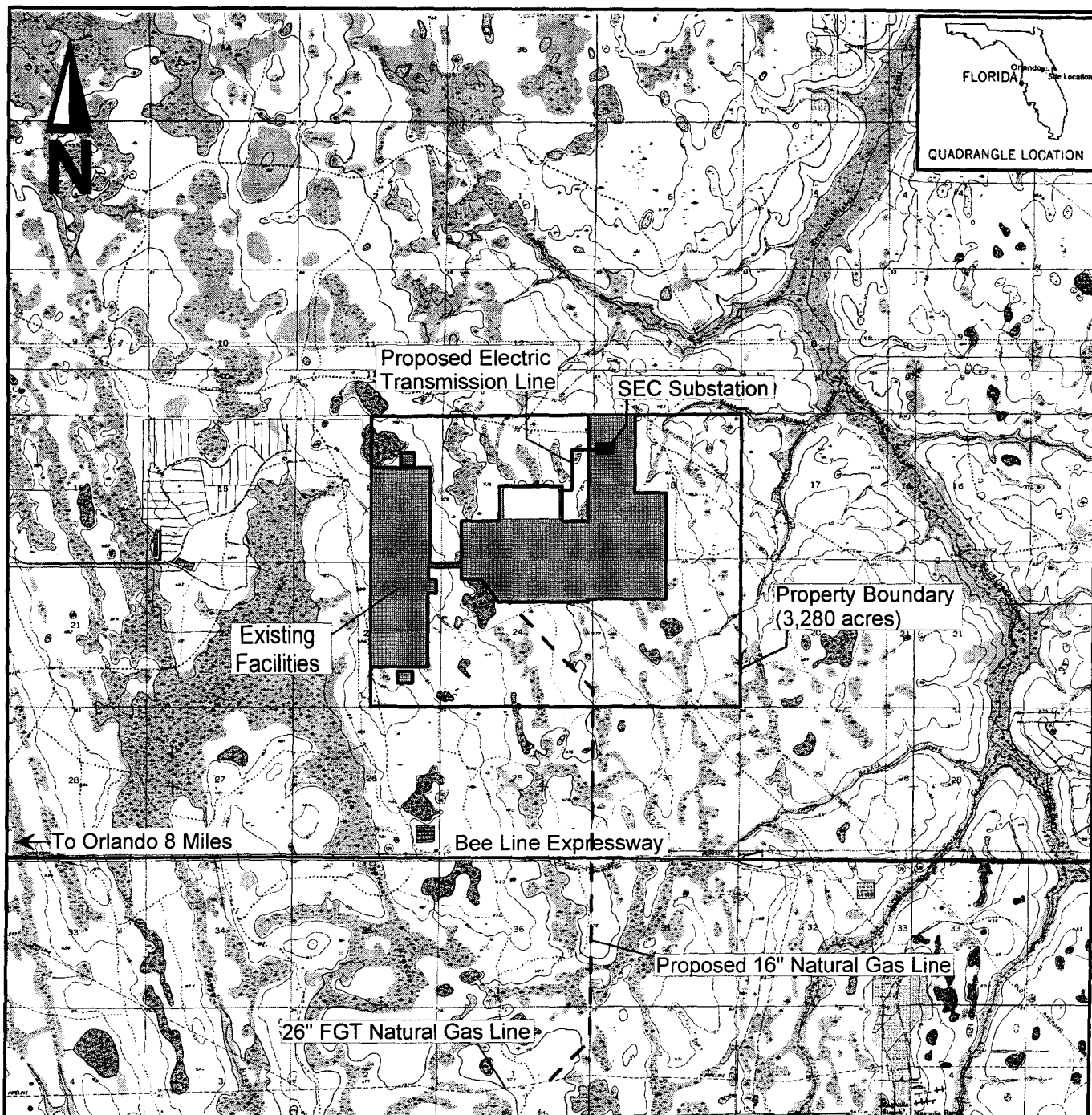
The Stanton Energy Center (SEC) is located in rural eastern Orange County. Figure 2.1-1 shows the general location of the SEC. The SEC address is:

Stanton Energy Center
5100 South Alafaya Trail
Orlando, Florida 32831

According to the US Geological Survey topographic survey, the site consists of Sections 13 and 24 and the eastern half of Sections 14 and 23, R31E, T23S and Sections 18 and 19, R32E, T23S. Figure 2.1-2 shows the SEC boundaries and identifies adjacent terrain. Table 2.1-1 provides information on the adjacent property owners. Stanton A will be a new unit located north of Units 1 and 2 as shown on Figure 2.1-3 Site Arrangement. Approximately 1,100 acres have been permitted for power development and support facilities at the SEC; approximately 60 acres will be leased to Southern-Florida for use in developing Stanton A.

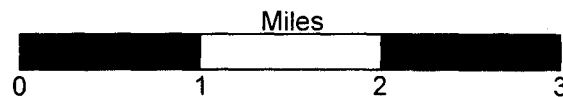
2.1.2 Site Modification

Proposed site modifications will consist of construction and operation of Stanton A, a 633 MW (nominal) combined cycle combustion turbine generating unit. The Stanton A facilities will occupy approximately 60 acres north of Units 1 and 2. New major equipment associated with Stanton A will include two combustion turbine generators, two heat recovery steam generators, a steam turbine generator, cooling tower, water and wastewater transfer facilities, fuel oil and water storage tanks, and natural gas delivery and metering facilities. A new onsite transmission line is necessary to connect Stanton A to the main SEC switchyard. This new transmission line will be located entirely on SEC property. Section 6.0 presents information concerning this transmission line and the natural gas line.



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Property Boundary: Orange Co.; Sections 13, 24, E1/2 14, E1/2 23 of Township 23S, Range 31E; Sections 18, 19 of Township 23S, Range 32E



**Stanton Energy Center
Property Location
Figure 2.1-1**

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.



Table 2.2-1
Surrounding Property Owners
Stanton Energy Center

Parcel ID	Owner	Acres	Owner Address
12-23-31-0000-00-002	Redditt, John Cecil	120	4414 Calm Water Ct. Orlando, FL 32817
12-23-31-0000-00-005	Redditt, Adeline Ann	120	710 N. Dean Rd. Orlando, FL 32825
12-23-31-0000-00-001	Morgran Co., Inc.	854.9	15 McMurrich St. Suite 1104 Toronto, Canada M5R3
11-23-31-0000-00-001	Orange Co. BCC	640	P.O. Box 1393 Orlando, FL 32802
14-23-31-0000-00-008	Orange Co. BCC	320	P.O. Box 1393 Orlando, FL 32802
23-23-31-0000-00-005	Orange Co. BCC	160	P.O. Box 1393 Orlando, FL 32802
21-23-31-0000-00-002	Orange Co. BCC	2,728.87	P.O. Box 1393 Orlando, FL 32802
25-23-31-0000-00-001	Orlando Business Park, LLC	629.7	1525 S. Andrews Ave. Suite 216 Ft. Lauderdale, FL 33316
30-23-32-0000-00-001	TIITF/DOC	609.08	3900 Commonwealth Blvd. Tallahassee, FL 32399
29-23-32-0000-00-002	Smith, W. Roger	509.5	601 Lake Harbor Cir. Orlando, FL 32809
20-23-32-0000-00-001	St. Johns River Water Management District	2,160	P.O. Box 1429 Palatka, FL 32178
07-23-32-0000-00-004	Avalon Associates of Delaware LP	914	13013 Founders Sq. Drive Orlando, FL 32828

Source: Orange County Property Appraiser (<http://pamap1.ocpafl.org>)

2.1.3 Existing and Proposed Uses

The SEC consists of 3,280 acres. Certification has previously been issued on December 14, 1982 for Unit 1 of the SEC. Supplemental certification was issued for Unit 2 on December 17, 1991 (DOAH Case No. 91-1813EPP). The SEC has been certified for additional coal and/or natural gas generating capacity of up to approximately 2,000 MW.

2.1.4 Flood Zones

The 100 year flood elevations on the SEC property vary from approximately 60 feet mean sea level (msl) at the northeast corner of the property to approximately 90 feet msl at the southwest corner. All Stanton A facilities will be located above the 100 year flood elevation.

2.2 Sociopolitical Environment

2.2.1 Governmental Jurisdictions

The Stanton A project site is located at the Stanton Energy Center (SEC) near Orlando, Florida in Orange County. The new unit will be located within the existing main power block area, north of Units 1 and 2. The site is located 4-3/4 miles south of Highway 50 and 1 mile north of the Bee Line Highway in eastern Orange County. Orlando is about 10 miles northwest and Bithlo is 5 miles northeast of the site. The site location relative to the Orlando area is shown on Figure 2.2-1. The Econlockhatchee River is about 3/4 mile east of the northeast corner of the site boundary. The Orange County Solid Waste Disposal facility is adjacent to the SEC along the west boundary. There are no incorporated areas within 5 miles of the SEC.

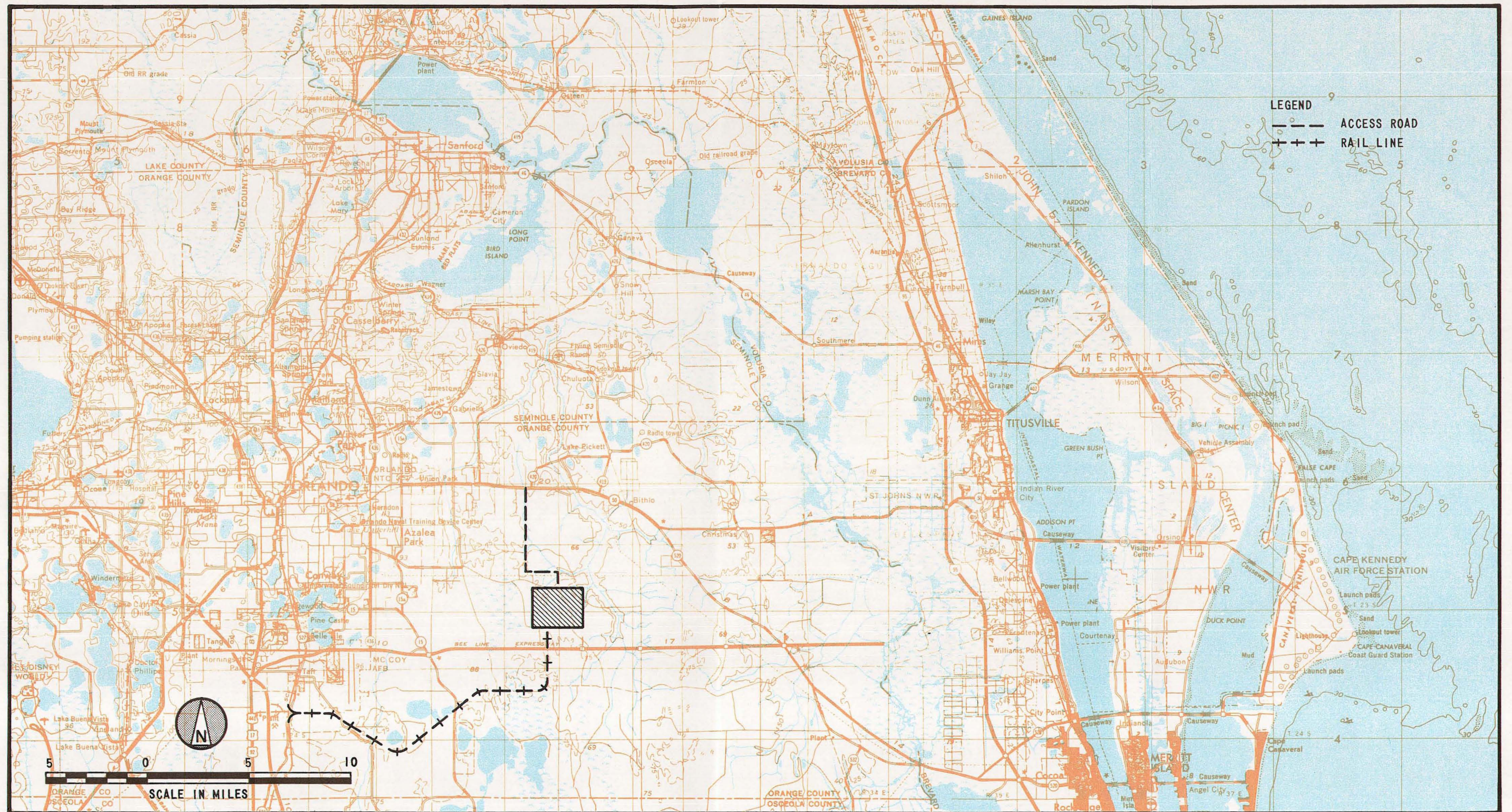
2.2.2 Zoning and Land Use Plans

On August 11, 1981, the Board of County Commissioners of Orange County, Florida signed a resolution granting a special exception to permit the OUC electric power plant and associated facilities within an A-2 zoning district. This special exception applied to the entire SEC site; thus, the special exception applies to Unit A. Prior to the use as a power generation site, the land had been used for the grazing of livestock. Stanton A is consistent with the SEC certification and the zoning and land use plans in Orange County, Florida.

The Orange County, Florida 1990-2010 Comprehensive Policy Plan (the "Plan") is a comprehensive guide to the county's decisions about land use, transportation, housing, the environment, and other topics important to the community. Originally approved in 1975, Orange County's Growth Management Policy was changed in 1980 to include various elements, such as: conservation, economic, housing, future land use, transportation, sewer and water, drainage, solid waste, electric utility, recreation and open space, community facility, and intergovernmental coordination.

Development and use of land in Orange County are determined by its zoning and future land use designations. Future land use designations are more general than zoning designations and address the long-range use of land in the county. Since the 1950s, Orange County has used zoning to ensure that land use is compatible with neighboring properties and the community. The zoning designation relates to the current land use and is very specific about any restrictions on that property.

The Plan includes a transportation and utilities land use category. Land uses in this category include approximately 11,000 acres of utility facilities, including electrical power facilities. The Plan provides that future land use in Orange County will include an increase in land use for utilities in proportion to population - 3.33 acres per 100 people. The projected total acreage dedicated to utilities and drainage for 2010 is 35,216.783 acres.



In addition to the Orange County Plan, Stanton A is consistent with the East Central Florida Regional Planning Council Interim Strategic Regional Policy Plan. By improving the reliability and increasing the supply of electricity in the region, Stanton A will enhance the potential for economic development in accordance with the policies of Section 1 of the Interim Strategic Regional Policy Plan. For example, an expanded, reliable supply of electricity will help “encourage development projects for which there is a demand” (Policy 1.7) and help the region develop “space-related research and manufacturing capabilities” (Policy 1.9.2).

2.2.3 Demography and Ongoing Land Use

Orange County and the surrounding Central Florida area have been transformed from a rural agricultural area to a thriving urban region. The annualized population growth rate in Orange County ranged from a high of 12.9 percent per year in the 1950s to a low of 2.5 percent per year in the 1990s. Likewise, the average annual increase ranged from a high of 20,663 persons in the 1980s to a low of 8,077 persons in the 1960s. In recent years, there has been a significant shift in the source of growth. Between 1990 and 1997, population in Orange County increased by an average of 16,700 each year and births averaged 11,900. Thus births, instead of net in-migration, have constituted the major source of growth in Orange County during the 1990s. The County population in 1980 was 471,016. By 1990, the population had increased 44 percent from 1980 to approximately 677,491. The 1999 estimated population was 846,328, a 25 percent increase since 1990. The average annual growth rate from 1990 to 2010 is projected at 2.6 percent with an average annual increase of 17,340 persons.

There are no incorporated areas within 5 miles of the SEC.

2.2.4 Easements, Title, Agency Works

The entire SEC site and utility corridor are owned by OUC. However, a utility crossing permit will be required for the natural gas pipeline crossing of the Bee Line (State Highway 528).

2.2.5 Regional Scenic, Cultural, and Natural Landmarks

There are no recorded historic, scenic, cultural, or natural landmarks located on the Stanton A or SEC site. The nearest recognized sites are located in or near Orlando. The National Register of Historic Places currently lists the following sites located in Orange County, Florida:

- Orlando – Old Orlando Railroad Depot.
- Orlando – First Church of Christ Scientist.
- Orlando – The Tinker Building.
- Winter Park – The Parsonage.

The National Registry of Natural Landmarks does not include any sites for Orange County, Florida.

2.2.6 Archeological and Historic Sites

In March 1981, in association with construction and operation of Unit 1, an archaeological and historic survey of the SEC property was conducted by personnel from the Florida Secretary of State, Division of Archives, History, and Records Management. Four sites were found during the surveys. Three were prehistoric archaeological sites and one was an historic hunting lodge from about the early 20th century. This lodge is located just off the SEC property near the southwest corner of the property line. The Division of Archives, History, and Records Management concluded that the sites did not represent significant archaeological or historical resources, and construction of SEC would not adversely impact any significant archaeological or historical resources.

A Phase I cultural resources investigation of the modified corridors was conducted by Bureau of Historic Sites and Properties of Florida in August 1982. The Bureau determined that no archaeological or historic sites have been recorded within the corridor modification which includes the railroad corridor in which the railroad access was constructed for Unit 1 and in which the natural gas pipeline will be constructed. The Department of State also concluded that the probability for significant, unrecorded sites to be present was low. Therefore, the Stanton A development areas are not anticipated to impact any archaeological or historical resources.

2.2.7 Socioeconomics and Public Services

This section describes the current socioeconomic situation in the area that would be affected by Stanton A development.

2.2.7.1 Social and Economic Characteristics. The SEC site is located in Orange County, roughly 10 miles from Orlando. Because the construction and operation of the Project may have socioeconomic impacts beyond the boundaries of Orange County, the project impact area was defined to include the counties of Orange, Seminole, Brevard, Osceola, and Lake. These counties were selected because of the proximity to the site and probable workforce contribution to the Project. Despite the large geographic area covered by this impact area, 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 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 Project site from relatively long distances. It is anticipated that metropolitan Orlando will receive the most impact from the construction.

Employment by Occupation

The latest breakdown in employment by occupation is found in the 1990 US Census data. These data were 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 almost two times the workforce of all the other four divisions combined. The predominant employment category varied by division. In the Kissimmee Division, nonprotective services was 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 was the dominant position. For the division of Seminole County (Oviedo Division), the dominant position was professional specialty. Table 2.2-1 provides details on the employment in the primary impact areas.

Employment by Industrial Sector

The latest data on employment by industry is from US Census Bureau 1998 statistics data. According to 1998 data, employment in the impact area is dominated by service workers. Over 50 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 55,232 construction jobs were in existence in 1998 in the five county area (Table 2.2-2).

Baseline Employment Projections

The economic activity in and around the Orlando area has been growing rapidly for the last 10 years and is expected to continue to grow at a similar pace in the future. For example, the annual employment growth rate from 1994 to 1999 was 4.49 percent. This was the third largest percentage expansion for major metropolitan areas in the United States for this time frame. The region is expected to rank first in the nation in terms of total employment growth through 2004 with the annual growth rate of 3.91 percent. The number of jobs grew in the Orlando market by 36.7 percent between 1990 and 1999. Specifically, construction jobs grew 20.7 percent between 1990 and 1999. The growth rate for service jobs in that same time frame was 52.7 percent. Table 2.2-3 provides the Orange County employment growth projections to 2007 for the 13 fastest growing occupations.

Table 2.2-1
Employment by Occupation
Primary Impact Areas, 1990

	Kissimmee Division Osceola ¹	Orlando Division ²	Palm Bay Division ³	Winter Garden-Ocoee Division ⁴	Oviedo Division ⁵
Total Employed Persons	38,558	219,708	30,044	29,735	18,713
Executive, Administrative, Managerial	3,659	27,465	3,240	3,141	3,063
Professional Specialty	3,441	27,660	4,329	2,758	3,702
Technicians and Support	896	7,240	1,725	758	808
Sales	4,828	28,736	3,568	7,450	2,833
Administrative Support	5,870	37,538	4,104	4,212	2,863
Private Household	89	962	88	78	78
Protective Service	893	4,099	581	534	350
Service, Except Protective	8,460	33,476	3,455	4,214	1,297
Farming, Forestry, Fishing	834	3,435	542	672	486
Precision Production, Craft, Repair	4,750	23,138	4,781	2,913	1,756
Transportation, Material Moving	1,844	8,149	960	924	521
Machine Operators, Assemblers, Inspectors	1,469	9,588	1,608	1,111	450
Handlers, Cleaners, Laborers, Helpers	1,525	8,222	1,063	970	506

¹ A 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).

² A 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).

³ A subdivision of Brevard County which includes zip codes 32901, 32904, 32905, 32907, 32908, and 32909.

⁴ A 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).

⁵ A subdivision of Seminole County which includes zip codes 32708, 32732, 32765, 32766.

Source: 1990 US Census of Population; US Department of Commerce, Bureau of Economic Analysis web page at venus.census.gov/cdrom/lookup/893180141.

Table 2.2-2
Employment by Industry,
by County, with Percentage of Workforce
(1998)

	Osceola		Brevard		Orange		Seminole		Lake	
Total Employment	47,905		154,136		528,249		122,055		47,696	
Agricultural Services, Forestry, and Fishing	349	1%	98	0%	908	0%	1,607	1%	141	0%
Mining	0	0%	420	0%	21	0%	0	0%	342	1%
Construction	2,699	6%	9,208	6%	25,827	5%	13,207	11%	4,291	9%
Manufacturing	1,511	3%	20,143	13%	32,716	6%	9,295	8%	3,589	8%
Transportation and Public Utilities	195	0%	7,661	5%	20,838	4%	1,778	1%	1,537	3%
Wholesale Trade	1,556	3%	4,501	3%	27,257	5%	7,411	6%	1,868	4%
Retail Trade	8,962	19%	24,865	16%	58,136	11%	22,368	18%	9,755	20%
Information	271	1%	2,551	2%	16,343	3%	5,571	5%	987	2%
Finance, Insurance, and Real Estate	3,866	8%	6,147	4%	35,709	7%	8,939	7%	2,568	5%
Services	28,435	59%	78,384	51%	310,204	59%	51,745	42%	22,560	47%
Unclassified Establishments	61	0%	158	0%	290	0%	134	0%	58	0%

Source: US Census Bureau at www.census.gov/datamap/www/12.html.

Table 2.2-3
Occupational Employment Projections to 2007 - Orange County
Aggregate Ranking by Openings, Wage, and Growth

Rank Order	Occupational Title	Percent Growth 1997-2007	Average Annual Openings	Average Hourly Wage 1998 (\$)
1	Computer Support Specialist	103.82	178	17.93
2	System Analyst	102.47	233	22.53
3	Physical, Corrective Therapy Assistant	88.64	45	11.8
4	Respiratory Therapist	84.51	35	16.83
5	Camera Operator, Actor, Entertainer	81.05	14	11.2
6	Producer, Director, Actor, Entertainer	80.71	102	14.18
7	Home Health Aide	74.14	167	7.82
8	Parking Lot Attendant	72.89	57	7.69
9	Director, Religious Activities/Education	71.16	38	12.71
10	Medical Assistant	70.34	130	10.08
11	Database Administrator	68.2	27	19.98
12	Residential Counselor	67.69	21	9.37
13	Physical Therapist	67.17	49	25.65

Source: Florida Bureau of Labor Statistics, 1998

Statewide, projections reflect the expectation that Florida's economy will continue to rapidly expand well into the 21st century. Table 2.2-4 provides the statewide employment growth projections to 2007 for the 13 fastest growing occupations.

Despite large population growth in the area, unemployment rates remain low. According to the Florida Bureau of Labor Statistics, the latest unemployment rate in the area was dated back to 1998. In Osceola County, the unemployment rate was 3.3 percent in 1998. For Orange County, it was 3.9 percent in 1996 and dropped to 3.1 percent in 1998. The Lake County unemployment rate was 3.4 percent in 1998. Seminole County had the lowest unemployment rate of 2.8 percent in 1998.

General Income Characteristics

A Bureau of Labor Statistics survey for the Orlando area from 1998 provides the latest information on wages for several economic divisions. The majority of occupations in the managerial and professional divisions have average (mean) wage rates in the upper wage ranges, while the majority of occupations in the clerical, service, and agricultural divisions have average hourly wages in the lower wage ranges. For example, 75 percent of managerial occupations have a mean occupational wage above \$19.24 per hour, while more than 55 percent of service occupations have a mean occupational wage below \$10.00 per hour. Occupations in the production division are paid hourly wages dispersed across the middle wage ranges.

In Orange County, the average annual salary was \$27,228 in 1998. Employees in the manufacturing industry have the highest incomes while workers in agriculture, forestry, and fishing receive the lowest incomes. Table 2.2-5 shows 1998 gross employment figures for Orange County as well as annual wage figures.

Baseline Income

According to Sales & Marketing Management 2000 survey of buying power, the median household effective buying income (EBI) in the impact area is higher than that of Florida and the nation. The median household effective buying income (EBI) in the Orlando Metropolitan Statistical Area (MSA) was \$37,044 in 1999, a 12.5 percent increase from that of 1996. In Osceola County, the median household EBI was \$31,965, an increase of 12.2 percent over this same time frame. Orange and Lake counties, with median household EBIs of \$37,232 and \$26,846, grew by 11.3 percent and 12.7 percent, respectively. For the same time frame, Seminole County residents had a median EBI of \$48,413. Incomes are expected to keep growing in the Project impact area for the next few years.

Table 2.2-4
Occupational Employment Projections to 2007 - Florida
Aggregate Ranking by Openings, Wage, and Growth

Rank Order	Occupational Title	Percent Growth 1997-2007	Average Annual Openings	Average Hourly Wage 1998 (\$)
1	Computer Support Specialist	77.2	1,410	17.85
2	System Analyst	70.07	1,955	24.25
3	Computer Engineer	68.63	630	28.49
4	Home Health Aide	64.56	2,297	8.04
5	Respiratory Therapist	62.06	391	17.00
6	Physical, Corrective Therapy Assistant	60.12	438	12.43
7	Producer, Director, Actor, Entertainer	57.68	401	15.93
8	Demonstrator and Product Promoter	56.45	348	9.96
9	Telemarketer, Door-to-Door Sales, Street Vendor	56.27	3,864	9.98
10	Production Inspector, Grader	53.80	1,664	10.17
11	Technical Writer	53.30	353	18.32
12	Medical Assistant	52.70	1,481	10.21
13	Residential Counselor	51.86	337	9.10

Source: Florida Bureau of Labor Statistics, 1997

Table 2.2-5
Employment by Industry – Orange County (1998)

Industry	Establishments	Employment	Annual Payroll, \$	Annual Wage, \$
Total All Industries	25,218	528,249	14,382,922,000	27,228
Agricultural, Forestry, and Fishing	26	908	9,979,000	10,990
Mining	6	21	691,000	32,905
Construction	2,007	25,827	829,051,000	32,100
Manufacturing	891	32,716	1,257,211,000	38,428
Transport, Comm., and Public Util.	653	20,838	630,092,000	30,238
Wholesale Trade	1,897	27,257	949,258,000	34,826
Retail Trade	3,958	58,136	1,098,713,000	18,899
Information	479	16,343	734,201,000	44,924
Finance, Insurance, and Real Estate	2,995	35,709	1,273,697,000	35,669
Services	12,052	310,204	7,594,744,000	24,483

Source: 1998 County Business Patterns for Orange, FL (<http://www.census.gov>)

Existing Housing Stock

Existing housing stock features both renter and owner-occupier situations. In September 1999, over 113,000 rental apartment units existed in the Orlando MSA according to the 1999 study by Charles Wayne Consulting, Inc. Of those, 6,103 units were vacant. In March 1998, 44,861 residential units existed in Lake County, and 42,526 and 237,561 existed 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 92,200 hotel rooms existed in the Orlando MSA. Also, over 40 camping and recreational vehicle sites are located in the area.

Building Activity

The housing stock in the Project impact area continues to expand rapidly. In 1999, 16,368 new residential units were started in the Orlando MSA. Also in 1999, 3,042 new residential units in Osceola County and 3,485 units in Lake County were started. There were 6,965 new residential units and 2,876 units started in Orange County and Seminole County, respectively, in the same time frame.

Housing Costs

Compared to other major metropolitan areas in the United States, the Project impact area is one of the most affordable places to buy a home. In 1999, the median price of a purchased home in Orlando was \$112,500, much less than the national average price of \$175,400. Compared to other major cities around the nation, Orlando was significantly lower than such areas as Dallas/Ft. Worth (\$126,300), Atlanta (\$151,600), Los Angeles (\$223,000), Seattle-Tacoma (\$176,900) and Phoenix (\$136,800). In fact, the average home price in the Orlando area was only 57 percent of the nationwide average, which stood at \$208,000.

Of course, housing values vary by location. Osceola County has the smallest value 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 the Orlando MSA, the median monthly rent for a 2 bedroom unit in 1999 was \$680; the rents were \$645 in the Kissimmee area and \$850 in south Orange County, respectively. In east Orange County, the median monthly rent was \$695 in 1999.

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 Stanton A. 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

In Florida, each county comprises a school district. No educational facilities exist within a 5 mile radius of the Project site. Metro Orlando is home to 153 elementary, 49 middle, and 29 high schools. There are two fully accredited, 4 year institutions (the University of Central Florida and Rollins Colleges) and three community colleges. There are also several other schools with a wide variety of specialized curricula and services in the area. These schools include Florida Southern College, National-Lois University, Orlando College, University of Phoenix, Warner Southern College, and Webster University.

Table 2.2-6 lists the 1998-1999 public school enrollment in grades kindergarten through 12, by district. In 1998-1999, Orange County had a combined total of 138,633 students in grades pre-K through 12.

Table 2.2-6 Public Schools by Grade and School Enrollment, 1998-1999				
	Orange County	Seminole County	Lake County	Osceola County
Elementary Schools	99	33	23	14
Middle/Junior High Schools	26	12	9	7
High Schools	13	8	6	6
Tech Schools	4	0	2	1
Total Schools (K-12)	142	53	38	25
Total Schools Students (K-12)	138,633	58,330	27,911	31,439
Source: County School Boards, 1998-1999 School Year Statistics				

The Project impact area is also home to four technical schools which offer a wide variety of courses, programs, and financial assistance; post-secondary training is also available. Businesses in Metro Orlando have come to rely on those technical schools, not only for new employees, but to train current workers.

Transportation

Since the Project impact area is such a popular vacation destination, the area transportation system is highly developed. The region boasts flexible and efficient multi-modal transportation, making it easily accessible by air, sea, and land.

Four airports serve the area - Kissimmee Municipal, Orlando International, Sanford, and Orlando Executive. Orlando International Airport, which features more than 30 scheduled airlines and 50 charters serving more than 25 million passengers each year, is about 10 miles west of the Stanton Energy Center. Kissimmee Municipal Airport and Orlando Executive Airport are approximately 28 miles and 12 miles from the Stanton Energy Center, respectively. Sanford Airport is approximately 24 miles from the Stanton Energy Center.

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, plus numerous state roadways, including the Bee Line Expressway. Toll roads expedite traffic through the area. Trucking in Florida is deregulated, helping to keep prices as much as 10 percent below the national average. 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. 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.

By sea, the nearby Atlantic Ocean, Gulf of Mexico, and St. Johns River give Metro Orlando a variety of shipping options. To the east is Port Canaveral, the world's only quadramodal transportation hub. To the west is Port of Tampa, which is ranked among the nation's top ten ports in overall tonnage. Just to the north, Port of Sanford has river barge access from the Atlantic Intercoastal Waterway in Jacksonville via the St. Johns River to Lake Monroe.

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

Florida Hospital, with more than 1,400 beds and 11,000 employees in Central Florida, is the largest private, nonprofit system in Florida and the second largest overall. Operated by the Seventh-Day Adventist Church, it has the largest family practice residency in the state, one of the top five cardiac centers in the nation, and a top 10 national ranking among hospitals for women. The Florida Hospital system includes six comprehensive hospitals, numerous outpatient and rehabilitation/sports medicine facilities, and over a dozen Centra Care walk-in medical centers. Walt Disney Memorial Cancer Institute at Florida Hospital Orlando is the largest and most comprehensive cancer program in Florida. In July 1998, the Adventist facility in Celebration began to offer 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 opened a walk-in facility in Poinciana in the summer of 1998. This hospital is the nearest medical facility and is only 9.6 miles away from the Stanton Energy Center.

The Orlando Regional Healthcare System (ORHS) includes many separate facilities in the Project impact area. The largest facility is the Orlando Regional Medical Center, a major teaching hospital with 517 beds 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 and Women, featuring a 78 bed neonatal intensive care unit and 27 miles away from the Stanton Energy Center; the M. D. Anderson Cancer Center Orlando; Sand Lake Hospital, a complete medical and surgical facility serving southwest Orange County and 16 miles away from the Stanton Energy Center; St. Cloud Hospital; and South Lake Hospital (a 68 bed hospital serving South Lake County). Florida Hospital - Kissimmee (formerly Kissimmee Memorial),

which has 100 inpatient beds and an emergency room, is about 11 miles from the site. In total, there are 11 hospitals in Orange County, three in Seminole County, four in Osceola County, and four in Lake County, respectively.

Firefighting Facilities

As with all unincorporated areas in Orange County, fire protection for the SEC is provided by the Orange County Fire Rescue Department. The fire department employs 851 staff, 681 of which are field personnel (firefighters, engineers, chief officers). Station 83, staffed with 15 firefighters on three shifts, is located at Lake Underhill Road of Orlando, approximately 8 to 9 miles from SEC.

Several political jurisdictions maintain staffs of professional firefighter personnel as well as a cadre of volunteers. The City of Kissimmee has 60 firefighters on staff, with 20 available to respond to calls at all times. Osceola County employs 104 firefighters. The City of Orlando Fire Department employs 350 firefighters and officers and maintains 12 fire stations. The Lake County Fire/Rescue Department has 32 paid professionals and 200 volunteer professionals.

Police Protection

Since the area is unincorporated, police protection is provided by the East Orange County Sheriff's Department, located at 1111 North Rock Springs of Orlando. This Department has 120 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 649 sworn officers and 200 civilian employees.

Recreation Facilities

The SEC property was previously used for the grazing of livestock; the surrounding area was under lease for hunting area. The only public recreation facility close to the SEC is Hal Scott Preserve, which is on the east side of the SEC and has miles of hiking trails. However, the Project impact area contains several of the most popular tourist attractions in the world, such as Walt Disney World, SeaWorld, and Universal Studios. 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. Orange County itself has 32 registered park and recreational areas.

The area offers dozens of recreational opportunities other than the major theme parks. Well over 30 golf courses operate in and around metropolitan Orlando. Furthermore, there are many municipal parks and recreation sites within the Project impact area. 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. Orlando Utilities Commission provides electricity in Orlando and Orange County; Florida Power Corporation (FPC) also serves portions of Orange County. In Osceola County, electricity is delivered by OUC, KUA, and FPC. Seminole County receives power from FPC.

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.

2.3 Bio-Physical Environment

2.3.1 Geohydrology

A description of the SEC geology is presented in this section. Two types of geologic data were used to identify the subsurface conditions: (1) published literature providing regional geologic information for Florida's Orange County geologic setting performed by and for the State of Florida Bureau of Geology, and (2) onsite subsurface investigations performed under the supervision of Black & Veatch, for the existing SEC. These data sources provided information on stratigraphy, aquifers, and soil engineering properties. Subsurface conditions for the proposed combined cycle site are anticipated to be similar to those encountered for Units 1 and 2. A detailed subsurface investigation will be performed onsite at the locations of the proposed structures and auxiliary facilities for the combined cycle unit prior to construction.

2.3.1.1 Regional Geology. The SEC lies within the physiographic boundary identified as the Osceola Plain, bounded on the east by Lake Wales and Mount Dora Ridges. Elevations within this region range from approximately 35 feet to nearly 90 feet above mean sea level (msl). The topography varies from undulating to nearly flat with few shallow depressions. Regional geology for this area consists of recent and Pleistocene Age undifferentiated surficial deposits underlain by the Miocene Age Hawthorn Formation underlain by Eocene Age limestone deposits. A stratigraphic section is presented in Table 2.3-1.

The surficial deposits consist of sands, silts, clay, and shell of Pliocene through Recent age. 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. This unit can be equated with several formations, depending upon the location. Inland in the St. Johns River Valley, the shell sand-clay lithology is equivalent to the Caloosahatchee Formation and possibly to a portion of the Fort Thompson Formation. Lichtler (1972) stated that fossils from one of the shell beds of eastern Orange County and from northwestern Orange County show these sediments to be equivalent to the upper part of the Tamiami Formation of Mio-Pliocene age.

The Hawthorn Formation includes sandy phosphatic limestones and dolomites, and sandy calcareous clays of Miocene age. 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 dolomites are buff colored, crystalline, soft to hard, and impure, containing varying amounts of sand, clay and phosphorite.

Table 2.3-1
Generalized Regional Stratigraphic Section

System	Series	Stratigraphic Unit	Thickness (feet)	Lithology	Aquifer
Quaternary	Recent	Undifferentiated Deposits	0-150	Alluvium, freshwater marl, peats, and muds in stream and lake bottoms. Also, some dunes and other windblown sand.	Unconfined Aquifer System
	Pleistocene			Mostly marine quartz sand, unconsolidated and generally well graded. Also, some fluvial and lacustrine sand, clay, and marl.	
Tertiary	Pliocene	Hawthorn Group	0-100	Interbedded deposits of sands, shell, and sandy clay; base characterized by phosphatic clay and rubble.	Secondary Artesian Aquifer
	Miocene		0-250	Cream to light green to greenish-gray clayey quartz sand, silt and sandy clay; often contains phosphatic sands and clays; phosphatic limestone often found at base of formation.	
	Eocene	Ocala Limestone	0-200	Marine foraminiferal limestone, white to cream to tan, soft to hard, granular, highly porous, sometimes dolomitic.	Floridan Aquifer System
		Avon Park Limestone	600-1600	Marine limestone, light brown to brown, poor to good porosity, highly fossiliferous, slightly carbonaceous, and dolomite, brown to dark brown, crystalline.	
		Oldsmar Formation	300-1350	Marine limestone, light brown to white, chalky, porous, fossiliferous, with interbedded brown crystalline dolomite.	
	Paleocene	Cedar Keys Formation	500-2200	Marine dolomite, light gray, hard, slightly porous to porous, crystalline, in part fossiliferous, with considerable anhydrite and gypsum, some limestone.	Confining Unit
Modified from Murray et al., 1996.					

Limestone found below the Hawthorn Formation consists of the Ocala Group and Avon Park Limestone. The Ocala Group is composed of a very fine to fine grained, white to cream, chalky, soft coquina of foraminifera. The top of the Ocala Group is an eroded surface which underlies the Hawthorn 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.

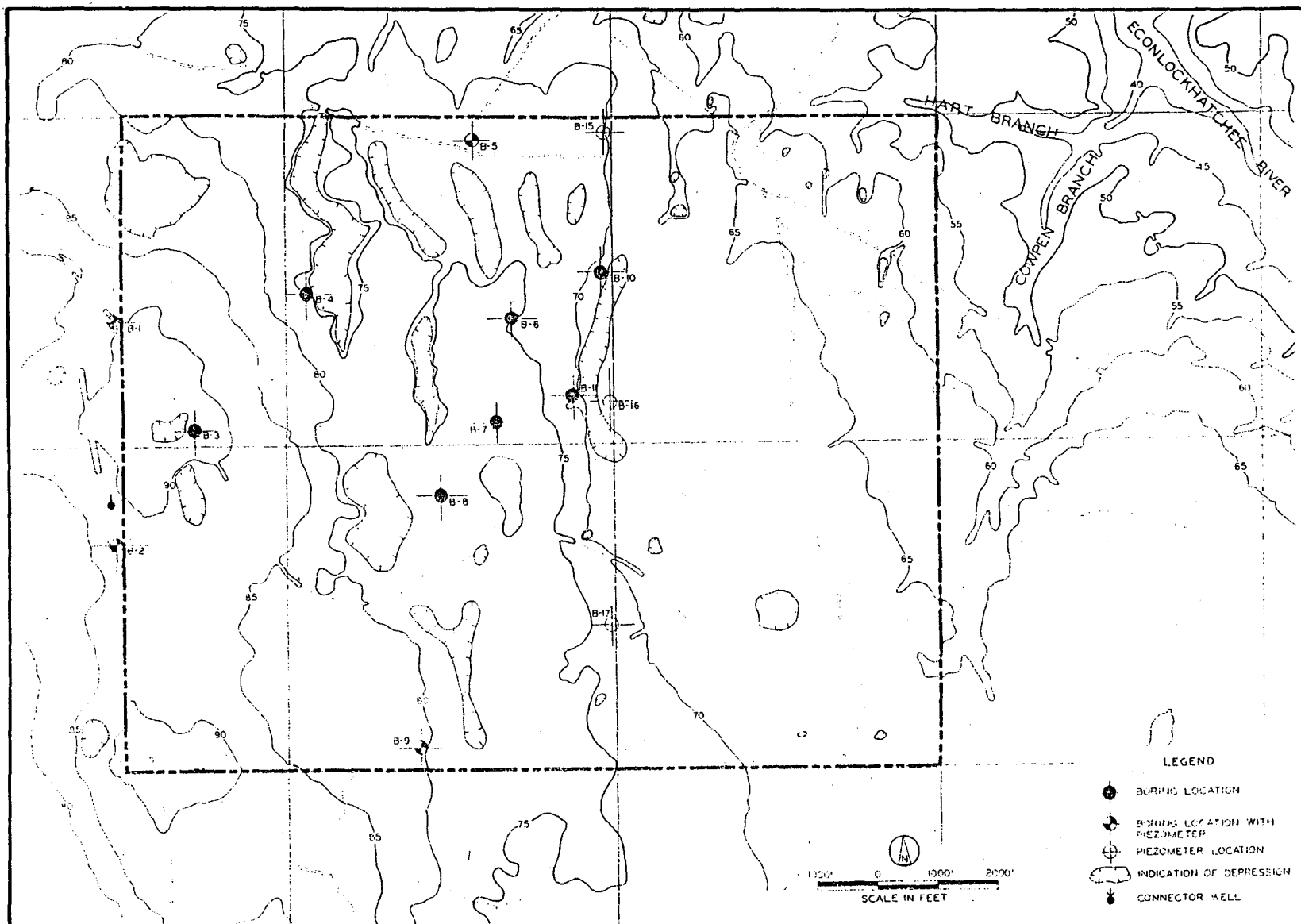
The site is located in the central geomorphic zone of the Florida section of the Coastal Plain province. The central zone may be characterized as having discontinuous highlands forming subparallel ridges separated by broad valleys, all roughly paralleling the present coastline. The ridges are above the piezometric surface of the surficial aquifer and the valley floors are below it. Broad shallow lakes are common on the valley floors. Dissolution of limestone and marine processes are predominant forces responsible for the development of the surface features.

Numerous depressions are present within the SEC boundaries. The major depressions are shown on Figure 2.3-1. The depressions tend to have an alignment and elongation along azimuths north 40° west, north 15° west, north 30° east, and north 50° east. The depressions are the result of longshore current modifications of former sandbars or may have developed from solution action begun in depressions formed by hurricane winds and water. Some contain cypress trees and some contain water during the rainy seasons. In addition to these surface depressions, there are many lineaments which cross the property in a general northwest and northeast direction (Figure 2.3-2). Based on the subsurface data collected during the Black & Veatch site investigations (detailed in Subsection 2.3.1.2), these onsite lineaments are the result of variations in overburden material, changes in underlying rock texture, and/or variations in primary porosity. The minimal impact on the property is expressed by the lack of correspondence with the longitudinal axes of the onsite depressions and the lack of hydrologic data from the subsurface investigations showing any kind of water table depressions.

The SEC 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.

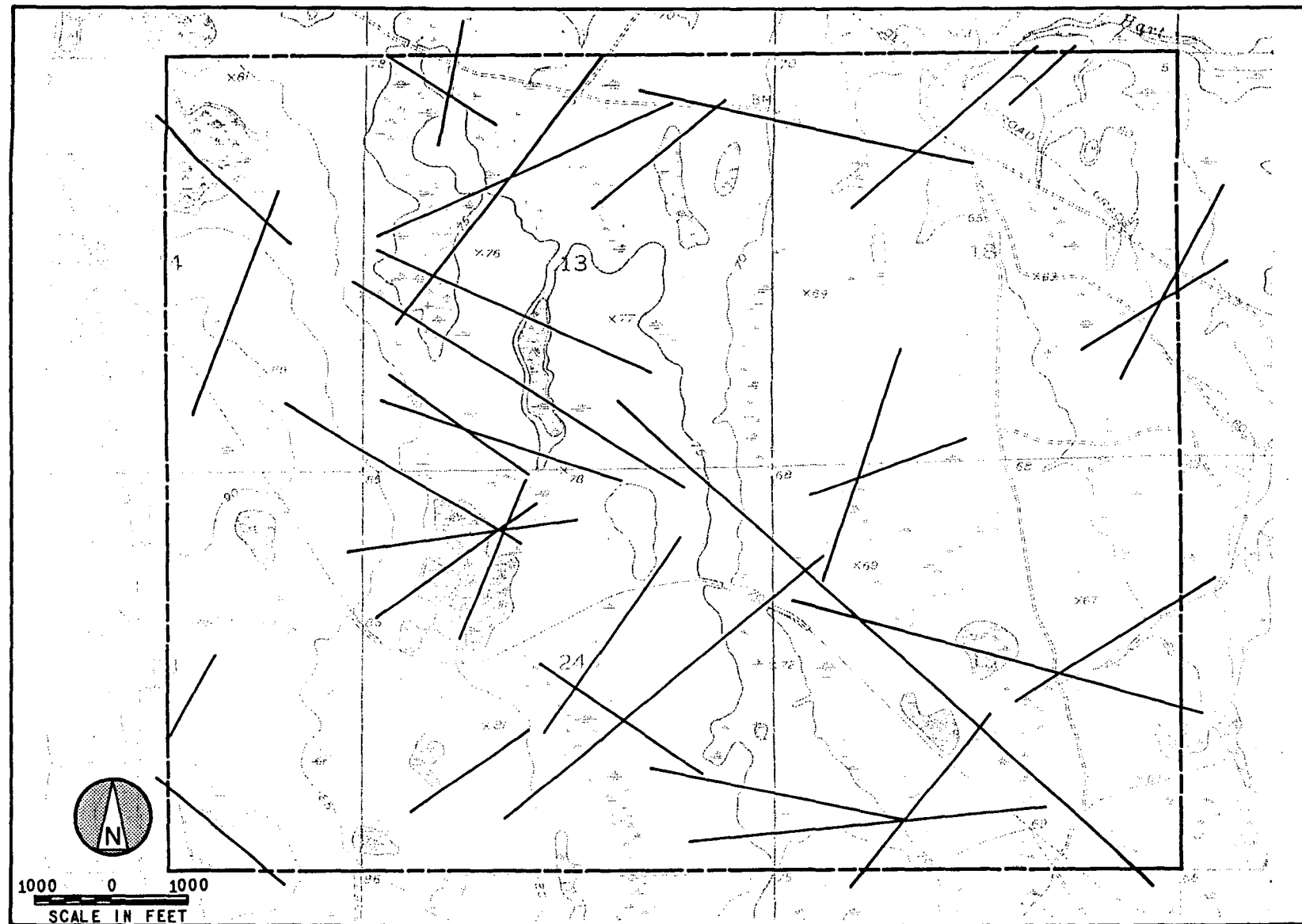
Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.



Source: OUC Stanton Unit 1 Site Certification Application

Figure 2.3-1
Major Depressions Within the SEC Boundary



SOURCE: SINKHOLE EVALUATION POTENTIAL
JAMMAL & ASSOCIATES, INC.

Figure 2.3-2
Lineaments in the SEC Area

2.3.1.2 Site-Specific Geology. Detailed subsurface conditions have been determined from the results of subsurface investigations completed for the existing SEC. These investigations included soil borings, installation of shallow piezometers, soil resistivity tests, and laboratory tests on selected samples. Data collected from these investigations is available (upon request) in the following data reports. The title sheet and Table of Contents from these reports are included in Section 10.6 of the Appendices:

- Soil Investigation, Orlando Utilities Commission - Stanton Energy Center, Black & Veatch Project No. 8927, includes Phase I Soil Investigation, May - June 1980 (Borings B-1 through B-11), and Phase II Soil Investigation, June - November 1981 (Borings B-12 through B-103).
- Laboratory Testing, Orlando Utilities Commission - Curtis H. Stanton Plant, Orlando, Florida, by Ardaman & Associates, Inc., September 10, 1980.
- Laboratory Testing, Orlando Utilities Commission - Curtis H. Stanton Plant, Orlando, Florida, August 6, 1981, by Ardaman & Associates, Inc.
- Laboratory and Field Materials Test Results, Orlando Utilities Commission - Stanton Energy Center Unit 2, Orlando, Florida, Black & Veatch Project No. 16805, by Universal Engineering Sciences, Inc., May 28, 1992 (Borings B-104 through B-119).

Field Investigations. Soil borings for Phases I and II were advanced to depths ranging from 25 feet to 265 feet below ground surface (bgs), with most ranging from 50 to 150 feet in depth. Soil borings for the Unit 2 investigation were extended to depths ranging from 80 to 95 feet bgs. Sampling while drilling consisted of Standard Penetration Test (SPT) samples at 2.5 foot intervals within the upper 10 feet (Phase II) to 25 feet (Phase I) of subsurface, with subsequent SPT samples obtained at 5 foot intervals. Hand augering of the top 5 to 10 feet of soil was performed for the soil borings drilled during the Unit 2 investigation. Cohesive soil, where encountered, was sampled using a combination of SPT samples and shelby tubes (undisturbed samples). Rock coring was performed in the deepest borings, where rock was usually encountered at a depth of about 200 feet bgs or greater. Borehole logging and field classification of samples were performed in the field by Black & Veatch representatives. The locations of the borings for the Phase I and II investigations are shown on Figure 2.3-3. Boring locations for the Unit 2 investigation are shown on Figure 2.3-4.

A total of 25 piezometers were installed at the SEC during the Phase I and II investigations, using a 5-1/8 inch to 5-7/8 inch diameter tricone roller bit with drilling fluid. Piezometer logs are included in the Phase I and II Soil Investigations data report.

A series of laboratory tests were performed on samples obtained during the subsurface investigation. These tests included natural moisture content, dry density, Atterberg limits, organic content, sieve and hydrometer analysis, triaxial and unconfined compression strength, consolidation, and constant head permeability tests. The results of these laboratory tests are included in the reports cited above.

Subsurface Conditions. The subsurface investigations indicate that soils are predominantly loose to medium dense sands with intermittent, discontinuous thin clay layers. Standard penetration tests indicate blow counts varying from 2 blows per foot (bpf) to 120 bpf. Density tends to increase with depth, but soft clay layers at deep intervals do exist.

The strata beneath the site to a depth of about 200 feet are divided into five stratigraphic layers: a surficial sand layer, an intermediate cohesive layer, a lower sand layer, a lower cohesive layer, and limestone bedrock. Stratigraphic cross sections are shown on Figures 2.3-5 and 2.3-6. These cross sections are based on the results of the Phase I soil investigation. Subsurface conditions during the subsequent Phase II and Unit 2 investigations were found to be very similar to those encountered in the early Phase I project.

The surficial sand layer consists of a heterogeneous arrangement of loose to dense, gray to brown sand, silty sand, and clayey sand, with an intermittent thin clay layer. This surficial layer varies in thickness from 32 feet to 71 feet. The granular soil is generally fine grained above elevation 45 feet msl, grading to medium and coarse grained with occasional shell fragments below that elevation. An intermittent cohesive layer of soft to stiff, gray, highly plastic clay and sandy clay, less than 4 feet thick, was encountered at depths between 32 and 35 feet.

Underlying the surficial sand layer is an intermediate cohesive layer of soft to stiff, gray to brown highly plastic clay, sandy clay, and silty clay, with occasional shell fragments. The layer was encountered at a maximum elevation of 58 feet msl and a minimum elevation of 3 feet msl, varying in thickness from 4 to 15 feet. This intermediate cohesive layer is not continuous under the SEC since it was absent in some of the borings.

The intermediate cohesive layer is underlain by a lower sand layer of loose to dense, white, gray, and olive, fine to coarse grained, poorly graded sand, silty sand, and clayey sand. This layer was encountered at elevations ranging from -1 to 17 feet msl, with a thickness varying from 78 to 81 feet.

Below the lower sand layer is a lower cohesive layer consisting of sandy clay and silty clay. This material is olive in color and has a stiff to hard consistency. This layer was encountered at elevations ranging from -56 to -79 feet msl, with a thickness varying

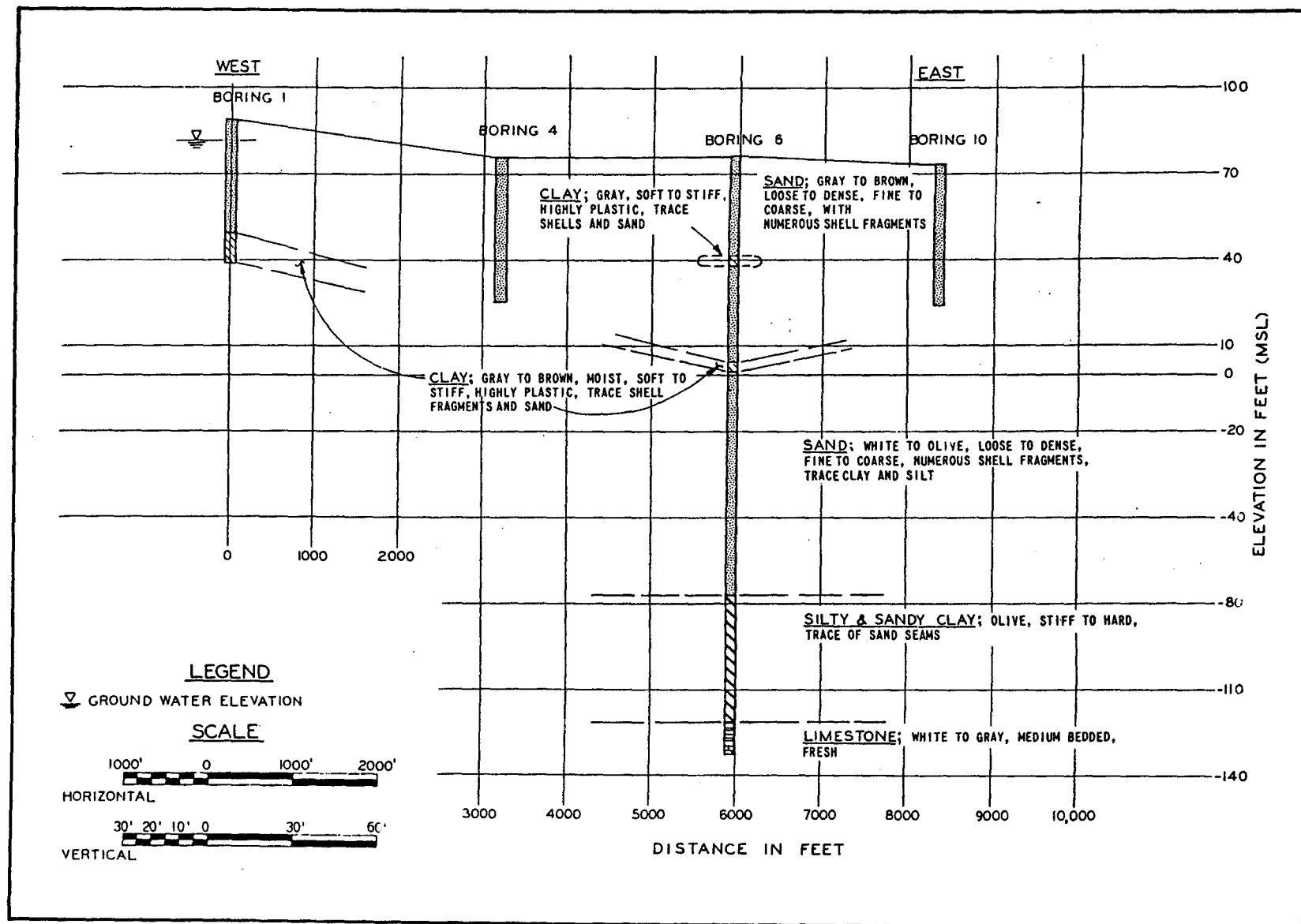


Figure 2.3-5
Stratigraphic Profile Beneath the SEC

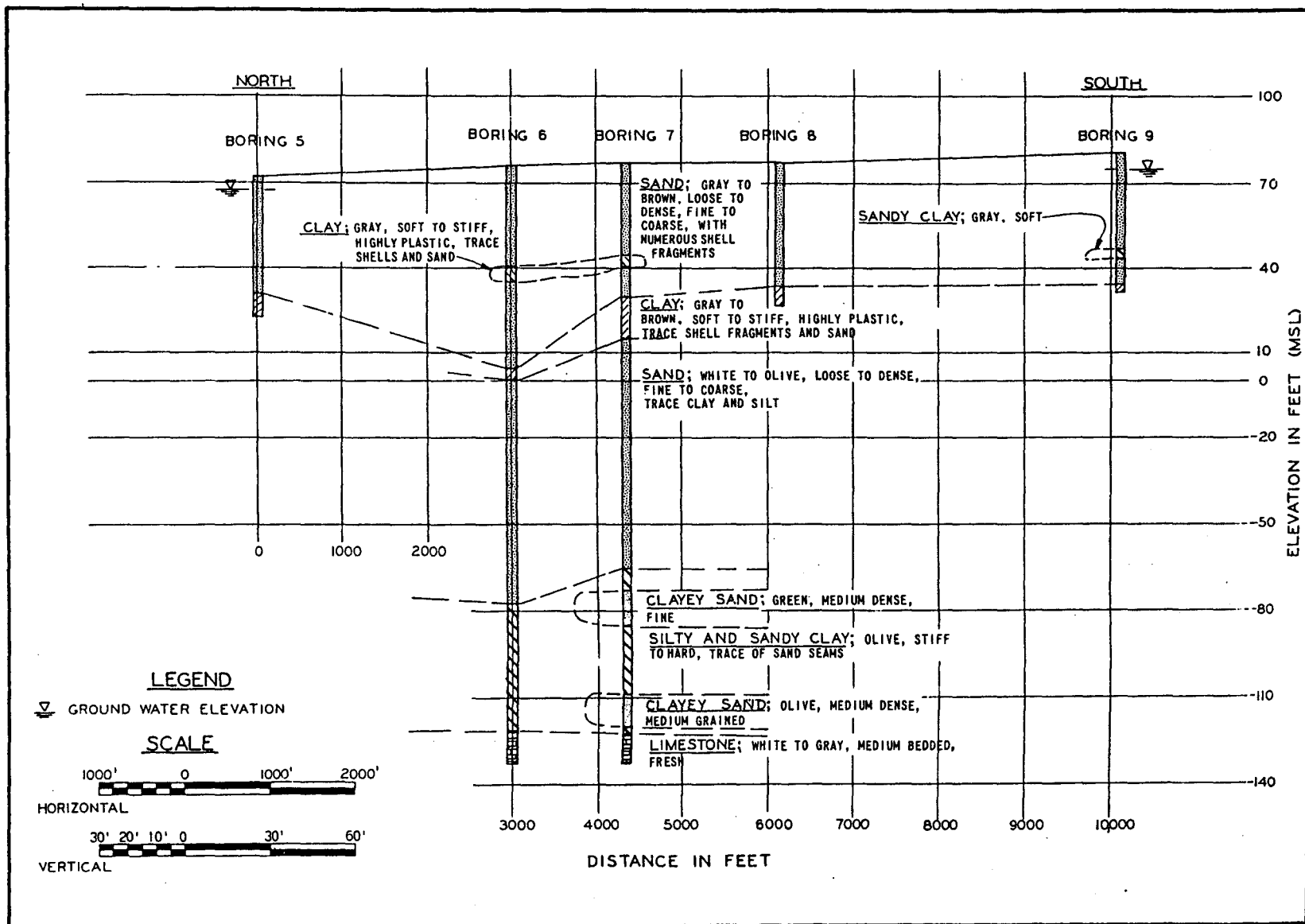


Figure 2.3-6
Stratigraphic Profile Beneath the SEC

from 43 to 61 feet. Intermittent layers of a medium dense, olive, fine to medium grained clayey sand, 7 to 11 feet in thickness, were encountered within this lower cohesive layer.

Limestone bedrock was encountered underlying the lower cohesive layer, at elevations ranging from -121 feet to -135 feet msl. The limestone is white to olive gray in color and is medium to thin bedded. It is argillaceous, fossiliferous, and fresh to slightly weathered. The limestone has voids between elevations -126 feet and -129 feet in Boring 6, and between elevations -130 feet and -131 feet in Boring 7. No other voids were reported in the Phase II deep borings.

The elevation on the SEC varies from approximately 92 feet msl in the southwest to approximately 52 feet msl in the northeast. The terrain is generally level with gradients of 15 feet per mile to the northeast. Grade at the main plant complex, including the area for Stanton A, was raised to an elevation of about 80 feet msl, requiring an average of 5 feet of compacted fill, to raise the site above the 100 year flood elevation.

2.3.1.3 Bearing Strength. The performance of the foundation systems for the proposed combined cycle unit 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.

Heavily loaded, settlement sensitive structures within the existing SEC are supported on deep foundations consisting of friction piling. These foundations have been performing very satisfactorily since installation and it is anticipated that similar methods will be used for the proposed combined cycle unit. More lightly loaded structures are anticipated to be supported on shallow footings or mats.

2.3.1.4 Karst Geohydrology. As a part of the original SCA for the existing SEC, a sinkhole evaluation potential study was performed by Jammal and Associates, Inc., in 1982. The conclusion from that study was that the potential for sinkholes is very low. No sinkholes have been reported at the SEC and sinkholes are not expected to be a problem for the proposed combined cycle unit. The Sinkhole Evaluation Potential report is available (upon request) and the title sheet and Table of Contents from this report are included in Section 10.6 of the Appendices.

2.3.2 Subsurface Hydrology

This section describes the groundwater aquifers beneath the SEC. The description is based on published data and data from piezometers and monitoring wells installed at various locations on and around the SEC. The location of these piezometers and monitoring wells is shown on Figure 2.3-7. Effects on the aquifers from construction

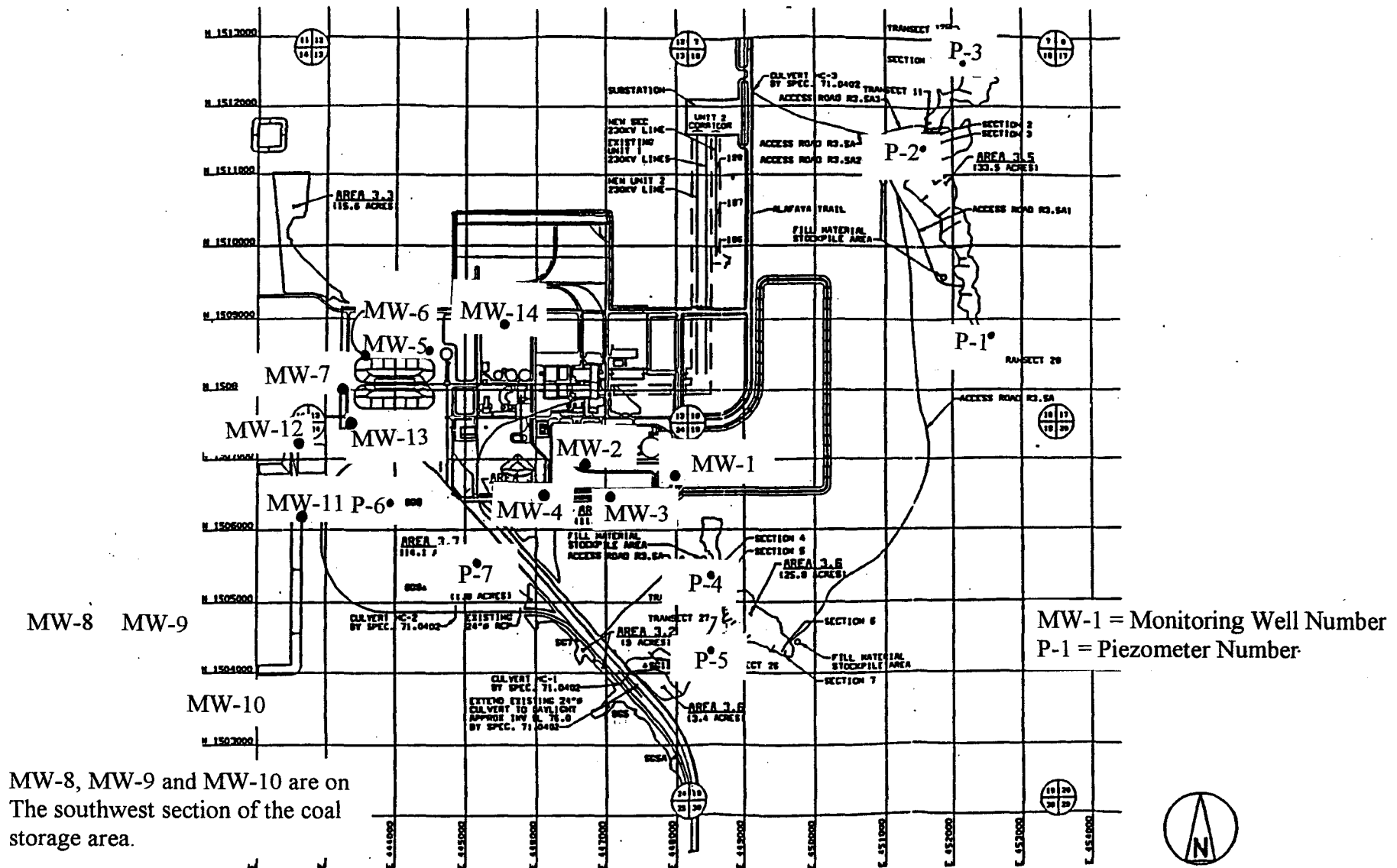


Figure 2.3-7
Piezometer and Monitoring Wells Location Plan

and plant operations are discussed in Section 4.3.1 of this SSCA; monitoring systems are discussed in Section 4.3.2.

The three aquifers beneath the site are the unconfined aquifer, the intermediate secondary artesian aquifer, and the Floridan Aquifer.

2.3.2.1 Unconfined Aquifer. This aquifer is referred to as the “shallow aquifer,” the “surficial aquifer,” or the “nonartesian aquifer” in literature. The unconfined aquifer is a surficial water table aquifer and consists primarily of sands and shell with varying amounts of clay and hardpan. The thickness of the aquifer is highly variable, ranging from less than 10 feet in areas of the St. Johns River Basin to greater than 150 feet along the high ridge areas of west Orange and east Lake counties. With increasing depth, the unconfined aquifer sediments generally grade into less permeable clayey or silty sands that, in some areas, compose the upper part of the intermediate secondary artesian aquifer and elsewhere directly confine the Floridan Aquifer system (Murray et al., 1996). The base of the surficial aquifer is approximately 40 feet bgs in much of Orange County (Lichtler, 1968).

At the SEC, the bottom of the unconfined aquifer was encountered at depths ranging from 32 feet to 71 feet bgs, the top of the intermediate cohesive layer. Beneath the intermediate cohesive layer, there is approximately 80 feet of sand underlain by the lower cohesive layer (Hawthorn Formation). Since the intermediate cohesive layer is absent at some boring locations, it is assumed there is a hydraulic connection between the groundwater in the sands above and below the intermediate cohesive layer. However, based on published data, the intermediate cohesive layer is considered to represent the base of the unconfined aquifer in the region.

The unconfined aquifer is recharged from direct infiltration of precipitation, irrigation, septic tank effluent, and in parts of southwest Orange County, by land application of reclaimed water. Water is discharged from the unconfined aquifer by seepage to lakes, streams, and ditches, evapotranspiration, pumpage, and downward leakage to the Floridan Aquifer system. Water levels in the unconfined aquifer fluctuate in a seasonal pattern, responding mainly to local rainfall. During most years low rainfall occurs from November through February, and high rainfall occurs from June through September. At present, seven piezometers and fourteen monitoring wells are located at the SEC to monitor groundwater levels and groundwater quality in the unconfined aquifer. The piezometers are located within the wetlands area south of the main plant facilities, the monitoring wells are located within the main facilities area. Groundwater levels and chemical analyses of groundwater samples obtained from the monitoring wells for the period 1998 to present is included in Exhibit A, which can be provided upon request. Groundwater levels are measured from the top of well casing which is, on the average,

about 3 feet above ground level. Monitoring well data indicate the water table is generally within 5 feet of the surface.

Data on the hydraulic properties of the unconfined aquifer is available from a US Geologic Survey (USGS) connector well located immediately west of the SEC (Bush, 1979). According to Bush, the unconfined aquifer has a transmissivity of approximately 590 square feet per day (ft^2/day), a storage coefficient of 0.01, a vertical hydraulic conductivity of 0.4 foot per day (ft/day) and a horizontal hydraulic conductivity of 15.7 ft/day . The vertical hydraulic conductivity has been confirmed to be representative by laboratory tests performed in conjunction with the Phase I subsurface investigation.

2.3.2.2 Intermediate Secondary Artesian Aquifer. The intermediate secondary artesian aquifer regionally separates the unconfined aquifer and the Floridan Aquifer, but is limited in continuity. This aquifer includes all sediment beds of the Hawthorn Group and, locally, low permeability beds of early Pliocene age (Miller, 1986). The intermediate secondary artesian aquifer consists of interbedded and interfingered sand, clayey sand, silty and sandy clay, and clay units.

The intermediate secondary artesian aquifer under the SEC has a thickness ranging from 125 feet to 156 feet. This thickness includes the intermediate cohesive layer, lower sand layer, and lower cohesive layer encountered during the subsurface investigations. Due to the absence of the intermediate cohesive layer at some boring locations, the continuous lower cohesive layer is believed to act as the primary aquitard between the unconfined and Floridan aquifers underneath the SEC. The lower cohesive layer has a thickness of about 50 feet.

Throughout the region, the quality of the water varies with depth, location, and local geologic and hydrologic conditions. Where present, the intermediate secondary artesian aquifer is the least likely to be polluted because the overlying, low permeability beds offer protection from surface pollution, and because drainage wells are usually cased through these aquifers into the deeper Floridan Aquifer.

Groundwater moves into and out of this unit at a very slow rate. Knochenmus, 1975 indicates, "...the finer grained strata of the confining layer and of the material above it retard the downward movement of water from the non-artesian aquifer to the Floridan." Tibbals and Frazee, 1976, indicate the "secondary artesian aquifers are recharged by leakage from above, and they discharge by leakage downward to the Floridan aquifer, and where tapped by wells." The water level of the secondary artesian aquifers generally stands about 10 feet below land surface (Tibbals and Frazee, 1976).

Tibbals and Frazee also indicate the intermediate secondary artesian aquifer can yield up to 700 gallons per minute (gpm) to properly constructed wells. However, the vertical hydraulic conductivity of the clays of the Hawthorn Group (lower cohesive layer)

has been measured in the laboratory to range from about 8×10^{-7} to 2×10^{-2} ft/day (Miller, 1986). Chemical analyses of water from the intermediate secondary artesian aquifer at locations surrounding the SEC are given in Table 2.3-2. This data corresponds to sampling performed between 1963 and 1970; however, groundwater quality within the secondary artesian aquifer is not expected to have changed significantly due to the lower permeability layers above and below the aquifer.

Table 2.3-2 Chemical Analyses of Water from the Secondary Artesian Aquifer in Eastern Orange County		
	Well No. 283249N0810532.2	Well No. 282530N0810542.3
Sample Date	10/63 - 4/70 (5 analyses)	1/69 - 4/70 (6 analyses)
SiO ₂ (Silica)	12-18	18-20
Fe (Iron)	0.00-0.47	---
Ca (Calcium)	107-120	63-112
Mg (Magnesium)	1.1-2.9	3.4-3.7
Na (Sodium)	8.4-13	15-16
K (Potassium)	0.9-2.7	1.0-4.1
HCO ₃ (Bicarbonate)	352-382	368
SO ₄ (Sulfate)	0.0-7.2	0.0-0.4
Cl (Chloride)	9.0-22	15-18
F (Fluoride)	0.2-0.6	0.1-0.2
NO ₃ (Nitrate)	0.0-1.6	0.0-0.7
Dissolved Solids	321-400	237-360
Hardness	279-316	172-296
Specific Conductance (microhms at 26° C)	550-620	386-602
pH	7.5-8.2	7.9-8.4
Color	0-20	0-10
Well Depth (feet)	75	172

Table taken from Knochenmus (1975). All quantities given in mg/L.

2.3.2.3 Floridan Aquifer. The Floridan Aquifer underlies all of Florida and, in the region, includes the Oldsmar Limestone, the Avon Park Limestone, the Ocala Group Limestone, and some portions of the Hawthorn Formation that are in hydraulic contact with the underlying limestones. The Floridan Aquifer thickness is generally taken at about 2,000 feet. The limestone is extensively solutioned, increasing the secondary porosity. The top of the Floridan Aquifer at the SEC is at about 200 feet bgs.

This aquifer is recharged primarily from infiltration of precipitation in its outcrop area. Minor amounts of recharge are also provided from leakage through the overlying confining layer and via connector and drainage wells constructed through the confining layer that hydraulically join the unconfined aquifer and the Floridan Aquifer. Discharge of groundwater from the Floridan Aquifer occurs by spring outflow, seepage into the St. Johns River, by outflow to other areas, outflow to the Atlantic Ocean, and by pumping in the area.

The Floridan Aquifer system is subdivided into the Upper Floridan Aquifer, the middle semiconfining unit, and the Lower Floridan Aquifer, as shown in Table 2.3-1 (Murray et al., 1996). The Upper Floridan Aquifer consists of the Ocala limestone and the dolomite and dolomitic limestones of the upper one-third of the Avon Park Formation. The middle semiconfining unit consists of less permeable, soft micritic limestone and dense dolomitic limestone in the middle one-third of the Avon Park Formation. The Lower Floridan Aquifer includes the bottom one-third to one-half of the Avon Park Formation and all of the Oldsmar Formation. Some interconnected solution channels exist within the middle semiconfining unit of this aquifer, providing some connection between the Upper and Lower parts of the aquifer. Where these solution channels are absent, vertical movement of water is inhibited (Murray et al., 1996). Lichtler (1968) indicates that the Upper Floridan extends from about 150 feet bgs to about 600 feet bgs; the Lower Floridan extends from about 1,100 feet to 1,500 feet bgs to 2,000 feet or more bgs.

Yields from the Floridan Aquifer have been measured up to several thousand gallons per minute; however, lower figures are more common. In most areas, the Floridan Aquifer will produce more potable water from the upper 1,000 feet of the aquifer. Pump tests at the Cocoa well field, about 6 miles southeast of the SEC, indicate the Upper Floridan Aquifer has a transmissivity ranging from 29,000 to 750,000 ft²/day and a storage coefficient of 0.0003 to 0.00007 (Tibbals and Frazee, 1976). Results of a pump test performed on the existing pumping well at the SEC indicate that the Upper Floridan Aquifer has a transmissivity of about 50,000 ft²/day. Table 2.3-3 summarizes the well characteristics and pumping rates at one SEC well and the Cocoa well field wells.

Table 2.3-3
Results of Pumping Tests in the
Upper Floridan At and Near the Stanton Energy Center

Year	Well No.	Depth of Well (feet)	Distance to Observation Well (feet)	Pumping Rate (gpm)	Transmissivity (ft ² /day)	Storage Coefficient
1963	Cocoa 13	509	-	2,100	29,000	-
	Cocoa 14	761	2,400		74,000	0.0003
1969	Cocoa 12A	600	-	1,000	510,000	-
	Cocoa A	516	5,200		550,000	0.0009
1969	Cocoa 7	490	-	980	210,000	-
	Cocoa 1	710	2,100		750,000	0.00007
1984	Stanton 1	535	400	850	50,000	0.0005

Adapted from Tibbals and Frazee (1976).

Aquifer test data for the Lower Floridan Aquifer are scarce. Lichtler (1968) reported on two tests performed at two water supply facilities in Orange County, which yielded relatively high transmissivities with values ranging from 574,000 to 668,000 ft²/day.

Little data are available for characterizing the middle semiconfining unit within the Floridan Aquifer. Recent USGS aquifer tests performed at the Cocoa well field indicate that the middle semiconfining unit can be highly anisotropic (Phelps and Schiffer, 1996). The vertical hydraulic conductivity of a section of this unit was estimated to be no greater than 5×10^{-2} ft/day; the horizontal hydraulic conductivity was estimated to be about 20 ft/day.

Storage coefficients calculated from aquifer tests conducted in the Upper and Lower Floridan Aquifers range from 1×10^{-3} to 7×10^{-5} , which is typical for confined aquifers.

The artesian pressure in the Floridan Aquifer is created by: 1) the difference in elevation between the surface of the Floridan Aquifer at its primary recharge area and elevation at the SEC, and 2) the presence of the confining layer above the Floridan Aquifer at the SEC. Figure 2.3-8 shows the depth to the potentiometric surface of the Floridan Aquifer taken at an observation well located 400 feet away from one of the existing pumping wells at the SEC. The depth to the potentiometric surface is

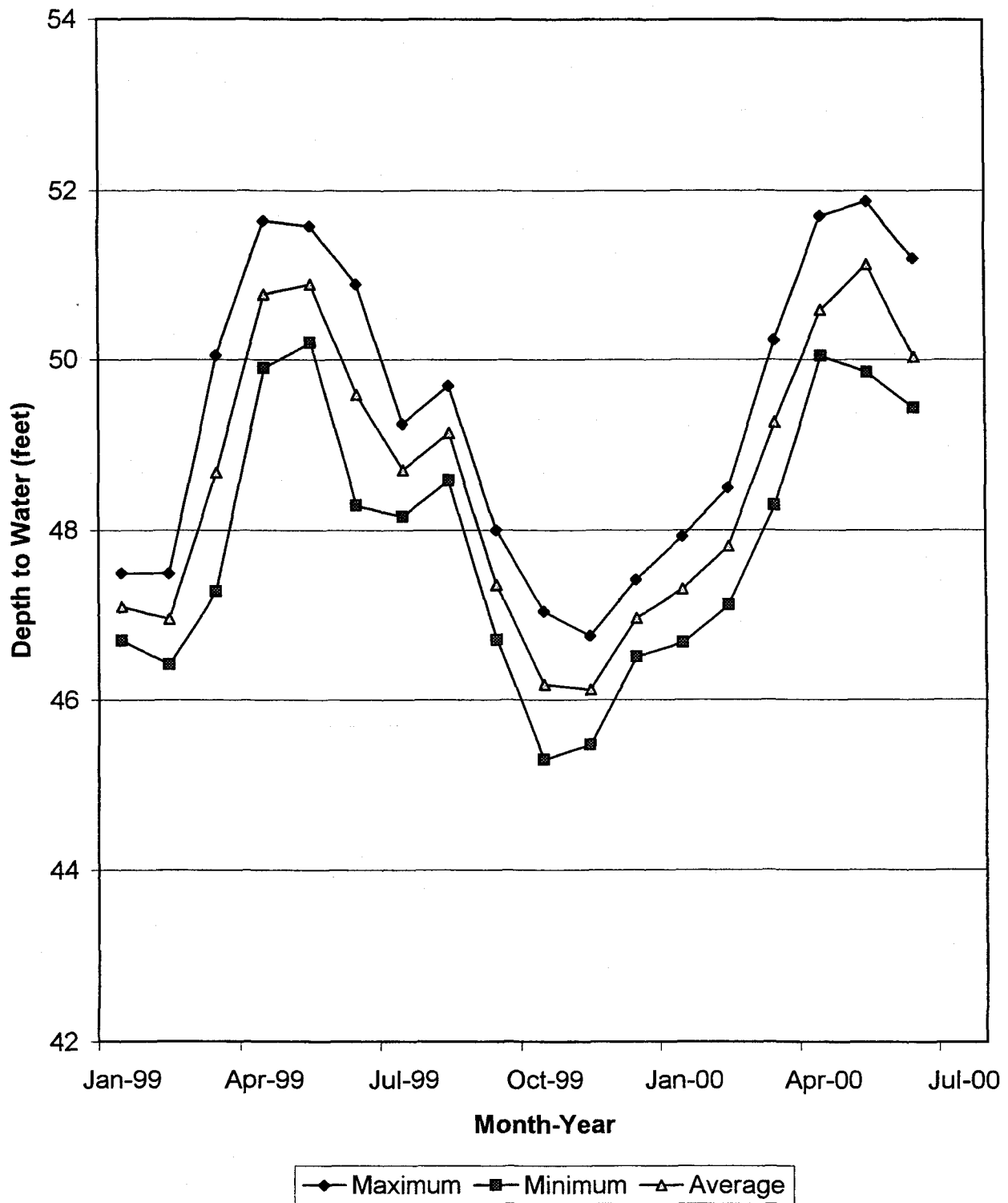


Figure 2.3-8
Upper Floridan Aquifer - Groundwater Levels
Within Stanton Energy Center Site

measured from the top of casing which is about 3.5 feet above ground surface, and is shown for the period 1999 to present. On average, for the period of record, the potentiometric surface of the Floridan Aquifer within the SEC is at 45 feet bgs (approximate Elevation 35 feet msl). The potentiometric surface of the Floridan Aquifer has been affected in recent years by the below normal precipitation in the region. The St. Johns River Water Management District (SJRWMD) indicates that between July 1999 and July 2000, there was a decrease of about 3 to 6 feet in the potentiometric surface of the Floridan Aquifer in the general region of the SEC. In general, the potentiometric surface of the Floridan Aquifer in the region is about 10 to 12 feet lower than in 1980. This is mainly due to increased groundwater withdrawals from new users in the region as well as below normal precipitation levels.

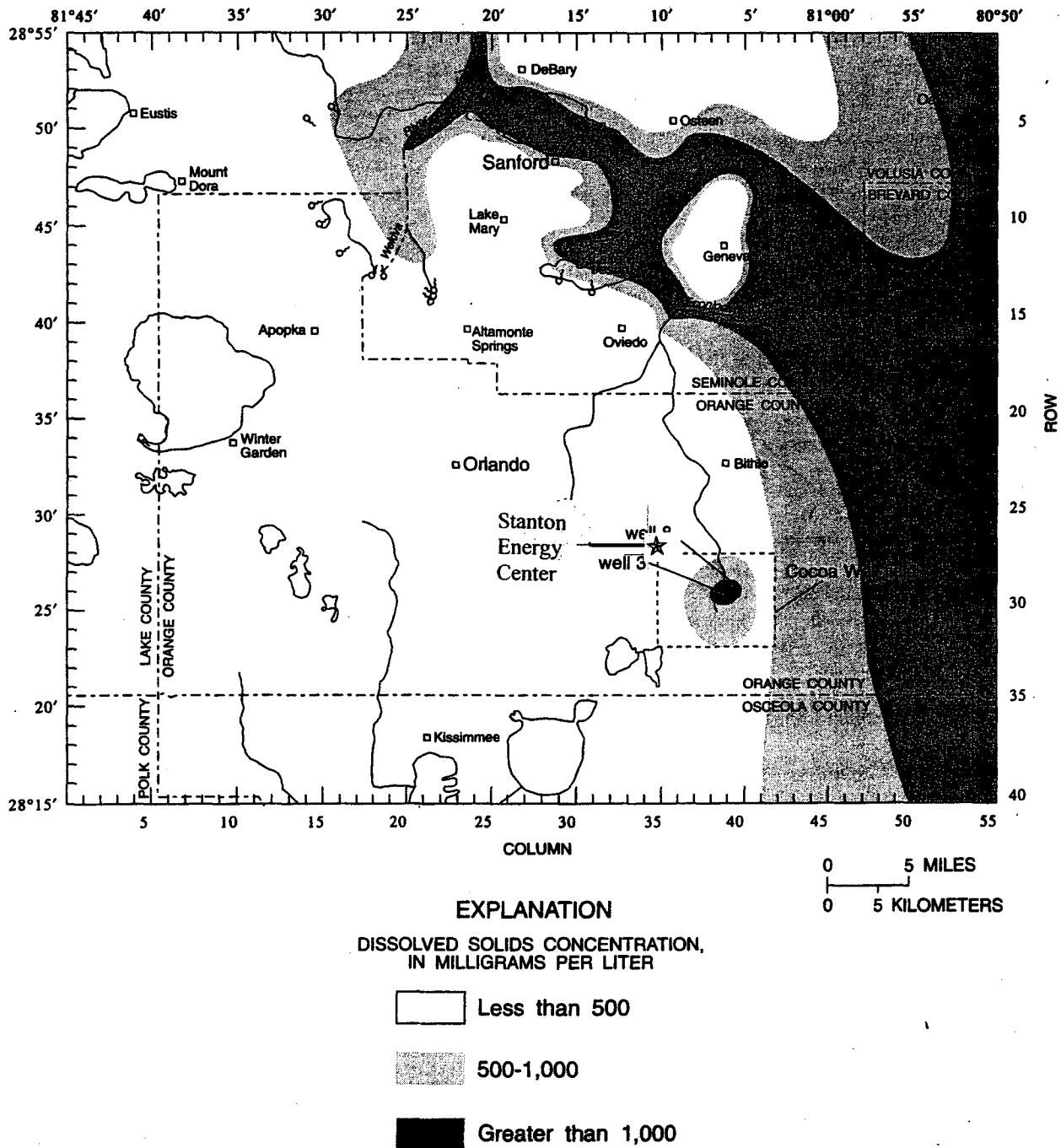
The gradient of the potentiometric surface is to the northeast at approximately 2 feet/mile. The aquifer discharges to the St. Johns River located about 18 miles east of the SEC where the potentiometric surface is above the ground surface, and artesian wells flow at the surface (Lichtler and others, 1968).

Water in the Floridan Aquifer system generally is of a calcium and magnesium bicarbonate type because of the reaction between the limestone aquifer matrix and the weak carbonic acid characteristic of rainfall as a source of recharge (Murray et al., 1996). The chemical quality of the groundwater in the Floridan Aquifer is better in the western than in the eastern part of Orange County. The concentration of dissolved solids near the St. Johns River is greater than 2,000 mg/L. The concentration of dissolved solids chloride and sulfates in the Floridan Aquifer beneath Orange County is shown on Figures 2.3-9 through 2.3-11 (Murray et al., 1996). Figure 2.3-10 also shows the depth to the freshwater-saline water interface, which is estimated between 1,500 to 2,000 feet bgs at the SEC. The occurrence of the slightly brackish water at two wells within the Cocoa well field southeast of the SEC may be the result of induced upward leakage of more brackish water from depth in the Floridan Aquifer due to heavy pumping (Tibbals and Frazee, 1976), or a local pocket of entrapped relict seawater that exists near or below the pumping wells (Murray et al., 1996).

Chemical analyses on groundwater samples taken from the well production pipelines at the SEC are included in Exhibit B for the last quarter of 1999 through mid-2000. Exhibit B can be provided upon request.

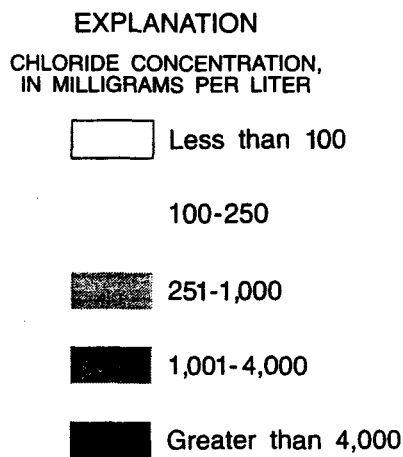
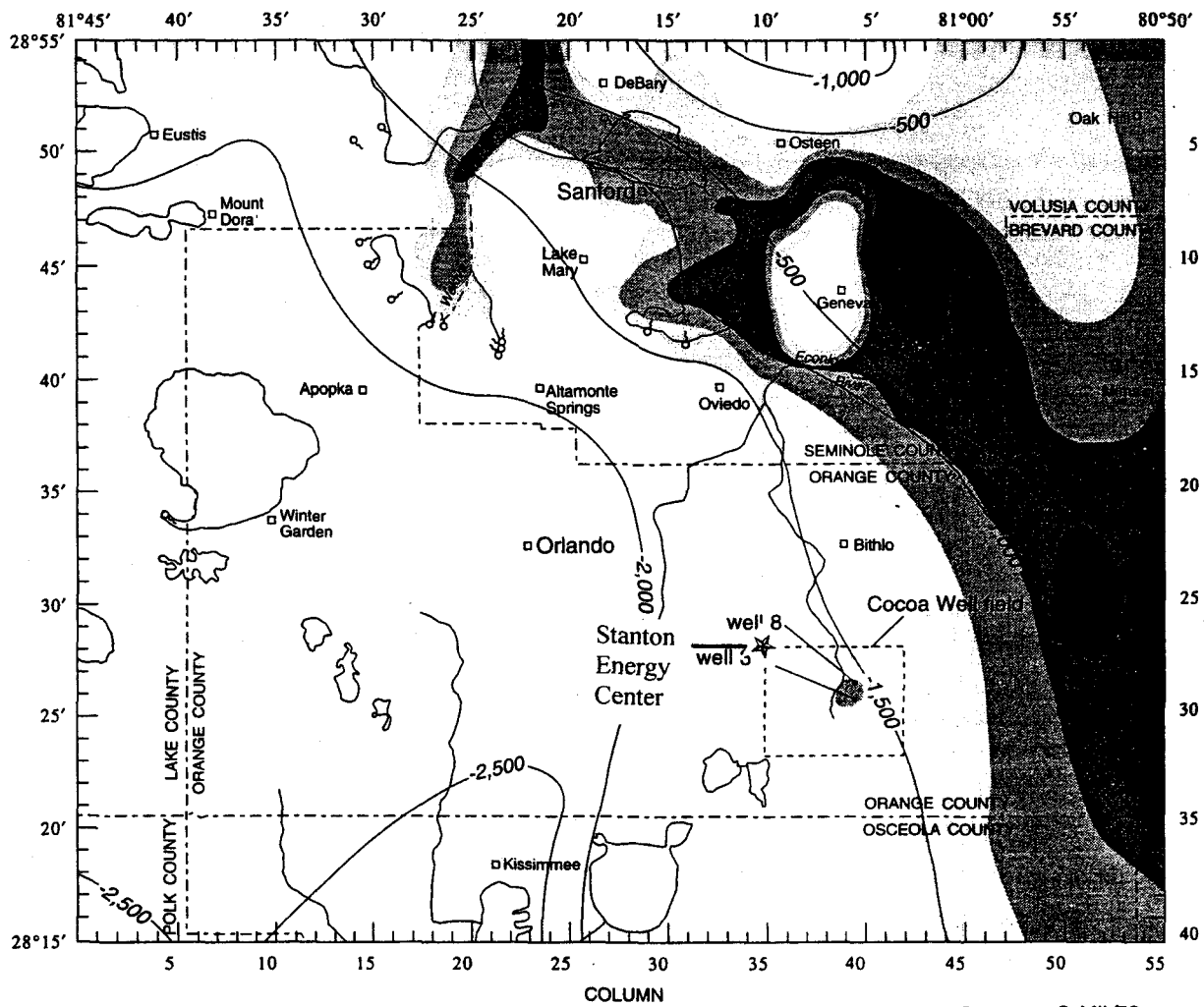
2.3.3 Site Water Budget and Area Users

Additional climatological information and the tables identified in this section are provided in Section 2.3.7 of this application. The following meteorological information was collected from the Orlando International Airport. This is the closest National Weather Service office to the SEC, approximately 10 miles west of the



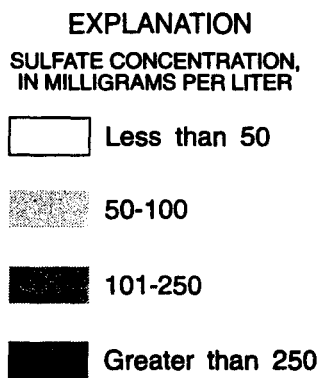
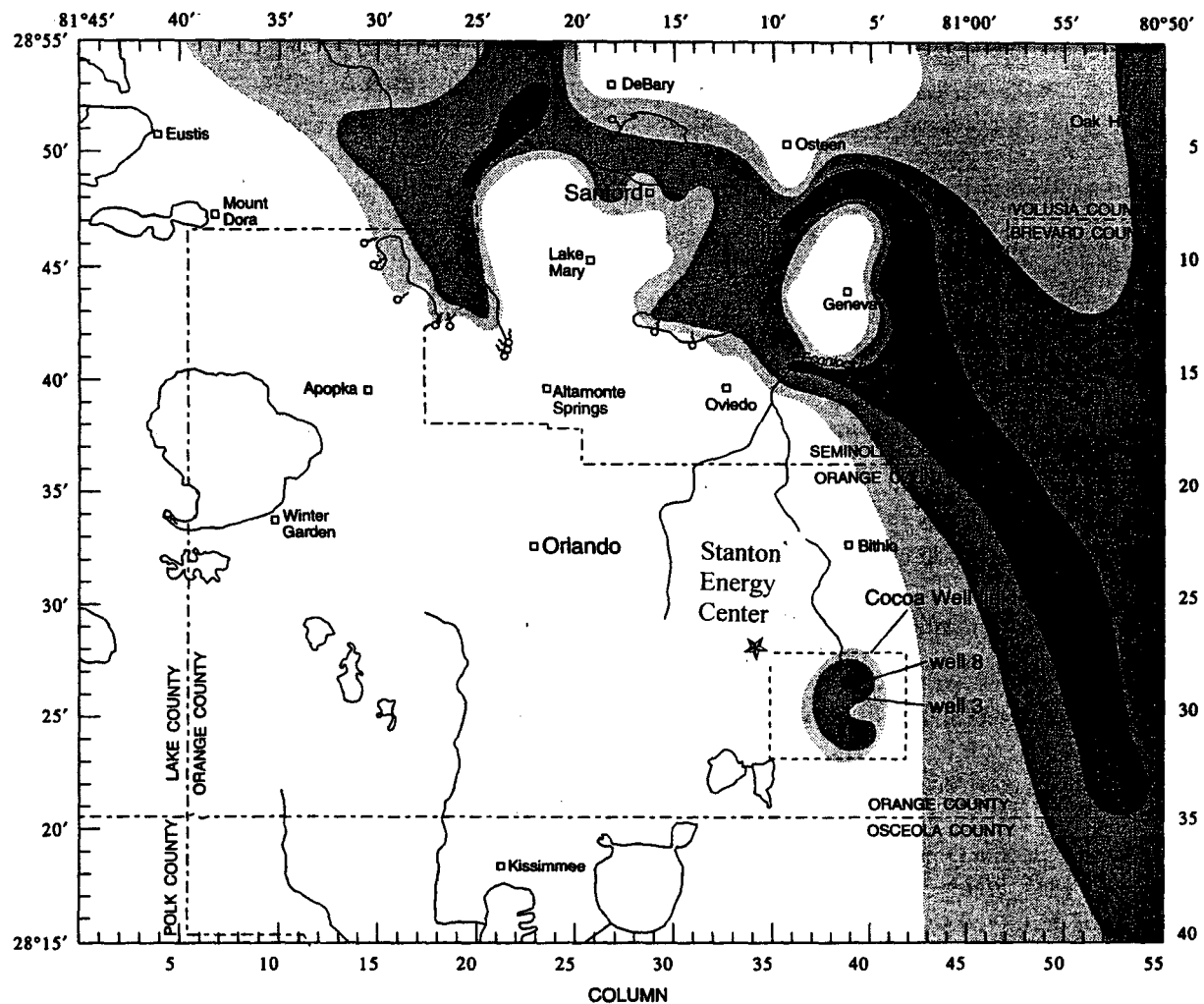
From Murray et al, 1996

Figure 2.3-9
Dissolved Solids Concentrations - Upper Floridan Aquifer



— -2,000 — LINE OF EQUAL DEPTH TO WATER WITH CHLORIDE CONCENTRATION
OF 10,000 MILLIGRAMS PER LITER OR GREATER - Interval 500 feet.
Datum is sea level

From Murray et al, 1996



From Murray et al, 1996

Figure 2.3-11
Sulfate Concentrations - Upper Floridan Aquifer

SEC, at Elevation 96 feet, msl. The Orlando airport data are considered to be representative of long-term SEC conditions.

2.3.3.1 Evapotranspiration and Runoff. Rainfall averages 50 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. Evaporation occurs from shallow lakes and reservoirs, and also, 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. The Natural Resource Conservation Service (NRCS) estimates evapotranspiration to be about 40 inches per year in this area from shallow lakes and reservoirs.

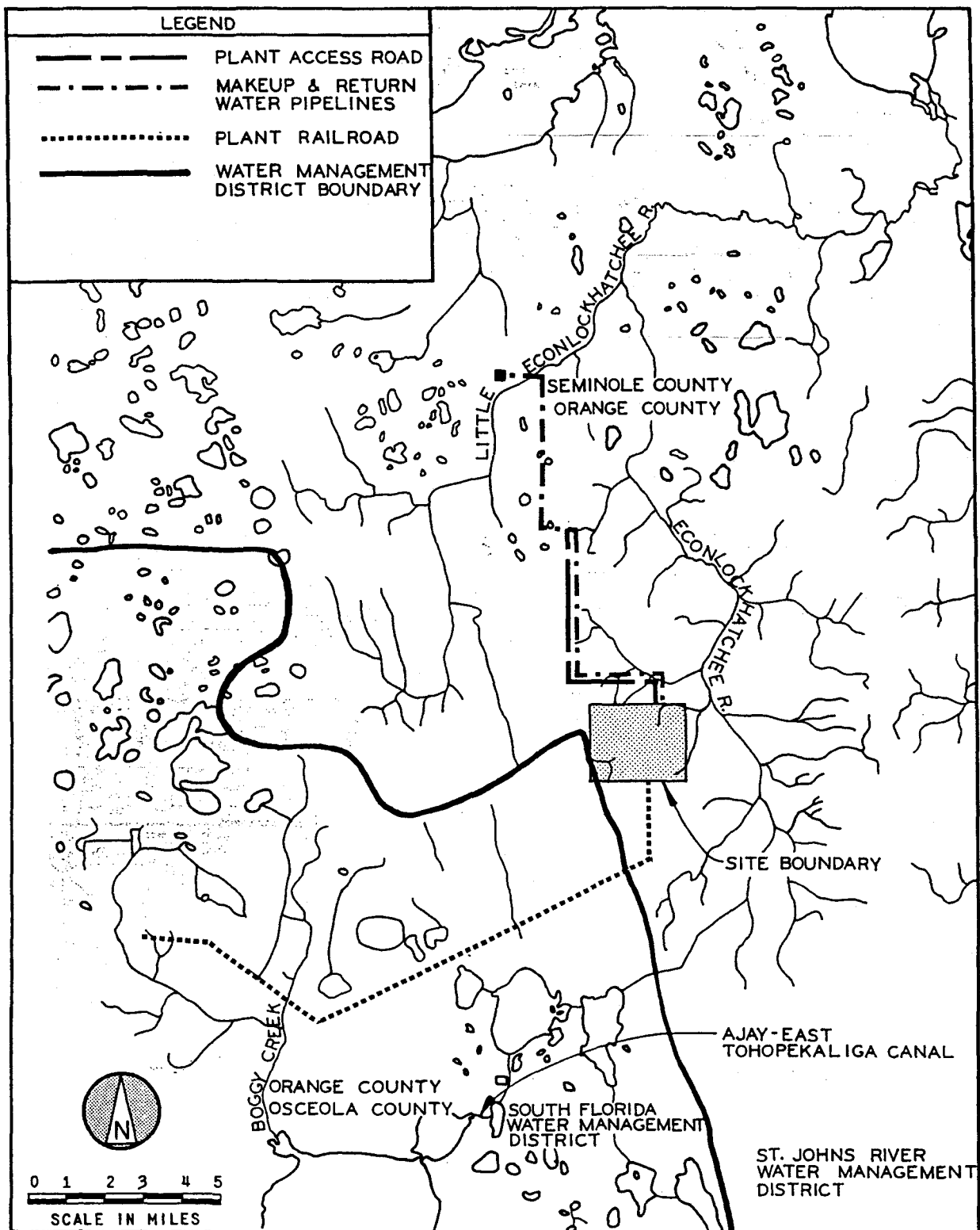
2.3.3.2 Water Use. Water resources in the SEC vicinity include the Econlockhatchee and Little Econlockhatchee rivers, east and west of the site respectively, and the Floridan Aquifer. Refer to Figure 2.3-12 for the location of surface waters within the SEC vicinity. No major streams are on the SEC. A small segment of the Hart Branch of the Econlockhatchee river extends into the northeast portion of the SEC which will not be disturbed by construction or operational activities. The Floridan Aquifer will supply plant service and potable water, and the Orange County wastewater treatment plant will supply cooling water makeup.

Major water uses in the SEC vicinity are for agricultural purposes such as irrigation, livestock watering, and various rural domestic uses. Very few irrigated lands are present in the vicinity. Most irrigated lands are found in the western portion of the county, where specialty citrus and vegetable crops are grown.

No industrial, municipal water supply, or wastewater facilities are located at the SEC. The Cocoa well field municipal water supply area is located about 5 to 6 miles south and southeast of the SEC, is owned and operated by the City of Cocoa, and supplies 15.5 million gallons per day (mgd) to central Brevard County. In addition, the new Orange County eastern regional municipal well field is being constructed about 5 to 6 miles west of the SEC and is expected to withdraw about 20 mgd by the year 2010.

Recreational opportunities on surface waters within 10 miles of the SEC are primarily of local importance. Lake Hart, Lake Mary Jane, and the numerous smaller lakes in the area provide ample opportunities for recreational activities. The Econlockhatchee and Little Econlockhatchee rivers receive limited use, primarily by local residents.

No reservoirs or natural lakes are on the SEC or within the 5 mile vicinity, but many natural lakes exist just outside the vicinity. Numerous smaller lakes to the west and south are used for recreation and irrigation water supply. The Disston Canal is located beyond the 5 mile vicinity, and diverts water from Lake Hart and Lake Mary Jane in the Kissimmee River basin, into the Econlockhatchee River. No transportation activities are known to occur on surface waters in the vicinity.



Water supply wells installed in the region since construction of Units 1 and 2 are shown on Figure 2.3-13. Three water supply wells have been installed within 1 mile of the SEC since 1992. The well owners and specific well information are summarized in Table 2.3-4.

Table 2.3-5 shows average groundwater use in the SJRWMD for the year 1995, and projected 2020 conditions (Vergara, 1998). Orange County alone used 136.8 mgd of groundwater in 1996 and 19.2 mgd of surface water, about 11 percent of the total water use in the SJRWMD, and is projected to increase its use to 12 percent of the total water use by 2020.

2.3.4 Surficial Hydrology

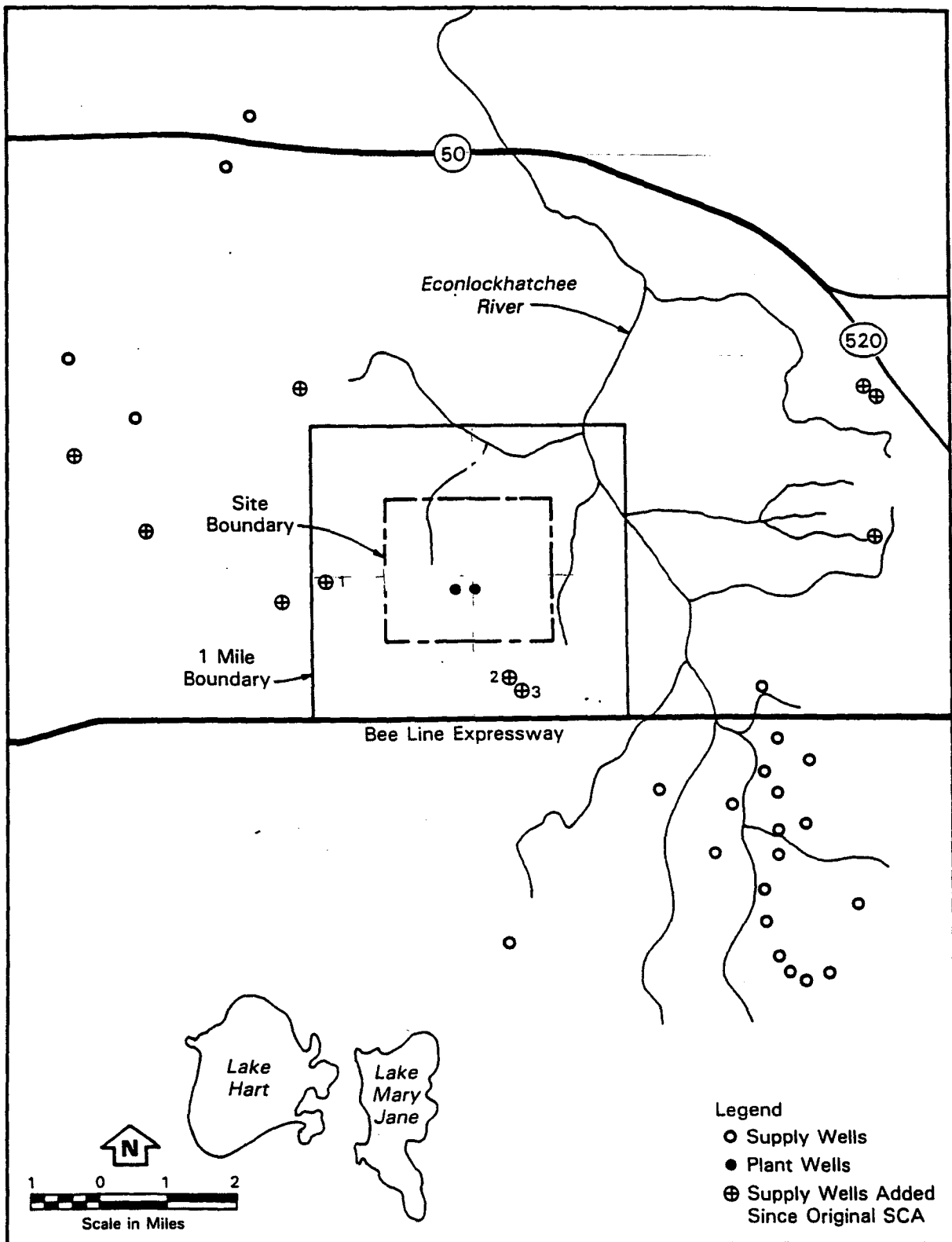
2.3.4.1 Regional Hydrology. The power block area of the SEC is located within the Econlockhatchee River Drainage Basin as shown on Figure 2.3-12. Numerous small ponds and wet depressions, as well as several unnamed intermittent streams, are located throughout the region.

The US Geological Survey maintains several lake stage and stream gaging stations within the region. The major characteristics of the gaged streams and lakes within the vicinity of the SEC are summarized in Tables 2.3-6 and 2.3-7, respectively.

Econlockhatchee River Drainage Basin

The Econlockhatchee River drains approximately 260 square miles of the western slope of the St. Johns River basin between Orlando and Bithlo. The headwaters are an elongated swamp within Orange and Osceola counties, with slow drainage and high evapotranspiration losses. From its headwaters, the Econlockhatchee River flows in a generally northward direction through Orange County and into Seminole County, where it is joined by its largest tributary, the Little Econlockhatchee River. Thereafter, the river flows in an easterly direction to its confluence with the St. Johns River.

Two streamflow gage stations are currently maintained on the Econlockhatchee River. The most upstream gaging station (USGS ID 02233001) is located at Magnolia Ranch, about 6 river miles upstream from the SEC. Streamflow records have been obtained since October 1972. The drainage area above this station is 32.9 square miles and the average discharge for the period of record (1972-1999) is 50 cubic feet per second (cfs). The maximum recorded discharge is 474 cfs. The river experiences no flow at this station many days each year. The second gaging station (USGS ID 02233500) is located downstream from the confluence of the Econlockhatchee River and Little Econlockhatchee River near Chuluota. Streamflow records have been obtained since October 1935. The drainage area above this station is 241 square miles and the



Source: SJRWMD, 1991

031591

2-49

Figure 2.3-13
Water Supply Wells in the SEC Area

Table 2.3-4
Supply Wells Within 1 Mile Boundary of SEC

Well No.	Owner	Well Use	Cased Depth (ft)	Total Depth (ft)
1	Waste Management Inc., of Florida	Public Supply	250	400
2	State of Florida, Dept. of Corrections	Public Supply	247	420
3	State of Florida, Dept. of Corrections	Public Supply	252	448
Source: SJRWMD, 2000				

Table 2.3-5
Total Water Demand for 1995 and 2020 in the St. Johns River Water Management District

Category	1995 Water Use (mgd)			Projected 2020 Water Use (mgd) Average Rainfall Year			
	Groundwater	Surface Water	Total	Groundwater	Surface Water	Total	Percent Change
Public Supply	443.04	12.15	455.19	702.48	16.81	719.29	58
Domestic and Other Small Public Supply	71.98	0.00	71.98	64.84	0.00	64.84	-10
Agricultural Irrigation	363.58	223.39	586.97	368.45	220.69	589.14	0
Recreational Irrigation	68.78	30.35	99.13	107.77	48.67	156.44	58
Commercial/Industrial/Institutional	96.03	38.13	134.16	102.63	44.19	146.82	9
Thermoelectric Power Generation	7.66	14.5	22.16	11.13	16.42	27.55	24
Total	1,051.07	318.52	1,369.59	1,357.30	346.78	1,704.08	24

Table 2.3-6
USGS Stream Data in the SEC Vicinity

Station Number	Latitude (ddmmss)	Longitude (ddmmss)	County	Basin Name	Drainage Area (miles ²)	Datum (feet above NGVD)
2233001	282527	810710	Orange	Upper St. Johns	32.9	-
2233500	284040	810651	Seminole	Upper St. Johns	241	2.14

Table 2.3-7
USGS Lake Stages in the SEC Vicinity

Station Number	Station Name	Drainage Area (miles ²)	Lake Surface Area (acres)
2261900	Lake Mary Jane	124	1,161
2262200	Lake Hart	166	1,841

average discharge for the period of record (1935 - 1996) is 266 cfs. The maximum recorded streamflow is 10,000 cfs and the minimum flow is 6.7 cfs. Figures 2.3-14 and 2.3-15 present the historical discharge flows for the period of record for these gaging stations.

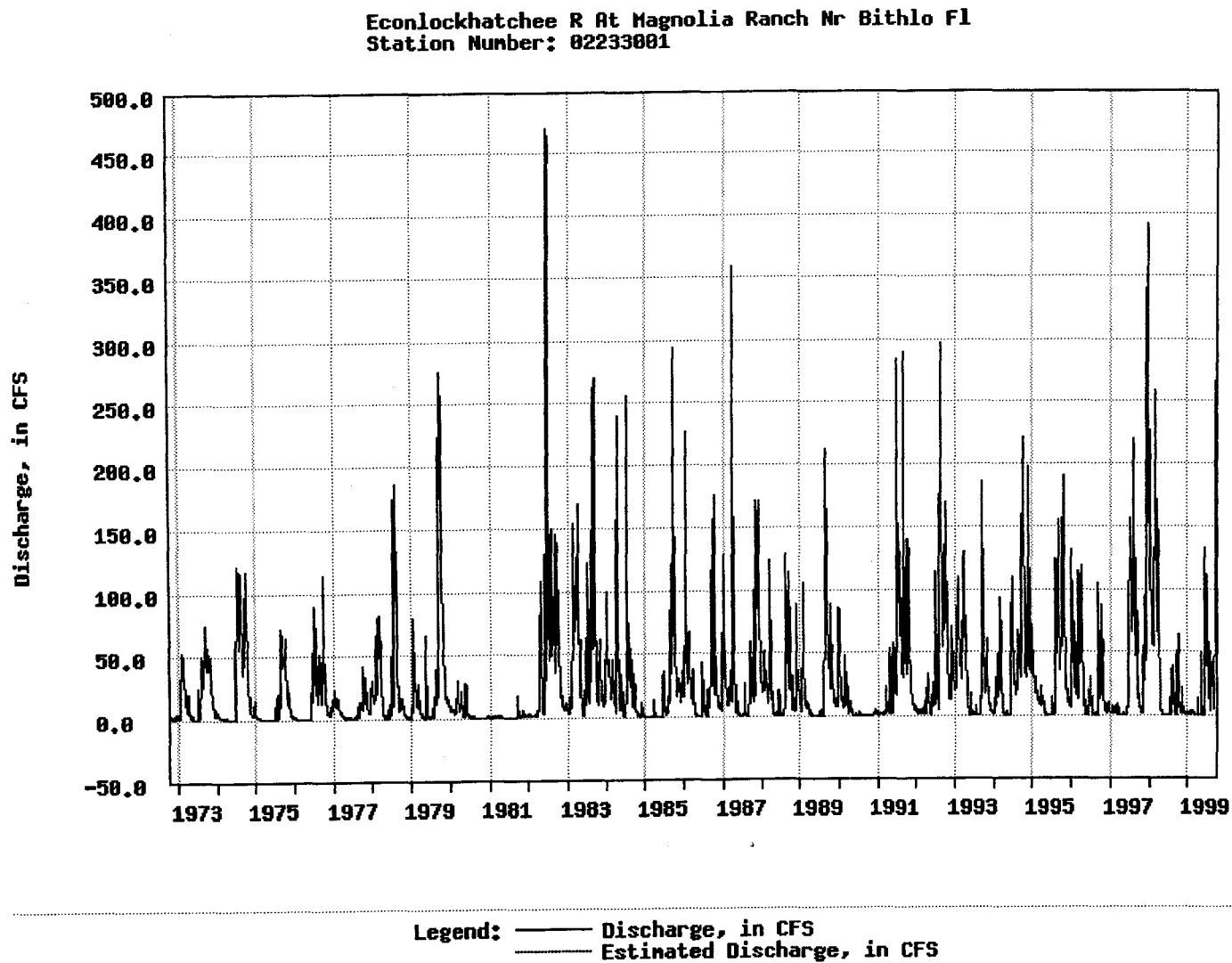
In addition to the two existing gaging stations, a partial record station (USGS ID 02233100) was located near Bithlo from September 1959 to May 1965. This partial record station was located approximately 6 miles downstream from the SEC, with a drainage area of 119 square miles. Based on available records, the estimated average flow at this station is 88 cfs. The maximum recorded discharge was 7,840 cfs and the river experiences zero flow at this station in most dry years.

The channel of the Econlockhatchee River is well developed in its lower reach. In this reach, the channel is incised into the water-table aquifer so that the river derives some base flow from the shallow aquifer during even the most severe droughts. In addition, streamflows are augmented by effluent from the Orlando sewage plant and flows diverted from Lake Mary Jane in the Kissimmee River Basin through Disston Canal.

2.3.4.2 Local Hydrology. The proposed combined cycle unit addition will be located approximately 3,500 feet southwest of the Econlockhatchee River, about 10 miles southeast of Orlando and 5 miles southwest of Bithlo.

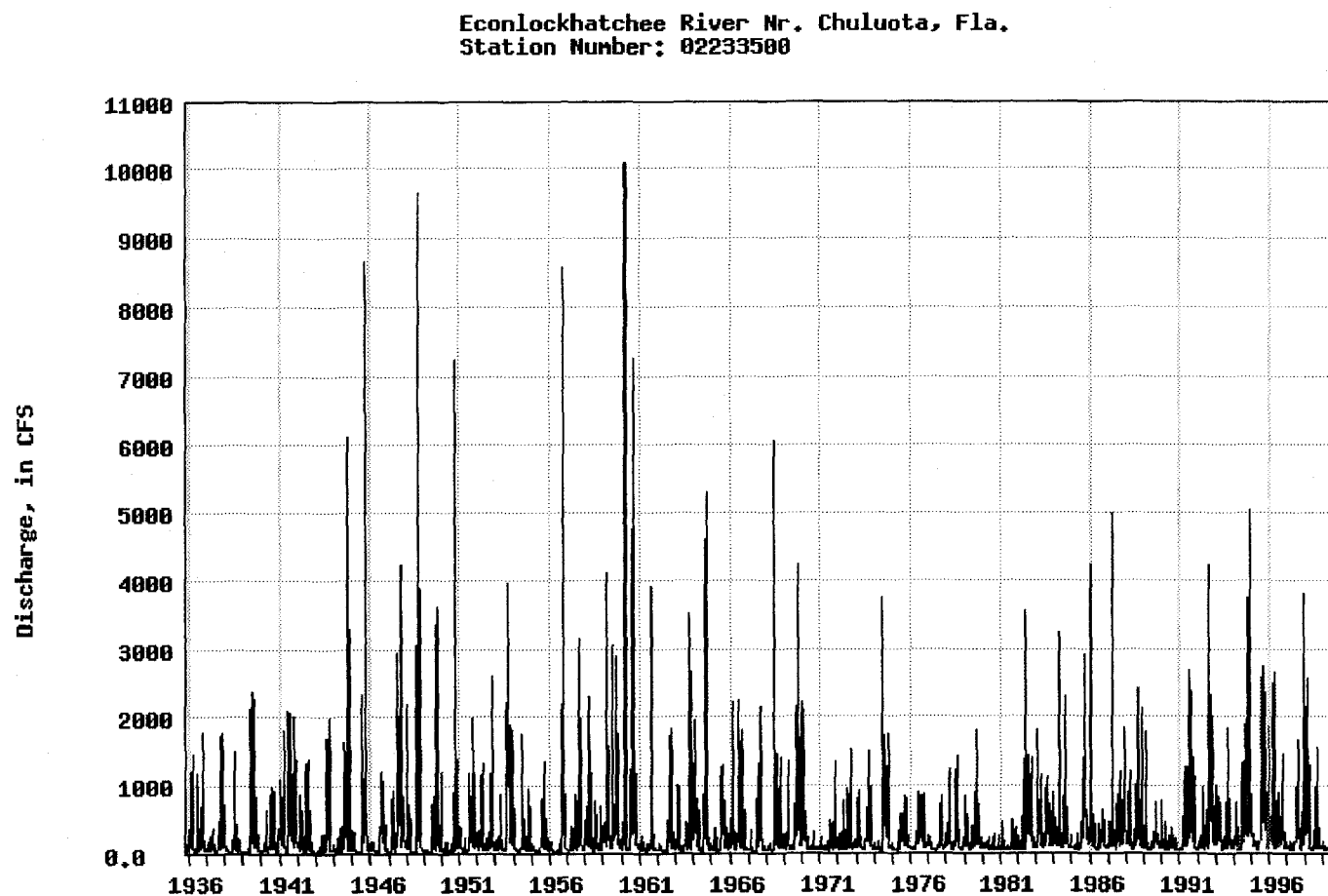
Predominant surface hydrologic features in the vicinity of the general site area include an unnamed tributary of the Econlockhatchee River to the north, Hart Branch and Cowpen Branch to the east, and Green Branch to the southeast. Hart, Cowpen, and Green Branch are tributaries of the Econlockhatchee River for which discharge records are not available. Approximate drainage areas of the above mentioned tributaries of the Econlockhatchee River are summarized in Table 2.3-8. The location of the SEC with respect to local surface hydrologic features is shown on Figure 2.3-16.

SEC elevations vary from approximately 54 feet at the northeastern corner to 92 feet near the west site boundary. Soils are composed of fine sands with variable organic content. Surface runoff from approximately 257 acres in the northwest corner of the SEC is directed in a northeasterly direction to an unnamed tributary of the Econlockhatchee River. Runoff from approximately 984 acres within the north central portion of the SEC flows in a northeasterly direction to Hart Branch. Approximately 1,305 acres comprising the central and eastern portions of the SEC are drained in a predominantly easterly direction to Cowpen Branch. Runoff from approximately 695 acres within the southwest portion of the SEC flows in a southeasterly direction to Green Branch. Many areas characterized as swamps or wooded marshes are located throughout the area.



Source: <http://waterdata.usgs.gov/nwis-w/FL/?statnum=02233001>

Figure 2.3-14
Historical Daily Streamflow Econlockhatchee River
at Magnolia Ranch Station



Source: <http://waterdata.usgs.gov/nwis-w/FL/?statnum=02233500>

Figure 2.3-15
Historical Daily Streamflow Econlockhatchee River
Near Chuluota, Florida Station

Table 2.3-8
Drainage Areas of Econlockhatchee River Tributaries
Within the Project Vicinity of the Proposed Stanton A

Tributary	Drainage Area (square miles)
Unnamed Tributary North of the Site	7.8
Hart Branch	2.0
Cowpen Branch	2.8
Green Branch	4.2

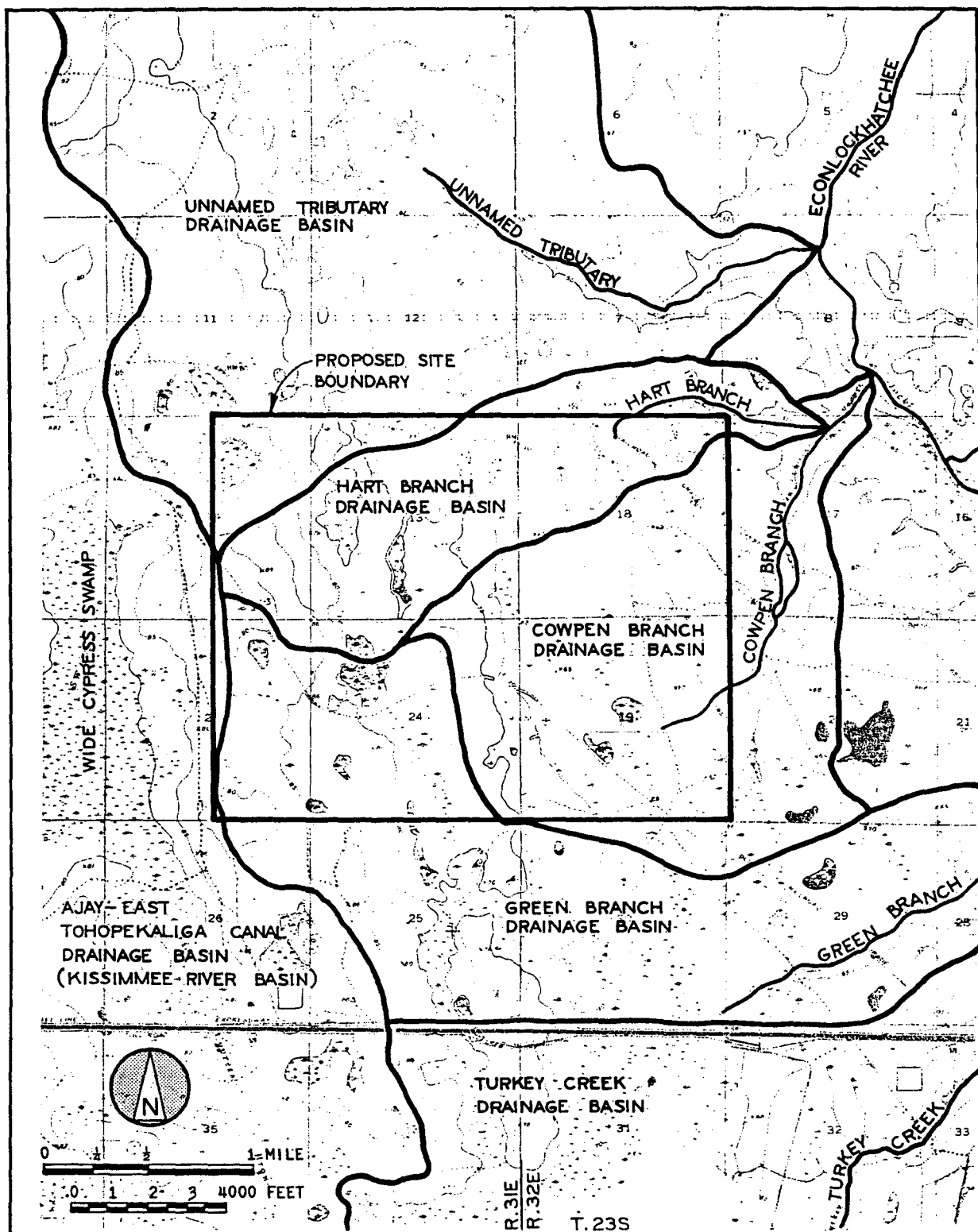


Figure 2.3-16
Local Surface Hydrologic Features in SEC Vicinity

The maximum recorded flows for the Econlockhatchee River occurred in March 1960. Peak flows of 10,000 cfs and 7,840 cfs were observed at the USGS gaging stations near Chuluota and Bithlo, respectively. The area drained at the Bithlo station is 119 square miles, while it is estimated that the Econlockhatchee River drains 74 square miles just above its confluence with Cowpen Branch. If it is assumed that the runoff observed at the Bithlo station during the peak flood of record is representative of the basin hydrologic conditions for the Econlockhatchee River above Cowpen Branch during the same period of time, then a peak discharge of about 4,875 cfs would have occurred within the Econlockhatchee River near the Stanton site.

The predominant type of flooding that may occur at the proposed Project site is known as sheet flooding. USGS Flood-Prone Area Maps indicate inundated areas during a flood having a 100 year recurrence interval. These flood prone areas are shown for the SEC on Figure 2.3-17.

Periods of zero flow have been recorded at the Magnolia Ranch station, as well as at the discontinued station near Bithlo. This indicates that periods of zero flow can be expected within the Econlockhatchee River, as well as within the local tributaries during drought conditions.

The majority of precipitation experienced within the area is lost through the process of evapotranspiration. The remaining available moisture either runs off or percolates to the unconfined aquifer. Average annual runoff from the entire Econlockhatchee River basin above the gaging station near Chuluota is approximately 15 inches. A portion of this runoff results from groundwater recharge to the Econlockhatchee River throughout the lower reaches. Within the lower portions of the basin, the Econlockhatchee River is incised into the unconfined aquifer and the actual direct surface runoff would be less than that computed from stream flow measurements. It has been estimated that average annual runoff is 10 inches per year within the Econlockhatchee River basin above the gaging station at Magnolia Ranch. Knochenmus (1975) indicates an average annual water loss by runoff to be between 10 and 25 percent of average annual precipitation for the general area. Evapotranspiration is estimated to be between 72 and 87 percent of average precipitation. Knochenmus states that the average annual water loss from evapotranspiration plus surface runoff is probably nearly uniform throughout the region; areas having lower rates of surface runoff have higher rates of evapotranspiration. The total of these two losses is estimated to be about 97 percent of precipitation, leaving 3 percent, or about 1.5 inches, available for percolation.

2.3.4.3 Surface Water Quality. The chemical character of the surface water throughout the region differs from stream to stream and varies seasonally and daily in individual streams due to natural causes and development. Suspended sediment is not a serious problem in peninsular Florida. Dissolved minerals, water temperature, and color

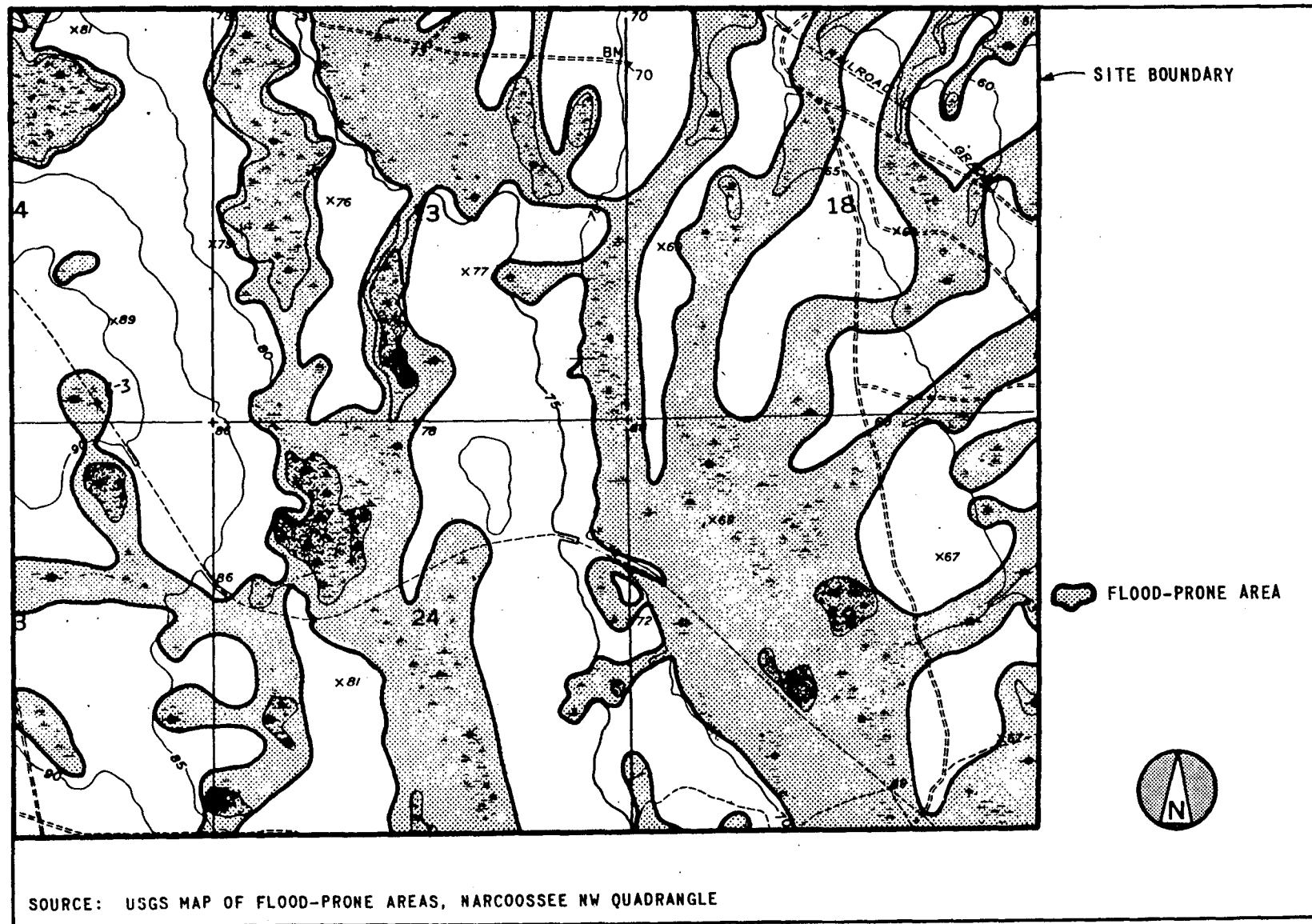


Figure 2.3-17
100 Year Flood-Prone Areas at the SEC

are the natural and man-influenced water quality phenomena significant to water use within the Project area. Surface water is generally low in mineral content if it is direct runoff or seepage from the unconfined aquifer and generally high in dissolved minerals if it was derived from the Floridan Aquifer.

Color of the surface water is extremely variable throughout the region and normally ranges from zero to about 200 Hazen units. After heavy rainfall, when highly colored water is flushed into small streams from swampy areas, the color may reach 300 to 600 Hazen units. Exhibit C includes chemical analyses performed on surface water samples from the Hart, Cowpen, and Green Branches of the Econlockhatchee River, performed by OUC as part of its monitoring program. The period of record is April 1999 to July 2000. Exhibit C can be provided upon request.

2.3.5 Vegetation/Land Use

The SEC lies within the Floridan section of the Atlantic Coastal Plain. The dominant drainage in the area is provided by the Econlockhatchee River, which flows in a northerly direction and terminates in the St. Johns River. Drainage from the SEC flows to this river via the Hart Branch and Cowpen Branch.

Stanton Units 1 and 2 were constructed primarily in the pine flatwoods and pond cypress plant communities. Stanton A construction will occur on site property that was prepared and used as a construction and equipment lay-down area for the original facility. This flat area, which contains various railroad spur tracks, is currently maintained with regular mowing and is considered poor wildlife habitat.

A botanical survey of the SEC was conducted from 1980 to 1981. Plant communities identified are described below and graphically depicted on Figure 2.3-18. Plants identified during the botanical surveys are listed in Table 2.3-9. Table 2.3-10 lists endangered and threatened plant species that may occur on or near the SEC.

Natural communities on the SEC are typical of the region. Nearly level flatwoods predominate, with scattered wetlands and low ridges on the western portion and in the center of the SEC. The wetlands are cypress-dominated strands that traverse the property in a north-south direction. The low ridges support oak scrub and are also aligned in a north-south direction. Intermediate between these low ridges and wetlands are longleaf pine flatwoods.

Pine flatwoods is an upland community with flat to slightly sloping topography and well to moderately drained soils. Longleaf pine (*Pinus palustris*) is the characteristic tree species in the flatwoods. The extremely open canopy permits development of a rich understory of shrubs and herbaceous species. Saw palmetto (*Serenoa repens*) is the most

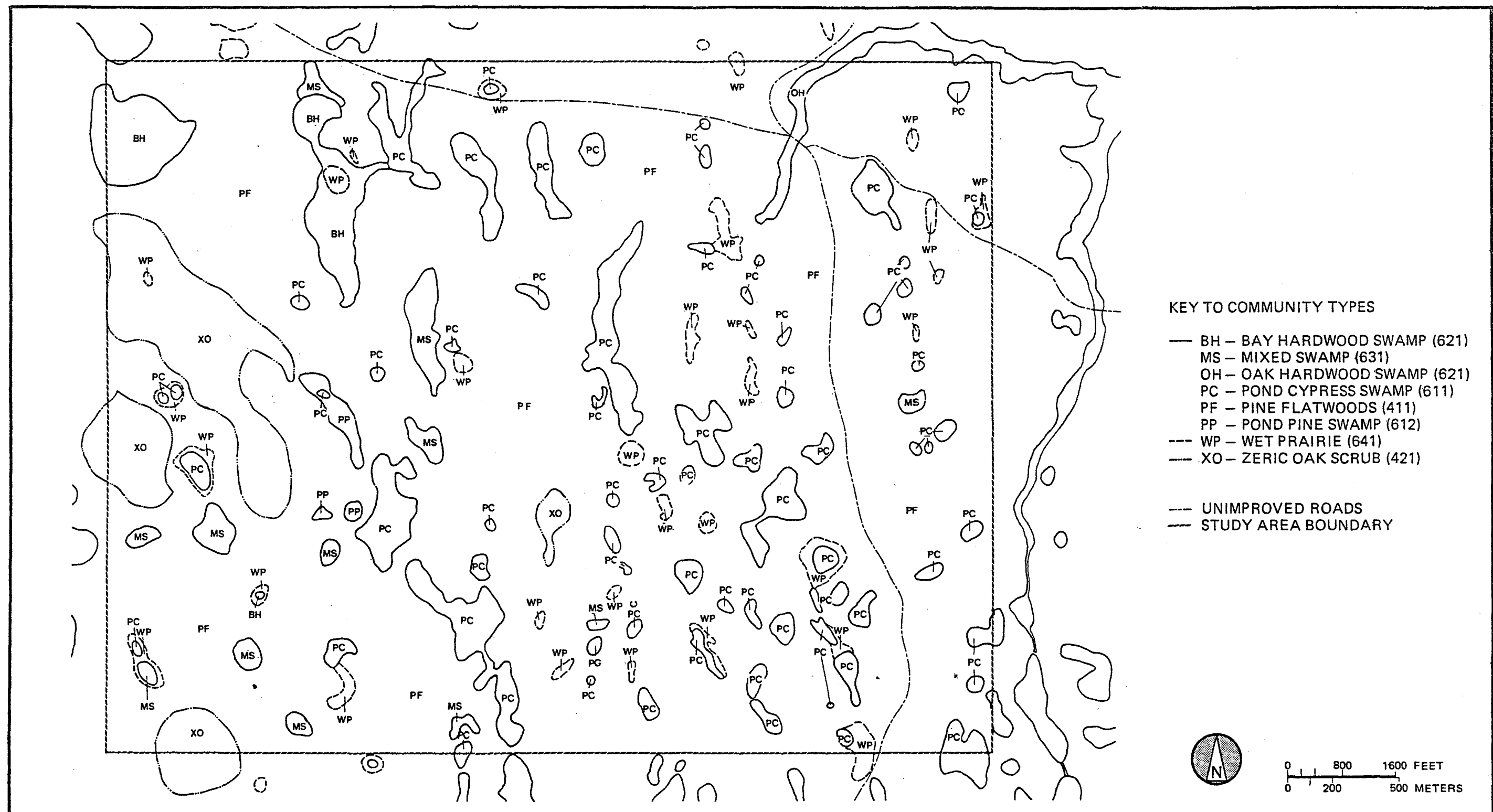


Figure 2.3-18
Vegetative Communities of the SEC

Table 2.3-9
Plants and Animals Observed at the SEC

Scientific Name	Common Name
Trees	
<i>Acer rubrum</i> var. <i>trilobum</i>	Red maple
<i>Broussonetia papyrifera</i>	Paper mulberry
<i>Cornus foemina</i>	Stiff dogwood
<i>Diospyros virginiana</i> 66	Persimmon
<i>Gordonia lasianthus</i>	Loblolly bay
<i>Ilex cassine</i>	Dahoon
<i>Magnolia virginiana</i>	Sweet bay magnolia
<i>Nyssa biflora</i> .	Swamp tupelo
<i>Persea palustris</i>	Swamp red bay
<i>Pinus palustris</i>	Longleaf pine
<i>P. serotina</i>	Pond pine
<i>Quercus geminata</i>	Sand live oak
<i>Q. laevis</i>	Turkey oak
<i>Q. laurifolia</i>	Laurel oak
<i>Q. nigra</i>	Water oak
<i>Q. virginiana</i>	Live oak
<i>Sabal palmetto</i>	Cabbage palm
<i>Taxodium ascendens</i>	Pond cypress
Shrubs	
<i>Asimina reticulata</i>	Pawpaw
<i>Baccharis halimifolia</i>	Groundsel bush
<i>Befaria racemosa</i>	Tar flower
<i>Callicarpa americana</i>	Beauty bush
<i>Cephalanthus occidentalis</i>	Button bush
<i>Gaylussacia dumosa</i>	Dwarf huckleberry
<i>G. frondosa</i>	Huckleberry
<i>Hypericum cistifolium</i>	Round pod St. John's wort

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Shrubs (Continued)	
<i>H. fasciculatum</i>	Peel bark St. John's-wort
<i>H. hypericoides</i>	St. Andrew's-cross
<i>H. reductum</i>	Atlantic St. John's-wort
<i>H. tetrapetalum</i>	Four petal St. John's-wort
<i>Ilex glabra</i>	Inkberry
<i>Itea virginica</i>	Virginia sweetspire
<i>Licania michauxii</i>	Gopher apple
<i>Lyonia ferruginea</i>	Rusty lyonia
<i>L. fruticosa</i> (Michx.)	Staggerbush
<i>L. lucida</i> (Lam.)	Fetterbush
<i>Myrica cerifera</i>	Wax myrtle
<i>M. pusilla</i>	Dwarf wax
<i>Parthenocissus quinquefolia</i>	Virginia creeper
<i>Quercus chapmanii</i>	Chapman's oak
<i>Q. minima</i>	Dwarf live oak
<i>Q. myrtifolia</i>	Myrtle oak
<i>Rhus copallina</i>	Winged sumac
<i>Rubus betulifolius</i>	Swamp blackberry
<i>Serenoa repens</i>	Saw palmetto
<i>Smilax auriculata</i>	Earloap greenbrier
<i>S. bona-nox</i>	Saw greenbrier
<i>S. laurifolia</i>	Laurel greenbrier
<i>S. walteri</i>	Coral greenbrier
<i>Toxicodendron radicans</i>	Poison ivy
<i>Vaccinium corymbosum</i>	Highbush blueberry
<i>V. darrowii</i>	Blueberry
<i>V. myrsinites</i>	Shiny blueberry
<i>Viburnum obovatum</i>	Black haw

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Plants	
<i>Vitis rotundifolia</i>	Muscadine grape
<i>Aletris lutea</i>	Yellow colic root
<i>Ambrosia artemisiifolia</i>	Annual ragweed
<i>Amphicarpum muhlenbergianum</i>	Blue maidencane
<i>Andropogon elliottii</i>	Broom-straw
<i>A. virginicus</i> var. <i>glaucopsis</i>	Silver beardgrass
<i>A. virginicus</i> var. <i>virginicus</i>	Broomsedge bluestem
<i>Aristida spiciformis</i>	Bottlerush threeawn
<i>A. stricta</i>	Wiregrass
<i>Axonopus furcatus</i>	Big carpet grass
<i>Bartonia virginica</i>	Yellow screwstem
<i>Bigelovia nudata</i> spp. <i>Australis</i>	Pineland rayless goldenrod
<i>Blechnum serrulatum</i>	Swamp fern
<i>Bulbostylis warei</i>	Ware's hairsedge
<i>Calopogon tuberosus</i>	Grass pink
<i>Carex glaucescens</i>	Southern waxy sedge
<i>Carphephorus odoratissimus</i>	Vanilla plant
<i>C. paniculatus</i>	Hairy chaffhead
<i>Cassia fasciculata</i>	Partridge pea
<i>Cenchrus incertus</i>	Sand spur
<i>Centella asiatica</i>	Coinwort
<i>Chenopodium ambrosioides</i>	Mexican tea
<i>Chrysopsis gossypina</i>	Cottony golden aster
<i>Cirsium horridulum</i>	Yellowthistle
<i>Cladium jamaicense</i>	Sawgrass
<i>Conyza canadensis</i> var. <i>pusilla</i>	Canadian horseweed
<i>Ctenium aromaticum</i>	Toothache grass
<i>Cyperus haspan</i>	Haspan flatsedge

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Plants (Continued)	
<i>Dichanthelium aciculare</i>	Needle-leaf witchgrass
<i>D. dichotomum</i> var. <i>breve</i>	Cypress panicgrass
<i>D. laxiflorum</i>	Open flower rosette grass
<i>D. sabulorum</i> var. <i>patulum</i>	Hemlock rosette grass
<i>Dichromena latifolia</i>	Whitetop sedge
<i>Diodia teres</i>	Buttonweed
<i>D. virginiana</i>	Virginia buttonweed
<i>Drosera capillaris</i>	Pink sundew
<i>Dulichium arundinaceum</i>	Three-way sedge
<i>Eleocharis baldwinii</i>	Baldwin's spikerush
<i>Encyclia tapensis</i>	Green-fly orchid
<i>Eragrostis refracta</i>	Coastal love grass
<i>E. spectabilis</i>	Purple love grass
<i>Erechtites hieracifolia</i>	Fireweed
<i>Erianthus giganteus</i>	Beard grass
<i>Erigeron quercifolius</i>	Fleabane
<i>E. vernus</i>	Fleabane
<i>Eriocaulon decangulare</i>	Greater pipewort
<i>Eryngium baldwinnii</i>	Baldwin's coyote-thistle
<i>Eupatorium aromaticum</i>	Thoroughwort
<i>E. capillifolium</i>	Dog fennel
<i>E. compositifolium</i>	Yankeeweed
<i>E. recurvans</i>	Thoroughwort
<i>Fimbristylis caroliniana</i>	Carolina fimbry
<i>Fuirena brevisita</i>	Umbrella grass
<i>Galactia</i> sp.	Milkpea
<i>Gratiola subulata</i>	Hedge hyssop
<i>Habenaria cristata</i>	Fringed orchid

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Plants (Continued)	
<i>Helianthus radula</i>	Rayless sunflower
<i>Hieracium gronovii</i>	Hawkweed
<i>Hydrocotyle umbellata</i>	Many flower pennywort
<i>Hypoxis juncea</i>	Yellow stargrass
<i>Iris hexagona</i> var. <i>savannarum</i>	Blue flag
<i>Juncus effusus</i> var. <i>solutus</i>	Lamp rush
<i>J. repens</i>	Black rush
<i>Lachnanthes caroliniana</i>	Red root
<i>Lachnocaulon anceps</i>	Bog buttons
<i>Lechea villosa</i>	Pinweed
<i>Liatris tenuifolia</i>	Liatris
<i>Lilium catesbaei</i>	Pine lily
<i>Linum medium</i> var. <i>taxanum</i>	Yellow flat
<i>Ludwigia maritima</i>	Seaside primrosewillow
<i>L. repens</i>	Creeping primrosewillow
<i>Lycopodium alopecoroides</i>	Foxtail club moss
<i>Lycopus rubellus</i>	Lycopus
<i>L. virginicus</i>	Virginia water horehound
<i>Mikania scandens</i>	Climbing hempweed
<i>Mitreola sessilifolium</i>	Swamp hornpod
<i>Oplismenus setarius</i>	Woodgrass
<i>Osmunda cinnamomea</i>	Cinnamon fern
<i>O. regalis</i> var. <i>spectabilis</i>	Royal fern
<i>Oxypolis filiformis</i>	Oxypolis
<i>Panicum albomarginatum</i>	Panic grass
<i>P. hemitomom</i>	Maidencane
<i>P. lancearium</i>	Panic grass
<i>P. purpurascens</i>	Panic grass

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Plants (Continued)	
<i>Paspalum laeve</i>	Paspalum grass
<i>P. notatum</i>	Bahia grass
<i>P. setaceum</i>	Thin paspalum grass
<i>Peltandra sagittifolia</i>	Spoon flower
<i>P. virginica.</i>	Green arrow arum
<i>Petalostemum carneus</i>	Prairie clover
<i>Phobanthus grandiflora</i>	Phobanthus
<i>Piloblephis rigida</i>	Savory pennyroyal
<i>Pinguicula lutea</i>	Yellow butterwort
<i>P. pumila</i>	Small butterwort
<i>Pluchea foetida</i>	Camphorweed
<i>P. rosea</i>	Rosy camphorweed
<i>Pogonia ophioglossoides</i>	Snakemouth orchid
<i>Polygala cruciata</i>	Drumheads
<i>P. cymosa</i>	Tall pinebarren
<i>P. lutea</i>	Orange milkwort
<i>P. rugellii</i>	Milkwort
<i>P. setacea</i>	Coastal plain milkwort
<i>Polypodium polypodioides</i>	Resurrection fern
<i>Pontederia cordata</i>	Pickernelweed
<i>Proserpinaca pectinata</i>	Mermaid fern
<i>Pteridium aquilinum</i>	Bracken fern
<i>Pterocaulon virgatum</i>	Wand blackroot
<i>Rhexia alifanus</i>	Savannah meadow beauty
<i>R. mariana</i> var. <i>mariana</i>	Maryland meadow beauty
<i>R. nashii</i>	Maid Marian meadow beauty
<i>R. nutallii</i>	Meadow beauty
<i>R. petiolata</i>	Fringed meadow beauty

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Plants (Continued)	
<i>Rhynchospora corniculata</i>	Short bristle beakrush
<i>R. divergens</i>	Spreading beakrush
<i>R. fascicularis</i>	Fasciculate beakrush
<i>R. miliacea</i>	Millet beakrush
<i>Rudbeckia hirta</i>	Black-eyed Susan
<i>Sabatia brevifolia</i>	Short-leaf rose-gentian
<i>S. grandiflora</i>	Large flower rose-gentian
<i>Sagittaria graminea</i>	Grassy arrowhead
<i>S. lancifolia</i>	Bulltongue arrowhead
<i>Sarracenia minor</i>	Hooded pitcher plant
<i>Saururus cernuus</i>	Lizard's tail
<i>Scleria hirtella</i>	Riverswamp nut rush
<i>S. reticularis</i>	Netted nut rush
<i>Sesbania vesicaria</i>	Bladderpod
<i>Setaria geniculata</i>	Foxtail grass
<i>Solidago microcephala</i>	Bush goldenrod
<i>Sphagnum sp.</i>	Peatmoss
<i>Stillingia sylvatica</i>	Queen Anne's delight
<i>Sygonanthus flavidulus</i>	Bantam buttons
<i>Tillandsia bartramii</i>	Bartram's air plant
<i>T. fasciculata</i>	Giant air plant
<i>T. usneoides</i>	Spanish moss
<i>T. utriculata</i>	Spreading air plant
<i>Triadenum virginicum</i>	Virginia marsh St. John's-wort
<i>Viola affinis</i>	Violet
<i>V. lanceolata</i>	Long-leaf violet
<i>V. septemloba</i>	Southern coastal violet
<i>Woodwardia areolata</i>	Net-veined chain fern

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Plants (Continued)	
<i>W. virginica</i>	Virginia chain fern
<i>Xyris ambigua</i>	Coast plain yellow-eyed grass
<i>X. brevifolia</i>	Yellow-eyed grass
<i>X. caroliniana</i>	Carolina yellow-eyed grass
<i>X. jupicai</i>	Richard's yellow-eyed grass
Animals	
<i>Didelphis virginiana</i>	Virginia opossum
<i>Cryptotis parva</i>	Least shrew
<i>Scalopus aquaticus</i>	Eastern mole
<i>Pipistrellus subflavus</i>	Eastern pipistrelle
<i>Eptesicus fuscus</i>	Big brown bat
<i>Lasiurus borealis</i>	Red bat
<i>Lasiurus seminolus</i>	Seminole bat
<i>Lasiurus intermedius</i>	Northern yellow bat
<i>Nycticeius humeralis</i>	Evening bat
<i>Plecotus rafinesquii</i>	Rafinesque's big-eared bat
<i>Tadarida brasiliensis</i>	Brazilian free-tailed bat
<i>Dasypus novemcinctus</i>	Nine-banded armadillo
<i>Sylvilagus floridanus</i>	Eastern cottontail
<i>Sylvilagus palustris</i>	Marsh rabbit
<i>Oryzomys palustris</i>	Rice rat
<i>Reithrodontomys humulis</i>	Harvest mouse
<i>Peromyscus polionotus</i>	Old-field mouse
<i>Peromyscus gossypinus</i>	Cotton mouse
<i>Peromyscus nuttalli</i>	Golden mouse
<i>Sigmodon hispidus</i>	Cotton rat
<i>Neotoma floridana</i>	Eastern woodrat
<i>Sciurus carolinensis</i>	Gray squirrel

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Animals (Continued)	
<i>Sciurus niger</i>	Fox squirrel, Sherman's
<i>Glaucomys volans</i>	Southern flying squirrel
<i>Vulpes vulpes</i>	Red fox
<i>Urocyon cinereoargenteus</i>	Gray fox
<i>Procyon lotor</i>	Raccoon
<i>Spilogale putorius</i>	Eastern spotted skunk
<i>Mephitis mephitis</i>	Striped skunk
<i>Lynx rufus</i>	Bobcat
<i>Sus scrofa</i>	Wild hog
<i>Odocoileus virginianus</i>	White-tailed deer
<i>Notophthalmus viridescens</i>	Peninsula newt
<i>Scaphiopus holbrooki</i>	Eastern spadefoot toad
<i>Rana areolata</i>	Crawfish frog
<i>Rana grylio</i>	Pig frog
<i>Rana utricularia</i>	Southern leopard frog
<i>Gastrophryne carolinensis</i>	Eastern narrow-mouth toad
<i>Bufo querecius</i>	Oak toad
<i>Bufo terrestris</i>	Southern toad
<i>Acris gryllus dorsalis</i>	Florida cricket frog
<i>Hyla cinerea cinerea</i>	Green treefrog
<i>Hyla femoralis</i>	Pine woods treefrog
<i>Hyla gratiosa</i>	Barking treefrog
<i>Hyla squirella</i>	Squirrel treefrog
<i>Pseudacris nigrita</i>	Chorus frog
<i>Limnaeodius ocularis</i>	Little grass frog
<i>Terrapene carolina bauri</i>	Florida box turtle
<i>Gopherus polyphemus</i>	Gopher tortoise
<i>Anolis sagrei</i>	Brown anole

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Animals (Continued)	
<i>Anolis carolinensis</i>	Green anole
<i>Sceloporus undulatus</i>	Fence lizard
<i>Sceloporus woodi</i>	Florida scrub lizard
<i>Leiolopisma laterale</i>	Ground skink
<i>Eumeces inexpectatus</i>	Southeastern five-lined skink
<i>Cnemidophorus sexlineatus</i>	Six-lined racerunner
<i>Ophisaurus ventralis</i>	Eastern glass lizard
<i>Ophisaurus longicauda</i>	Slender glass lizard
<i>Nerodia sipedon</i>	Banded water snake
<i>Virginia stripula</i>	Rough earth snake
<i>Storeria occipitomaculata</i>	Red-bellied snake
<i>Storeria dekayi</i>	Brown snake
<i>Heterodon platyrhinos</i>	Eastern hognose snake
<i>Heterodon simus</i>	Southern hognose snake
<i>Diadophis punctatus</i>	Ringneck snake
<i>Farancia abacura</i>	Mud snake
<i>Coluber constrictor</i>	Black racer
<i>Pituophis melanoleucus</i>	Pine snake
<i>Masticophis flagellum</i>	Eastern coachwhip
<i>Opheodrys aestivus</i>	Rough green snake
<i>Elaphe obsoleta</i>	Rat snake
<i>Drymarchon corais couperi</i>	Indigo snake
<i>Lampropeltis elapsoides</i>	Scarlet kingsnake
<i>Lampropeltis getulus getulus</i>	Eastern kingsnake
<i>Cemophora coccinea</i>	Scarlet snake
<i>Tantilla relicta relicta</i>	Peninsula crowned snake
<i>Micrurus fulvius</i>	Eastern coral snake
<i>Agkistrodon piscivorus conanti</i>	Florida cottonmouth

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Animals (Continued)	
<i>Sistrurus miliarius barbouri</i>	Dusky pigmy rattlesnake
<i>Crotalus adamanteus</i>	Eastern diamondback rattlesnake
<i>Bubulcus ibis</i>	Cattle egret
<i>Cathartes aura</i>	Turkey vulture
<i>Coragyps atratus</i>	Black vulture
<i>Haliaeetus leucocephalus</i>	Bald Eagle
<i>Accipiter striatus</i>	Sharp-shinned hawk
<i>Buteo jamaicensis</i>	Red-tailed hawk
<i>Buteo lineatus</i>	Red-shouldered hawk
<i>Circus cyaneus</i>	Marsh hawk
<i>Pandion haliaetus</i>	Osprey
<i>Falco sparverius</i>	American kestrel
<i>Colinus virginianus</i>	Bobwhite
<i>Charadrius vociferus</i>	Killdeer
<i>Zenaida macroura</i>	Mourning dove
<i>Columbina passerina</i>	Ground dove
<i>Caprimulgus carolinensis</i>	Chuck-will's widow
<i>Chordeiles minor</i>	Common nighthawk
<i>Colaptes auratus</i>	Common flicker
<i>Dryocopus pileatus</i>	Pileated woodpecker
<i>Centurus carolinus</i>	Red-bellied woodpecker
<i>Melanerpes erythrocephalus</i>	Red-headed woodpecker
<i>Sphyrapicus varius</i>	Yellow-bellied sapsucker
<i>Picoides villous</i>	Hairy woodpecker
<i>Picoides pubescens</i>	Downy woodpecker
<i>Picoides borealis</i>	Red-cockaded woodpecker
<i>Tyrannus tyrannus</i>	Eastern kingbird
<i>Myiarchus crinitus</i>	Great crested flycatcher

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

<i>Scientific Name</i>	Common Name
Animals (Continued)	
<i>Sayornis phoebe</i>	Eastern phoebe
<i>Iridoprocne bicolor</i>	Tree swallow
<i>Cyanocitta cristata</i>	Blue jay
<i>Corvus brachyrhynchos</i>	Common crow
<i>Corvus ossifragus</i>	Fish crow
<i>Parus carolinensis</i>	Carolina chickadee
<i>Parus bicolor</i>	Tufted titmouse
<i>Sitta pusilla</i>	Brown-headed nuthatch
<i>Regulus calendula</i>	Ruby-crowned kinglet
<i>Troglodytes aedon</i>	House wren
<i>Thryothorus ludovicianus</i>	Carolina wren
<i>Mimus polyglottos</i>	Mockingbird
<i>Dumetella carolinensis</i>	Gray catbird
<i>Turdus migratorius</i>	American robin
<i>Sialia sialis</i>	Eastern bluebird
<i>Poliophtila caerulea</i>	Blue-gray gnatcatcher
<i>Lanius ludovicianus</i>	Loggerhead shrike
<i>Vireo griseus</i>	White-eyed vireo
<i>Dendroica coronata</i>	Yellow-rumped warbler
<i>Dendroica pinus</i>	Pine warbler
<i>Dendroica discolor</i>	Prairie warbler
<i>Dendroica palmarum</i>	Palm warbler
<i>Geothlypis trichas</i>	Common yellowthroat
<i>Sturnella magna</i>	Eastern meadowlark
<i>Agelaius phoeniceus</i>	Red-winged blackbird
<i>Quiscalus major</i>	Boat-tailed grackle
<i>Quiscalus quiscula</i>	Common grackle
<i>Piranga rubra</i>	Summer tanager

Table 2.3-9 (Continued)
Plants and Animals Observed Onsite

Scientific Name	Common Name
Animals (Continued)	
<i>Cardinalis cardinalis</i>	Cardinal
<i>Carduelis tristis</i>	American goldfinch
<i>Pipilo erythrophthalmus</i>	Rufous-sided towhee
<i>Passerculus sandvicensis</i>	Savannah sparrow
<i>Aimophila aestivalis</i>	Bachman's sparrow
<i>Aphelocoma coerulescens</i>	Florida scrub jay
<i>Toxostoma rufum</i>	Brown thrasher
<i>Accipiter cooperii</i>	Cooper's hawk
<i>Meleagris gallopavo</i>	Turkey
<i>Philohela minor</i>	American woodcock
<i>Coccyzus americanus</i>	Yellow-billed cuckoo
<i>Otus asio</i>	Screech owl
<i>Bubo virginianus</i>	Great horned owl
<i>Strix varia</i>	Barred owl
<i>Caprimulgus vociferus</i>	Whip-poor-will
<i>Archilochus colubris</i>	Ruby-throated hummingbird
<i>Catharus guttatus</i>	Hermit thrush
<i>Catharus fuscescens</i>	Veery
<i>Vireo flavifrons</i>	Yellow-throat vireo
<i>Vireo solitarius</i>	Solitary vireo
<i>Vireo olivaceus</i>	Red-eyed vireo
<i>Minotilta varia</i>	Black and white warbler
<i>Protonotaria citrea</i>	Prothonotary warbler
<i>Parula americana</i>	Northern parula
<i>Dendroica dominica</i>	Yellow-throated warbler
<i>Setophaga ruticilla</i>	American redstart
<i>Pipilo erythrophthalmus</i>	Rufous-sided towhee
<i>Melospiza georgiana</i>	Swamp sparrow

Table 2.3-10 State/Federally Listed Species On or Near the SEC
Protected Plants
Green Fly Orchid (<i>Encyclia tapensis</i> , Commercially Exploited)
Pine Lilly (<i>Lilium catesbaei</i> , State Threatened)
Cinnamon Fern (<i>Osmunda cinnamomea</i> , Commercially Exploited)
Royal Fern (<i>Osmunda regalis</i> , Commercially Exploited)
Butterwort (<i>Pinguicula lutea</i> , State Threatened)
Snake Mouth Orchid (<i>Pogonia ophioglossoides</i> , State Threatened)
Hooded Pitcher Plant (<i>Sarracenia minor</i> , State Threatened)
Giant Air Plant (<i>Tillandsia fasciculata</i> , State Endangered)
Spreading Air Plant (<i>Tillandsia utriculata</i> , State Endangered)

abundant shrub in the flatwoods. Coastal plain staggerbush (*Lyonia fruticosa*) and fetterbush lyonia (*Lyonia lucida*) are also common. Wiregrass (*Aristida stricta*) dominates the herbaceous layer, but is accompanied by a diverse array of herbaceous species.

Xeric oak scrub is an upland community typically consisting of clumped patches of low growing oaks interspersed with bare areas of white sand. This community occurs on areas of deep, well drained, sterile sands. The dense xeric oak scrub canopy is dominated by myrtle oak (*Quercus myrtifolia*), Chapman's oak (*quercus chapmanii*), sand-live oak (*Quercus geminata*), scrub holly (*Ilex* spp.), scrub hickory (*Carya floridana*), and rosemary (*Ceratiola ericoides*). The understory is dominated by saw palmetto and ground cover is sparse.

Cypress strands are stillwater swamp communities in depressions that are flooded for most of the year. The vegetation is dominated by a canopy of pond cypress (*Taxodium ascendens*), but also includes pond pine (*Pinus serotina*), swamp tupelo (*Nyssa biflora*), and sweetbay magnolia (*Magnolia virginiana*). The understory ranges from dense to somewhat open and includes wax myrtle (*Morella cerifera*), St. John's Wort (*Hypericum fasciculatum*), shiny lyonia (*Lyonia*, spp.), Dahoon holly (*Ilex cassine*), and gallberry (*Ilex glabra*). Characteristic species of the ground cover include beak rush (*Rhynchospora* spp.), moss (*Sphagnum* spp.), sawgrass (*Cladium jamaicense*), bog buttons (*Eriocanlon decangulare*), grape (*Vitis rotundifolia*), greenbrier (*Similax* spp.), and netted-chain fern (*Woodwordia virginica*).

Pond pine strand is a wetland community that is dominated by pond pine which typically occurs on wetter flats with low pH values. The understory is dominated by gallberry and saw palmetto. Ground cover is sparse, except for sphagnum moss, because of the dense shrub and tree canopies.

Bay hardwood strand is a wetland community with flat to slightly sloping topography, which may be inundated for up to 6 months per year. The tree canopy is dominated by sweetbay magnolia and loblolly bay (*Gordonia lasianthus*). The understory and groundcover plants present in the bay strand are similar to those in the cypress strand except for bay species (magnolia, loblolly bay, and red bay) present in the understory of the bay strand.

Oak hardwood strand is a wetland community with flat to slightly sloping topography, which may be inundated for 6 months per year. The canopy is dominated by water oak (*Quercus nigra*). Other trees present include red maple (*Acer rubrum*), cabbage palm (*Sabal palmetto*), sweetbay magnolia, and live oak (*Quercus virginiana*). The understory is dominated by wax myrtle and also includes persimmon (*Dioxyros virginiana*), wax myrtle, and a dense cover of mesic herbaceous species such as broomsedge (*Andropogon virginicus*) and bottlebrush threeawn (*Aristida spiciformis*).

OUC has conducted prescribed burns in 1984 to 1991, 1993, 1996, and 1997 to manage the existing habitats. This management is required by Condition 31 of the Unit 1 Site Certification, which covered both management and monitoring guidelines for the 2,000 acre management area at the SEC.

2.3.6 Ecology

This section identifies endangered, threatened, and other sensitive species that have the potential to occur within 5 miles of SEC which might reasonably be expected to be affected by the construction and operation of Stanton A. Sensitive species include plants and animals listed as endangered or threatened by the USFWS; species listed by the FFWCC 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.

Endangered and threatened animal species were identified from current state listings and federal listings. Table 2.3-11 shows those animal species that may potentially occur in the area and their current (2000) status. Field surveys for endangered, threatened, and other sensitive species were conducted from 1980 to 1981. In addition, vegetation monitoring and red-cockaded woodpecker field surveys are conducted annually as required by the Joint Agency Mitigation and Monitoring Plan for construction of Units 1 and 2. No critical habitat for federally listed species occurs on SEC property. Protected species which are known to occur on SEC property are discussed below.

The eastern indigo snake occurs in peninsular Florida, in a few widely scattered areas of the Georgia Coastal Plain, and in parts of the Florida Panhandle. This snake occupies a wide variety of habitat types. In xeric habitats, the shelter provided by gopher tortoise burrows apparently is a critical factor for the survival of this snake. No indigo snakes were observed on SEC property, although one was sighted within the Stanton to Pershing transmission line corridor.

The gopher tortoise is locally distributed in the Coastal Plain from South Carolina and Florida to eastern Louisiana. In Florida, it may be encountered widely in northern sections with relict, scattered populations occurring in suitable habitats in the south. Preferred habitat consists of old field areas, longleaf pine sandhill, live oak hammock, and beach scrub, usually with abundant herbaceous cover of several types. A few burrows may occur in maintained pastures, mixed swamp, and hydric hammock, but generally these habitats are not utilized. Some important burrow symbionts, which may occur in these same habitats, include the pine snake, indigo snake, Florida mouse, and Florida gopher frog. Other commensals include a large number of invertebrates, eastern diamondback rattlesnake, and various mammals.

Table 2.3-11
State/Federally Listed Species On or Near the SEC

Protected Animals

Eastern Indigo Snake (*Drymarchon corais couperi*, State Threatened, Federally Threatened)

Gopher Tortoise (*Gopherus polyphemus*, State Species of Special Concern)

Pine Snake (*Pituophis melanoleucus*, State Species of Special Concern)

Florida Scrub Jay (*Aphelocoma coerulescens*, State Threatened, Federally Threatened)

Kirtland's Warbler (*Deudroica Kirtlandii*, State Endangered, Federally Endangered)

American Kestrel (*Falco sparverius*, State Threatened)

Bald Eagle (*Haliaeetus leucocephalus*, State Threatened, Federally Threatened)

Red-Cockaded Woodpecker (*Picoides borealis*, State Threatened, Federally Endangered)

Sherman's Fox Squirrel (*Sciurus niger*, State Species of Special Concern)

Florida Black Bear (*Ursus americanus floridanus*, State Threatened)

Populations of gopher tortoise on SEC property are centered mainly on the higher elevation in the western and south-central portion of the property. In these areas, an average of seven active burrows was recorded per mile of survey.

Florida pine snakes typically occur in sandy areas covered by stands of longleaf pine and/or turkey oak. They are known to occur from South Carolina to Alabama and to all but the southern tip of Florida. The Florida pine snake is a constrictor. It digs out pocket gophers with the large vertical plate on its snout and also eats rats, small rabbits, squirrels, birds, and bird eggs. Florida pine snakes have been observed onsite in cypress wetlands and pine flatwoods.

The Florida scrub jay is characteristic of oak scrub communities and is confined mainly to such habitats. Surveys for this bird, conducted in scrub oak communities within SEC boundaries, resulted in an estimate of 4 to 8 family units. Scrub jays were observed in areas adjacent to the Project site.

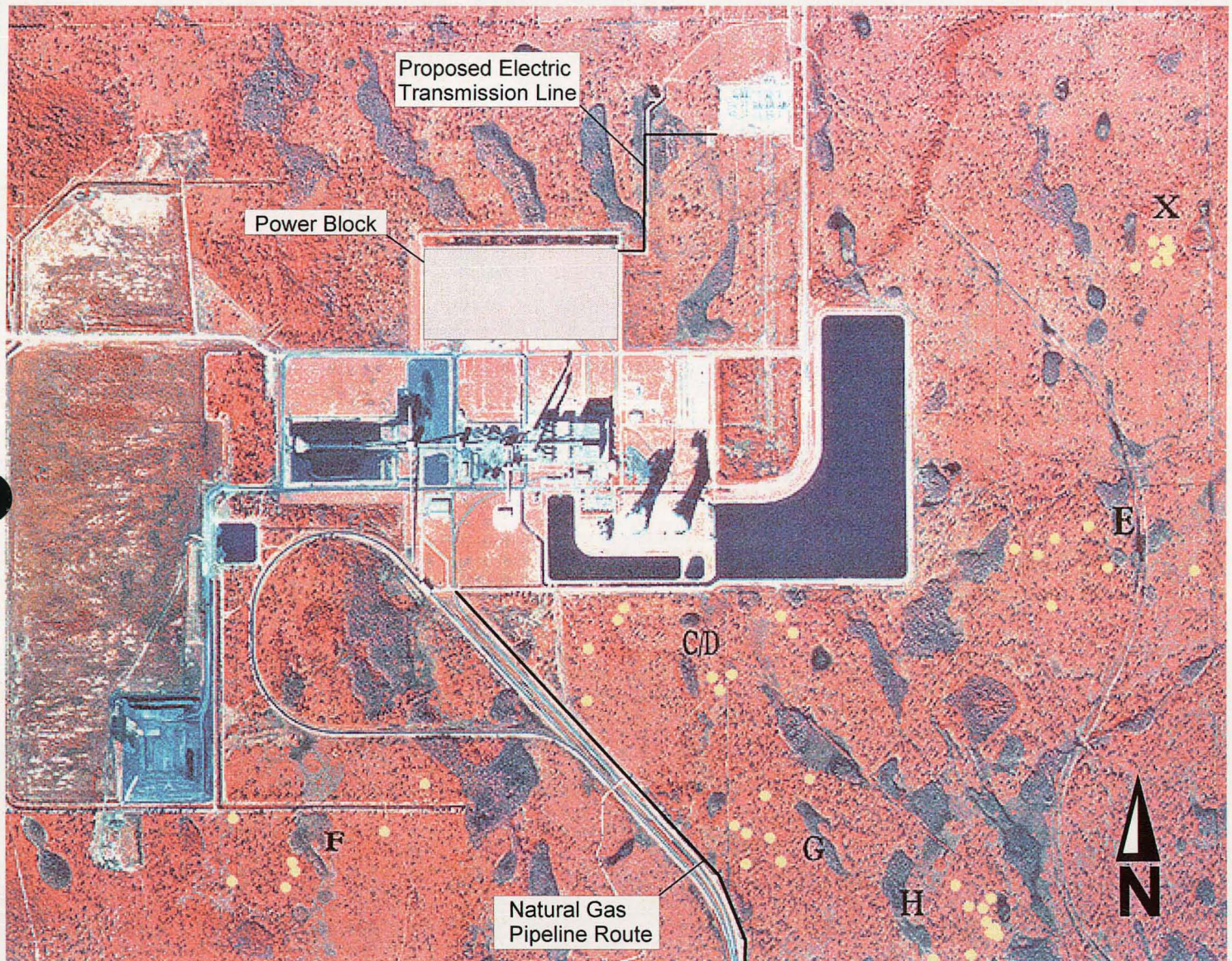
Kirtland's warbler may occur as a rare spring or fall transient throughout the southeastern United States. This warbler apparently breeds only in a restricted area of jack pine forest in southern Michigan (Mayfield, 1960). Winter habitat is confined to pinewoods, broadleafed scrub, and Australian pine. This species may occur occasionally in the area during spring and fall migration.

Kestrels prefer open areas with scattered trees and frequently nest parks, towns, and along rivers. They hunt primarily from an exposed perch such as an overhead line but also hover frequently. American kestrels have been observed onsite in the winter, probably during winter migration.

In the south, bald eagles typically nest estuaries, along large rivers, and around lakes. In Florida, nest sites are usually located in large pines, but also include cypress and mangrove. Bald eagles have been observed east of Project property and along the existing electrical transmission corridors. An eagle nest was discovered in 2000 on the east side of the plant makeup pond, approximately 1 miles from Stanton A.

Red-cockaded woodpeckers are characterized as inhabiting mature, open pine forests. During the 1980 to 1981 study, 19 unreported colonies were located on or in the immediate vicinity of the SEC property. A total of 45 active cavity trees and 35 red-cockaded woodpeckers were observed. Twenty of these active cavity trees occur on SEC property and represent six colonies (refer to Figure 2.3-19). During recent surveys (1999-2000), twenty active cavity trees and six colonies were observed on the SEC property. Group size has increased marginally, but steadily over the past 4 years. Monitoring required by the Conditions of Certification for Units 1 and 2 will also be performed for Stanton A. The woodpecker habitat is currently managed with periodic

Location of Red-Cockaded Woodpecker Clusters and Cavity
Trees (Yellow Spots), Curtis H. Stanton Energy Center, Orlando, Florida, 2000.



Source: Progress Report on Red-Cockaded Woodpeckers for the Curtis H. Stanton Energy Center, 1999; DeLotelle & Guthrie, Inc.

Figure 2.3-19
Red-Cockaded Woodpecker Colony Sites
and Home Ranges on the SEC

prescribed burns. For a more complete discussion of these and other parameters concerning the red-cockaded woodpecker, copies of the *Joint Agency Mitigation Monitoring Plan* for the SEC and the *Progress Report on Red-Cockaded Woodpeckers for the Curtis H. Stanton Energy Center, 1999* can be provided upon request.

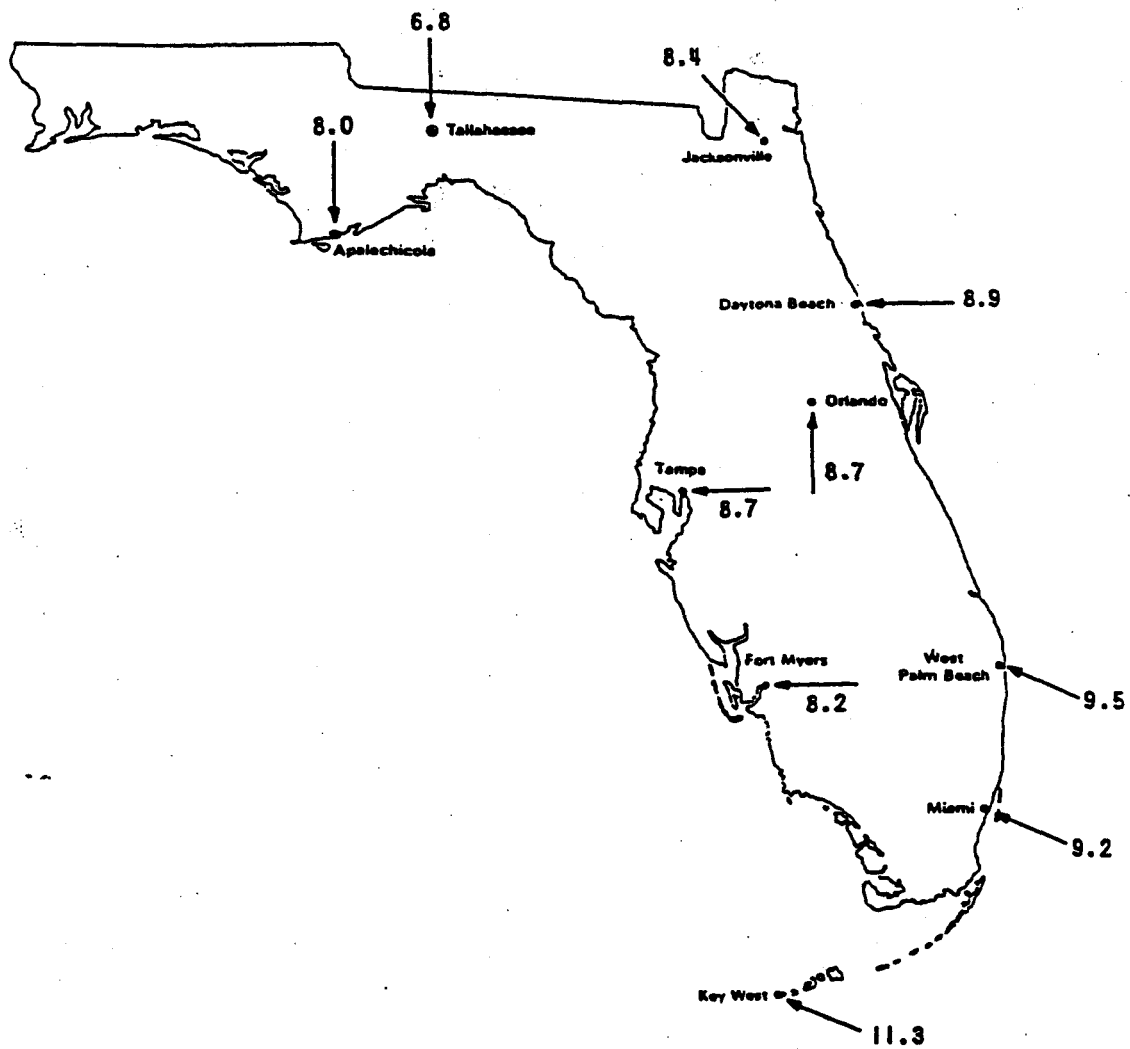
The range of the Sherman's fox squirrel is limited to peninsular Florida and, perhaps, southeastern Georgia. Longleaf pine/turkey oak forests seem to be the most frequently used habitat, but sand, scrub, bayheads, pine flatwoods, and borders of cypress swamps are also used. Although optimum habitat is not found onsite, fox squirrels do inhabit some pine flatwoods and various flatwood-wetland ecotones. Too few fox squirrels were sighted to estimate population levels, but two were sighted along the transmission line and four were observed on SEC property; two in pine flatwoods and two in cypress domes.

Originally, the Florida black bear ranged throughout Florida. Current populations are mainly centered in Apalachicola, Osceola, and Ocala National Forests, with remnant populations occurring in various parts of the state. According to Hamilton (1943) in *Mammals of the Eastern United States*, secluded swamps and forests are areas of preferred habitation for bears. Major areas of occupied habitat within the region are located to the east along the St. Johns River and to the north along the Wekiva River. No Florida black bears or bear tracks were observed in the SEC area. The habitat in this area does not appear suitable.

2.3.7 Meteorology and Ambient Air Quality

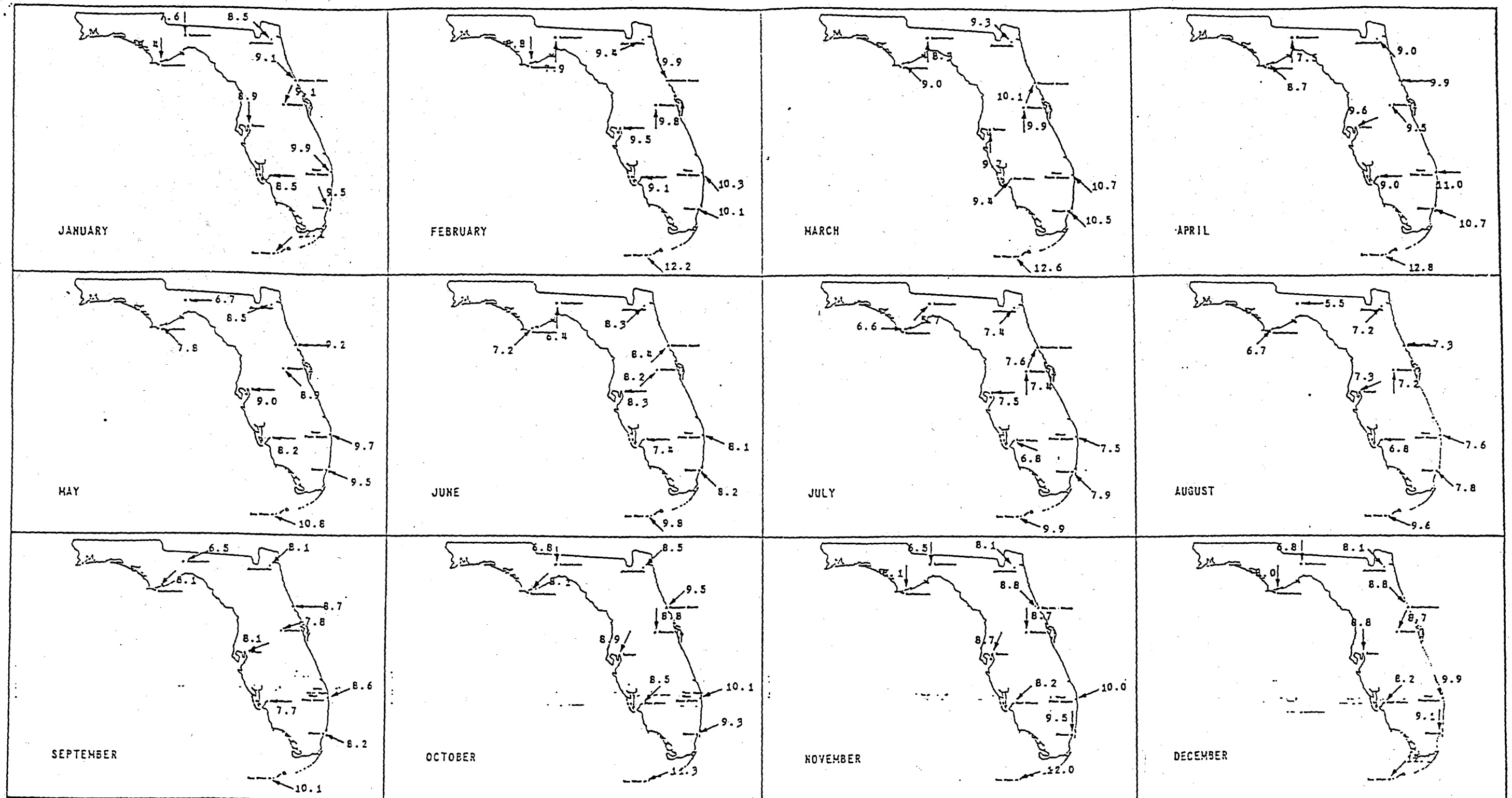
2.3.7.1 Regional Climatology/Meteorology. The prevailing subtropical marine climate of the central Florida region results from the influence of the Atlantic Ocean and the Bermuda high-pressure system. Long, warm, humid summers and short, mild winters prevail. Because of the southerly location and marine influences, this area has a climate characterized by relatively 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 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 2.3-20 and 2.3-21, 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).



**NOTE: NUMBERS GIVEN ARE SCALAR AVERAGE
WIND SPEED IN MILES PER HOUR.
ARROWS FLY WITH WIND.**

Figure 2.3-21
Annual Average Wind Speed and Prevailing
Direction for Selected Florida Cities



NOTE: NUMBERS GIVEN ARE SCALAR AVERAGE WIND SPEED IN MILES PER HOUR. ARROWS FLY WITH WIND.

Figure 2.3-20
Monthly Average Wind Speed and Prevailing Direction for Selected Florida Cities

The average annual rainfall in this region is approximately 50 inches. Summer precipitation resulting from frequent afternoon thundershowers typically exceeds winter precipitation resulting from frontal systems, prefrontal 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 SEC 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 ocean influencing and 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.

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 SEC is located in central Florida about 25 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 SEC. However, there is a location with meteorological data covering long periods of record which are considered representative of the SEC area. This location is the National Weather Service (NWS) office in Orlando, Florida. The NWS office is approximately 10 miles west of the SEC at an elevation of 96 feet above mean sea level. Meteorological data from this location have been summarized in the following paragraphs.

Temperatures and Humidity

The temperature variation from season to season is slight, with warm, humid summers and mild winters. Table 2.3-12 presents a summary of the means and extremes of monthly and daily dry-bulb temperatures. Temperatures above 90° F occur during the

Table 2.3-12
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	101
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	101
Fall	74.7	65.2	84.3	29	98
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-1998, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1999.

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.

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. 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. The absolute temperature range is from 102° F (May) to 19° F (January).

Table 2.3-13 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 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 2.3-13 also includes other design temperatures for percentages of 2.5, 10, 97.5, and 99.

Average relative humidities are presented in Table 2.3-14 (US Department of Commerce, 1997). The table shows that the average annual relative humidity is approximately 74 percent. Average hourly 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 2.3-15 gives mean monthly and annual degree-day totals considered representative of the SEC area.

Precipitation

Normal monthly and annual precipitation (rain) totals are shown in Table 2.3-16. As shown in the table, precipitation is highest during the summer months. Annually, thunderstorms occur during 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 2 inches have been recorded only a few times in the last century. Only a trace of snowfall was recorded during the period

Table 2.3-13
Wet-Bulb and Dry-Bulb Design Temperatures
for Orlando, Florida

Percent of Time	Temperatures	
	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.

Table 2.3-14
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--1998, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1999.

Table 2.3-15
Heating and Cooling Degree-Day Data
for Orlando, Florida*

Month	Normal Degree-Day	
	Heating**	Cooling**
January	234	70
February	164	58
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--1998, Orlando, Florida, National Climatic Data Center, Asheville, North Carolina, 1999.

Table 2.3-16
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--1998, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1999.

1973 through 1998. Extreme monthly precipitation totals are listed in Table 2.3-17. 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 2.3-18. Precipitation maximums and intensities for various return periods and durations are shown in Table 2.3-19.

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 2.3-22 through 2.3-34. These wind roses are considered appropriate for describing the general wind flow at the SEC. Table 2.3-20 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 SEC 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. Dispersion 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 2.3-20 presents values of seasonal and annual morning and afternoon mixing depths and wind speeds representative of the SEC area.

Table 2.3-17
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	8.74	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	Trace	Trace
June	8.40	18.28	1.58	--	--
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	12.63	Trace	--	--
Annual	9.67	19.57	Trace	Trace	Trace

*Period of record: 1943-1998.

Source: United States Department of Commerce, Local Climatological Data--Annual Summary with Comparative Data--1998, Orlando, Florida, National Climatic Center, Asheville, North Carolina, 1999.

Table 2.3-18
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 2.3-19
Precipitation Amounts and Intensities for
Selected Durations and Return Periods
Expected in the Stanton Energy Center Area

Precipitation Amounts (Inches)

Duration (hours)	Return Period						
	1 Year	2 Year	5 Year	10 Year	25 Year	50 Year	100 Year
1/2	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

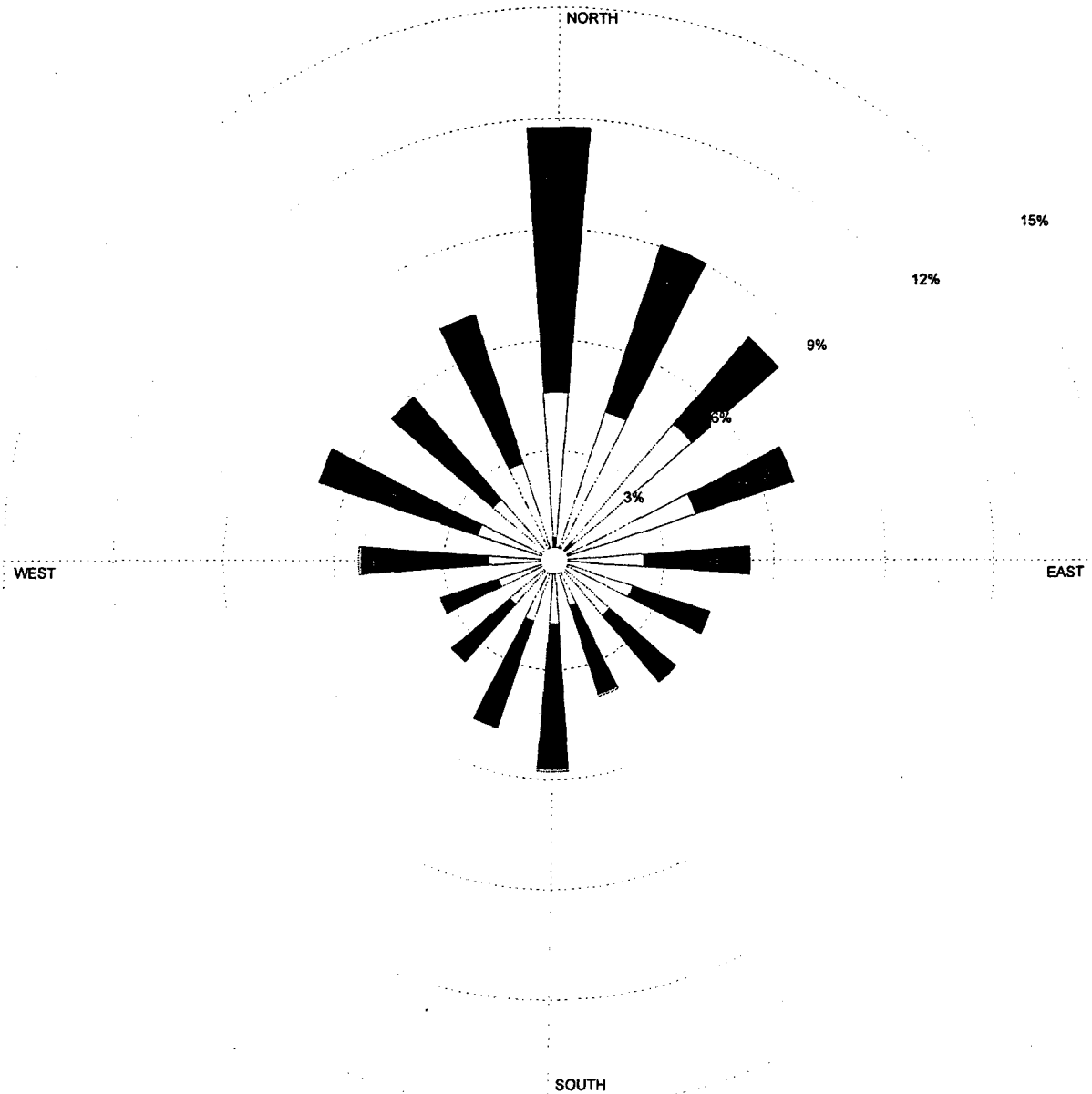
Precipitation Intensities (inches/h)

Duration (hours)	Return Period						
	1 Year	2 Year	5 Year	10 Year	25 Year	50 Year	100 Year
1/2	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, Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24 Hours and Return Periods from 1 to 100 Years, Technical Paper No. 40, Washington, D. C., May 1961.

WIND ROSE PLOT

January Wind Rose for Orlando, Florida

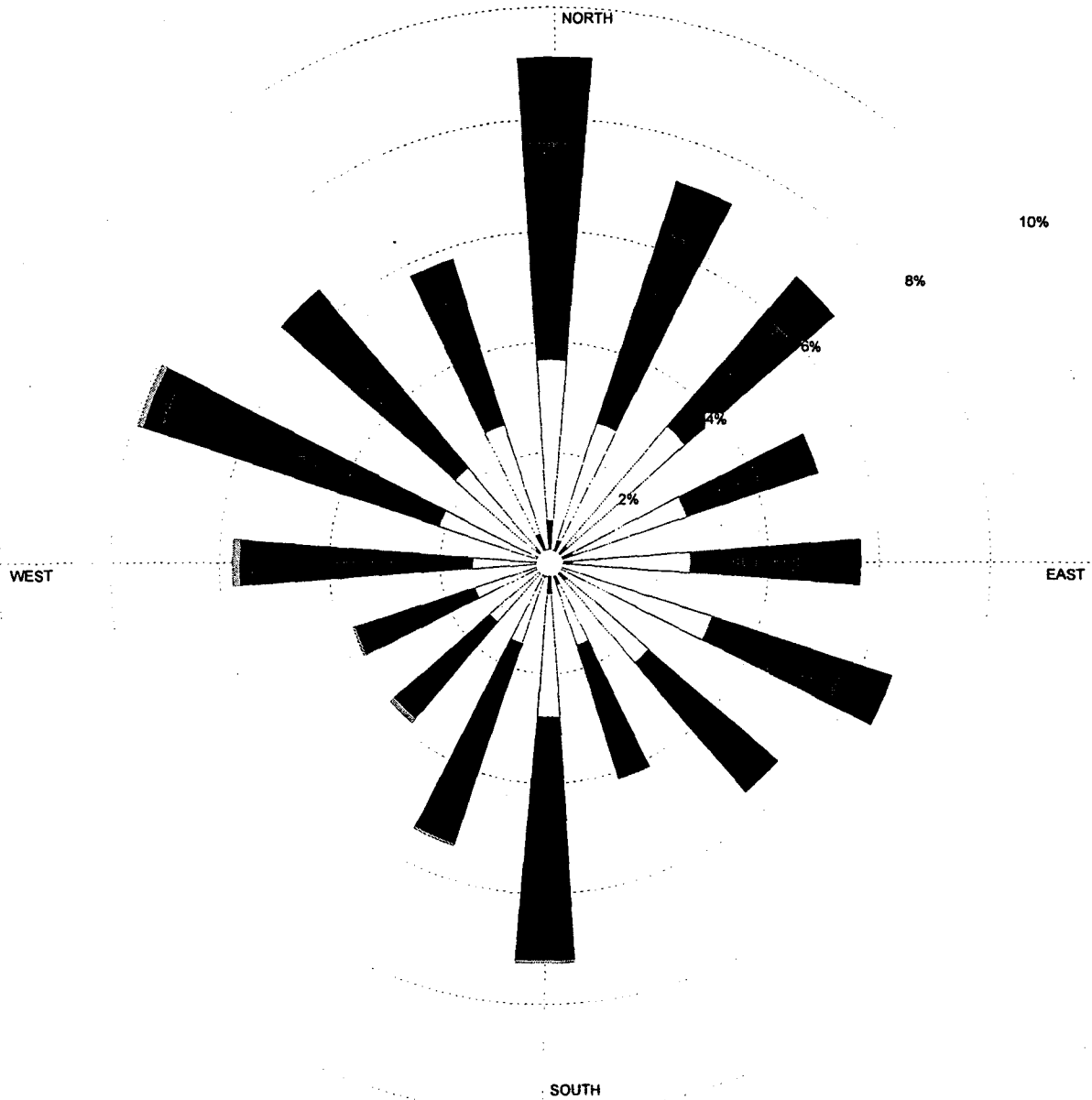


Wind Speed (Knots)	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 7.82 Knots	CALM WINDS 2.72%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 January 1 - January 31 Midnight - 11 PM	

Figure 2.3-22
January Wind Rose for Orlando, Florida
Period of Record: 1988-1992

WIND ROSE PLOT

February Wind Rose for Orlando, Florida

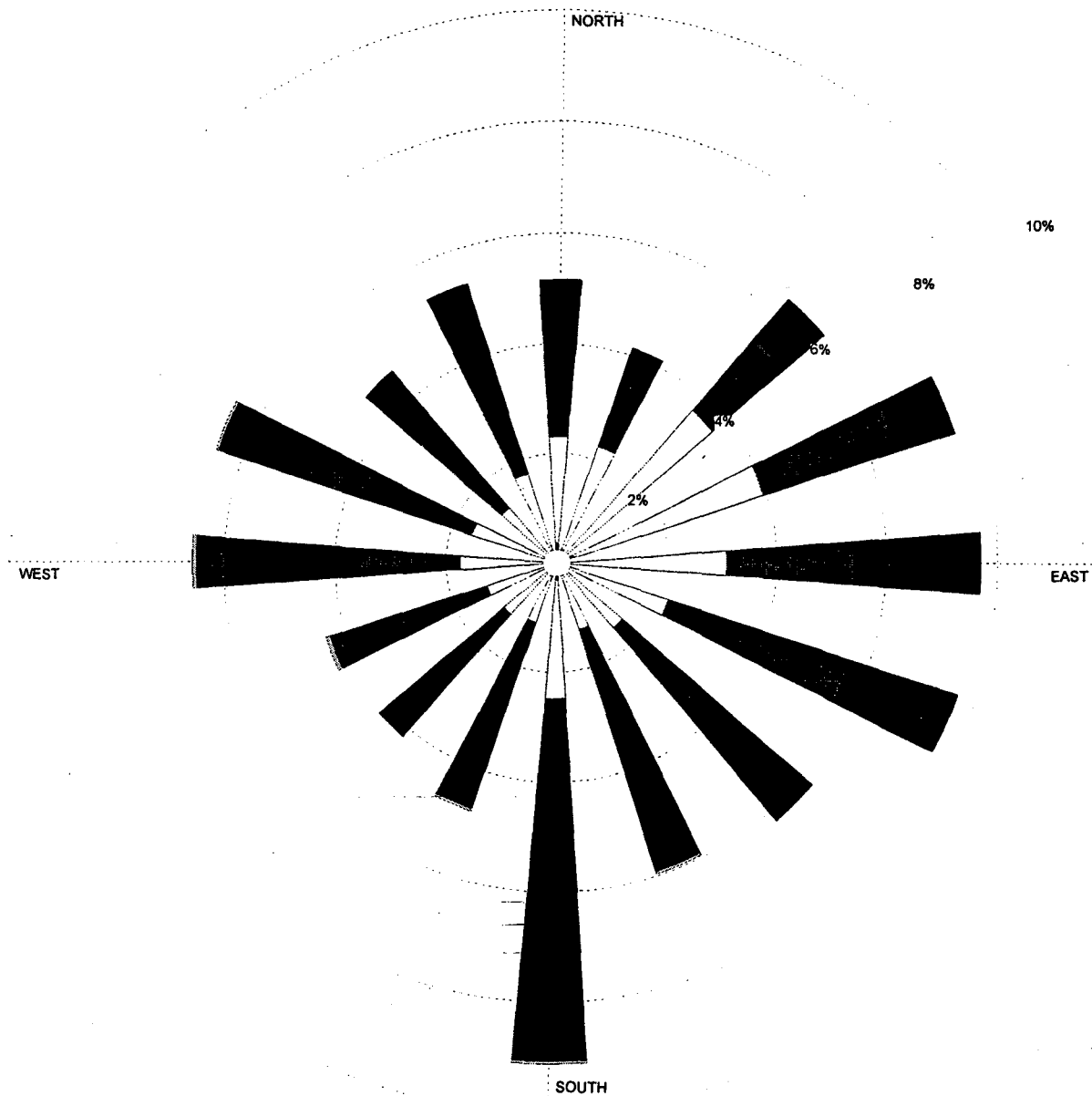


Wind Speed (Knots)	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 8.19 Knots	CALM WINDS 3.04%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 February 1 - February 28 Midnight - 11 PM	

Figure 2.3-23
February Wind Rose for Orlando, Florida
Period of Record: 1988-1992

WIND ROSE PLOT

March Wind Rose for Orlando, Florida

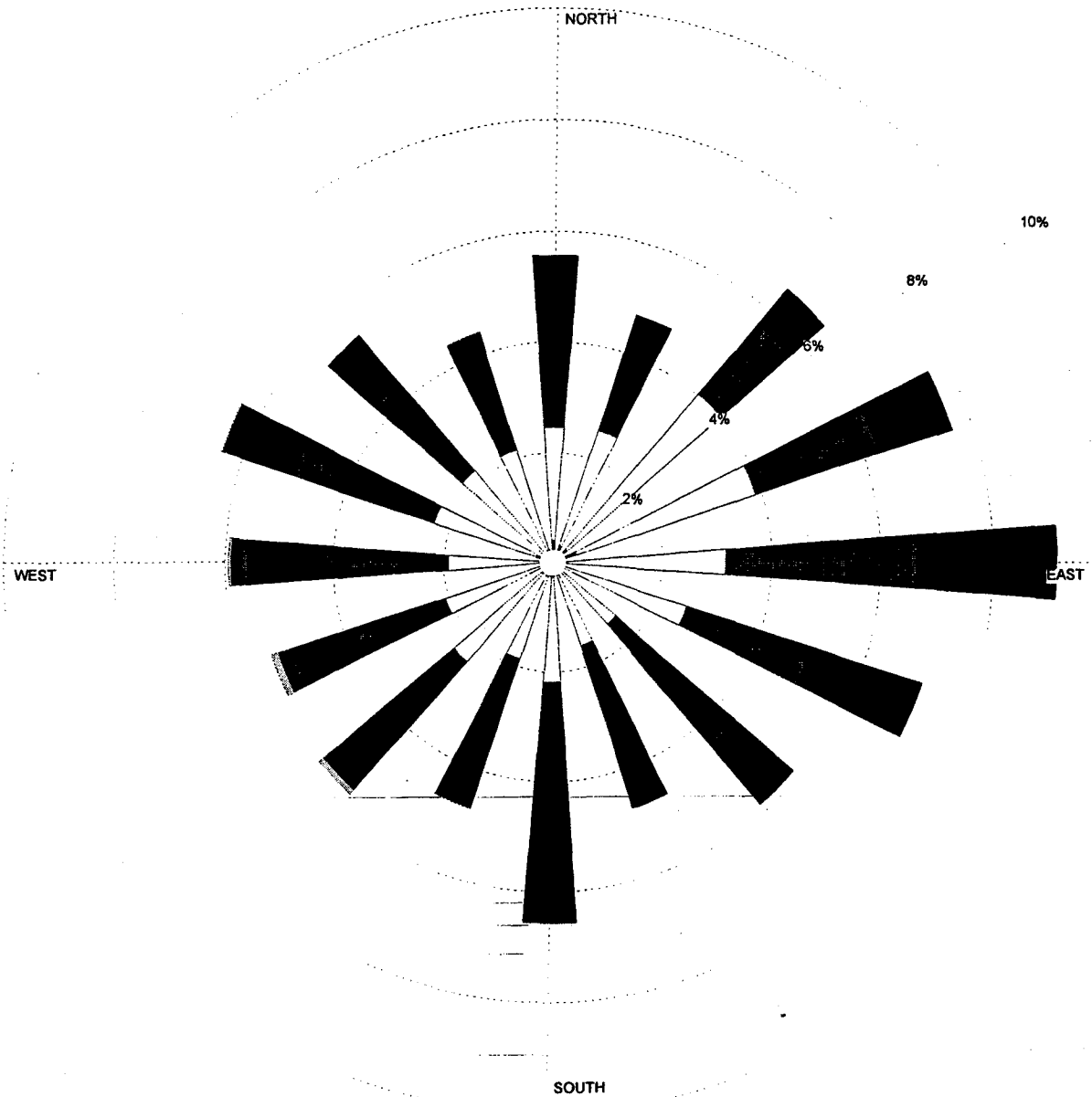


Wind Speed (Knots)	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 8.64 Knots	CALM WINDS 3.28%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 March 1 - March 31 Midnight - 11 PM	Figure 2.3-24 March Wind Rose for Orlando, Florida Period of Record: 1988-1992

WRPLOT View 2.22 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

April Wind Rose for Orlando, Florida

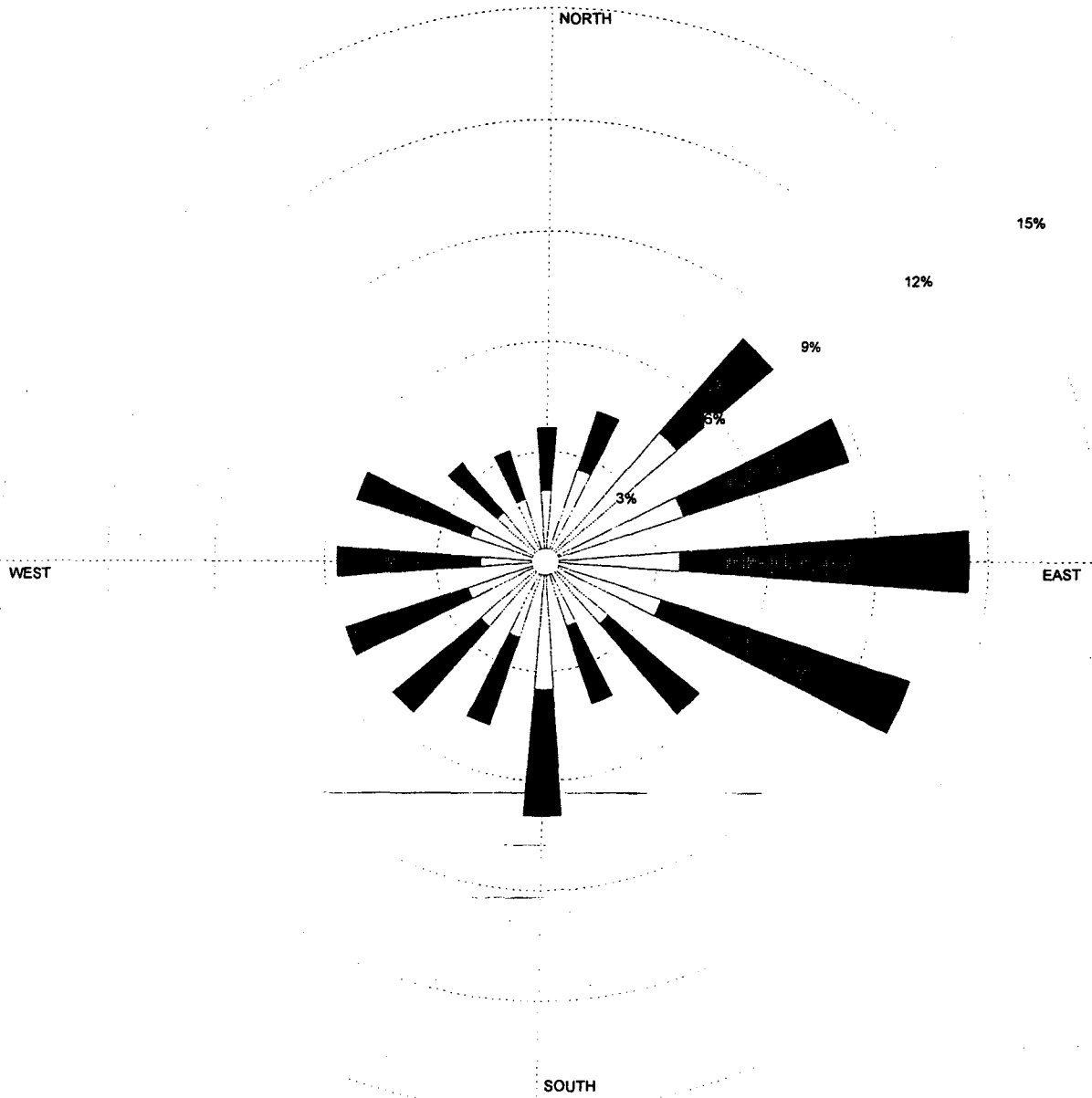


Wind Speed (Knots)  > 21 17 - 21 11 - 16 7 - 10 4 - 6 1 - 3	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 8.00 Knots	CALM WINDS 3.69%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 April 1 - April 30 Midnight - 11 PM	Figure 2.3-25 April Wind Rose for Orlando, Florida Period of Record: 1988-1992

WRPLOT View 2.22 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

May Wind Rose for Orlando, Florida

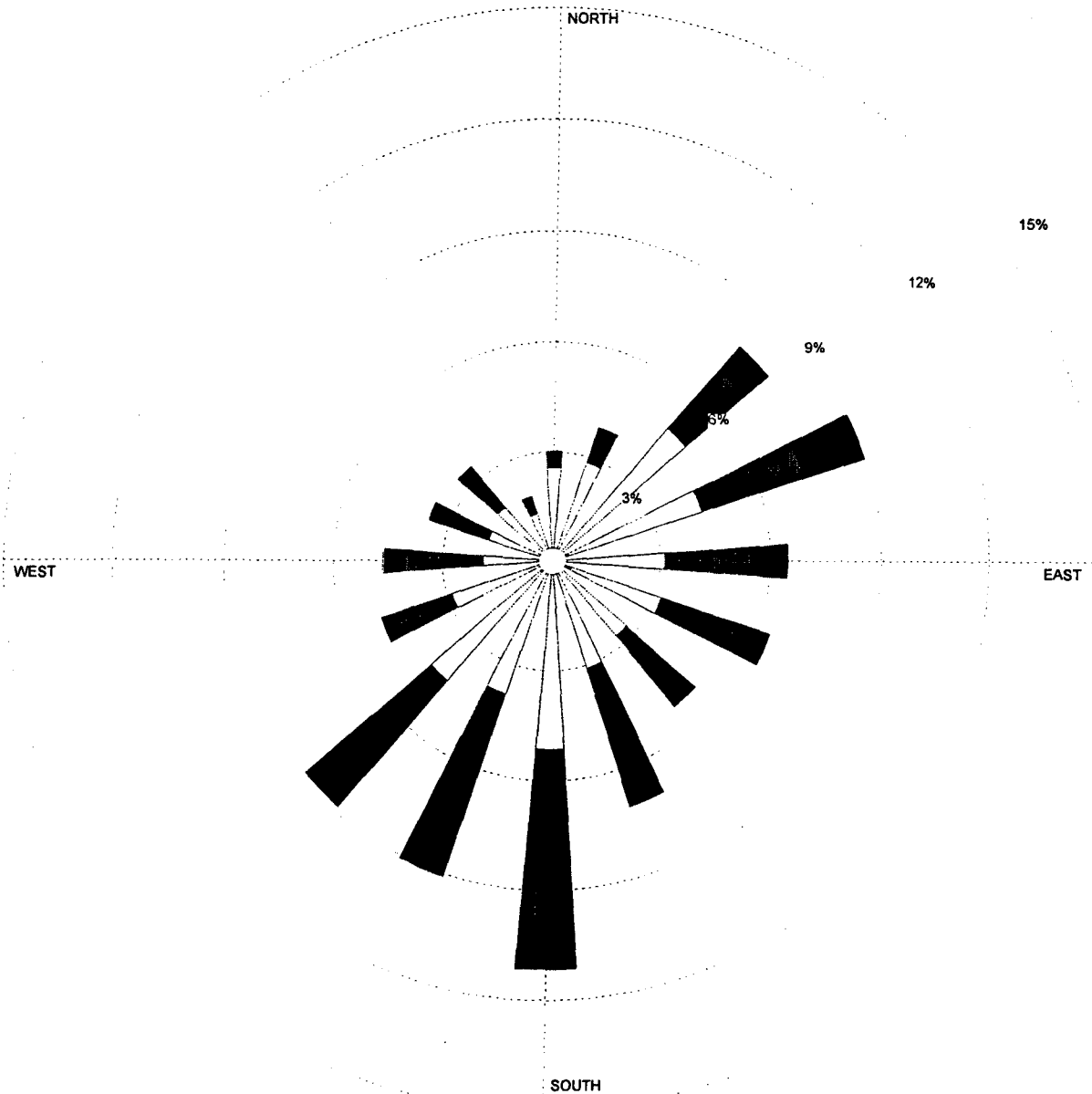


Wind Speed (Knots)	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 7.79 Knots	CALM WINDS 2.47%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 May 1 - May 31 Midnight - 11 PM	Figure 2.3-26 May Wind Rose for Orlando, Florida Period: 1988-1992

WRPLOT View 2.22 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

June Wind Rose for Orlando, Florida

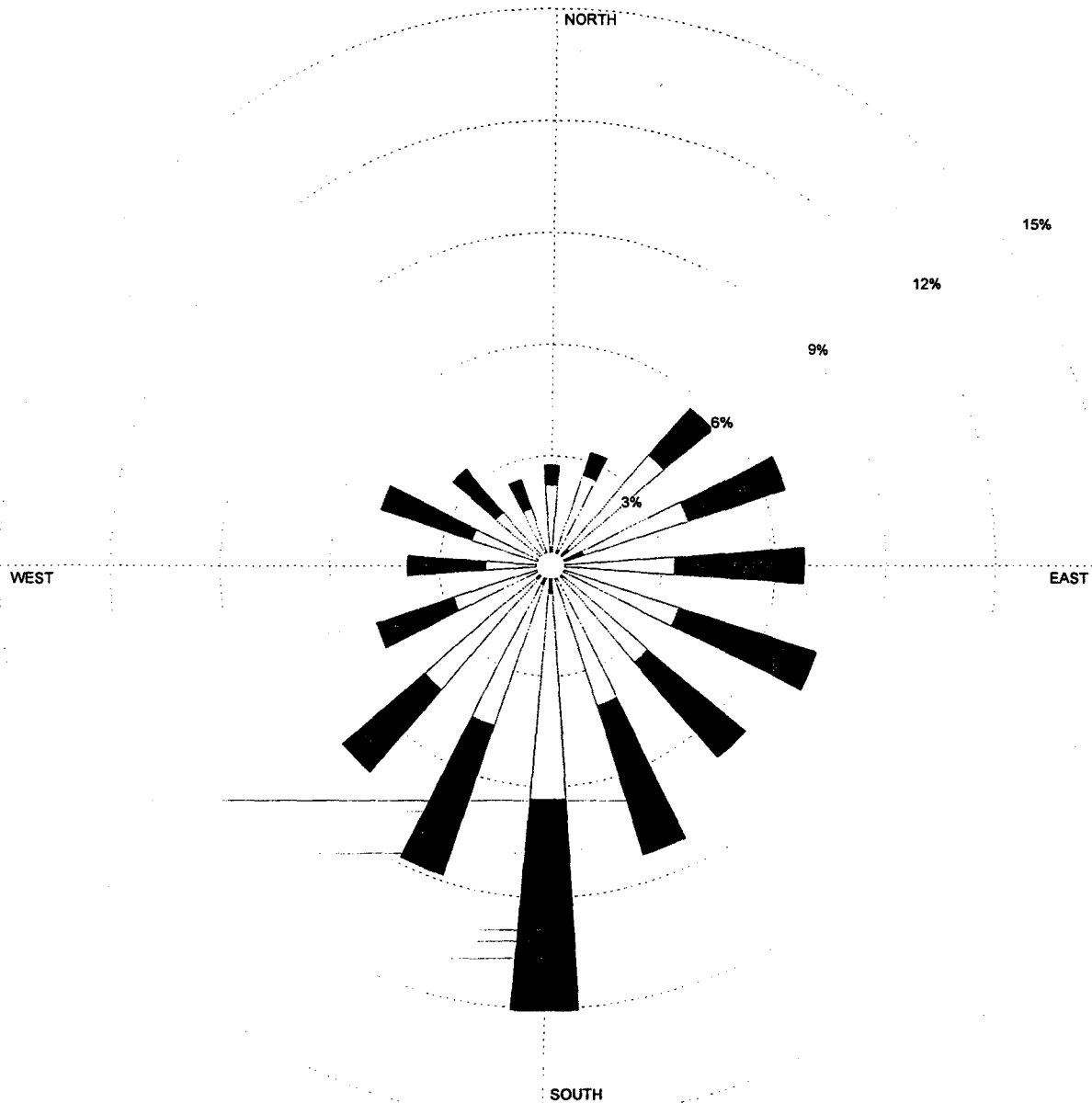


Wind Speed (Knots)	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 7.10 Knots	CALM WINDS 3.00%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 June 1 - June 30 Midnight - 11 PM	Figure 2.3-27 June Wind Rose for Orlando, Florida Period: 1988-1992

WRPLOT View 2.22 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

July Wind Rose for Orlando, Florida

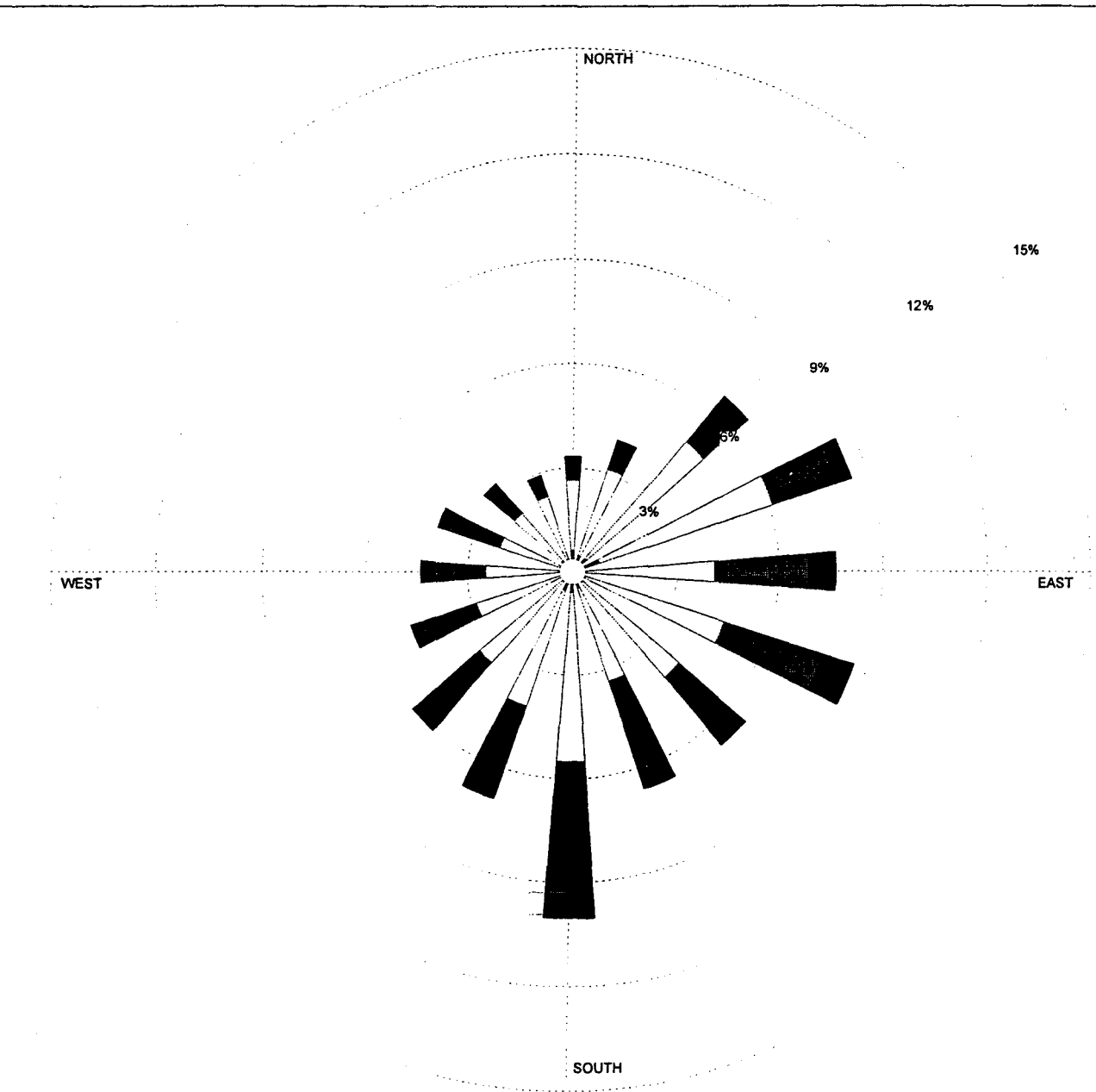


Wind Speed (Knots) > 21 17 - 21 11 - 16 7 - 10 4 - 6 1 - 3	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 6.74 Knots	CALM WINDS 3.55%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 July 1 - July 31 Midnight - 11 PM	

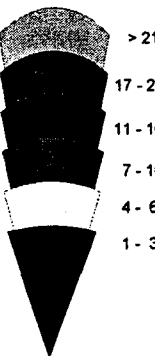
Figure 2.3-28
July Wind Rose for Orlando, Florida
Period: 1988-1992

WIND ROSE PLOT

August Wind Rose for Orlando, Florida



Wind Speed (Knots)



MODELER

Makens, Matthew P.

DATE

6/12/2000

COMPANY NAME

Black & Veatch

DISPLAY

Wind Speed

UNIT

Knots

AVG. WIND SPEED

6.40 Knots

CALM WINDS

4.38%

ORIENTATION

**Direction
(blowing from)**

PLOT YEAR-DATE-TIME

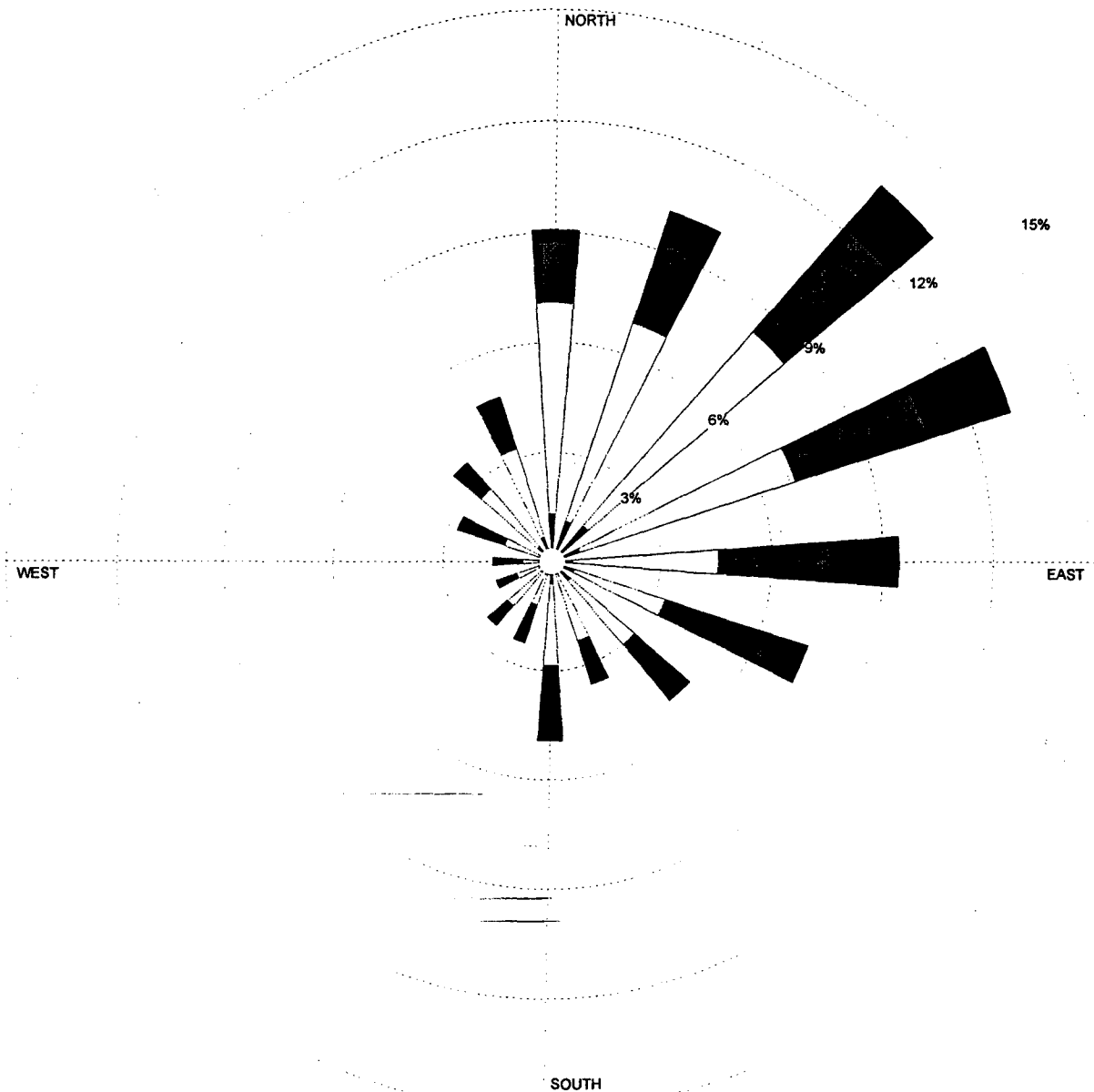
**88 89 90 91 92
August 1 - August 31
Midnight - 11 PM**

COMMENTS

**Figure 2.3-29
August Wind Rose for Orlando, Florida
Period: 1988-1992**

WIND ROSE PLOT

September Wind Rose for Orlando, Florida

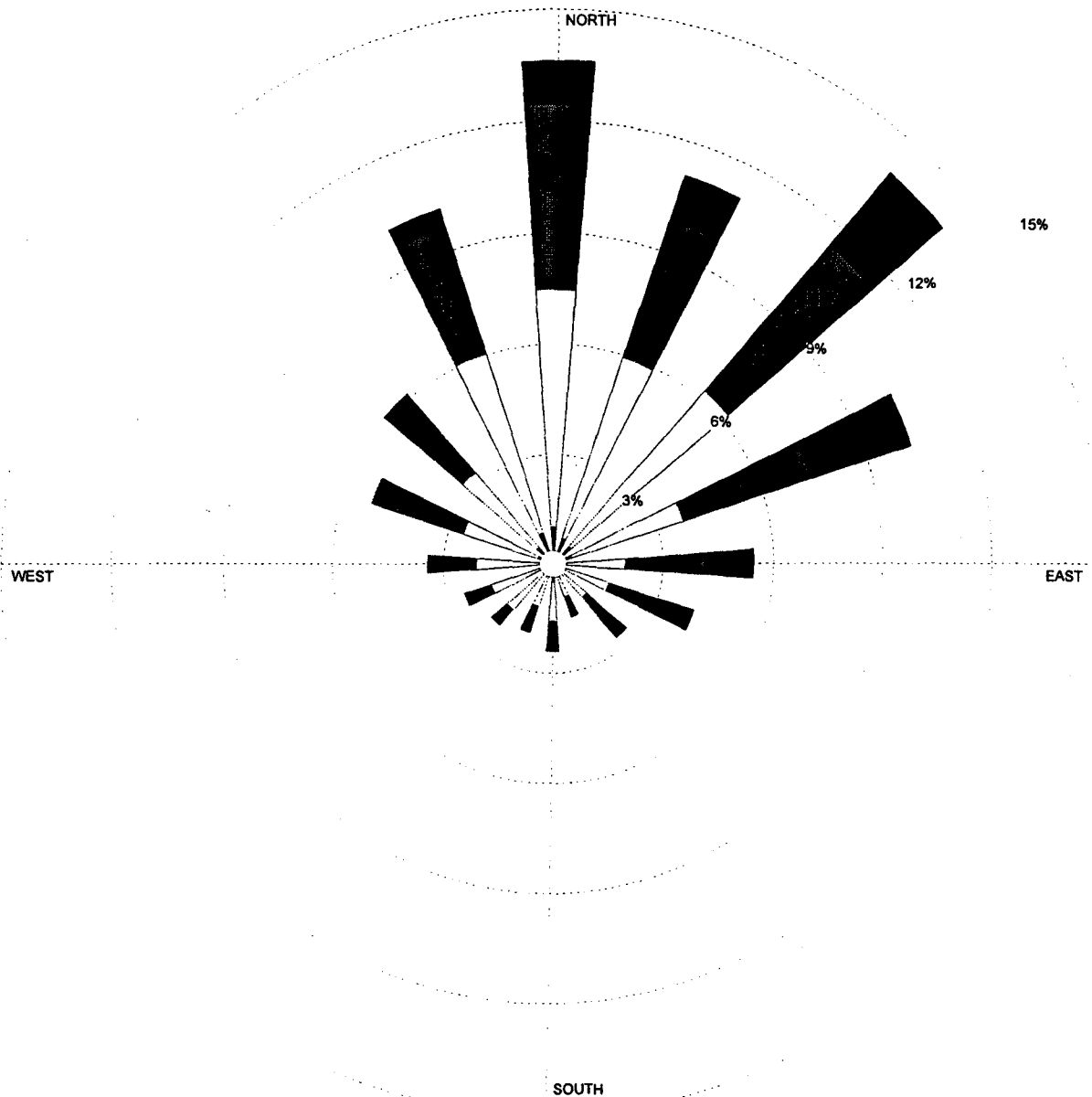


Wind Speed (Knots) > 21 17 - 21 11 - 16 7 - 10 4 - 6 1 - 3	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 6.55 Knots	CALM WINDS 4.17%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 September 1 - September Midnight - 11 PM	

Figure 2.3-30
September Wind Rose for Orlando, Florida
Period: 1988-1992

WIND ROSE PLOT

October Wind Rose for Orlando, Florida

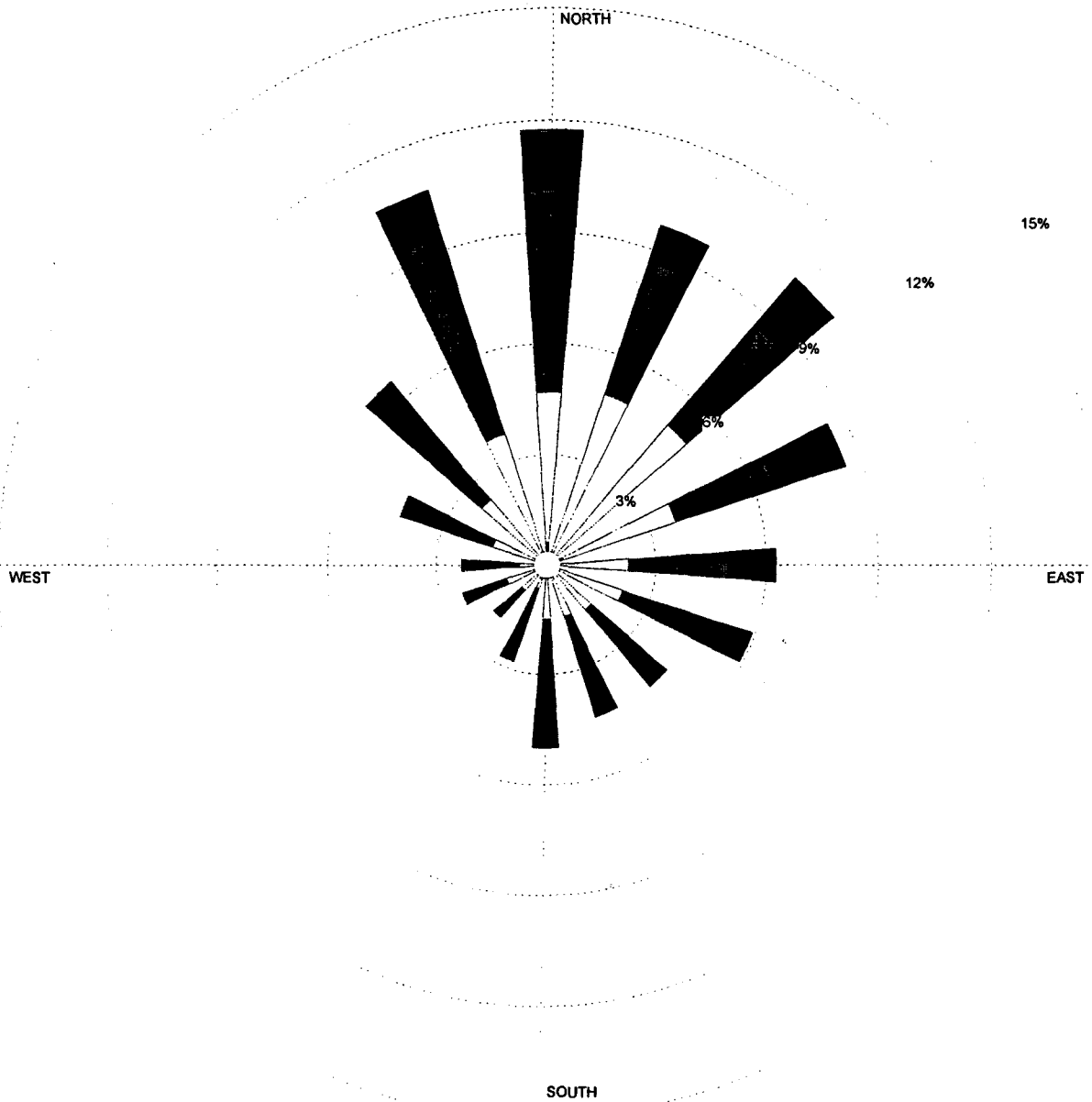


Wind Speed (Knots) > 21 17 - 21 11 - 16 7 - 10 4 - 6 1 - 3	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 7.12 Knots	CALM WINDS 2.47%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 October 1 - October 31 Midnight - 11 PM	Figure 2.3-31 October Wind Rose for Orlando, Florida Period: 1988-1992

WRPLOT View 2.22 by Lakes Environmental Software - www.lakes-environmental.com

WIND ROSE PLOT

November Wind Rose for Orlando, Florida



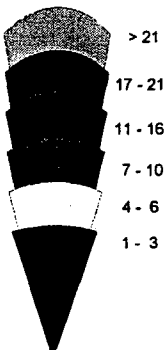
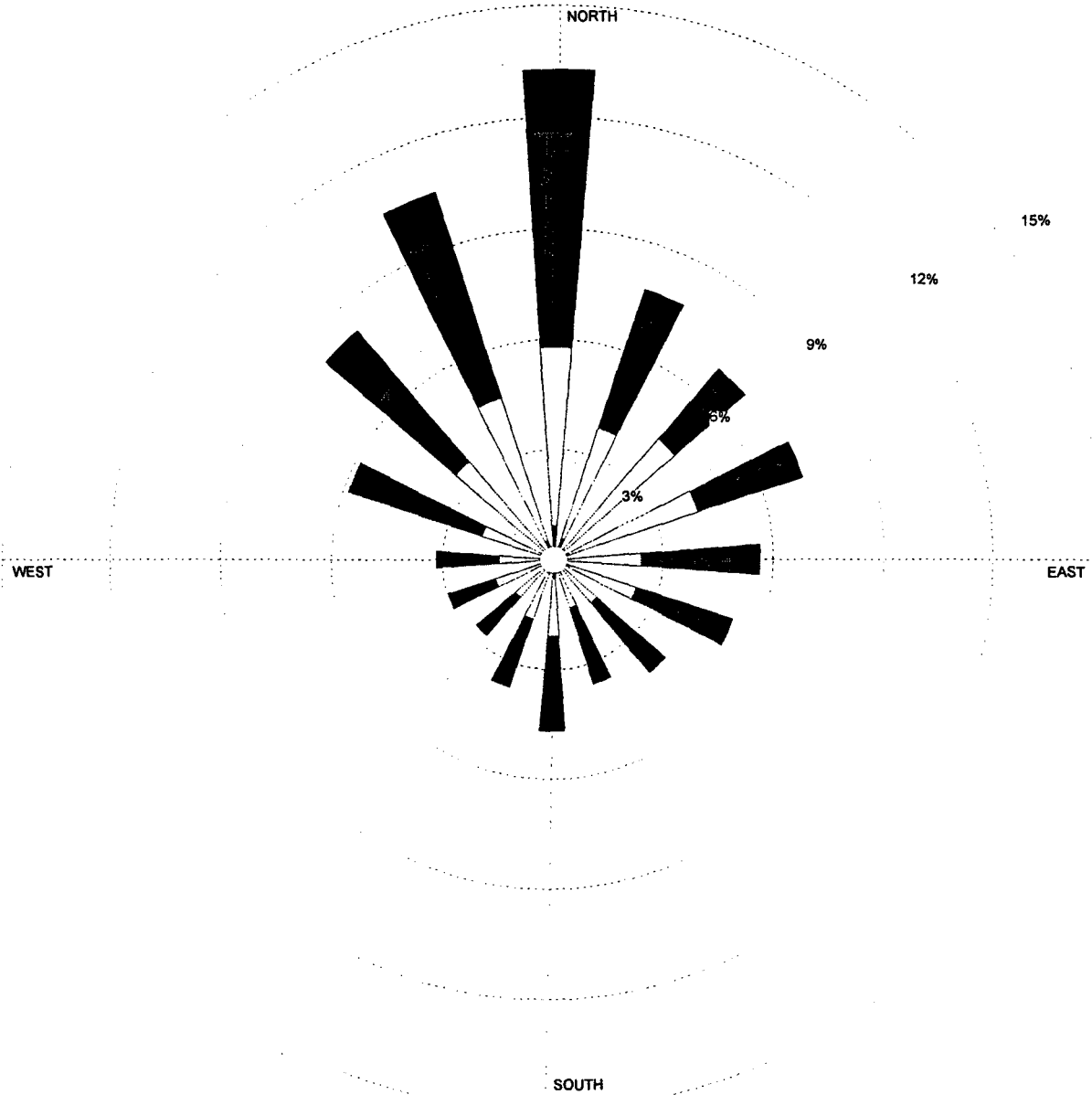
Wind Speed (Knots)  > 21 17 - 21 11 - 16 7 - 10 4 - 6 1 - 3	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 7.87 Knots	CALM WINDS 2.19%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 November 1 - November 30 Midnight - 11 PM	

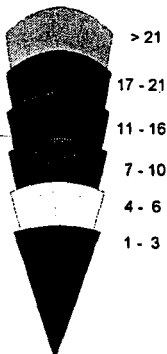
Figure 2.3-32
November Wind Rose for Orlando, Florida
Period: 1988-1992

WIND ROSE PLOT

December Wind Rose for Orlando, Florida



Wind Speed (Knots)



MODELER
Makens, Matthew P.

DATE
6/12/2000

COMPANY NAME
Black & Veatch

DISPLAY
Wind Speed

UNIT
Knots

COMMENTS

AVG. WIND SPEED
7.38 Knots

CALM WINDS
3.92%

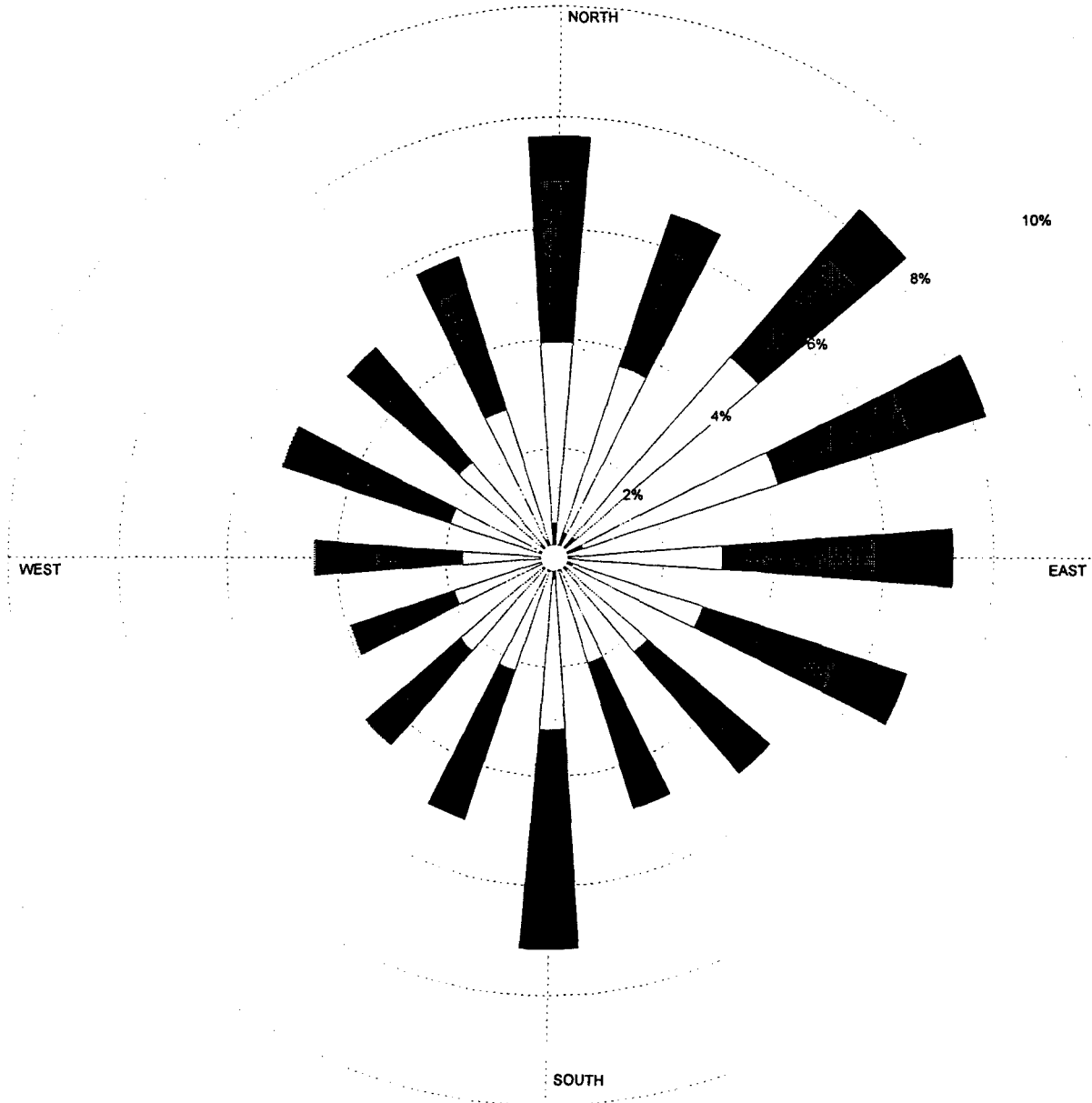
ORIENTATION
**Direction
(blowing from)**

PLOT YEAR-DATE-TIME
**88 89 90 91 92
December 1 - December 31
Midnight - 11 PM**

**Figure 2.3-33
December Wind Rose for Orlando, Florida
Period: 1988-1992**

WIND ROSE PLOT

Annual Wind Rose for Orlando, Florida



Wind Speed (Knots)	MODELER Makens, Matthew P.	DATE 6/12/2000	COMPANY NAME Black & Veatch
	DISPLAY Wind Speed	UNIT Knots	COMMENTS
	AVG. WIND SPEED 7.46 Knots	CALM WINDS 3.24%	
	ORIENTATION Direction (blowing from)	PLOT YEAR-DATE-TIME 88 89 90 91 92 January 1 - December 31 Midnight - 11 PM	

Figure 2.3-34
Annual Wind Rose for Orlando, Florida
Period: 1988-1992

Table 2.3-20
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).

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 dispersion 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 2.3-21 through 2.3-27.

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 SEC 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 2.3-28.

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 SEC area is classified as PSD Class II. Class II PSD increments will be applicable for this analysis in all areas surrounding the SEC.

Table 2.3-21
Estimated Average Mixing Heights and Average Wind Speeds
Through the Mixed Layer Representative
of the Stanton Energy Center 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.

Table 2.3-22
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		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 2.3-23
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 2.3-24
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 2.3-25
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 2.3-26
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	5	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 2.3-27
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 2.3-28
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.

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 SEC 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 2.3-29 summarizes the monitoring data used as background pollutant concentrations.

2.3.8 Noise

The proposed equipment will be located on the site of the existing Stanton Energy Center. The site is quite large in area, approximately 2 miles by 2.5 miles. The proposed Unit A equipment will be located approximately 2,500 feet from the nearest property boundary.

The land uses surrounding the site are primarily undeveloped. The closest resident is located approximately 8,000 feet northeast of the proposed Unit A equipment location. The only noise sources within the area are the existing power facility and Highway 528 traffic (approximately 12,000 feet south of the Unit A equipment). The only other anticipated noise sources would include natural noise sources, such as wind, birds, and insects. Noise sources within the residential community would include local traffic, lawnmowers, and other residential type noises. The existing noise environment is anticipated to be typical of a quiet suburban community.

2.3.9 Other Environmental Features

The red-cockaded woodpecker monitoring plan, as approved under the Site Certification for Units 1 and 2, will also be followed for Stanton A. No changes to this plan are proposed.

Table 2.3-29
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.

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REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=30'-0"
D-PS-9000-3	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"

PRELIMINARY

"THIS DOCUMENT CONTAINS PROPRIETARY, CONFIDENTIAL, AND/OR TRADE SECRET INFORMATION OF THE SUBSIDIARIES OF THE SOUTHERN COMPANY OR THIRD PARTIES. IT IS INTENDED FOR USE ONLY BY EMPLOYEES OF, OR AUTHORIZED CONTRACTORS OF THE SUBSIDIARIES OF THE SOUTHERN COMPANY. UNAUTHORIZED POSSESSION, USE, DISTRIBUTION, COPYING, DISSEMINATION, OR DISCLOSURE OF ANY PORTION HEREOF IS PROHIBITED."

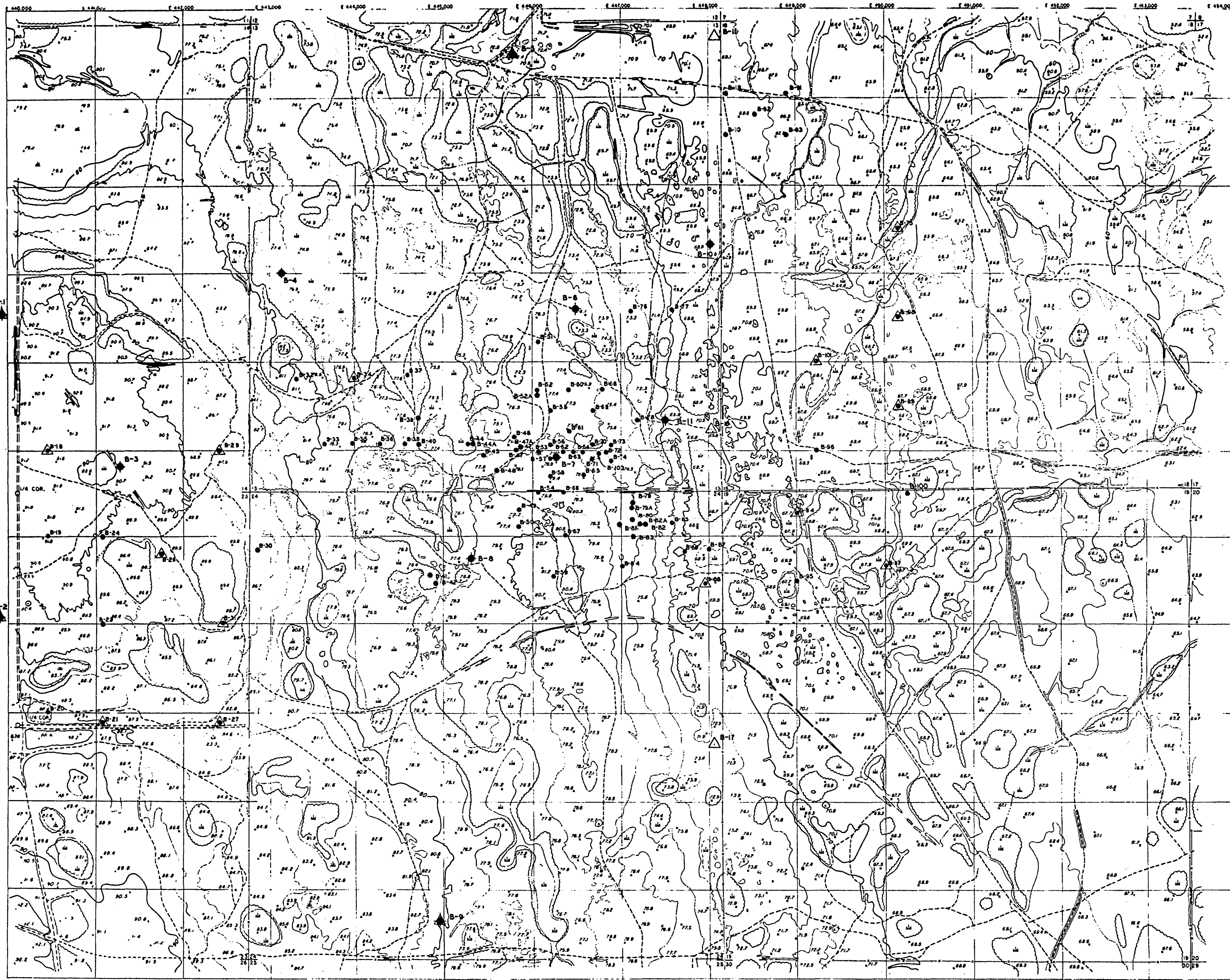
SOUTHERN COMPANY GENERATION

STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=100'-0"

DESIGNED SHW	DRAWN SHW	CHECKED
SCALE	SHEET NO.	DRAWING NUMBER

SCALE	PROJECT I.D.	DRAWING NUMBER	REV
1"=100'-0"		D-PS-9000-1	A

REVISION		DATE		REVISION		DATE		REVISION		DATE		REVISION		DATE													
BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5



BORING LOCATIONS				
BORING NUMBER	COORDINATES	DEPTH (FEET)	REMARKS	
B-1	1,508,948 439,941	30.0	30 FT PIEZOMETER	
B-2	1,508,952 439,908	30.0	30 FT PIEZOMETER	
B-3	1,507,832 441,181	51.5		
B-4	1,510,000 443,137	30.0		
B-5	1,512,045 445,732	30.0	30 FT PIEZOMETER	
B-6	1,508,548 446,508	206.5		
B-7	1,507,818 446,285	209.2		
B-8	1,506,754 446,310	30.0		
B-9	1,503,640 449,362	30.0	30 FT PIEZOMETER	
B-10	1,510,342 446,020	30.0		
B-11	1,508,353 447,512	30.0		
B-12	-	-	NOT DRILLED	
B-13	1,515,420 457,310	-	24.5 FT PIEZ ONLY	
B-14	1,515,425 453,425	-	24.5 FT PIEZ ONLY	
B-15	1,512,630 448,070	-	24.5 FT PIEZ ONLY	
B-16	1,508,283 448,020	-	24.5 FT PIEZ ONLY	
B-17	1,504,430 448,050	-	24.5 FT PIEZ ONLY	
B-18	1,508,000 440,425	51.0	30 FT PIEZOMETER	
B-19	1,508,990 440,420	75.0		
B-20	1,506,005 440,220	30.0		
B-21	1,504,800 441,075	30.0	30 FT PIEZOMETER	
B-22	1,505,994 441,075	30.0		
B-23	-	-	NOT DRILLED	
B-24	1,507,000 441,075	30.0		
B-25	-	-	NOT DRILLED	
B-26	1,508,300 441,740	30.0	30 FT PIEZOMETER	
B-27	1,504,900 442,410	75.0	30 FT PIEZOMETER	
B-28	-	-	NOT DRILLED	
B-29	1,508,000 442,410	30.0	30 FT PIEZOMETER	
B-30	1,508,350 442,850	30.0		
B-31	1,508,978 442,910	30.0	30 FT PIEZOMETER	
B-32	1,508,800 443,300	25.0		
B-33	1,508,075 443,650	75.0		
B-34	1,508,800 444,000	30.0	30 FT PIEZOMETER	
B-35	1,508,073 443,973	150.0		
B-36	1,508,075 443,275	75.0		
B-37	1,508,330 444,600	25.0		
B-38	1,508,075 444,675	150.5		
B-39	1,508,375 444,738	150.5		
B-40	1,508,080 444,738	75.5		
B-41	1,506,550 444,845	150.0		
B-42	1,506,450 444,910	150.0		
B-43	-	-	NOT DRILLED	
B-44	1,508,047 445,312	180.0		
B-45	1,507,825 445,450	150.0		
B-46	1,508,150 446,800	75.0		
B-47	1,508,000 445,825	150.5		
B-48	1,507,750 445,000	75.0		
B-49	1,507,300 445,850	25.0		
B-50	1,507,100 445,850	150.0		
B-51	1,508,200 446,075	25.0		
B-52	1,508,675 446,050	254.0		
B-53	1,507,975 446,075	233.5		
B-54	1,507,475 446,075	75.0		
B-55	1,508,450 446,208	151.0		
B-56	1,508,058 446,200	185.5		
B-57	1,507,900 446,187	150.0		
B-58	1,507,887 446,202	150.0		
B-59	1,506,500 446,250	25.0		
B-60	1,506,678 446,398	148.3		
B-61	1,508,225 446,400	260.0		
B-62	1,507,975 446,350	151.5		
B-63	1,507,575 446,475	150.5		
B-64	1,507,975 446,675	130.0		
B-65	1,507,700 446,738	75.0		
B-66	1,507,475 446,747	150.0		
B-67	1,507,000 446,373	25.0		
B-68	1,508,675 446,800	232.0		
B-69	1,508,450 446,675	148.9		
B-70	1,508,075 446,675	150.5		
B-71	1,507,800 446,675	150.5		
B-72	1,507,875 446,840	258.5		
B-73	1,508,075 446,900	150.5		
B-74	1,507,905 446,900	150.0		
B-75	1,512,502 450,148	30.0	30' ANI 75' PIEZOMETER	
B-76	1,508,550 447,122	150.0		
B-77	1,508,550 447,000	150.0		
B-78	1,508,375 447,175	26.5		
B-79	1,507,400 447,125	151.5		
B-80	1,507,200 447,125	265.0		
B-81	1,507,150 446,975	151.5		
B-82	1,507,150 447,275	151.5		
B-83	1,507,000 447,125	151.5		
B-84	1,508,850 447,000	25.0		
B-85	1,507,150 447,600	110.0		
B-86	1,508,800 447,725	75.0		
B-87	1,508,850 446,000	75.0		
B-88	1,508,150 447,975	30.0	30 FT PIEZOMETER	
B-89	1,512,015 448,200	75.0		
B-90	1,511,675 448,200	75.0		
B-91	1,512,045 448,895	75.0		
B-92	1,511,825 448,140	75.0		
B-93	1,511,675 448,940	75.5		
B-94	1,507,267 448,000	30.0	30 FT PIEZOMETER	
B-95	1,508,483 449,011	50.0		
B-96	1,508,000 449,275	50.0		
B-97	1,508,650 450,100	30.0	30 FT PIEZOMETER	
B-98	1,508,500 450,150	50.0	30 FT PIEZOMETER	
B-99	1,508,500 450,150	50.0	22' AND 74' PIEZOMETER	
B-100	1,507,102 450,247	50.0		
B-101	1,509,000 449,725	50.0	28.5 FT PIEZOMETER	
B-102	-	-	NOT DRILLED	
B-103	1,507,595 446,715	150.0		
B-104	1,508,075 445,327	40.5		
B-105	1,508,007 445,328	40.0		
B-106	1,508,065 446,050	45.0		
B-107	1,507,375 447,125	125.0	LOGGED FROM 80'-125'	
B-108	1,507,150 447,250	75.0	LOGGED FROM 80'-75.0'	

LEGEND
● PHASE I BORING
▲ PHASE I BORING W/PIEZOMETER
△ PIEZOMETER
● PHASE II BORING
▲ PHASE II BORING W/PIEZOMETER

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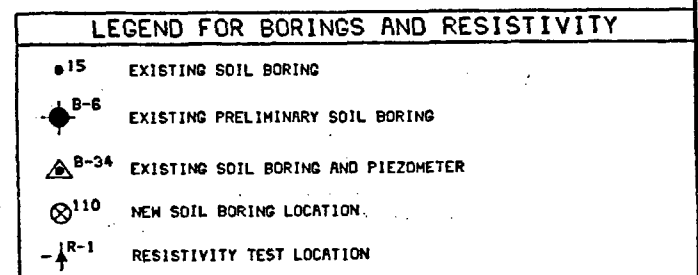
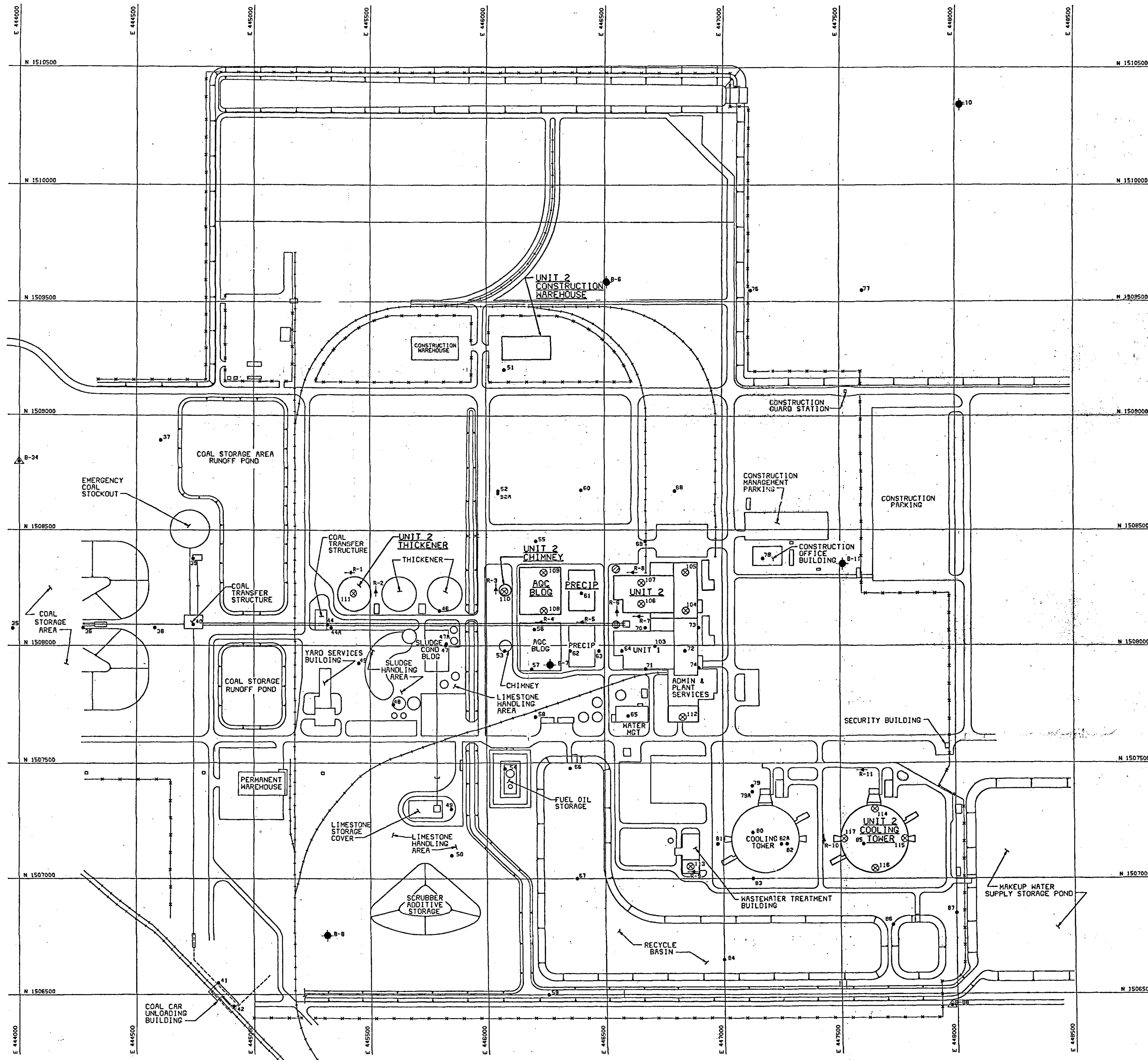
150' 75' 0 150' 300'
1"=150'

I HEREBY CERTIFY THAT THIS DOCUMENT HAS
BEEN PREPARED BY ME OR UNDER MY DIRECT SUPER-
VISION AND THAT I AM A duly REGISTERED PRO-
FESSIONAL ENGINEER UNDER THE LAWS OF THE
STATE OF FLORIDA
SIGNED _____ DATE _____ REG. NO. _____

BLACK & VEATCH
ENGINEERS-ARCHITECTS
ENGINEER HLP DRAWN EGS
CHECKED _____ DATE _____

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2
BORING LOCATION PLAN

PROJECT 16805-DS-0121
CODE _____ AREA _____
DATE OF ISSUE _____
NOT TO BE USED
FOR CONSTRUCTION
Figure 2.3-4



NOT TO BE USED
FOR CONSTRUCTION
DATE OF ISSUE _____

3.0 The Plant and Directly Associated Facilities

3.1 Background

The Curtis H. Stanton Energy Center (SEC) 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 the combined cycle unit (Stanton A) is also shown.

Stanton A will include two combustion turbine generators, two heat recovery steam generators, one steam turbine generator, and a natural gas delivery system. Many of the existing systems, such as water supply, treatment, and disposal systems, and storm water management facilities, will be used by Stanton A. 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 through the main SEC switchyard.

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. Combustion and emissions control measures, such as dry low NO_x combustors, temperature control by water injection, and selective catalytic reduction (SCR), will be installed to meet current regulations.

Cycle heat rejection will be accomplished using a rectangular, multicell, mechanical draft cooling tower. Treated sewage effluent supplied by the Orange County Plant will be used as cooling tower makeup water. Additional effluent may be supplied by the City of Orlando near the time Stanton A is operational. Service and potable water is supplied from onsite wells pumping from the Floridan Aquifer.

3.2 Site Layout

The Site Arrangement depicts the proposed layout for the Stanton A development, and associated facilities. The general profile associated with Stanton A combustion turbines 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. Figures 3.2-2 and 3.2-3 depict the proposed site arrangement of all the buildings associated with Stanton A.

3.3 Fuel

3.3.1 Fuel Types and Qualities

The primary fuel for Stanton A will be natural gas. The Florida Gas Transmission Company (FGT) will supply gas for the new unit. Table 3.3-1 presents typical property values for the primary fuel.

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

*At 14.730 and 60° F.

**At 14.730 psia and uncorrected for compressibility.

Total sulfur = 74.1% of 16 ppm = 11.8 ppm/V.

The backup fuel will be low sulfur (0.05 percent) No. 2 fuel oil. Approximately 1.68 million gallons will be stored onsite as indicated on Figure 3.2-2. Operation on oil is limited to a specific number of hours (1,000 hours) per year per turbine. 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 the combined cycle unit would be approximately 4,580,000 cubic feet per hour.

The fuel oil consumption rate for operating the combined cycle unit at a 100 percent capacity factor would be approximately 640,425 gallons per day.

3.3.3 Fuel Transportation

Natural gas is the primary fuel for the new combined cycle unit and is supplied via an underground 16 inch diameter natural gas line owned by OUC. The new line ties into an existing FGT natural gas line, as discussed in Section 6.2.

No. 2 fuel oil is the secondary (backup) fuel for the new unit. Fuel oil is delivered to the site by tanker trucks and/or rail. Once onsite, the fuel is transferred from the tankers to the onsite storage tank.

3.3.3.1 Natural Gas Delivery and Metering. Natural gas is delivered to the facility as described in Subsection 3.3.3. A metering station will be installed in conjunction with the 16 inch natural gas line to support the location. A gas metering station will be located at the connection to the main FGT pipeline and at the new facility, as shown on Figure 3.2-2.

3.3.3.2 Fuel Oil Storage and Handling. One new 1.68 million gallon fuel oil (No. 2) storage tank will be added at the SEC for the new combined cycle unit.

The construction, materials, installation, and use of the bulk storage tank will conform to API Standard 650, AISC, ASTM, NEC, and OSHA standards. The location of this storage tank is indicated on the Site Arrangement, Figure 2.1-3.

Fuel will be delivered to a vertical oil storage tank by tanker truck or rail, as described in Subsection 3.3.3 above. The containment area for the fuel oil tank is provided by an earthen berm. The berm is designed to meet Florida Department of Environmental Protection (FDEP) requirements (Chapter 62-761 Florida Administration Code) 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, the containment area is provided with a synthetic liner. The liner is sufficiently impermeable to ensure that no oil can escape by infiltrating through the liner and soil and into surface or groundwaters, as required by FDEP regulation.

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 at 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

The fuel oil truck unloading station is located northwest of the existing coal units, as indicated on the Site Arrangement. The station spill containment includes above-ground and double-walled below grade piping running to the storage tanks outside and inside the earthen berm area. The station also includes a manually operated isolation valve and a check valve immediately adjacent to the station to allow 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 rail line used to deliver equipment and coal to the existing units will be upgraded as required for the purpose of unloading fuel oil tankers. That portion of the existing track that will be upgraded is located northwest of the existing coal units and adjacent to the proposed fuel tank. Secondary containment for the fuel oil truck and rail unloading areas will be designed in accordance with the Environmental Protection Agency (EPA) 40 CFR Part 112 entitled "Oil Pollution Prevention" and/or the Florida Administration Code Chapter 62-761.

The existing SEC Spill Prevention, Control, and Countermeasures Plan will be modified as required to include the new combined cycle facility.

3.3.4 Alternate Fuel Types

OUC investigated various alternative technologies and fuels for phased development at the SEC. Economics, environmental acceptability, and the tourist/entertainment culture of the project region were important considerations in the analysis.

OUC 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 SEC. Natural gas does not require delivery vehicles, storage facilities, secondary containment structures, or large, dedicated acreage. 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

The existing Makeup Water Supply Storage Pond, which receives effluent from the Orange County Eastern Water Reclamation Facility, will supply raw water for cooling tower makeup. All other process, service, and potable water uses will be supplied from the existing Stanton Units 1 and 2 service and demineralized water systems. The existing service and demineralized water systems are supplied by onsite wells, each with an 850 gpm pump. Well water withdrawal is increased with the addition of Stanton A because of the need for additional potable water, steam cycle makeup, and general plant service water. Additional well water required to provide potable water, service water, demineralized water, and the wastes associated with producing water for these uses for Stanton A will average approximately 316,000 gpd on an annual basis. The water use for Stanton A is shown on Figure 3.5-1.

Normal fuel is natural gas; however, Stanton A will be designed to allow the units to also be fired on oil. Water usage will increase when firing on fuel oil due to the additional demineralized water required for combustion turbine injection to control NO_x emissions. The average annual water use for Stanton A included on Figure 3.5-1 assumes firing 1,000 hours per year on oil. The water balance on Figure 3.5-1 represents operation at 95 percent capacity conditions. Actual average annual flows may vary, dependent upon the electrical loading of the generators.

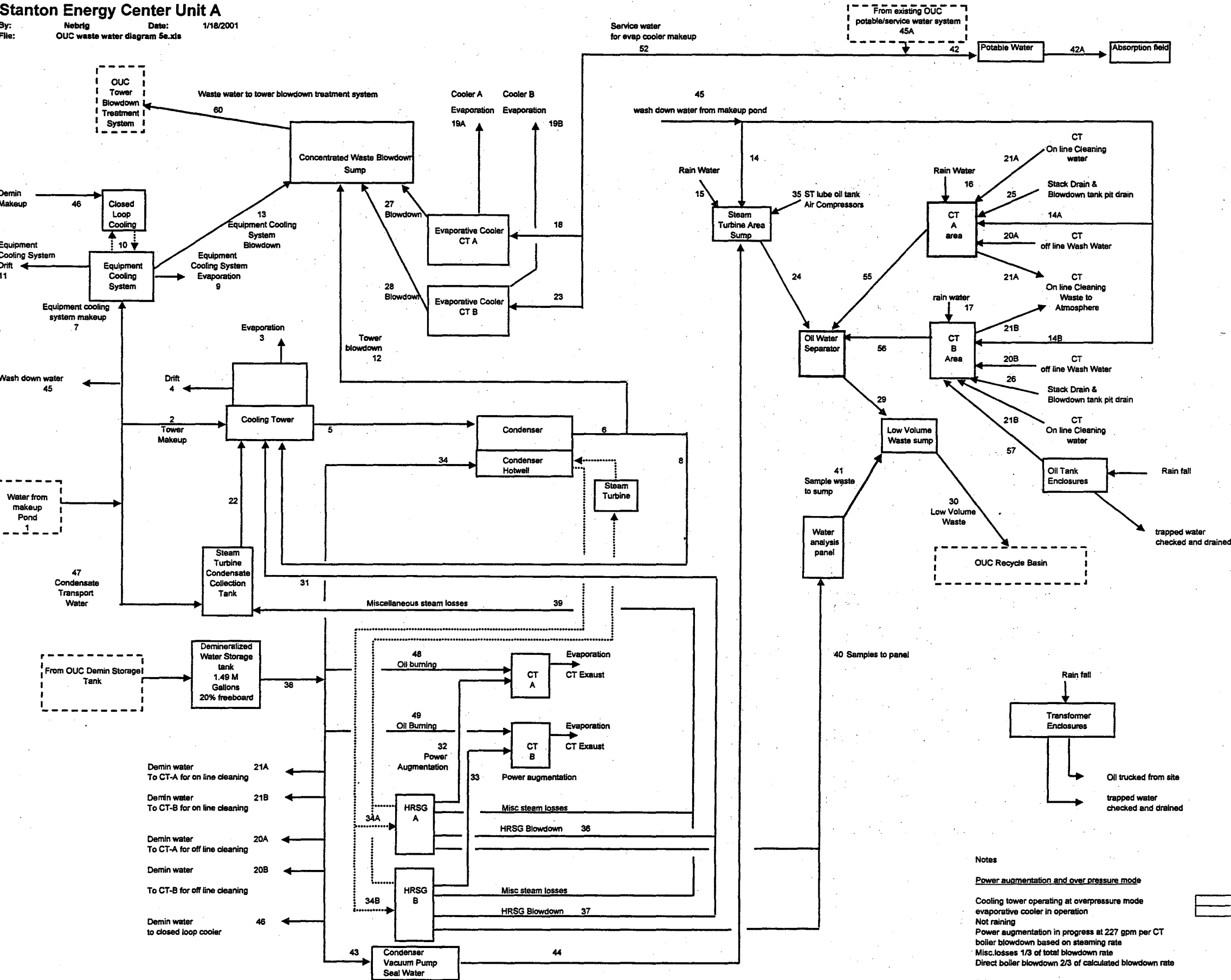
In addition to the normal operation uses, groundwater is requested for cooling water use during emergency conditions. If the effluent supply is interrupted, or there are makeup pond shortages, the use of groundwater is requested to provide cooling water to maintain Stanton A operation. An additional 2.13 mgd is required to meet the cooling water demand. The withdrawal is requested for use 30 days per year.

3.5.1 Heat Dissipation System (Cooling Towers)

Waste heat from Stanton A will be rejected to the atmosphere by a cooling cycle consisting of a main cooling system using a mechanical draft cooling tower for the steam turbine condenser and a separate auxiliary cooling system using either a mechanical draft cooling tower or an industrial process cooler. The primary source of cooling water makeup will be the existing Makeup Water Supply Storage Pond, which receives treated effluent from the Orange County Eastern Regional Water Reclamation Facility.

Stanton Energy Center Unit A

By: Nebrig Date: 1/18/2001
File: OUC waste water diagram 5e.xls



Line No.	Stream	Average Flow based on plant operation gpm	Max Flow Power Aug over press gpm
Flows are block flows unless otherwise noted			
1	Makeup water from OUC makeup pond	2021.6	2778.8
2	Cooling tower makeup	1878.6	2628.8
3	Cooling tower evaporation	1724.5	2402.0
4	Cooling tower drift	2.4	2.5
5	Circulating water pump discharge	118750.0	125000.0
6	Condenser inlet	118750.0	125000.0
7	Equipment cooling system makeup	90.3	95.0
8	Condenser discharge after blowdown	118505.2	124659.0
9	Equipment cooling system evaporation	78.9	83.0
10	Closed loop cooling flow	9500.0	10000.0
11	Equipment cooling system Drift	0.2	0.2
12	Cooling tower blowdown	243.8	341.0
13	Equipment cooling system blowdown	11.2	11.8
14	Makeup pond water to steam turbine area for wash down	0.2	0.0
14A	Makeup pond water to CT-A area	0.2	0.0
14b	Makeup pond water to CT-B area	0.2	0.0
15	Rain water to steam turbine area	0.1	0.0
16	Rain water to CT-A area	0.0	0.0
17	Rain water to CT-B area	0.0	0.0
18	Makeup water to CT-A evaporative cooler	26.1	27.4
19A	CT-A evaporative cooler evaporation	22.8	24.0
19B	CT-B evaporative cooler evaporation	22.8	24.0
20A	CT-A off line cleaning wash water	0.1	0.0
20B	CT-B off line cleaning wash water	0.1	0.0
21A	CT-A on line wash water	0.5	0.0
21B	CT-B on line wash water	0.5	0.0
22	Steam Turbine collection tank to cooling tower basin	65.4	75.4
23	Water to CT-B evaporative cooler	26.1	27.4
24	Steam turbine area to oil water separator	0.3	0.0
25	CT A stack drain and blowdown tank pit drain	0.0	0.0
26	CT A stack drain and blowdown tank pit drain	0.0	0.0
27	CT-A evap cooler blowdown	3.3	3.4
28	CT-B evap cooler blowdown	3.3	3.4
29	Oil water separator to low volume sump	0.8	0.0
30	Low volume waste to OUC recycle basin	10.3	10.0
31	Total block boiler blow down	26.7	41.4
32	Power augmentation to CT A	25.9	227.0
33	Power augmentation to CT B	25.9	227.0
34	Makeup to Condenser Hotwell	101.2	525.7
34a	Makeup for losses at HRSG A	50.6	262.9
34b	Makeup for losses at HRSG B	50.6	262.9
35	Steam turbine lube oil tank and Air Compressors	0.0	0.0
36	HRSG A Blowdown to tower	13.4	20.7
37	HRSG B Blowdown to tower	13.4	20.7
38	Demin. water to process	154.0	525.7
39	Total HRSG miscellaneous losses	13.2	20.4
39A	HRSG A misc. losses	6.6	10.2
39B	HRSG B misc. losses	6.6	10.2
40	Water analysis panel waste	9.5	10.0
41	Panel waste to low volume sump	9.5	10.0
42	Potable water to block from potable water supply	0.6	0.0
42A	Sewage to treatment from block	0.6	0.0
43	Condenser vacuum pump seal water makeup	0.0	0.0
44	Condenser vacuum pump seal water waste	0.0	0.0
45	washdown water	0.6	0.0
45A	From existing OUC potable/service water system	52.7	54.9
46	Closed loop cooling water makeup	0.0	0.0
47	Condensate transport water	52.3	55.0
48	Demin water to CT- A during fuel oil burn	25.8	0.0
49	Demin water to CT- B during fuel oil burn	25.8	0.0
50	Spare		
51	Fire Protection water to site	0.0	0.0
52	Evap cooler makeup from OUC site	52.1	54.9
53	Spare		
54	Spare		
55	CT - A area sump to oil water separator	0.3	0.0
56	CT - B area sump to oil water separator	0.3	0.0
57	Oil storage tanks to CT - B area sump	0.0	0.0
58	Spare		
59	Spare		
60	Conc. Waste sump to OUC tower blowdown sump	281.5	359.7

Notes

Power augmentation and over pressure mode

Cooling tower operating at overpressure mode
evaporative cooler in operation
Not raining
Power augmentation in progress at 227 gpm per CT
boiler blowdown based on steaming rate
Misc. losses 1/3 of total blowdown rate
Direct boiler blowdown 2/3 of calculated blowdown rate

Blowdown

hot reheat	719782
Lp admission	20469
Main steam	803371
	1543622 #/hr
	30.87244 gpm

Average Flow Based on plant operation

operation factor	0.95
Normal operation a function of power factor and power aug. and oil burning	
power augmentation operation	1000 hours
oil burning	1000 hours
evaporative cooler in operation	12 hours per day
Assume washdown of 100 gpm for 60 minutes per week (20 minutes per area)	
rain water	48.11 inches annual
steam turbine sump	1556 ft2
CT A sump	220 ft2
CTB sump	220 ft2
on line cleaning 780 gallons once per day exhausted to atmosphere	
off line cleaning 2430 gallons once per month trucked from site	
assume 30 gallons per day per person, 30 persons/day	
1% boiler blowdown based on steaming rate	
Misc. losses 1/3 of total blowdown rate	
Direct boiler blowdown 2/3 of calculated blowdown rate	

Figure 3.5-1
Water Balance

The estimated total cooling water makeup for Stanton A is approximately 2.9 mgd annual average, and a maximum daily use of 4.0 mgd. Blowdown and collected miscellaneous steam losses from the heat recovery steam generators will be routed to the cooling tower to provide a small portion of the cooling water makeup requirement. The amount of makeup water supplied to the cooling towers from HRSG blowdown and collected steam losses is estimated to average approximately 57,000 gpd. The effluent from the cooling tower blowdown treatment system will be routed to the existing Makeup Water Supply Storage Pond to provide a portion of the total makeup requirements for all units. The blowdown treatment system effluent attributable to Unit A will reduce site makeup requirements by 369,000 gpd, assuming 98 percent of the water is recovered.

Cooling water requirements for Stanton A are included on the water balance on Figure 3.5-1. Cooling tower blowdown will be directed to and treated in a cooling tower blowdown treatment system as described in Subsection 3.6.1.

3.5.2 Domestic/Sanitary Wastewater

Domestic/sanitary wastewater is generated by showers, lavatories, sinks, toilets, urinals, and drinking fountains.

It is estimated that there will be a total of ten new employees per shift and 3 shifts per day in association with Stanton A. At a flow of 30 gallons per person per day, approximately 900 gpd additional sanitary waste will be generated.

Stanton A sanitary wastes will be collected and routed to a new septic system and tile field.

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 Stanton A will be provided from an extension of the existing SEC service/potable water system, which is a permitted noncommunity public water system supplied by treated well water. The estimated potable water analysis prior to treatment is shown in Table 3.5-1.

3.5.4 Process Water Systems

Fire water for Stanton A will be obtained from an extension of the existing SEC fire water system. The system utilizes 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.

Table 3.5-1 Potable Water Analysis	
Constituent	Concentration
Calcium, mg/l as CaCO ₃	37
Magnesium, mg/l as CaCO ₃	16
Sodium, mg/l as CaCO ₃	42
Potassium, mg/l as CaCO ₃	0
M-Alkalinity, mg/l as CaCO ₃	35
Sulfate, mg/l as CaCO ₃	21
Chloride, mg/l as CaCO ₃	39
Silica, mg/l as SiO ₂	12
Total Dissolved Solids, mg/l	130

Demineralized water will be required for use as makeup to the steam-condensate-feedwater cycle associated with the Stanton A heat recovery steam generators (HRSGs). The makeup is required to replace cycle losses and boiler blowdown. In addition, demineralized water will be used to control combustion turbine NO_x emissions when firing fuel oil and to produce steam for power augmentation, as well as for demineralizer regeneration.

Demineralized water will be supplied from the existing SEC ion exchange demineralizer system. Service water is transferred to the demineralizer inlet. As the water passes through the system, it is progressively demineralized until the effluent contains essentially no dissolved solids. Exhausted ion exchange resin is regenerated using sulfuric acid and sodium hydroxide. The resulting chemical wastewater flows are treated as described in Section 3.6 below.

3.5.5 Water Use Variations

All water requirements described in the preceding sections are based on operation of the facility at 95 percent capacity. When the units operate at more or less than 95 percent capacity, the evaporation rate from the cooling towers, and consequently the cooling tower makeup and blowdown rates, vary proportionately. Cooling tower makeup (treated effluent) is the major water use. Changing the operating capacity results in a change in overall water use. Demineralized water makeup requirements also vary proportionately at varying capacity loads. Demineralized water requirements also

increase when firing with oil due to NO_x control requirements and when steam is used for power augmentation. The balance of water uses will be basically independent of the operating load.

In the event of combined cycle mode shutdown, the main cooling system (cooling towers) will be shut down. No main cooling tower or steam cycle makeup will be required, but other systems may continue to operate. In the event of combustion turbine shutdown, the main cooling system and the evaporative coolers will be shut down. No makeup will be required for the main cooling system, the HRSGs, or the evaporative coolers. The load on the auxiliary cooling system will decrease significantly. Makeup for the auxiliary cooling system and miscellaneous plant uses will be minimized.

3.6 Chemical and Biocide Waste

The facility has five major sources of wastewater. These are sanitary wastes, oil/water separator effluent, cooling tower blowdown, chemical wastes, and boiler blowdown. Oil/water separator effluent will be routed to the existing SEC recycle basin where it will be reused in Units 1 and 2 flue gas desulfurization and ash systems. Cooling tower and evaporative cooler blowdown will be treated in a new brine concentrator system. The brine concentrator system recovers a large amount of the water in the blowdown and recycles it to the cooling towers while producing a "dry" solid product that is disposed of in the SEC landfill. Sanitary wastes will be directed to a new septic tank/tile field system constructed to serve Unit A. Boiler blowdown from the HRSG will be routed to the Stanton A cooling tower for reuse.

It is estimated that an additional 10,000 lb/day of dry solids consisting of the minerals present in the cooling water supply will be produced from treatment of the cooling tower blowdown from Stanton A at 95 percent capacity. These solids will be disposed of in the Units 1 and 2 combustion waste landfill, which is the current procedure.

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 Treatment

Chemicals used in cooling tower water treatment will include sulfuric acid for pH adjustment, a biocide control, and a commercial scale inhibitor. Cooling tower

blowdown will be collected and treated in a new brine concentrator system. The water recovered in this system is then available for reuse as makeup to the site cooling tower system.

3.6.2 Sanitary Waste Treatment

Sanitary wastes will be directed to a new septic tank/tile field system constructed to serve Unit A.

3.6.3 Steam Cycle Water Treatment

The steam cycle water will be provided by the existing SEC water treatment system. Demineralized water is 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 boiler water pH in the steam generator. 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 used as makeup for the cooling tower.

3.6.4 Makeup Water Demineralization

As discussed in Subsection 3.5.4, the makeup water to the steam cycle will be provided by the existing SEC demineralization system that consists of ion exchange resin beds. The demineralization system uses sulfuric acid for cation resin regeneration and sodium hydroxide for anion resin regeneration. The sulfuric acid and sodium hydroxide are stored in tanks located in curbed concrete containment areas near the treatment areas. Any spillage of chemicals in the curbed areas is routed to the neutralization basin for treatment. The use of these chemicals is dependent on demineralized water requirements.

Wastewater from the cation resin regeneration includes regenerant water containing unreacted sulfuric acid and dissolved sulfate salts of cations removed from the resin during regeneration. Wastewater from anion resin regeneration includes regenerant water containing unreacted sodium hydroxide and dissolved sodium salts of anions removed from the resin during regeneration.

The additional regenerant wastewater flow resulting from Stanton A is estimated to average approximately 12,000 gpd. The demineralizer regenerant wastes will be routed to the existing SEC neutralization basin, as described in Subsection 3.6.7, for pH adjustment prior to being transferred to the SEC recycle basin.

3.6.5 Chemical Cleaning Wastes

The Stanton A heat recovery steam generator and preboiler piping will be chemically cleaned during commissioning. The steam generators will also be periodically cleaned during the life of the 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.
- Aqueous ammonia.
- 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 facility.

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 neutralized if required and routed to the SEC recycle basin.

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 SEC 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

The existing SEC neutralization basin will be used for processing Stanton A chemical wastewaters. Neutralized water is directed to the SEC recycle basin.

3.7 Solid and Hazardous Waste

Stanton A will not produce solid wastes associated with combustion since the firing of natural gas or fuel oil does not create significant combustion byproducts. Stanton A will generate solid waste associated with the brine concentrator treatment of the cooling tower blowdown. This waste is combined with the solid discharge waste produced by the treatment of the blowdown from Units 1 and 2.

Waste oil is the only potentially hazardous substance generated by Stanton A 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

This section describes the drainage systems that will be used to control runoff and potential impacts of erosion on the project site and surrounding property. A copy of the storm water management plan (SWMP) has been included in Section 3.10.

3.8.1 Design Concepts

The site drainage facilities for the new Stanton Unit A plant will be constructed and operated to control storm water runoff on the site during construction and operation of the plant. The system is designed using St. Johns River Water Management District (SJRWMD) and Florida Department of Environmental Protection (FDEP) criteria for control of quality and quantity of storm water runoff. The existing onsite drainage system will be utilized to the greatest extent possible. This system has been previously permitted for the entire site acreage to intercept runoff from the pervious and impervious surfaces for all three Stanton units. The runoff will be conveyed to an existing wet detention pond through a series of ditches, swales, and culverts and will be treated and released to adjacent wetland systems. The storm water control structure within the pond has been upgraded to meet the applicable requirements for existing and proposed flows.

The existing pond will provide treatment of the first 2.5 inches of runoff over the impervious areas and will attenuate the peak flows from the 100 year – 24 hour storm event. Postdevelopment discharge rates do not exceed predevelopment discharge rates from the site.

3.8.2 Site Layout and Impervious Areas

Approximately 38.3 acres of the existing 52 acre site is currently impervious surface. An additional 2.9 acres of impervious area will be added for the Stanton Unit A facility. The remaining 13.7 acres will be pervious surfaces of grass or landscaping.

3.8.3 Surface Receiving Waters

Discharge from the wet detention pond will continue to be in an easterly direction into adjacent wetlands which follow natural drainage patterns. The existing discharge structure will be removed and replaced with a structure that has been designed for the postdevelopment runoff conditions.

3.8.4 Ground Receiving Waters

Infiltration of storm water both on and offsite will be minimal due to ground water conditions that are typically within 1.5 to 2 feet of ground elevation. Groundwater may be higher in some of the filled areas of the site.

3.8.5 Diversion of Existing Drainage

The proposed grades onsite will somewhat impede existing drainage patterns. The undisturbed areas surrounding the proposed construction will be regraded such that storm water will continue to be conveyed in the direction of the detention pond.

3.8.6 Erosion Control Measures

Erosion control barriers shall be installed along the construction boundary prior to the initiation of construction activities. Silt fencing and straw bales will be utilized to control the transport of sediment from the site. Ditch bottoms and side slopes will be stabilized to protect against erosion using grassing or matting as needed. Disturbed areas will be minimized to limit erosion potential. Finished slopes will be gradual in order to limit velocities which may promote erosion.

3.8.7 Runoff Control

The drainage collection system will utilize existing and improved swales, culverts, and sloped surfaces to convey runoff to the wet detention pond. Swales will

have a maximum 3:1 horizontal:vertical side slope, and longitudinal slopes will be minimized in order to limit flow velocities. Existing drainage culverts will be utilized to the greatest extent possible. Any culverts within the collection system that require replacement will be designed for the 100 year, 24 hour storm capacity and will be constructed of either reinforced concrete or high-density polyethylene pipe. The onsite collection system will be graded such that runoff is routed to the storm water pond in such a manner as to limit ponding in low lying areas.

3.8.8 Location of Discharge Points or Storm Runoff

Runoff from the site will be conveyed to the storm water detention ponds and will outfall to adjacent wetland systems to the east.

3.8.9 Storm Water Detention

Storm water control measures used on the new plant are designed to comply with requirements of local, state, and federal regulations. Storm water runoff calculations, runoff volumes, peak discharges, and control structures were determined or designed using methods described by St. Johns River Water Management District (SJRWMD), Applicants Handbook: Regulation of Stormwater Management Systems Chapter 40C-42, Florida Administrative Code.

Existing and proposed storm water will be collected in the existing wet retention basin located north of the proposed construction area. The pond has been designed to provide water quality treatment and attenuation of storm water runoff from the existing 52 acre site. Supporting calculations show that the existing pond is capable of providing adequate treatment of the additional flow with modifications to the existing discharge structure. The location and configuration of the detention pond is shown on Figure 3.8-1.

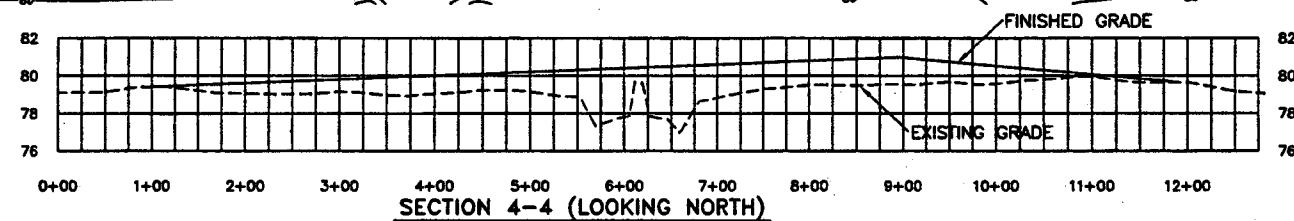
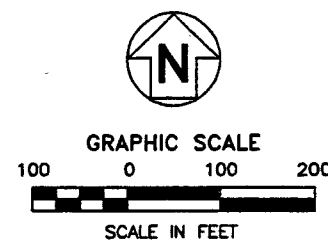
The detention basin will be excavated to an elevation of 72.0 feet, such that the depth of the permanent pool is 3.2 feet deep. The permanent pool volume will provide the 14 day residence time required during the wet season (June through October) to assure adequate sedimentation and water quality treatment of storm water runoff. Under normal conditions, the permanent pool elevation of the pond will be 75.20 feet. An orifice located in the outlet structure will be used to recover 50 percent of the detention volume within the first 60 hours following the rainfall event.

The storm water pond will attenuate the peak flows from the 100 year – 24 hour storm to below the predevelopment rate through the outlet control structure. The existing discharge structure will be removed and replaced to provide the necessary treatment and release of the additional flow volumes. Discharge will be directed to the existing wetland system adjacent to the site.



1. GEOTEXTILE FABRIC SILT FENCE SHALL BE PLACED ALONG PROJECT BOUNDARY IN ACCORDANCE WITH FLORIDA DOT STANDARD SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION.
2. ALL EROSION CONTROL AND SEDIMENT TRAPPING DEVICES SHALL BE INSPECTED AND REPAIRED OR REPLACED AS NEEDED AFTER EACH SIGNIFICANT RAINFALL. EARTHWORK CONTRACTOR WHILE ON SITE, SHALL BE RESPONSIBLE FOR MAINTAINING EROSION CONTROL DEVICES. BEFORE CONTRACTOR LEAVES THE SITE ALL EROSION CONTROL DEVICES SHALL BE INSPECTED AND APPROVED BY THE OWNER.
3. TOPSOIL SHALL BE STRIPPED FOR ALL PERMANENT AND TEMPORARY ROADS, CONSTRUCTION LAYDOWN, CONSTRUCTION AND PERMANENT PARKING AREAS, SWITCHYARD, AND PLANT AREA CONTAINED BY PERMANENT PLANT ACCESS ROADS.
4. ENTIRE SITE INSIDE PROJECT BOUNDARY SHALL BE CLEARED AND GRUBBED.
5. DUST SHALL BE CONTROLLED ON THE ENTRANCE ROADS AND PLANT ROADS BY SPRINKLING WITH WATER.

1. ALL INTERIOR SIDE SLOPES TO BE DISTURBED TO THE LEAST EXTENT POSSIBLE
2. ANY INTERIOR SIDE SLOPES DISTURBED DURING CONSTRUCTION SHALL BE REGRADED AT 4:1 (MAX)
3. THE EXISTING DISCHARGE STRUCTURE SHALL BE REMOVED AND REPLACED (SEE NEW WEIR PLAN AND SECTIONS ON DRAWING FIGURE-2.
4. THE LITTORAL ZONE SHALL BE REPLANTED TO PRE-CONSTRUCTION CONDITION PRIOR TO PROJECT COMPLETION. EVERY EFFORT SHALL BE MADE TO AVOID DISRUPTION OF THESE AREAS DURING CONSTRUCTION.

[illegible]

The storm water detention pond will serve as a sedimentation basin during construction. The detention pond will allow suspended solids or loose sediments to be settled to the bottom. The will be maintained for proper operation immediately following construction.

Supporting calculations for the wet detention system are located Storm Water Management Plan as included in Section 3.10.

3.9 Construction Materials and Equipment Handling

The major components associated with the combined cycle unit addition at the Stanton Energy Center include the following:

- Combustion Turbine.
- Heat Recovery Steam Generator.
- Generator Step-Up Transformer.
- Cooling Tower.
- Steam Turbine.
- Steam Turbine Building.
- Water Storage Tanks.
- Fuel Oil Storage Tank.
- Natural Gas Supply Pipeline.

The major components and all other required equipment and materials will be delivered to the SEC by truck or rail. All deliveries associated with construction and operation will use Alafaya Trail which connects the SEC to State Highway 50 on the SEC south access road, which connects to the Bee Line Expressway. All deliveries will be cleared through the Control Room or the security guardhouses located near the main and secondary gates. Once onsite, construction materials will be directed to the construction laydown area or its permanent location for offloading and transport to the proper storage area by portable cranes, forklifts, and trucks.

3.10 Unit A 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. A copy of the storm water management plan is also included.

STORM WATER MANAGEMENT PLAN

Stanton Unit A

Prepared by:

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Pensacola, FL 32520-0328

January 2001

TABLE OF CONTENTS

<u>Section</u>	<u>Page</u>
1.0 INTRODUCTION	
1.1 PROJECT DESCRIPTION	1
1.2 SITE DESCRIPTION	1
2.0 DESIGN CRITERIA	
2.1 SITE GRADING	2
2.2 ROADS AND PARKING AREAS	2
2.3 PERVIOUS AND IMPERVIOUS AREAS	2
2.4 DRAINAGE DITCHES AND SWALES	3
2.5 CULVERTS	3
2.6 DETENTION BASIN	3
2.7 EROSION CONTROL	4
3.0 STORM WATER MANAGEMENT PLAN AND PRACTICES	
3.1 CONSTRUCTION PHASE STORM WATER CONTROL MEASURES AND PRACTICES	5
3.2 OPERATING PHASE STORM WATER CONTROL MEASURES AND PRACTICES	6
ATTACHMENT -- STORM WATER CALCULATIONS	

1.0 INTRODUCTION

This storm water management plan (SWMP) describes measures that will be implemented to control storm water runoff on the site of the Stanton Unit A project located in Orange County, Florida. A copy of the site plan is attached as Figure 1. The SWMP includes storm water control measures that will be implemented during both construction and operation periods.

1.1 PROJECT DESCRIPTION

The Stanton Unit A plant will consist of two natural gas fired combustion turbines in combination with two heat recovery steam generators and one steam turbine generator. The operating capacity of the proposed facility is 633 megawatts.

1.2 SITE DESCRIPTION

The plant will be constructed on an existing 52-acre block within the Stanton site, which currently includes Stanton 1 and 2 facilities. The proposed construction will require approximately 13.7 acres. The undeveloped area proposed for construction is located north of the existing facility and will utilize the existing infrastructure to the greatest extent possible.

The existing site currently drains to an established wet-detention pond located immediately north of the proposed construction. Storm water is currently conveyed to the treatment pond through a series of existing ditches, swales, and culverts. Overflow is to an adjacent wetland east of the pond. Existing storm water flow will be routed around the proposed site to the west and east by the natural drainage patterns created by the new construction.

The proposed construction area will be elevated by fill material to achieve proper surface drainage and to prevent flooding in the facility area. Storm water will be directed to the east and west by a ridge line that will run north and south along the site, and will be conveyed via sheet flow. Runoff will continue to enter the pond through existing culverts, which will be resized as needed to ensure accommodation of existing and proposed flows. The pond will be further described within the calculations portion of the SWMP and depicted in associated drawings.

2.0 DESIGN CRITERIA

Storm water control measures used on the new plant are designed to comply with requirements of local, state, and federal regulations. Storm water runoff calculations, runoff volumes, peak discharges, and control structures were determined or designed using methods described by St. Johns River Water Management District (SJRWMD), Applicants Handbook: Regulation of Stormwater Management Systems Chapter 40C-42, Florida Administrative Code.

2.1 SITE GRADING

The site will be filled and graded to provide a finished surface for construction of structures and associated facilities including roadways, parking areas, construction laydown areas, storm water detention basins, and conveyances. The grading will provide adequate drainage for all buildings, structures, and working areas.

Site drainage will be accomplished by gravity flow, utilizing a surface drainage system consisting of mild surface slopes that sheet flow to existing drainage ditches, swales, and culverts. First floor elevations will be above the 100-year flood elevation of 75 feet. The site will be graded to elevations of 77 feet or higher. Figure 1 shows the site grading and drainage plan and depicts cross sections of the site according to the proposed site elevations. Figure 2 provides details of the proposed storm water control structure.

2.2 ROADS AND PARKING AREAS

A roadway system will provide access to various portions of the site. It includes permanent gravel roads or driveways with minimum 20 foot wide surfaces. During construction, roadways will be surfaced with aggregate. All impervious areas used for roads and parking will have sloped surfaces that will convey storm water to the proposed collection system.

2.3 PERVIOUS AND IMPERVIOUS AREAS

As calculated from the site layout plan, approximately 2.9 acres of the proposed 13.7 – acre construction area will be impervious surface. An additional 9 acres of directly connected impervious area will be provided to account for the wet detention pond. Impervious surfaces include transformers, concrete pads, buildings, and associated facilities. Pervious areas that will be part of the improved area (approximately 10.8 acres) will either be grassed or landscaped.

2.4 DRAINAGE DITCHES AND SWALES

Existing collection systems which will convey runoff to the wet detention ponds are designed for the 100-year, 24-hour capacity. Ditches and swales that are rerouted to accommodate the proposed construction area will be regraded and grassed, and will be included in the plant's normal maintenance program.

2.5 CULVERTS

Existing drainage culverts will be utilized to the greatest extent possible. Any culverts within the collection system that require replacement will be designed for the 100 year – 24 hour storm capacity and will be constructed of either reinforced concrete or high-density polyethylene pipe.

2.6 DETENTION BASIN

Existing and proposed storm water will be collected in the existing wet retention basin located north of the proposed construction area. The pond has been designed to provide water quality treatment and attenuation of storm water runoff from the existing 52-acre site. Supporting calculations show that the existing pond is capable of providing adequate treatment of the additional flow with modifications to the existing discharge structure. The location and configuration of the detention pond is shown in Figure 1.

The detention basin will be excavated to an elevation of 72.0 feet, such that the depth of the permanent pool is three feet deep. The permanent pool volume will provide the 14-day residence time required during the wet season (June through October) to assure adequate sedimentation and water quality treatment of storm water runoff. Under normal conditions, the permanent pool elevation of the pond will be 75.20 feet. An orifice located in the outlet structure will be used as a bleed down device to recover the detention and water quality treatment volume. The bleed down device will recover 50 percent of the detention volume within the first 60 hours following the rainfall event. The bleed down orifice will be 5 inches in diameter, with an invert elevation of 75.20 feet.

The pond will attenuate the peak flows from the 100 year – 24 hour storm below the predevelopment rate through the outlet control structure. Discharge will be directed to the existing wetland system adjacent to the site. Predevelopment peak discharge from the pond during the 100 year – 24 hour storm event is 138.76 cubic feet per second, with a maximum stage elevation of 79.42 feet. Postdevelopment peak discharge during the 100 year – 24 hour storm event is 49.38 cubic feet per second, with a maximum stage elevation of 79.37 feet.

The storm water detention pond will serve as a sedimentation basin during construction. The detention pond will allow suspended solids or loose sediments to be settled to the bottom. The will be maintained for proper operation immediately following construction.

Supporting calculations for the wet detention system are located in the attachment to this SWMP.

2.7 EROSION CONTROL

During construction, site erosion will be controlled by maintaining finished surface slopes to less than 1 percent. Silt fencing and straw bale barriers will be used to prevent sedimentation along the perimeter of the site. Surfaces will be vegetated to prevent sediment loss and ditches will be stabilized as necessary. Erosion control is depicted at the limits of construction shown in Figure 1.

3.0 STORM WATER MANAGEMENT PLAN AND PRACTICES

The storm water management plan for the Stanton Unit A project is shown in Figure 1, including site layout, general arrangement of equipment and facilities, arrangement and location of storm water runoff control structures, location of storm water runoff outfall structures, and offsite storm water runoff receiving areas. Control practices for storm water during construction and operational periods are described below.

3.1 CONSTRUCTION PHASE STORM WATER CONTROL MEASURES AND PRACTICES

During construction of the Stanton Unit A facility, a combination of silt fencing, straw bale sediment barriers, and the storm water detention basin will be used to control erosion on the site and to reduce the potential for transport of eroded sediment offsite. All grading will be accomplished in phases, with each graded area seeded and mulched after construction is complete.

A portion of the existing storm water detention basin will be regraded during the initial phases of site preparation to serve as a sedimentation basin. Subsequently, the drainage system will be constructed such that storm water continues to be conveyed to the detention basins to remove suspended solids from runoff.

Movement of sediment off graded areas will initially be controlled by the use of silt fences that will provide continuous silt barriers on the down gradient sides of all actively graded areas. Interception of runoff by drainage ditches established early in the construction phase will allow removal of sediment by straw bale fences, with subsequent conveyance of runoff to the storm water detention basin.

To isolate runoff from materials storage areas, appropriate containment such as earth berms will be provided. Runoff from these areas will be treated by onsite wastewater treatment facilities.

Site dewatering flows during construction will be routed through a sedimentation barrier to the detention basin for treatment before offsite discharge. A silt fence/straw bale barrier will be used for initial removal of sediment from dewatering flows as they enter the system in order to minimize sedimentation impacts on the detention basin volume during construction. Available capacity of the detention pond will be monitored during dewatering activity to assure that flow volumes are not damaging the existing littoral

shelf and that adequate capacity remains available for detention of the 100 year – 24 hour design storm event.

3.2 OPERATING PHASE STORM WATER CONTROL MEASURES AND PRACTICES

The proposed storm water collection system will intercept all onsite runoff from both the existing and proposed developed site areas under design storm conditions and convey it to the storm water detention basin. In accordance with SJRWMD requirements, the detention basin is sized to retain and treat the runoff volume that results from 2.5 inches of runoff from the impervious site areas. In addition, the basin will attenuate the 100 year – 24 hour storm event. All storm water runoff will be drained by gravity to the wet detention basin.



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3. TOPSOIL SHALL BE STRIPPED FOR ALL PERMANENT AND TEMPORARY ROADS, CONSTRUCTION LAYDOWN, CONSTRUCTION AND PERMANENT PARKING AREAS, SWITCHYARD, AND PLANT AREA CONTAINED BY PERMANENT PLANT ACCESS ROADS.
4. ENTIRE SITE INSIDE PROJECT BOUNDARY SHALL BE CLEARED AND GRUBBED.
5. DUST SHALL BE CONTROLLED ON THE ENTRANCE ROADS AND PLANT ROADS BY SPRINKLING WITH WATER.

POND NOTES

1. ALL INTERIOR SIDE SLOPES TO BE DISTURBED TO THE LEAST EXTENT POSSIBLE.
2. ANY INTERIOR SIDE SLOPES DISTURBED DURING CONSTRUCTION SHALL BE REGRADED AT 4:1 (MAX)
3. THE EXISTING DISCHARGE STRUCTURE SHALL BE REMOVED AND REPLACED (SEE NEW WEIR PLAN AND SECTIONS ON DRAWING FIGURE-2).
4. THE LITTORAL ZONE SHALL BE REPLANTED TO PRE-CONSTRUCTION CONDITION PRIOR TO PROJECT COMPLETION. EVERY EFFORT SHALL BE MADE TO AVOID DISRUPTION OF THESE AREAS DURING CONSTRUCTION.



GRAPHIC SCALE

100 0 100 200



SCALE IN FEET

CAD FIGURE-1.DWG

AutoCad	SHW-2000I
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Southern Company Services, Inc.
FOR

SOUTHERN COMPANY GENERATION

STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
GRADING AND DRAINAGE PLAN

DESIGNED		DRAWN SHW		CHECKED	
5	SCALE	PROJECT I.D.	DRAWING NUMBER	REV	
			FIGURE-1	A	

REVISION		DATE	REVISION		DATE	REVISION		DATE	REVISION		DATE	REVISION A		DATE 01/05/01						
												ISSUED FOR REVIEW								
BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
												SHW								

ATTACHMENT
STANTON UNIT 3 STORM WATER CALCULATIONS

Design Requirements:

Design Rainfall Events: Mean Annual = 4.4 inches
 25 Year – 24 Hour = 8.7 inches
 100 Year – 24 Hour = 10.8 inches

Design Rainfall Distribution: SCS Type II

Pond Sizing / Treatment Volumes:

Directly Connected Impervious Area (DCIA):

DCIA = pond area = 393,621 square feet = 9 acres

$$\%DCIA = \frac{9.0}{52.0 + 9.0} = 14.75\%$$

Treatment Volume:

The design treatment volume shall be the greater of the following:

- 1) 1" over entire treatment area
 Area = 52.0 acres

$$\text{Volume}_1 = 52.0 \text{ acres} \times \frac{43,560 \text{ ft}^2}{\text{acre}} \times 1" \text{ runoff} \times \frac{1'}{12"} \times \frac{1}{12}$$

$$\text{Volume}_1 = 188,760 \text{ ft}^3$$

- 2) 2.5" over contributing impervious areas
 Total impervious area = 41.2 acres

$$\text{Volume}_2 = 41.2 \text{ acres} \times \frac{43,560 \text{ ft}^2}{\text{acre}} \times 2.5" \text{ runoff} \times \frac{1'}{12"} \times \frac{1}{12}$$

$$\text{Volume}_2 = 373,890 \text{ ft}^3$$

$$\text{Required treatment volume} = 373,890 \text{ ft}^3$$

Stage-Area Relationship:

<u>Elevation</u>	<u>Area (square feet)</u>	<u>Area (acres)</u>
73.0	245,525	5.6
75.0	281,781	6.5
77.0	318,549	7.3
80.0	374,661	8.6

Groundwater table and permanent pool elevation: 75.20 feet

Depth of treatment volume:

$$\frac{373,890 \text{ ft}^3}{(1,320,825 \text{ ft}^3 - 734,254 \text{ ft}^3)} = 0.64 \text{ feet}$$

Elevation of treatment volume = 75.84 feet

Recovery Time:

The outfall structure will draw down 50 percent of the required treatment volume between 48 and 60 hours.

Outlet Structure:

Q = Rate of discharge (cfs)

A = Orifice area (ft²)

g = Gravitational constant = (32.2 ft/sec²)

h = Depth of Water above the flow line of the orifice

C = Orifice coefficient (assumed 0.6)

Treatment volume = 373,890 ft³

The average discharge rate required to draw down half the treatment volume in a 60 hours is given by:

$$Q = \frac{186,945 \text{ ft}^3}{2 (60 \text{ hr})(3,600 \text{ sec/hr})} = 0.43 \text{ cfs}$$

The depth of water (h) set to the average depth above the flow line between the top of the treatment volume and the stage at which half of the treatment volume has been released is:

$$h = \frac{0.64 + 0.32}{2} = 0.48 \text{ feet}$$

$$A = \frac{Q}{C(2gh)^{1/2}} = \frac{0.86}{0.6[(2)(32.2)(0.48)]^{1/2}} = 0.13 \text{ ft}^2$$

$$D = \left(\frac{4A}{3.1416} \right)^{1/2} = 0.41 \text{ feet} = 5 \text{ inch orifice diameter}$$

Permanent Pool :

$$PPV_{\text{reqd}} = \frac{DA \times C \times R \times RT}{WS \times CF}$$

$$= \frac{(52)(0.78)(31)(14)}{(153)(12)}$$

$$= 9.59 \text{ acre-ft}$$

$$= 417,641 \text{ ft}^3$$

where PPV = Permanent pool volume (acre-ft)

RT = Residence time (days)

R = Wet season rainfall (inches)

FR = Average flow rate (acre-ft/day)

CF = 12 (inches / foot)

C = runoff coefficient

$$C = \frac{(41.2 \text{ acres} \times 0.9) + (10.8 \text{ acres} \times 0.30)}{52 \text{ acres}} = 0.78$$

$$PPV_{\text{provided}} = 734,254 \text{ ft}^3$$

$PPV_{\text{provided}} > PPV_{\text{reqd}}$ therefore the existing permanent pool is adequate

Littoral Zone:

The littoral zone for the treatment basin has already been established. Any disruption to the littoral zone will be restored to pre-construction conditions prior to project completion.

Pond Depth:

The depth of the pond will be excavated to a constant depth of 3 feet, which will comply with the maximum pond depth requirement of not less than 2 feet and not more than 8 feet.

Pond Configuration:

The length to width ratio is greater than the required 2:1. The discharge structure will be located out of close proximity of the inlet structures that there is adequate mixing and short-circuiting is prevented.

Ground Water Table:

The groundwater table is located at approximately 75.20 feet. The 100 year flood elevation downstream of the discharge point is 75.0 feet.

Pond Side Slopes:

The existing pond side slopes are 4:1 (horizontal:vertical), which exceeds the minimum requirement of 3:1.

Stanton 3
Pre-Development Analysis

***** Input Report *****

-----Class: Node-----

Name: DISCHARG Base Flow(cfs): 0 Init Stage(ft): 75
 Group: BASE Warn Stage(ft): 0
 Comment:

Time(hrs)	Stage(ft)
0	75
48	75

-----Class: Node-----

Name: SITE Base Flow(cfs): 0 Init Stage(ft): 78.5
 Group: BASE Warn Stage(ft): 0
 Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

-----Class: Operating Table-----

Name: WEIR Type: Rating Curve
 Comment:

U/S Stage(ft)	Discharge(cfs)
73	0
78.5	0
79	69.74
80	362.37

-----Class: Simulation-----

C:\ICPR2\STANTON\STANTON

Execution: Both

Header: Stanton 3

Pre-Development Analysis

Mean Annual Precipitation Event

-----HYDRAULICS-----HYDROLOGY-----

Max Delta Z (ft): 1
 Delta Z Factor: 0.05 Override Defaults: No
 Time Step Optimizer: 10
 Drop Structure Optimizer: 10
 Sim Start Time(hrs): 0
 Sim End Time(hrs): 48
 Min Calc Time(sec): 0.5
 Max Calc Time(sec): 60
 To Hour: PInc(min): To Hour: PInc(min):
 48 15 48 15

-----GROUP SELECTIONS-----

+ BASE [01/11/01]

fl
[1]

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Stanton 3
Pre-Development Analysis

***** Basin Summary - STANTON

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH

Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	4.40
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	84.90
DCIA (%):	14.75

Time Max (hrs):	12.53
Flow Max (cfs):	55.49
Runoff Volume (in):	3.03
Runoff Volume (cf):	670463

fl

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Stanton 3
Pre-Development Analysis
Mean Annual Precipitation Event

***** Link Maximum Conditions - STANTON *****

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	13.25	40.42	0.68	13.25	78.79	0.00	75.00

fl

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[1]

Stanton 3
Pre-Development Analysis
Mean Annual Precipitation Event

***** Node Maximum Conditions - STANTON *****

(Time units - hours)										
Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	13.25	40.42	0.00	0.00
SITE	BASE	13.25	78.79	0.00	0.0049	351910.41	12.50	54.99	13.25	40.42

Stanton 3
 Pre-Development Analysis

***** Input Report *****

-----Class: Node-----

Name: DISCHARG Base Flow(cfs): 0 Init Stage(ft): 75
 Group: BASE Warn Stage(ft): 0
 Comment:

Time(hrs)	Stage(ft)
0	75
48	75

-----Class: Node-----

Name: SITE Base Flow(cfs): 0 Init Stage(ft): 78.5
 Group: BASE Warn Stage(ft): 0
 Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

-----Class: Operating Table-----

Name: WEIR Type: Rating Curve
 Comment:

U/S Stage(ft)	Discharge(cfs)
73	0
78.5	0
79	69.74
80	362.37

-----Class: Simulation-----

C:\ICPR2\STANTON\STANTON

Execution: Both

Header: Stanton 3

Pre-Development Analysis

25 Year - 24 Hour Precipitation Event

-----HYDRAULICS-----

-----HYDROLOGY-----

Max Delta Z (ft): 1	
Delta Z Factor: 0.05	Override Defaults: No
Time Step Optimizer: 10	
Drop Structure Optimizer: 10	
Sim Start Time(hrs): 0	
Sim End Time(hrs): 48	
Min Calc Time(sec): 0.5	
Max Calc Time(sec): 60	
To Hour: 48	PInc(min): 15
To Hour: 48	PInc(min): 15

-----GROUP SELECTIONS-----

+ BASE [01/11/01]

Stanton 3
Pre-Development Analysis
25 Year - 24 Hour Precipitation Event

***** Basin Summary - STANTON *****

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH

Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	8.70
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	84.90
DCIA (%):	14.75

Time Max (hrs):	12.53
Flow Max (cfs):	130.40
Runoff Volume (in):	7.13
Runoff Volume (cf):	1578746

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Stanton 3
Pre-Development Analysis
25 Year - 24 Hour Precipitation Event

***** Link Maximum Conditions - STANTON *****

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	13.03	105.02	2.81	13.03	79.12	0.00	75.00

Stanton 3
 Pre-Development Analysis
 25 Year - 24 Hour Precipitation Event

***** Node Maximum Conditions - STANTON *****

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	13.03	105.02	0.00	0.00
SITE	BASE	13.03	79.12	0.00	0.0109	358098.59	12.50	129.49	13.03	105.02

Stanton 3
 Post-Development Analysis

***** Input Report *****

-----Class: Node-----

Name: DISCHARG Base Flow(cfs): 0 Init Stage(ft): 75
 Group: BASE Warn Stage(ft): 0
 Comment:

Time(hrs)	Stage(ft)
0	75
48	75

-----Class: Node-----

Name: SITE Base Flow(cfs): 0 Init Stage(ft): 78.5
 Group: BASE Warn Stage(ft): 0
 Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

-----Class: Operating Table-----

Name: WEIR Type: Rating Curve
 Comment:

U/S Stage(ft)	Discharge(cfs)
75	0
75.5	0.36
76	0.59
76.5	0.75
77	14.3
77.5	26.09
78	33.96
78.5	40.31
79	45.78
79.5	50.66
80	55.1

-----Class: Simulation-----

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Execution: Both

Header: Stanton 3

Post-Development Analysis

25 Year - 24 Hour Precipitation Event

-----HYDRAULICS-----HYDROLOGY-----

Max Delta Z (ft): 1
 Delta Z Factor: 0.05 Override Defaults: No
 Time Step Optimizer: 10
 Drop Structure Optimizer: 10
 Sim Start Time(hrs): 0
 Sim End Time(hrs): 48
 Min Calc Time(sec): 0.5
 Max Calc Time(sec): 60
 To Hour: PInc(min): To Hour: PInc(min):
 48 15 48 15

-----GROUP SELECTIONS-----

+ BASE [01/11/01]

Stanton 3
Post-Development Analysis
25 Year - 24 Hour Precipitation Event

***** Basin Summary - STANTON *****

Basin Name: BLOCK
Group Name: BASE
Node Name: SITE
Hydrograph Type: UH

Unit Hydrograph: UH256
Peaking Factor: 256.00
Spec Time Inc (min): 8.00
Comp Time Inc (min): 8.00
Rainfall File: SCSII-24
Rainfall Amount (in): 8.70
Storm Duration (hr): 24.00
Status: ONSITE
Time of Conc. (min): 60.00
Lag Time (hr): 0.00
Area (acres): 61.00
Vol of Unit Hyd (in): 1.00
Curve Number: 90.70
DCIA (%): 14.75

Time Max (hrs): 12.53
Flow Max (cfs): 139.20
Runoff Volume (in): 7.73
Runoff Volume (cf): 1711179

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Stanton 3
Post-Development Analysis
25 Year - 24 Hour Precipitation Event

***** Link Maximum Conditions - STANTON *****

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	15.15	42.59	40.31	15.15	78.71	0.00	75.00

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Stanton 3
 Post-Development Analysis
 25 Year - 24 Hour Precipitation Event

***** Node Maximum Conditions - STANTON *****

(Time units - hours)											
Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)	
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	15.15	42.59	0.00	0.00	
SITE	BASE	15.15	78.71	0.00	0.0203	350388.38	12.50	138.35	15.15	42.59	

Stanton 3
 Pre-Development Analysis

***** Input Report *****

-----Class: Node-----

Name: DISCHARG Base Flow(cfs): 0 Init Stage(ft): 75
 Group: BASE Warn Stage(ft): 0
 Comment:

Time(hrs)	Stage(ft)
0	75
48	75

-----Class: Node-----

Name: SITE Base Flow(cfs): 0 Init Stage(ft): 78.5
 Group: BASE Warn Stage(ft): 0
 Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

-----Class: Operating Table-----

Name: WEIR Type: Rating Curve
 Comment:

U/S Stage(ft)	Discharge(cfs)
73	0
78.5	0
79	69.74
80	362.37

-----Class: Simulation-----

C:\ICPR2\STANTON\STANTON

Execution: Both

Header: Stanton 3

Pre-Development Analysis

100 Year - 24 Hour Precipitation Event

-----HYDRAULICS-----HYDROLOGY-----

Max Delta Z (ft): 1	
Delta Z Factor: 0.05	Override Defaults: No
Time Step Optimizer: 10	
Drop Structure Optimizer: 10	
Sim Start Time(hrs): 0	
Sim End Time(hrs): 48	
Min Calc Time(sec): 0.5	
Max Calc Time(sec): 60	
To Hour: PInc(min):	To Hour: PInc(min):
48 15	48 15

-----GROUP SELECTIONS-----

+ BASE [01/11/01]

Stanton 3
Pre-Development Analysis
100 Year - 24 Hour Precipitation Event

***** Basin Summary - STANTON *****

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH

Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	10.80
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	84.90
DCIA (%):	14.75

Time Max (hrs):	12.53
Flow Max (cfs):	167.05
Runoff Volume (in):	9.18
Runoff Volume (cf):	2033462

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Stanton 3
Pre-Development Analysis
100 Year - 24 Hour Precipitation Event

***** Link Maximum Conditions - STANTON *****

(Time units - hours)								
Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	12.98	138.76	3.88	12.98	79.24	0.00	75.00

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Stanton 3
 Pre-Development Analysis
 100 Year - 24 Hour Precipitation Event

***** Node Maximum Conditions - STANTON *****

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	12.98	138.76	0.00	0.00
SITE	BASE	12.98	79.24	0.00	0.0136	360270.26	12.50	165.95	12.98	138.76

Stanton 3
 Post-Development Analysis

***** Input Report *****

-----Class: Node-----

Name: DISCHARG Base Flow(cfs): 0 Init Stage(ft): 75
 Group: BASE Warn Stage(ft): 0
 Comment:

Time(hrs)	Stage(ft)
0	75
48	75

-----Class: Node-----

Name: SITE Base Flow(cfs): 0 Init Stage(ft): 78.5
 Group: BASE Warn Stage(ft): 0
 Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

-----Class: Operating Table-----

Name: WEIR Type: Rating Curve
 Comment:

U/S Stage(ft)	Discharge(cfs)
75	0
75.5	0.36
76	0.59
76.5	0.75
77	14.3
77.5	26.09
78	33.96
78.5	40.31
79	45.78
79.5	50.66
80	55.1

-----Class: Simulation-----

C:\ICPR2\STANTON\STANTON

Execution: Both

Header: Stanton 3

Post-Development Analysis

100 Year - 24 Hour Precipitation Event

-----HYDRAULICS-----HYDROLOGY-----

Max Delta Z (ft): 1

Delta Z Factor: 0.05

Override Defaults: No

Time Step Optimizer: 10

Drop Structure Optimizer: 10

Sim Start Time(hrs): 0

Sim End Time(hrs): 48

Min Calc Time(sec): 0.5

Max Calc Time(sec): 60

To Hour: PInc(min):

48 15

To Hour: PInc(min):

48 15

-----GROUP SELECTIONS-----

+ BASE {01/11/01}

Stanton 3
Post-Development Analysis
100 Year - 24 Hour Precipitation Event

***** Basin Summary - STANTON *****

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH

Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	10.80
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	90.70
DCIA (%):	14.75

Time Max (hrs):	12.53
Flow Max (cfs):	175.37
Runoff Volume (in):	9.81
Runoff Volume (cf):	2172260

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Stanton 3
Post-Development Analysis
100 Year - 24 Hour Precipitation Event

***** Link Maximum Conditions - STANTON *****

(Time units - hours)								
Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	15.35	49.38	40.31	15.35	79.37	0.00	75.00

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Stanton 3
 Post-Development Analysis
 100 Year - 24 Hour Precipitation Event

***** Node Maximum Conditions - STANTON *****

(Time units - hours)											
Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)	
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	15.35	49.38	0.00	0.00	
SITE	BASE	15.35	79.37	0.00	0.0257	362783.83	12.50	174.34	15.35	49.38	

STANTON

flow based on weir equation

$$Q = cLh^{1.5}$$

where: c= 3
L= 10
h= head in feet

weir elev.= 76.8

stage	h (ft)	Q(cfs)
80	3.2	53.67
79.5	2.7	49.30
79	2.2	44.50
78.5	1.7	39.12
78	1.2	32.86
77.5	0.7	25.10
77	0.2	13.42
76.5	0	0.00
76	0	0.00
75.5	0	0.00
75	0	0.00
74.5	0	0.00
74	0	0.00

flow based on orifice

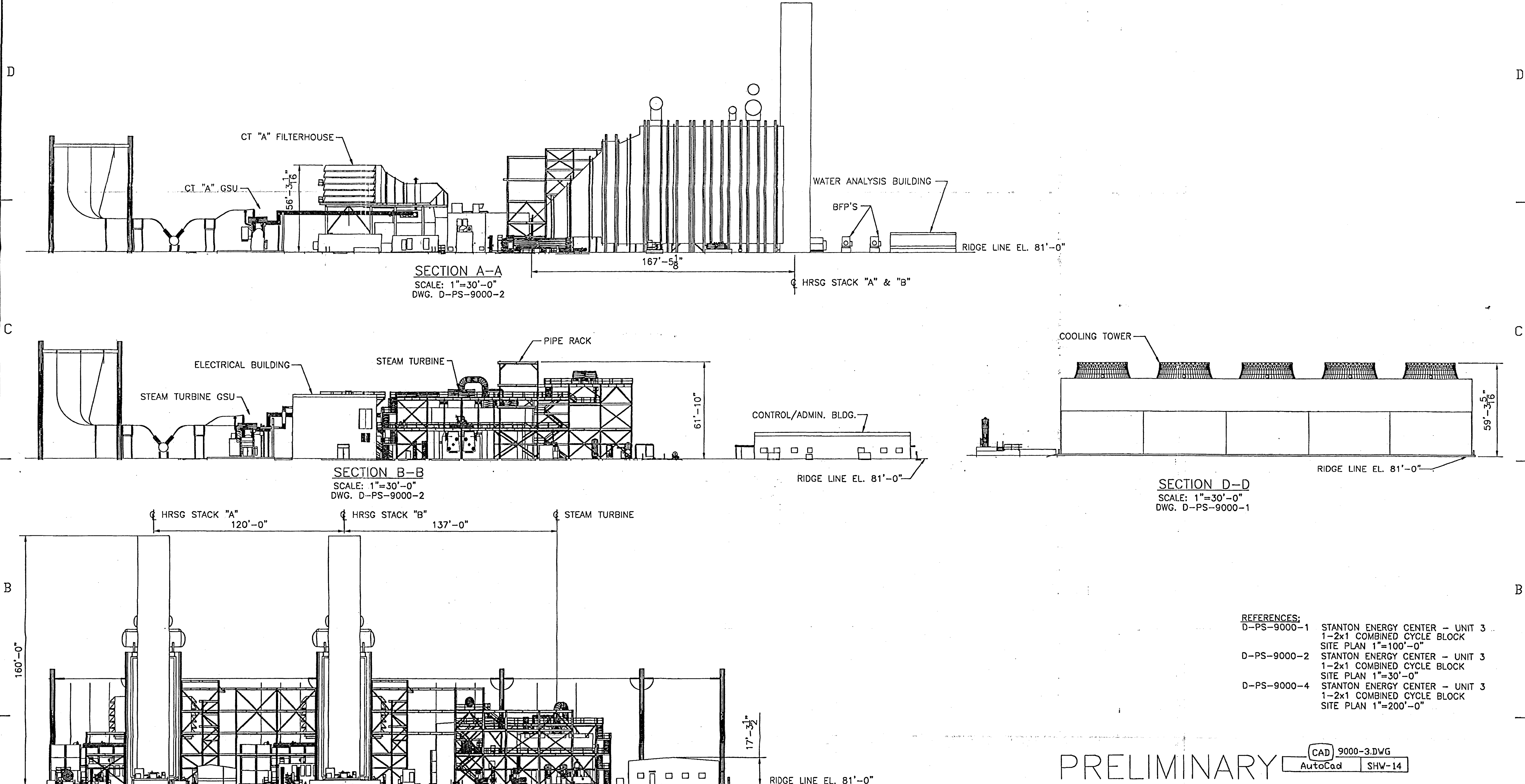
$$Q = cA(2gh)^{0.5}$$

where: c= 0.6
A= 0.14
h= head in feet
g= 32.2 ft/sec^2

orifice elev.= 75.2

stage	h(ft)	Q(cfs)	TOTAL Q cfs
80	4.8	1.44	55.10
79.5	4.3	1.36	50.66
79	3.8	1.28	45.78
78.5	3.3	1.19	40.31
78	2.8	1.10	33.96
77.5	2.3	1.00	26.09
77	1.8	0.88	14.30
76.5	1.3	0.75	0.75
76	0.8	0.59	0.59
75.5	0.3	0.36	0.36
75	0	0.00	0.00
74.5	0	0.00	0.00
74	0	0.00	0.00

orifice in inches= 5
in feet = 0.42

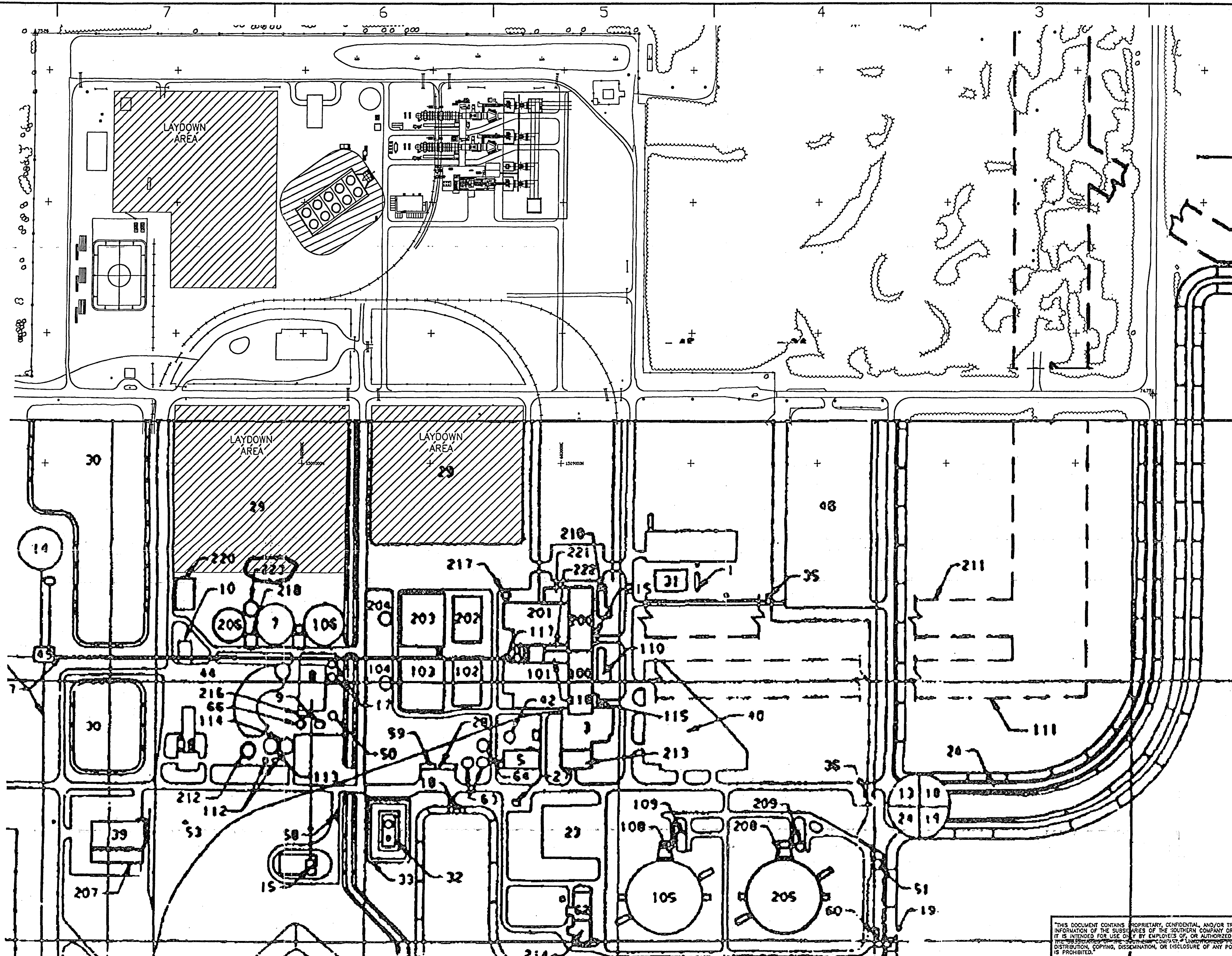


- REFERENCES:
- D-PS-9000-1 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=100'-0"
 - D-PS-9000-2 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=30'-0"
 - D-PS-9000-4 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

PRELIMINARY

CAD 9000-3.DWG
AutoCad SHW-14

SECTION C-C SCALE: 1"=30'-0" DWG. D-PS-9000-2																				THIS DOCUMENT CONTAINS PROPRIETARY, CONFIDENTIAL, AND/OR TRADE SECRET INFORMATION OF THE SUBSIDIARIES OF THE SOUTHERN COMPANY OR THIRD PARTIES. IT IS INTENDED FOR USE ONLY BY EMPLOYEES OF, OR AUTHORIZED CONTRACTORS OF THE SUBSIDIARIES OF THE SOUTHERN COMPANY. UNAUTHORIZED POSSESSION, USE, DISTRIBUTION, COPYING, DISSEMINATION, OR DISCLOSURE OF ANY PORTION HEREOF IS PROHIBITED.										Southern Company Services, Inc. FOR																																																																																																																																																
REVISION					DATE					REVISION					DATE					REVISION					DATE					REVISION					DATE					REVISION A					DATE 9/22/00					SOUTHERN COMPANY GENERATION STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS																																																																																																																												
																																								ISSUED FOR REVIEW																																																																																																																																						
BY					CHK'D					APPR. 1					APPR. 2					APPR. 3					APPR. 4					APPR. 5					BY					CHK'D					APPR. 1					APPR. 2					APPR. 3					APPR. 4					APPR. 5					BY					CHK'D					APPR. 1					APPR. 2					APPR. 3					APPR. 4					APPR. 5					BY					CHK'D					APPR. 1					APPR. 2					APPR. 3					APPR. 4					APPR. 5					SHW										AS NOTED															D-PS-9000-3					A				



REFERENCES:
D-PS-9000-1 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=100'-0"
D-PS-9000-2 STANTON ENERGY CENTER - UNIT 3
1 - 2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=30'-0"
D-PS-9000-3 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SECTIONS

CAD 9000-4	
AutoCad	SHW-14

Southern Company Services, Inc.
FOR

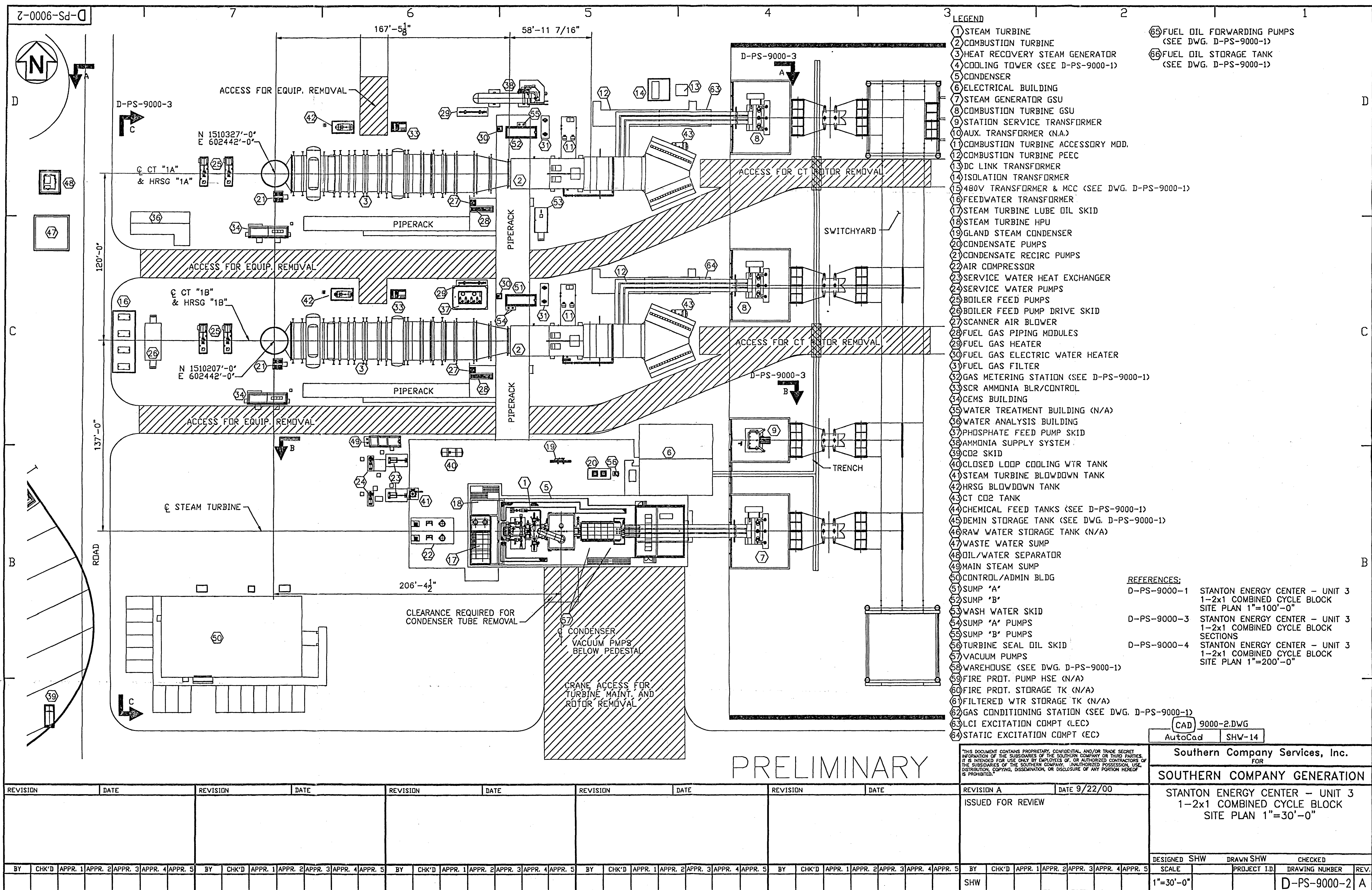
SOUTHERN COMPANY GENERATION

STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

	DESIGNED SHW	DRAWN SHW	CHECKED	
5	SCALE	PROJECT I.D.	DRAWING NUMBER	REV
	1"=200'-0"		D-PS-9000-4	A

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REVISION A	DATE 9/22/00
ISSUED FOR REVIEW	



5.0 Effects of Plant Operation

5.1 Effects of the Operation of the Heat Dissipation System

Stanton Energy Center (SEC) Stanton A will use a mechanical draft cooling tower as the major equipment for heat dissipation and cooling. Cooling tower makeup water is taken from the existing SEC Makeup Water Supply Storage Pond, which receives effluent from the Orange County Eastern Subregional Water Reclamation Facility. Cooling tower blowdown will be routed to a new brine concentrator/crystallizer treatment system where most of the water is recovered for reuse at the plant.

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. Most of the blowdown water from the heat dissipation system will be recovered for reuse at the plant.

5.1.2 Effect on Aquatic Life

Since 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

Stanton A will use municipal effluent water for cooling water. Since modified circulation of a water body will not occur, 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 the Stanton A cooling tower. Potential impacts from the cooling tower include plume induced fogging and icing, deposition from circulating water drift, and visible plume formation. The following subsections describe the cooling tower, 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 addition of the combined cycle combustion turbines (CCCT) at the SEC 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 10 cells in one housing arranged along a southwest-northeast axis just to the west of the proposed combined cycle units.

5.1.4.2 Technical Approach. A computer modeling analysis was performed for Stanton A to evaluate the magnitude and extent of the potential environmental impacts resulting from the operation of the cooling tower at the SEC. 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 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.

The SEC 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 to 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 SEC location.

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 Stanton A were all based on data representative of a typical tower sized to reject waste heat from the proposed unit's heat cycle.

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 project area's water quality.

Table 5.1-1
SACTI Cooling Tower Modeling Input Parameters

Site-Specific Data		Data Source/Notes
Site Latitude	28.47 N	Measured
Site Longitude	81.16 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	444 m (morning) 1,424 m (afternoon)	SACTI User's Manual
Wind Instrument Reference Height	6.1 m (anemometer height)	NWS
Tower-Specific Data		
Tower Type	Linear Mechanical Draft	Preliminary Design
Number of Towers	1	Preliminary Design
Effective Exhaust Diameter	32.8 m	Preliminary Design
Tower Height	13.6 m	Preliminary Design
Tower Width	37.2 m	Preliminary Design
Tower Length	80.8 m	Preliminary Design
Total Heat Dissipation Rate	1,312 MBtu/h	Preliminary Design
Total Circulating Water	125,000 gpm	Preliminary Design
Total Drift Loss Rate	158 g/s	Preliminary Design, based on 0.002% drift rate.
Total Airflow Rate	7,204 kg/s	Preliminary Design

Table 5.1-1 (Continued)
SACTI Cooling Tower Modeling Input Parameters

Water-Specific Data		
Cooling Tower Salt Concentration	0.0037 g Salt/g Soln	Preliminary Design Estimated Estimated, based on Hamon cooling tower drift data.
Salt Density	2.66 g/cm ³	
Drift Droplet Spectrum	Drop Size	
	Mass	
	<u>(μm)</u>	
	<u>Fraction</u>	
	0-20	
	20-40	
	40-60	
	60-80	
	80-100	
	100-120	
	120-140	
	140-160	
	160-180	
	180-200	
	200-220	
	220-240	
	240-260	
	260-280	
	280-300	
	300-320	
	320-340	

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 tower is 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 tower.

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 tower. The 16 wind direction labels in the columns of the table represent the direction from the cooling tower that the plume is headed. The data represent the total hours (over the 5 year database) 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 5.0 hours (over the 5 year database) of plume fogging occur approximately 100 m (328 ft) south of the cooling tower.

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.

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.	5.0	2.8	0.3	1.5	2.2	1.6	1.1	0.9	2.5	0.1	0.8	0.1	2.0	0.8	0.1	2.0	23.8
200.	3.9	1.2	0.3	2.0	1.9	2.1	1.3	1.1	2.1	0.1	1.0	0.1	1.7	1.0	0.1	0.2	20.2
300.	3.0	0.2	0.0	0.4	1.5	0.2	0.1	0.1	2.0	0.0	0.2	0.0	1.4	0.1	0.0	0.0	9.3
400.	1.4	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.5	0.0	0.0	0.0	3.5
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.

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 5.1-3 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 tower. The 16 wind direction labels in the columns of the table represent the direction from the cooling tower that the water deposition is predicted to occur.

The SACTI model predicted that the maximum cooling tower water deposition would occur approximately 900 m (2,953 ft) south of the cooling tower at a rate of $2,800 \text{ kg}/\text{km}^2/\text{month}$. The average water deposition at a 900 m (2,953 ft) radius from the cooling tower (considering all directions of plume travel) is predicted to be $1,200 \text{ kg}/\text{km}^2/\text{month}$.

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 database) salt deposition rate in units of $\text{kg}/\text{km}^2/\text{month}$ associated with the proposed cooling tower. The 16 wind direction labels in the columns of the table represent the direction from the proposed cooling tower that the salt deposition is predicted to occur.

The maximum salt deposition occurs approximately 900 m (2,953 ft) south of the cooling tower at a rate of $11.2 \text{ kg}/\text{km}^2/\text{month}$. The average salt deposition at a radius of 900 m (2,953 ft) from the cooling tower (considering all directions of plume travel) is predicted to be $5.1 \text{ kg}/\text{km}^2/\text{month}$. Beyond 900 m (2,953 ft) from the cooling tower, the salt deposition continually decreases. In fact, the average salt deposition beyond 2,700 m (8,858 ft) from the cooling tower in all directions is less than $1 \text{ kg}/\text{km}^2/\text{month}$.

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 database) predicted plume length frequency of occurrence associated with the cooling tower. The 16 wind direction labels in the columns of the table represent the direction from the cooling tower 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.

Table 5.1-3
Average Monthly Predicted Cooling Tower Water Deposition

Water Deposition in the Direction Plume is Headed (kg/km ² -month)																		
Distance From Tower (m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG	
100.	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00
200.	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00
300.	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00
400.	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00	.00E+00
500.	.89E+03	.58E+03	.44E+03	.43E+03	.43E+03	.19E+03	.27E+03	.37E+03	.87E+03	.61E+03	.38E+03	.41E+03	.31E+03	.24E+03	.19E+03	.28E+03	.43E+03	
600.	.21E+04	.13E+04	.10E+04	.11E+04	.13E+04	.53E+03	.67E+03	.84E+03	.21E+04	.13E+04	.89E+03	.96E+03	.94E+03	.63E+03	.44E+03	.62E+03	.11E+04	
700.	.21E+04	.12E+04	.90E+03	.88E+03	.11E+04	.40E+03	.57E+03	.75E+03	.21E+04	.12E+04	.77E+03	.83E+03	.80E+03	.52E+03	.39E+03	.57E+03	.94E+03	
800.	.25E+04	.14E+04	.10E+04	.99E+03	.11E+04	.42E+03	.64E+03	.88E+03	.24E+04	.15E+04	.91E+03	.98E+03	.85E+03	.60E+03	.46E+03	.71E+03	.11E+04	
900.	.28E+04	.15E+04	.11E+04	.10E+04	.12E+04	.43E+03	.67E+03	.92E+03	.26E+04	.15E+04	.94E+03	.10E+04	.93E+03	.63E+03	.48E+03	.75E+03	.12E+04	
1000.	.24E+04	.14E+04	.98E+03	.91E+03	.12E+04	.39E+03	.60E+03	.84E+03	.23E+04	.14E+04	.85E+03	.92E+03	.88E+03	.57E+03	.44E+03	.69E+03	.10E+04	
1100.	.22E+04	.12E+04	.83E+03	.78E+03	.12E+04	.32E+03	.51E+03	.71E+03	.21E+04	.12E+04	.73E+03	.78E+03	.86E+03	.48E+03	.37E+03	.59E+03	.92E+03	
1200.	.20E+04	.94E+03	.67E+03	.63E+03	.10E+04	.27E+03	.41E+03	.57E+03	.19E+04	.95E+03	.59E+03	.62E+03	.76E+03	.40E+03	.30E+03	.49E+03	.78E+03	
1300.	.12E+04	.62E+03	.45E+03	.43E+03	.59E+03	.19E+03	.28E+03	.38E+03	.11E+04	.62E+03	.40E+03	.41E+03	.46E+03	.28E+03	.20E+03	.34E+03	.50E+03	
1400.	.12E+04	.64E+03	.48E+03	.47E+03	.59E+03	.23E+03	.29E+03	.40E+03	.11E+04	.64E+03	.41E+03	.43E+03	.46E+03	.30E+03	.21E+03	.34E+03	.51E+03	
1500.	.10E+04	.48E+03	.36E+03	.36E+03	.49E+03	.18E+03	.22E+03	.30E+03	.88E+03	.46E+03	.30E+03	.31E+03	.37E+03	.23E+03	.16E+03	.26E+03	.40E+03	
1600.	.71E+03	.38E+03	.29E+03	.29E+03	.32E+03	.16E+03	.18E+03	.24E+03	.59E+03	.36E+03	.24E+03	.25E+03	.26E+03	.19E+03	.13E+03	.21E+03	.30E+03	
1700.	.68E+03	.38E+03	.28E+03	.27E+03	.28E+03	.14E+03	.17E+03	.23E+03	.57E+03	.35E+03	.24E+03	.24E+03	.24E+03	.24E+03	.13E+03	.22E+03	.29E+03	
1800.	.64E+03	.36E+03	.26E+03	.25E+03	.28E+03	.12E+03	.16E+03	.22E+03	.55E+03	.34E+03	.22E+03	.23E+03	.23E+03	.17E+03	.12E+03	.21E+03	.27E+03	
1900.	.65E+03	.34E+03	.26E+03	.25E+03	.28E+03	.11E+03	.16E+03	.21E+03	.56E+03	.34E+03	.22E+03	.22E+03	.22E+03	.16E+03	.12E+03	.19E+03	.27E+03	
2000.	.45E+03	.16E+03	.12E+03	.12E+03	.18E+03	.63E+02	.74E+02	.99E+02	.36E+03	.14E+03	.10E+03	.98E+02	.15E+03	.84E+02	.61E+02	.10E+03	.15E+03	
2100.	.29E+03	.14E+03	.11E+03	.11E+03	.12E+03	.58E+02	.66E+02	.89E+02	.22E+03	.13E+03	.90E+02	.86E+02	.10E+03	.77E+02	.57E+02	.94E+02	.11E+03	
2200.	.30E+03	.14E+03	.10E+03	.10E+03	.12E+03	.57E+02	.65E+02	.87E+02	.22E+03	.12E+03	.86E+02	.82E+02	.10E+03	.75E+02	.55E+02	.90E+02	.11E+03	
2300.	.29E+03	.14E+03	.11E+03	.99E+02	.12E+03	.53E+02	.64E+02	.85E+02	.22E+03	.12E+03	.85E+02	.82E+02	.10E+03	.71E+02	.58E+02	.89E+02	.11E+03	
2400.	.32E+03	.15E+03	.11E+03	.10E+03	.13E+03	.52E+02	.65E+02	.87E+02	.24E+03	.12E+03	.89E+02	.85E+02	.11E+03	.72E+02	.63E+02	.95E+02	.12E+03	
2500.	.33E+03	.15E+03	.11E+03	.11E+03	.13E+03	.54E+02	.67E+02	.90E+02	.24E+03	.13E+03	.91E+02	.87E+02	.10E+03	.75E+02	.66E+02	.99E+02	.12E+03	
2600.	.32E+03	.15E+03	.11E+03	.11E+03	.13E+03	.55E+02	.68E+02	.90E+02	.24E+03	.13E+03	.91E+02	.87E+02	.99E+02	.75E+02	.66E+02	.10E+03	.12E+03	
2700.	.29E+03	.16E+03	.12E+03	.11E+03	.12E+03	.60E+02	.72E+02	.96E+02	.22E+03	.13E+03	.99E+02	.92E+02	.93E+02	.80E+02	.74E+02	.11E+03	.12E+03	
2800.	.28E+03	.15E+03	.11E+03	.10E+03	.12E+03	.55E+02	.67E+02	.90E+02	.22E+03	.13E+03	.92E+02	.86E+02	.90E+02	.74E+02	.68E+02	.10E+03	.11E+03	
2900.	.27E+03	.13E+03	.96E+02	.86E+02	.11E+03	.44E+02	.57E+02	.79E+02	.21E+03	.11E+03	.80E+02	.76E+02	.85E+02	.61E+02	.57E+02	.85E+02	.10E+03	
3000.	.23E+03	.11E+03	.82E+02	.72E+02	.94E+02	.42E+02	.55E+02	.76E+02	.18E+03	.94E+02	.68E+02	.63E+02	.73E+02	.59E+02	.54E+02	.81E+02	.90E+02	
3100.	.20E+03	.67E+02	.50E+02	.43E+02	.84E+02	.28E+02	.32E+02	.44E+02	.16E+03	.50E+02	.41E+02	.33E+02	.65E+02	.38E+02	.38E+02	.57E+02	.65E+02	
3200.	.12E+03	.61E+02	.45E+02	.39E+02	.45E+02	.23E+02	.27E+02	.37E+02	.81E+02	.45E+02	.36E+02	.31E+02	.35E+02	.32E+02	.32E+02	.49E+02	.46E+02	
3300.	.11E+03	.59E+02	.44E+02	.39E+02	.43E+02	.22E+02	.26E+02	.35E+02	.79E+02	.44E+02	.36E+02	.31E+02	.34E+02	.30E+02	.30E+02	.46E+02	.45E+02	
3400.	.11E+03	.51E+02	.39E+02	.37E+02	.43E+02	.19E+02	.23E+02	.31E+02	.79E+02	.40E+02	.32E+02	.28E+02	.34E+02	.27E+02	.25E+02	.40E+02	.41E+02	
3500.	.11E+03	.47E+02	.36E+02	.34E+02	.37E+02	.18E+02	.22E+02	.29E+02	.74E+02	.37E+02	.30E+02	.27E+02	.30E+02	.25E+02	.24E+02	.37E+02	.39E+02	
3600.	.95E+02	.47E+02	.39E+02	.38E+02	.32E+02	.17E+02	.21E+02	.28E+02	.67E+02	.38E+02	.32E+02	.29E+02	.27E+02	.24E+02	.23E+02	.36E+02	.37E+02	
3700.	.74E+02	.46E+02	.34E+02	.32E+02	.27E+02	.17E+02	.21E+02	.28E+02	.56E+02	.36E+02	.29E+02	.26E+02	.23E+02	.24E+02	.23E+02	.36E+02	.33E+02	
3800.	.73E+02	.44E+02	.32E+02	.28E+02	.27E+02	.16E+02	.20E+02	.27E+02	.55E+02	.35E+02	.27E+02	.23E+02	.22E+02	.24E+02	.21E+02	.35E+02	.32E+02	
3900.	.73E+02	.38E+02	.29E+02	.26E+02	.27E+02	.14E+02	.17E+02	.23E+02	.55E+02	.32E+02	.23E+02	.21E+02	.22E+02	.19E+02	.17E+02	.27E+02	.29E+02	
4000.	.73E+02	.35E+02	.27E+02	.24E+02	.27E+02	.13E+02	.16E+02	.22E+02	.55E+02	.30E+02	.22E+02	.20E+02	.22E+02	.17E+02	.16E+02	.24E+02	.28E+02	
4100.	.73E+02	.32E+02	.24E+02	.22E+02	.27E+02	.12E+02	.15E+02	.21E+02	.55E+02	.29E+02	.21E+02	.19E+02	.22E+02	.16E+02	.15E+02	.23E+02	.27E+02	
4200.	.71E+02	.32E+02	.23E+02	.21E+02	.26E+02	.11E+02	.15E+02	.21E+02	.53E+02	.28E+02	.20E+02	.19E+02	.21E+02	.16E+02	.14E+02	.22E+02	.26E+02	
4300.	.70E+02	.31E+02	.23E+02	.21E+02	.26E+02	.11E+02	.15E+02	.21E+02	.51E+02	.28E+02	.20E+02	.18E+02	.21E+02	.16E+02	.14E+02	.22E+02	.26E+02	
4400.	.68E+02	.31E+02	.22E+02	.20E+02	.25E+02	.11E+02	.15E+02	.21E+02	.50E+02	.28E+02	.20E+02	.18E+02	.20E+02	.16E+02	.14E+02	.22E+02	.25E+02	
4500.	.62E+02	.30E+02	.22E+02	.20E+02	.22E+02	.11E+02	.15E+02	.21E+02	.46E+02	.28E+02	.20E+02	.18E+02	.18E+02	.16E+02	.14E+02	.22E+02	.24E+02	
4600.	.60E+02	.30E+02	.22E+02	.20E+02	.21E+02	.11E+02	.14E+02	.20E+02	.45E+02	.28E+02	.20E+02	.18E+02	.18E+02	.15E+02	.14E+02	.21E+02	.24E+02	
4700.	.60E+02	.30E+02	.22E+02	.20E+02	.21E+02	.10E+02	.14E+02	.20E+02	.45E+02	.27E+02	.19E+02	.18E+02	.17E+02	.15E+02	.13E+02	.21E+02	.23E+02	
4800.	.60E+02	.30E+02	.22E+02	.19E+02	.21E+02	.10E+02	.14E+02	.19E+02	.45E+02	.27E+02	.19E+02	.18E+02	.17E+02	.15E+02	.13E+02	.21E+02	.23E+02	
4900.	.58E+02	.30E+02	.22E+02	.19E+02	.21E+02	.10E+02	.14E+02	.19E+02	.44E+02	.27E+02	.19E+02	.18E+02	.17E+02	.15E+02	.13E+02	.21E+02	.23E+02	
5000.	.57E+02	.30E+02	.21E+02	.19E+02	.20E+02	.67E+01	.84E+01	.12E+02	.44E+02	.27E+02	.19E+02	.17E+02	.17E+02	.99E+01	.92E+01	.15E+02	.21E+02	

Source: SACTI cooling tower model.

Table 5.1-4
Average Monthly Predicted Cooling Tower Salt Deposition

Salt Deposition in the Direction Plume is Headed (kg/km ² -month)																	
Distance From Tower (m)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	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
200.	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
300.	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
400.	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
500.	3.35	2.26	1.77	1.78	1.67	0.77	1.09	1.44	3.31	2.34	1.50	1.59	1.21	0.94	0.73	1.07	1.68
600.	8.42	5.25	5.33	6.28	8.19	3.58	3.63	4.05	9.39	5.57	4.51	4.82	5.44	3.60	2.15	2.78	5.19
700.	8.52	4.94	4.61	5.21	6.98	2.88	3.13	3.64	9.02	5.18	3.90	4.16	4.74	3.07	1.93	2.58	4.66
800.	10.05	5.87	4.97	5.27	6.60	2.65	3.21	3.97	10.01	6.11	4.27	4.56	4.60	3.11	2.09	3.01	5.02
900.	11.23	6.01	4.80	4.86	6.48	2.40	3.10	3.98	10.89	6.24	4.16	4.46	4.63	3.03	2.10	3.13	5.09
1000.	9.79	5.47	4.19	4.11	5.78	1.90	2.66	3.52	9.54	5.66	3.64	3.89	4.20	2.54	1.85	2.82	4.47
1100.	9.33	4.79	3.69	3.64	6.29	1.69	2.33	3.06	9.15	4.95	3.21	3.42	4.38	2.24	1.61	2.46	4.14
1200.	8.66	3.95	3.08	3.08	5.80	1.47	1.95	2.56	8.35	4.06	2.68	2.84	4.04	1.91	1.35	2.08	3.62
1300.	5.63	2.79	2.29	2.41	4.10	1.17	1.43	1.84	5.38	2.82	1.98	2.06	2.88	1.47	0.98	1.53	2.55
1400.	5.59	2.96	2.60	2.80	4.10	1.59	1.63	1.99	5.36	2.94	2.08	2.22	2.87	1.66	1.08	1.58	2.69
1500.	4.73	2.34	2.09	2.26	3.59	1.37	1.32	1.59	4.54	2.28	1.63	1.73	2.48	1.36	0.87	1.27	2.22
1600.	3.52	1.98	1.78	1.95	2.54	1.21	1.12	1.33	3.28	1.87	1.35	1.44	1.83	1.16	0.74	1.08	1.76
1700.	3.39	2.00	1.77	1.92	2.24	1.16	1.11	1.33	3.14	1.87	1.35	1.43	1.70	1.16	0.76	1.11	1.72
1800.	3.26	1.96	1.73	1.87	2.24	1.08	1.07	1.29	3.09	1.85	1.33	1.40	1.69	1.11	0.74	1.08	1.67
1900.	3.34	1.90	1.70	1.85	2.24	1.06	1.05	1.26	3.12	1.82	1.30	1.39	1.65	1.06	0.72	1.00	1.65
2000.	2.59	1.19	1.19	1.36	1.89	0.86	0.72	0.81	2.34	1.06	0.85	0.89	1.39	0.77	0.50	0.67	1.19
2100.	1.98	1.14	1.15	1.33	1.65	0.84	0.70	0.78	1.79	1.00	0.81	0.85	1.20	0.75	0.48	0.65	1.07
2200.	2.04	1.07	1.05	1.20	1.68	0.84	0.70	0.77	1.84	0.95	0.77	0.80	1.22	0.75	0.48	0.64	1.05
2300.	2.04	1.06	0.97	1.06	1.68	0.68	0.63	0.73	1.84	0.92	0.76	0.76	1.21	0.68	0.48	0.64	1.01
2400.	2.14	1.19	1.30	1.55	1.65	0.59	0.59	0.71	1.89	1.07	1.03	1.05	1.19	0.65	0.49	0.66	1.11
2500.	2.14	1.21	1.31	1.56	1.54	0.60	0.61	0.72	1.79	1.08	1.04	1.06	1.02	0.66	0.51	0.68	1.10
2600.	2.12	1.19	1.24	1.44	1.55	0.60	0.61	0.73	1.78	1.05	0.98	0.99	1.02	0.67	0.51	0.68	1.07
2700.	1.96	1.16	0.99	1.00	1.31	0.63	0.63	0.76	1.65	0.97	0.76	0.74	0.90	0.69	0.55	0.73	0.96
2800.	1.91	1.09	0.93	0.94	1.16	0.59	0.60	0.72	1.59	0.93	0.71	0.70	0.83	0.65	0.52	0.69	0.91
2900.	1.84	0.97	0.81	0.80	1.12	0.51	0.53	0.63	1.54	0.83	0.62	0.62	0.80	0.56	0.45	0.61	0.83
3000.	1.73	0.86	0.72	0.72	1.32	0.49	0.52	0.62	1.54	0.71	0.55	0.54	0.91	0.54	0.44	0.59	0.80
3100.	1.72	0.58	0.52	0.53	2.28	0.40	0.38	0.43	1.81	0.44	0.38	0.36	1.50	0.41	0.34	0.45	0.78
3200.	1.21	0.54	0.49	0.51	2.05	0.38	0.35	0.39	1.34	0.41	0.36	0.34	1.33	0.38	0.31	0.40	0.67
3300.	1.18	0.63	0.85	1.10	2.04	0.37	0.34	0.38	1.32	0.55	0.67	0.69	1.32	0.37	0.29	0.39	0.78
3400.	1.15	0.76	1.39	1.96	1.90	0.36	0.33	0.36	1.27	0.75	1.13	1.20	1.23	0.35	0.27	0.36	0.92
3500.	0.92	0.74	1.37	1.94	0.74	0.33	0.31	0.34	0.78	0.74	1.12	1.19	0.51	0.33	0.26	0.34	0.75
3600.	0.80	1.06	2.48	3.71	0.48	0.32	0.30	0.33	0.65	1.18	2.07	2.24	0.35	0.33	0.25	0.33	1.05
3700.	0.70	0.67	1.17	1.64	0.45	0.32	0.30	0.33	0.59	0.66	0.95	1.01	0.32	0.33	0.25	0.33	0.63
3800.	0.69	0.45	0.42	0.45	0.44	0.31	0.29	0.33	0.58	0.36	0.31	0.31	0.31	0.32	0.24	0.33	0.38
3900.	0.69	0.42	0.40	0.44	0.42	0.30	0.28	0.31	0.57	0.35	0.30	0.30	0.31	0.30	0.22	0.29	0.37
4000.	0.69	0.39	0.38	0.41	0.42	0.29	0.27	0.30	0.57	0.33	0.28	0.28	0.31	0.29	0.21	0.27	0.36
4100.	0.69	0.36	0.35	0.39	0.42	0.28	0.26	0.28	0.57	0.32	0.27	0.27	0.31	0.27	0.20	0.26	0.34
4200.	0.69	0.34	0.33	0.37	0.42	0.26	0.24	0.26	0.56	0.31	0.26	0.26	0.30	0.25	0.17	0.23	0.33
4300.	0.68	0.33	0.32	0.36	0.42	0.26	0.24	0.26	0.56	0.30	0.25	0.26	0.30	0.25	0.17	0.23	0.32
4400.	0.67	0.33	0.32	0.36	0.41	0.26	0.24	0.26	0.55	0.30	0.25	0.26	0.30	0.25	0.17	0.23	0.31
4500.	0.61	0.33	0.32	0.36	0.38	0.26	0.24	0.26	0.52	0.30	0.25	0.26	0.28	0.25	0.17	0.22	0.31
4600.	0.59	0.33	0.32	0.36	0.37	0.26	0.23	0.26	0.51	0.30	0.25	0.25	0.27	0.25	0.17	0.22	0.31
4700.	0.58	0.33	0.32	0.36	0.37	0.25	0.23	0.26	0.50	0.29	0.25	0.25	0.26	0.25	0.17	0.22	0.31
4800.	0.58	0.32	0.32	0.36	0.37	0.25	0.23	0.26	0.50	0.29	0.25	0.25	0.26	0.25	0.17	0.22	0.30
4900.	0.57	0.32	0.32	0.36	0.36	0.25	0.23	0.26	0.50	0.29	0.25	0.25	0.26	0.25	0.17	0.22	0.30
5000.	0.55	0.32	0.29	0.31	0.36	0.19	0.16	0.17	0.49	0.28	0.22	0.23	0.25	0.18	0.12	0.16	0.27

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.	10.62	6.44	6.95	7.24	9.62	5.62	4.56	4.69	9.05	4.92	4.56	4.51	6.76	5.11	4.58	4.75	100.00
200.	0.34	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.35	0.14	0.12	0.05	0.11	0.07	0.10	0.13	2.02
300.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
400.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
500.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
600.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
700.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
800.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
900.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1000.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1100.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1200.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1300.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1400.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1500.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1600.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1700.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1800.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
1900.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2000.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2100.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2200.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2300.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2400.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2500.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2600.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2700.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2800.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
2900.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3000.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3100.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3200.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3300.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3400.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3500.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3600.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3700.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3800.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
3900.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4000.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4100.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4200.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4300.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4400.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4500.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4600.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4700.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4800.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
4900.	0.32	0.11	0.10	0.08	0.09	0.06	0.06	0.12	0.33	0.14	0.12	0.05	0.09	0.07	0.10	0.13	1.96
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 also less than 200 m (656 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 10.6 percent of the year in an area 100 m (328 ft) south of the cooling tower.

5.1.4.4 Environmental Impact. The following sections discuss the potential environmental impacts associated with the operation of the proposed cooling tower. 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 tower.

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 effect 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 SEC are calm about 6 percent of the year. However, 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 moderately 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).

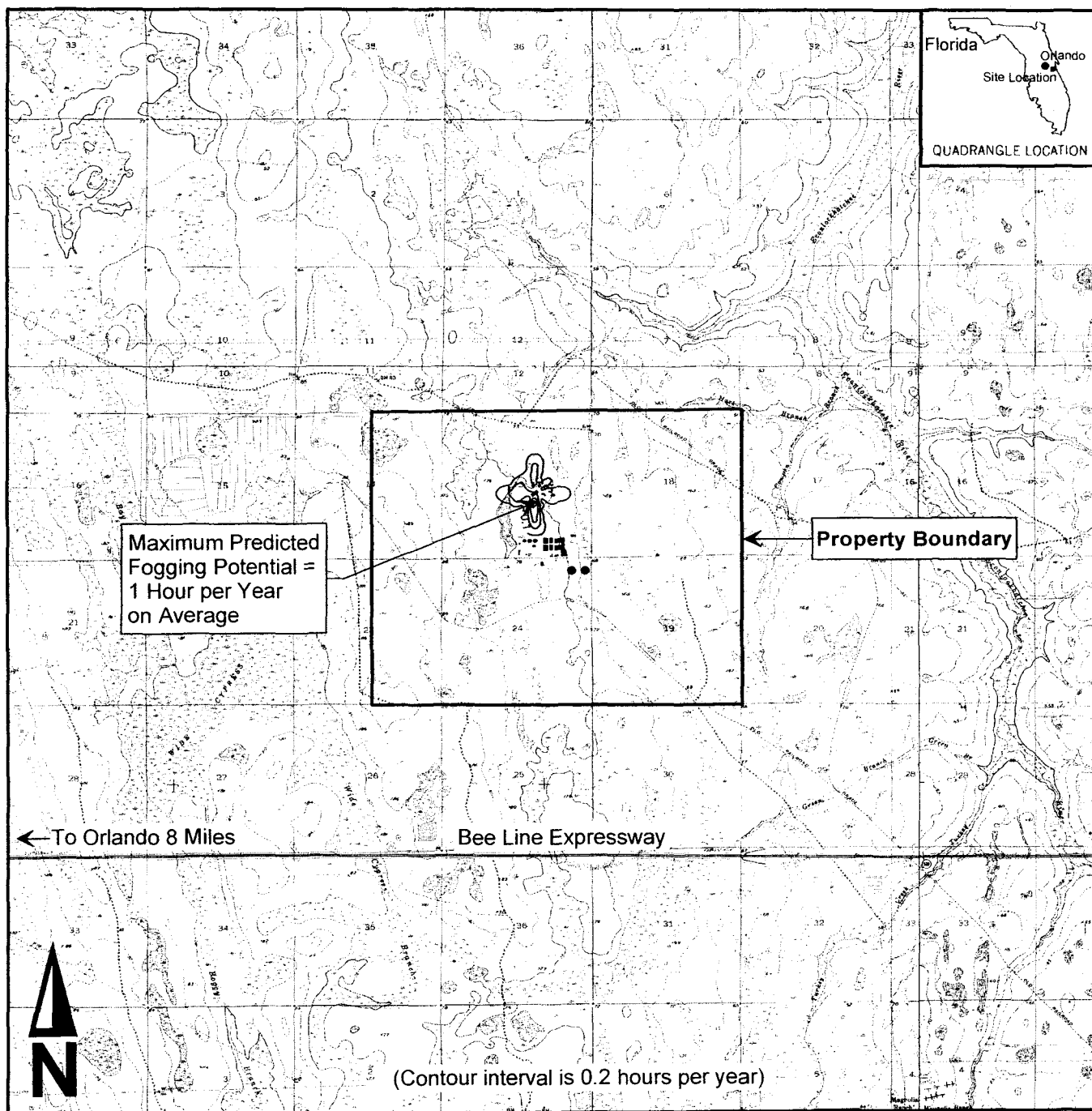
Cooling tower induced fogging can occur at any time during the year, but it is most commonplace during periods of moderate wind speeds (which bend the plume to intercept the ground), high relative humidity, and cool temperatures. These meteorological conditions frequently occur during the late evening 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 SEC entrance road, which is restricted from public access, the nearest transportation arteries include the Alafaya Trail immediately adjacent to the eastern SEC boundary and the Bee Line Expressway approximately 2 miles south of the power block.

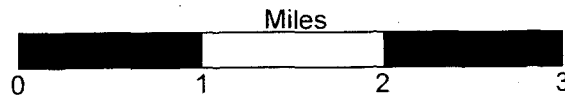
As discussed in Subsection 5.1.4.3.1, the maximum cooling tower plume induced fogging is predicted to occur approximately 5.0 hours (over the 5 year database) within 100 m (328 ft), and no amount of fogging is predicted to extend beyond a radius of 500 m (1,640 ft) from the cooling tower.

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 0.2 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 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 of the energy center (conservatively assuming that reported fogging events last for only 1 hour per day), which is approximately 26 times greater than the maximum annual fogging hours predicted by the SACTI model in the vicinity of the SEC.



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)
Contour Interval = 0.2 hours/yr.



Stanton Energy Center Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results
Average Annual Hours of Predicted Plume Fogging

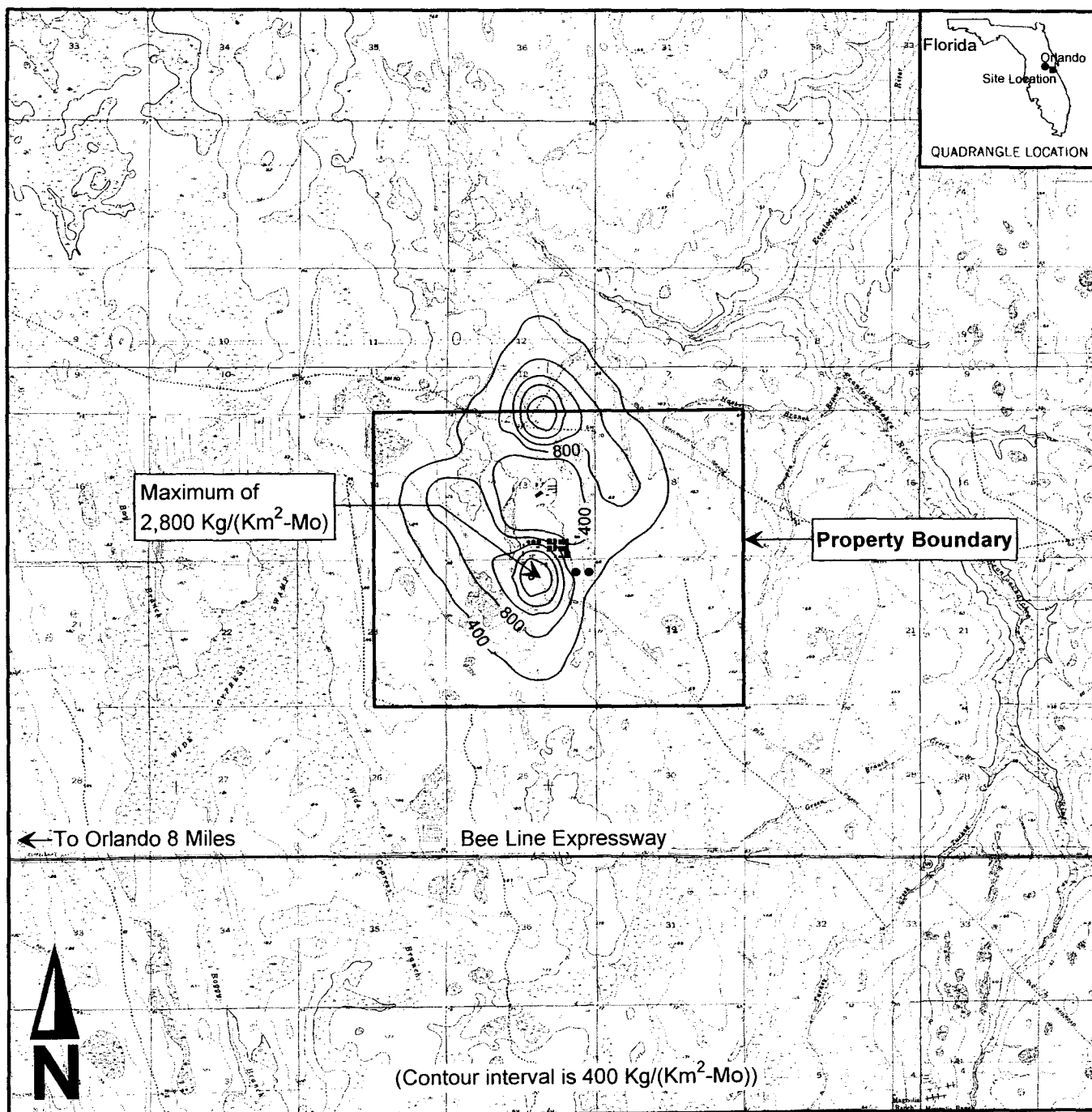
Figure 5.1-1

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 the cooling tower 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 SEC 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 900 m (2,953 ft) south of the power block at a deposition rate of 2,800 kg/km²/month. Land use in this area is characterized as electrical power facilities (area is within the energy center boundary) as illustrated on Figure 2.3-3. Predicted water deposition rates in this area range from 800 to 2,000 kg/km²/month.

A second predicted location of maximum of water deposition occurs north of the power block, approximately 900 m (2,953 ft) north of the cooling tower as illustrated on Figure 5.1-2. Predicted water deposition rates in this area range from 800 to 2,000 kg/km²/month. Vegetation in this area is primarily characterized as mixed scrub, shrub wetlands, and cypress. 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 (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 (2,800 kg/km²/month) is approximately less than 0.01 mm per month. By comparison, this precipitation rate is significantly less than 1/10 percent of the average monthly rainfall of the driest month.



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)
Contour Interval = 400 Kg/Km²-Mo

Stanton Energy Center Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results
Average Monthly Predicted Cooling Tower Water Deposition

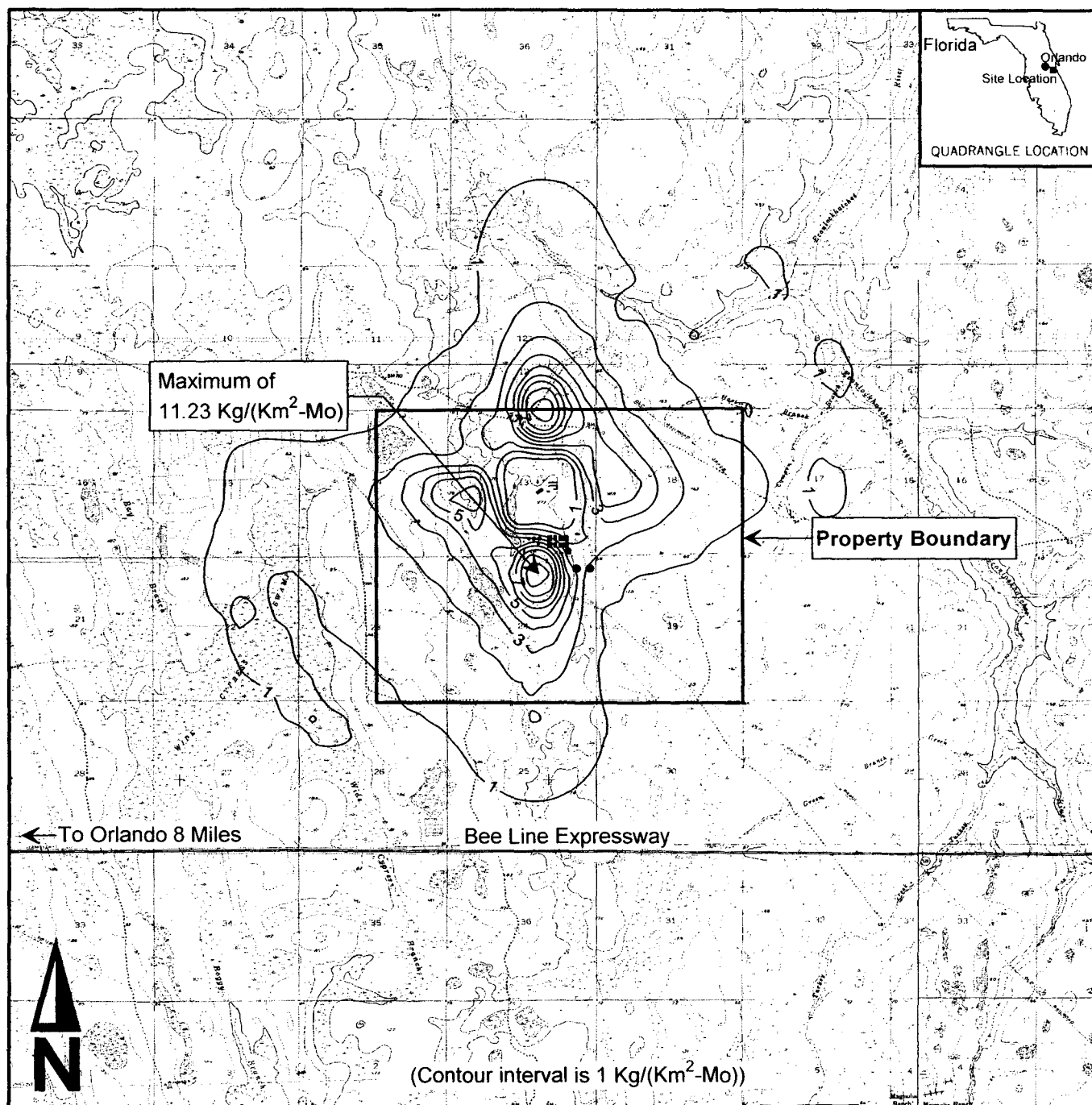
Figure 5.1-2

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 US midwestern 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 71,400 times greater than the maximum water deposition rate predicted by the SACTI model. This suggests that the water deposition from the cooling tower 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 south of the power block at a deposition rate of 11.23 kg/km²/month. Vegetation and land use in this area is also classified as electrical power facilities (area is within the energy center boundary). Predicted salt deposition rates in this area, including the upland natural area of the SEC, range from 2 to 8.5 kg/km²/month.

A second predicted location of maximum of salt deposition occurs just north of the power block, approximately 900 m (2,953 ft) from the proposed location of the cooling tower. Predicted salt deposition rates in this area generally range from 5 to 10 kg/km²/month. Vegetation and land use in this area is characterized primarily as mixed scrub, shrub wetlands, and cypress.

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 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.



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)
Contour Interval = 1 Kg/Km²-Mo

Stanton Energy Center Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results
Average Monthly Predicted Cooling Tower Salt Deposition

Figure 5.1-3

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 as 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 $400 \text{ kg/km}^2/\text{month}$ 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 $400 \text{ kg/km}^2/\text{month}$ 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 $400 \text{ kg/km}^2/\text{month}$ are generally not considered to have a significant impact on vegetation. The maximum predicted salt deposition rate from the cooling tower is $11.2 \text{ kg/km}^2/\text{month}$. 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.

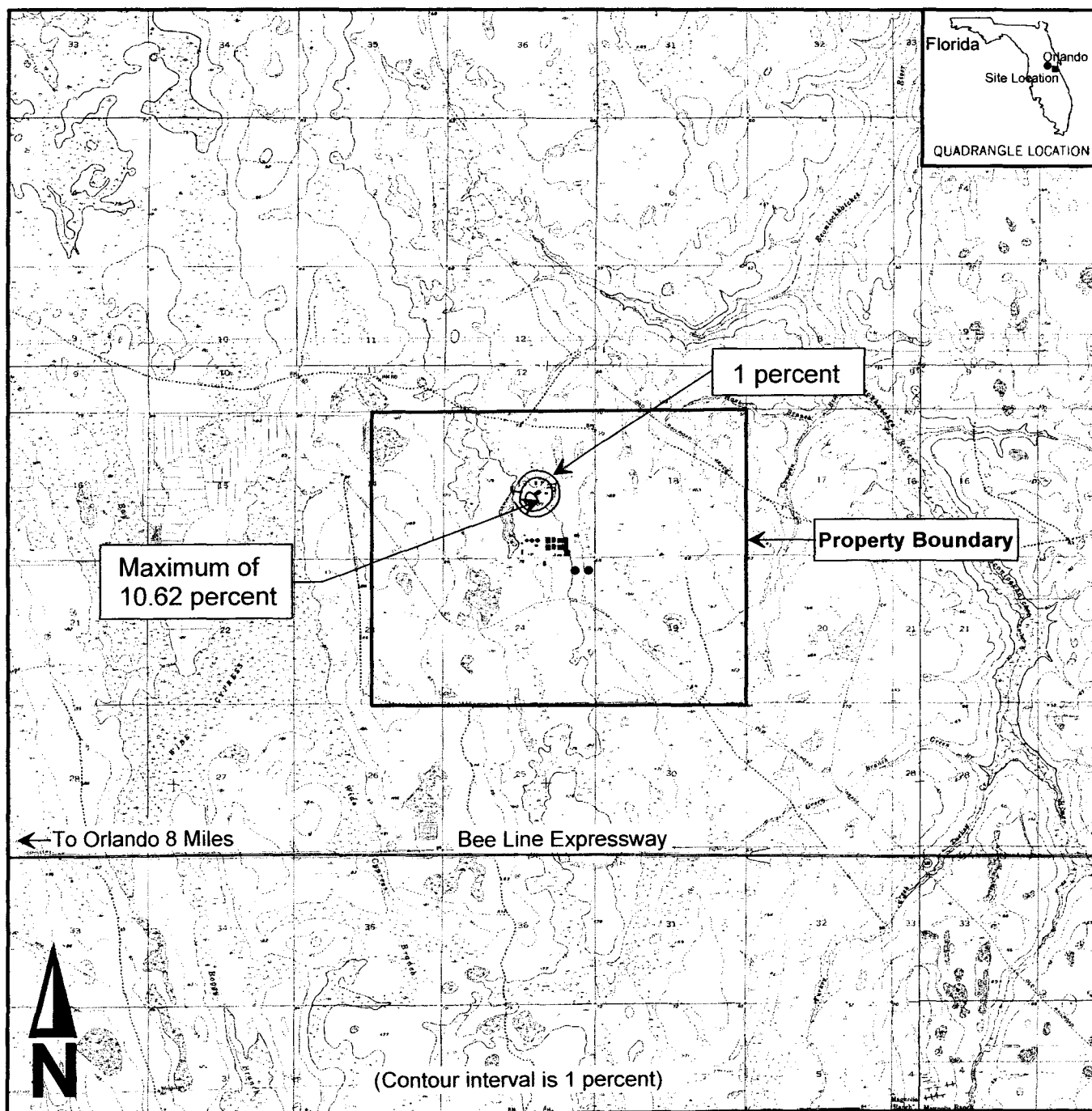
Perhaps the most obvious environmental impact from a cooling tower is the formation of a visible plume extending out from the cooling tower cell exhaust ports. The visible plume may extend several hundred yards downwind, potentially obstructing visibility on the site and at nearby residences. The factors 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 drier 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 the cooling tower 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 tower for approximately 11 percent of the year on average. Over the remaining portions of the SEC and the immediate vicinity, the frequency of occurrence of a visible plume for a particular location generally ranges from about 1 to 6 percent of the year. Based on these results, it is concluded that the presence of a visible plume from the cooling tower will only minimally contribute to the visible and aesthetic impacts in the area.



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)
Contour Interval = 1 Percent

Stanton Energy Center Cooling Tower Effects of Offstream Cooling

SACTI Cooling Tower Model Results
Average Annual Predicted Plume Length Frequency of Occurance

Figure 5.1-4

The visible plume from the cooling tower is also predicted to periodically extend offsite. However, as shown on Figure 5.1-4, this is predicted to occur less than 1 percent of the year on average, and therefore will have little or no impact on nearby residences or the areas that surround the power block and SEC. The conditions potentially leading to visible plume formations are discussed earlier in Subsection 5.1.4.4.3.

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

There are no measurement programs proposed for the heat dissipation system.

5.2 Effects of Chemical and Biocide Discharges

As shown on the water mass balance (Figure 3.5-1) in Section 3.0, there will be no discharges resulting from operations associated with the addition of Stanton A. All wastewater streams resulting from operation will be treated and reused as described in the following subsections.

5.2.1 Industrial Wastewater Discharge

Wastewaters potentially contaminated with grease or oil from the Stanton A plant floor drain system will be treated by an oil/water separator before being transferred to the existing SEC recycle basin for reuse in Units 1 and 2 facility systems. Effluent from the oil/water separator will contain no more than 10 ppm oil/grease. Drainage from new oil containment and transformer enclosure areas will be trapped in the enclosure areas. The oil in the enclosures will be skimmed and trucked from the site, and the trapped water will be checked and drained to the stormwater pond.

5.2.2 Cooling Tower Blowdown

Cooling tower blowdown will be transferred to a new brine concentrator/crystallizer zero discharge treatment system. Water recovered in the zero discharge system will be recycled to the facility's cooling tower system or the makeup water supply storage pond.

5.2.3 Measurement Program

The existing Unit 1 and 2 Site Certification established groundwater monitoring requirements for the site. No discharge to groundwater will occur with the addition of Stanton A, except for that deriving from the septic system, which will flow into the surficial aquifer.

Makeup water to Stanton A will be provided from existing SEC facilities and wastewater will be processed through new and existing facilities for reuse at the SEC. Therefore, no additional monitoring is proposed.

5.3 Impacts on Water Supplies

5.3.1 Surface Water

Impacts on naturally occurring surface waters at the SEC were addressed in the Site Certification Applications for Units 1 and 2. Stanton A facility operations will not withdraw or discharge to surrounding surface waters; therefore, no impacts to these surface waters are expected as a result of Stanton A facility operations.

The Stanton A storm water 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 directed into a drainage system and then routed to the storm water pond north of the Stanton A location. A detailed description of the onsite drainage system is provided in Section 3.8.

Facility operations are not expected to affect surface water quality within the area. Undisturbed area will remain in its existing state.

5.3.2 Groundwater

The following subsections describe the effects of plant operations on the aquifers underlying the facility.

5.3.2.1 Surficial Aquifer. Under normal operating conditions, the Stanton A facility will not have a significant effect on the surficial aquifer quality. No water will be withdrawn from this water table zone. Wastewaters are not discharged to groundwater, except from the septic system.

In the event that the cooling tower blowdown treatment system is disabled, the cooling tower blowdown will be routed to the existing recycle basin, similar to existing Units 1 and 2. The recycle basin is lined to minimize any impact on groundwater.

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, as is the case for Units 1 and 2. Hydrogeological and water quality data for the Floridan Aquifer are presented in Subsection 2.3.2.

Two wells were installed into the Floridan Aquifer during the construction of Units 1 and 2. Withdrawals were certified for an annual allocation not to exceed 321.2 mgy, and a maximum daily allocation not to exceed 2.0 mgd.

Stanton A water requirements will result in an estimated additional average daily usage of 0.316 mpd (219 gpm) of well water on an annual average basis at 95 percent capacity. The total expected average facility usage including existing Units 1 and 2 and Stanton A will be 0.793 mgd (551 gpm) at 95 percent capacity. Average daily water usage will be supplied from the two existing wells. Each well is capable of producing a maximum of 850 gpm.

Cooling tower makeup water will normally be obtained from the existing Makeup Water Supply Storage Pond, which receives effluent from the Orange County Eastern Water Reclamation Facility. The average required cooling tower makeup water flow for Stanton A at 95 percent capacity will be 2.9 mgd. The total average makeup requirements from the Orange County Facility for Units 1, 2, and A at 95 percent capacity will be 12.8 mgd.

5.3.2.3 Groundwater Model Description. A modular three-dimensional finite difference groundwater flow model developed by the US Geologic Survey titled Visual MODFLOW 2.80 was used to investigate the impact of withdrawals associated with SEC operations on the Floridan Aquifer. The objective of the model was to determine the change in piezometric head and associated radius of influence in response to anticipated SEC groundwater withdrawals. Input for the model consisted of aquifer parameters and average daily and maximum daily withdrawals from the aquifer for predetermined simulated times and conditions. Aquifer parameters were developed from a literature search of existing aquifer data for the study area and results of pump testing of the aquifer.

The model was defined by a series of grids increasing in size from 1 foot to 400 feet extending outward from the wells. Total model dimensions were approximately 21,120 feet (4 miles) per side; therefore, the model boundaries were 2 miles from the center of the site. The piezometric head was fixed at the boundaries and allowed to fluctuate at all other locations.

The model consisted of four layers with a total thickness of 1,400 feet. The following layers were established:

- Layer 1, 150 feet thick, includes the surficial sand, the intermediate cohesive layer, and the lower sand layer.
- Layer 2, 50 feet thick, consists of the lower cohesive layer (Hawthorn Formation).
- Layer 3, 400 feet thick, consists of the Upper Floridan Aquifer.
- Layer 4, 800 feet thick, consists of the semiconfining unit between the Upper and Lower Floridan aquifers.

The configuration for Layers 1 and 2 was selected because the intermediate cohesive layer is absent at some boring locations, while the lower cohesive layer is continuous across the SEC, and appears to represent the primary confining unit at the top of the Floridan Aquifer. Where the intermediate cohesive layer is absent, the surficial sand and the lower sand layers are directly connected. Even though these sand layers are considered to be in separate aquifers in the literature, under these conditions the two sand layers are expected to act as one hydrologically. Additionally, using only the lower cohesive layer as the confining unit (Layer 2) at the top of the Floridan Aquifer will result in greater modeled impacts to the unconfined aquifer (Layer 1) than will be anticipated under actual conditions at the SEC.

The total thickness of 1,400 feet for the model was used based on the following:

- The depth to brackish water in the SEC vicinity, which has been estimated at 1,400 to 1,500 feet bgs, and
- The base of the semiconfining unit within the Floridan Aquifer has been estimated at 1,300 to 1,400 feet bgs, as mentioned in Subsection 2.3.2.3 of this SCA. The thicknesses of the Upper Floridan Aquifer and the semiconfining unit are based on published data.

The recharge from rainfall, surface water, and other sources was assumed negligible and was not used in the model, adding a conservancy factor to the model.

Model Hydrologic Parameters. Initial model parameters used for the model are as follows:

- Layer 1--Unconfined Groundwater:
 - Piezometric head was set at ground surface.
 - Storage Coefficient, $S = 0.01$.
 - Horizontal Permeability, $K_h = 15.7$ ft/day.
 - Vertical Permeability, $K_v = 0.4$ ft/day.

- Layer 2--Confining Unit:
 - Piezometric head was set at 15 feet below ground surface.
 - Storage Coefficient, $S = 1 \times 10^{-5}$.
 - Horizontal Permeability, $K_h = 1 \times 10^{-3}$ ft/day.
 - Vertical Permeability, $K_v = 1 \times 10^{-7}$ ft/day.
- Layer 3--Upper Floridan Aquifer:
 - Piezometric head was set at 45 feet below ground surface.
 - Storage Coefficient, $S = 0.0005$.
 - Transmissivity, $T = 50,000$ ft²/day.
- Layer 4--Middle Semiconfining Unit within Floridan Aquifer:
 - Piezometric head was set at 45 feet below ground surface.
 - Storage Coefficient, $S = 0.0005$.
 - Horizontal Permeability, $K_h = 20$ ft/day.
 - Vertical Permeability, $K_v = 0.05$ ft/day.

Parameters for Layers 1, 2, and 3 were taken from values used in the original SCA for Unit 1 at the SEC. Parameters for Layer 4 were taken from published literature (Murray et al., 1996).

Projected Plant Water Usage. Operation of Units 1 and 2 requires withdrawal of water from two existing wells installed in the Upper Floridan Aquifer. These wells consist of 11 inch diameter open boreholes extending to a depth of 535 feet bgs, with the upper 230 feet of borehole cased. The casing extends 30 feet into the bedrock, resulting in 305 feet of open borehole within the limestone bedrock for groundwater production. Each well has a pump with a capacity of 850 gpm, and each is able to supply 100 percent of the currently required plant capacity.

Under normal operating conditions, the average daily groundwater usage for Units 1 and 2, running at a 70 percent annual average capacity factor, is about 244 gpm, while the maximum daily usage at 100 percent load under peak service water demand is about 607 gpm. The existing wells were certified with a maximum annual allocation not to exceed 321.2 million gallons, while the maximum daily allocation is not to exceed 2 million gallons. Current withdrawal from these two wells has had minimal effects on the surrounding water supply wells shown on Figure 2.3-13.

Under normal operating conditions at a 95 percent capacity, Stanton A groundwater requirements include an additional annual average daily usage of 219 gpm, with a maximum daily usage of 621 gpm at 100 percent capacity with steam being used for power augmentation. The estimated total SEC average daily groundwater usage, including Stanton A, will then be 551 gpm with Units 1,2 and A operating at 95 percent capacity, while the total maximum daily usage will be 1,228 gpm. Average and

maximum daily groundwater usage will be supplied from the two existing wells at the SEC. Table 5.3-1 shows the existing and proposed distribution of the water usage at the SEC.

Table 5.3-1 Stanton Energy Center Water Usage				
Source	Existing Units 1 and 2		Proposed Stanton A	
	Average Water Use (95% Capacity)	Maximum Water Use (100% Capacity)	Average Water Use (95% Capacity)	Maximum Water Use (100% Capacity and Steam Used for Power Augmentation)
Onsite Wells (Groundwater)	0.477 mgd	0.874 mgd	0.316 mgd	0.895 mgd
Onsite Wastewater Treatment Effluent	0.631 mgd	0.796 mgd	0.369 mgd	0.508 mgd
Site Runoff	-	0.156 mgd	-	-
Site Precipitation	-	0.354 mgd	-	-
Municipal Wastewater Treatment Facility Effluent	9.88 mgd	10.2 mgd	2.91 mgd	4.00 mgd

5.3.2.4 Model Calibration. A pump test was conducted on the existing wells after initial construction of Unit 1. A constant rate of discharge of 850 gpm for a test duration of 48 hours resulted in 1.5 and 2.0 feet drawdown at the pumping well and 0.1 foot of drawdown in a monitoring well located 400 feet from the pumping well. Observation wells installed in the unconfined aquifer registered no water level movement, indicating there is no direct connection from the screened zones in these wells to the Floridan Aquifer.

The model calibration used the same hydrologic parameters as the model used to permit the existing wells, with the exception of the Upper Floridan Aquifer transmissivity, which was increased to 72,000 ft²/day. This was done to facilitate model calibration with the results of the pump test performed originally at the SEC. The transmissivity of 72,000 ft²/day used for the Upper Floridan Aquifer is considered representative based on results of various regional models and pump tests performed at the Cocoa Well Field, 6 miles southeast from the SEC. Published transmissivities for the regional models and the Cocoa Well Field range from 26,000 to 200,000 ft²/day (Murray et al. 1996, Skipp 1988, Tibbals and Frazee, 1976). When calibrated, the modeled

drawdown at the pumping well was about 3.5 feet, while the drawdown at the observation well 400 feet away was about 1.2 feet. These drawdowns are considered similar to those obtained from the pump tests, namely 1.5 to 2 feet of drawdown at the pumping well, and 0.1 foot at the observation well. Therefore, the new model approximates the existing conditions.

5.3.2.5 Impact Assessment. Once the model was calibrated, the following two SEC water usage conditions were simulated:

- **Average daily flow--**A single onsite well was modeled to pump at a capacity of 551 gpm (0.793 mgd); equivalent to the combined average daily groundwater usage for all three units. The model was set to simulate steady-state conditions. Groundwater supply was obtained from the Upper Floridan Aquifer.
- **Maximum Daily Flow--**The two onsite wells were modeled to pump at a combined capacity of 1228 gpm (1.77 mgd). Two cases were considered: one with each well pumping 614 gpm; and the other with one well pumping 850 gpm and one pumping 378 gpm. This model used transient conditions, and was run for 30 days, the assumed continuous time for the maximum usage condition.

Unconfined Aquifer. The results of the simulations described above indicate that total plant operations will have negligible effect on the unconfined aquifer water levels and no impact on groundwater quality. No additional facilities that would affect the water table zone will be constructed for Stanton A operation. No water will be withdrawn from the unconfined aquifer.

Intermediate Secondary Artesian Aquifer. Total plant operation will have negligible effect on the intermediate secondary artesian aquifer water levels and no impact on groundwater quality. No new facilities will be constructed that would affect the intermediate secondary artesian aquifer for Stanton A operation. No water will be withdrawn from the intermediate secondary artesian aquifer.

Floridan Aquifer. The literature search conducted for the groundwater flow model, as well as the investigation of the site conducted by Black & Veatch, indicate that the Floridan Aquifer, the proposed groundwater source for the wells, acts as a confined aquifer in the SEC area. Therefore, withdrawal of groundwater from the aquifer will not affect the adjacent surface water bodies. Due to the confined nature of the aquifer, the proposed water use will not effect environmental features that have a direct or indirect relationship to wetland habitats for rare, endangered, or threatened species. The SEC 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.

The model indicates that the average daily groundwater flow will result in a drawdown at the pumping well of 2.5 feet, and a drawdown of 0.2 feet a radius of 1 mile from the pumping well. Figure 5.3-1 shows the model drawdown levels with distance away from the pumping well. The increased average daily groundwater flow will continue to have a minimal effect on the surrounding water supply wells.

For the maximum daily groundwater flow simulation with both wells pumping 614 gpm, the model indicates that, at the end of the 30 days, the drawdown in each of the pumping wells will be 3.0 feet. Drawdown at a radius of 1 mile away from the wells is estimated to be about 0.4 foot. Figure 5.3-2 shows the model drawdown levels with distance away from the pumping wells.

For the maximum daily groundwater flow simulation with one well pumping 850 gpm and the second well pumping 378 gpm, the model indicates that at the end of the 30 days, the drawdown at the well pumping 850 gpm will be 4.0 feet. Drawdown at a radius of 1 mile away from the wells is estimated to be about 0.4 foot. Figure 5.3-3 shows the model drawdown levels with distance away from the pumping wells.

The predicted drawdown in the vicinity of the pumping wells indicates that there will be no effects to existing domestic, irrigation, or other public water supply wells due to average or maximum groundwater withdrawals at the SEC. The 0.4 foot drawdown at a 1 mile radius observed for the maximum groundwater usage condition is a transient situation that will have no permanent effects on the groundwater levels. Groundwater levels will return to the original state once the units revert back to average groundwater usage.

The proposed water use will not cause any saltwater intrusion. As mentioned previously in Subsection 2.3.2, the depth to brackish groundwater within the SEC site is anticipated to be between 1,500 feet to 2,000 feet bgs, i.e., within the Lower Floridan Aquifer. The presence of the semiconfining layer within the Floridan Aquifer system prevents any major flow of water between the Upper and Lower Floridan aquifers. Maximum potentiometric head decreases in the semiconfining layer (Layer 4) are limited to 0.05 foot for the average groundwater usage, and 0.1 foot for the maximum groundwater usage conditions (maximum drawdowns correspond to the pumping well locations). Average and maximum groundwater usage are not considered to be sufficient to cause the required head changes to induce saltwater intrusion into the semiconfining unit from the Lower Floridan Aquifer.

In summary, groundwater withdrawal from the Floridan Aquifer at the SEC will not affect unconfined groundwater elevations, will have no adverse impacts on other users, and will not result in saline water intrusion.

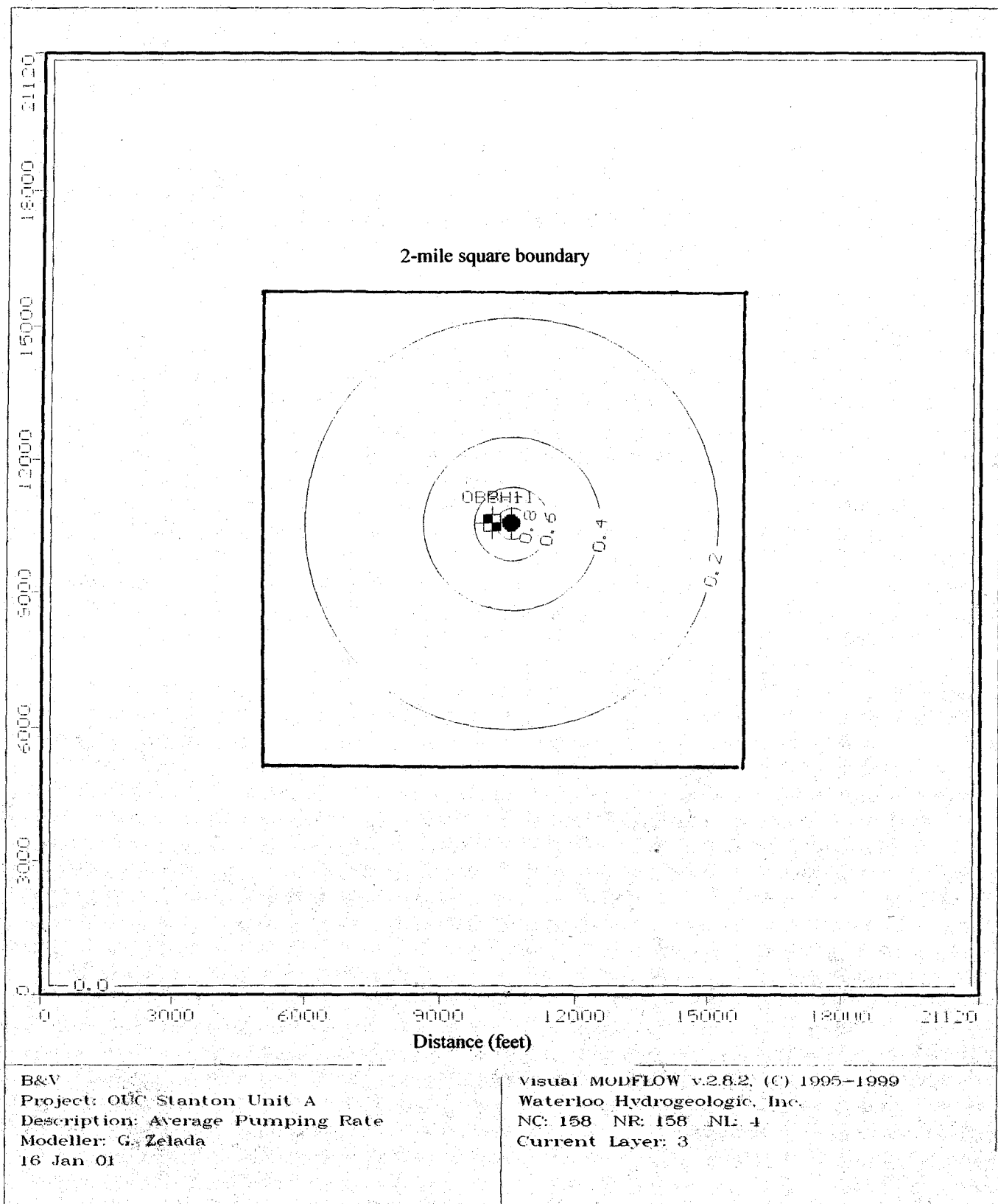


Figure 5.3-1
5-31 Drawdown (Feet) in Upper Floridan Aquifer
Due to Maximum Pumping Rate Conditions

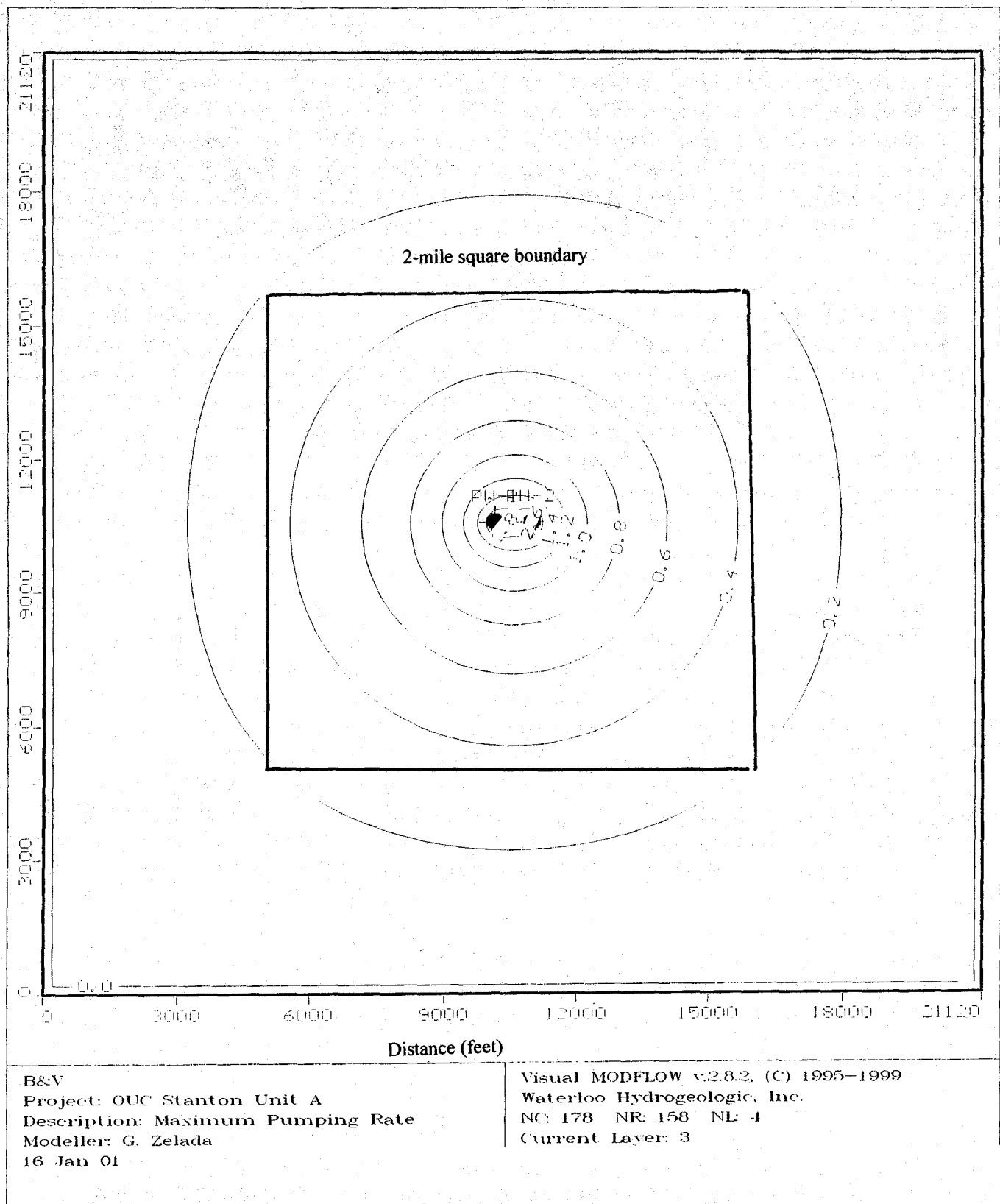


Figure 5.3-2
Drawdown (Feet) in Upper Floridan Aquifer Due to Maximum
Pumping Rate Conditions, Two Wells Pumping 443 gpm

5.3.2.6 Measuring and Monitoring Program. As mentioned previously in Section 4.3.2 of this SCA, a groundwater monitoring system has been established at the SEC to measure the seasonal groundwater level fluctuations and perform chemical analyses of samples from both the unconfined aquifer and the Floridan Aquifer. Monitoring of these wells will continue during construction and operation of Stanton A. No changes to the existing monitoring program are proposed.

The groundwater in the Floridan Aquifer is monitored to measure fluctuation in the potentiometric surface and water quality. Water level readings of the potentiometric surface in the Floridan Aquifer are made on a monthly basis at an observation well located 400 feet from one of the existing water supply wells. Water quality analyses of samples of the groundwater in the well production pipeline are obtained on a quarterly basis. Exhibit B as referenced in Section 2.3 includes records of the groundwater chemical analyses and groundwater levels obtained from the water supply wells and observation wells. Water quality samples will continue to be collected from the existing well production pipeline.

5.3.3 Drinking Water

The effects of facility groundwater withdrawals during operation on drinking water supplies are discussed in Subsection 5.3.2. The effects of leachate and runoff are discussed in Subsection 5.3.4. The locations and descriptions of existing wells are provided in Subsection 2.3.3. There will be no harm to any existing legal users or to the resources by any of the activities associated with the facility.

5.3.4 Leachate and Runoff

There is no source of leachate associated with the addition of Stanton A; therefore, there will be no impact on the underlying aquifers due to leachate.

5.3.5 Measurement Programs

5.3.5.1 Surface Water Monitoring. The general site runoff will be monitored in accordance with the existing surface water monitoring program.

5.3.5.2 Groundwater Monitoring. No modifications to the existing groundwater monitoring plan are proposed.

5.4 Solid/Hazardous Waste Disposal Impacts

The solid wastes generated by the operation of Stanton A will consist of the incremental dewatered solids from the cooling tower blowdown treatment system. The solids will be disposed of in the SEC combustion waste storage landfill by the

macroencapsulation method. It is anticipated that cooling tower blowdown solids will be delivered one or two times per week to a specified area within the landfill and the delivery noted on a daily log. The cooling tower blowdown solids will be spread and compacted and will be totally covered with conditioned Unit 1 and 2 combustion waste material by the end of each day.

No hazardous waste is produced at the SEC site except for waste oils as described in Section 3.7. These wastes will be hauled offsite to a licensed disposal facility.

5.5 Sanitary and Other Waste Discharges

A minor amount of additional sanitary wastes will result from Stanton A. Sanitary wastes will be collected and treated by a new septic tank and tile field system which will meet applicable federal, state, and local requirements.

5.6 Air Quality Impacts

The air quality impacts associated with the addition of the combined cycle unit are addressed in the PSD Air Permit Application attached to this Site Certification Application as Appendix 10.7 under separate cover.

5.7 Operation 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.

5.7.1 Computer Program

The SEC 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 soft ground and 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 1/3 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 associated with the combined cycle unit operation include the combustion turbines (including casing radiated and inlet noise), the heat recovery steam generators (HRSGs) (including wall radiated and stack emitted noise), the steam turbine generator, the generator transformers, and the cooling tower. All modeling represents the combined cycle unit equipment 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. Where equipment vendor data are not available, the noise emissions are 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, generator transformers, and steam turbine were estimated using information provided in the EEI guide.

5.7.3 Predicted Noise Impacts

Predictive noise modeling contours were developed for the full facility operation. The contours are shown on Figure 5.7-1. The modeled sound level results indicate that the facility noise emission associated with the combined cycle unit operating at baseload is approximately 50 dBA at the nearest boundary and approximately 39 dBA at the nearest residential location.

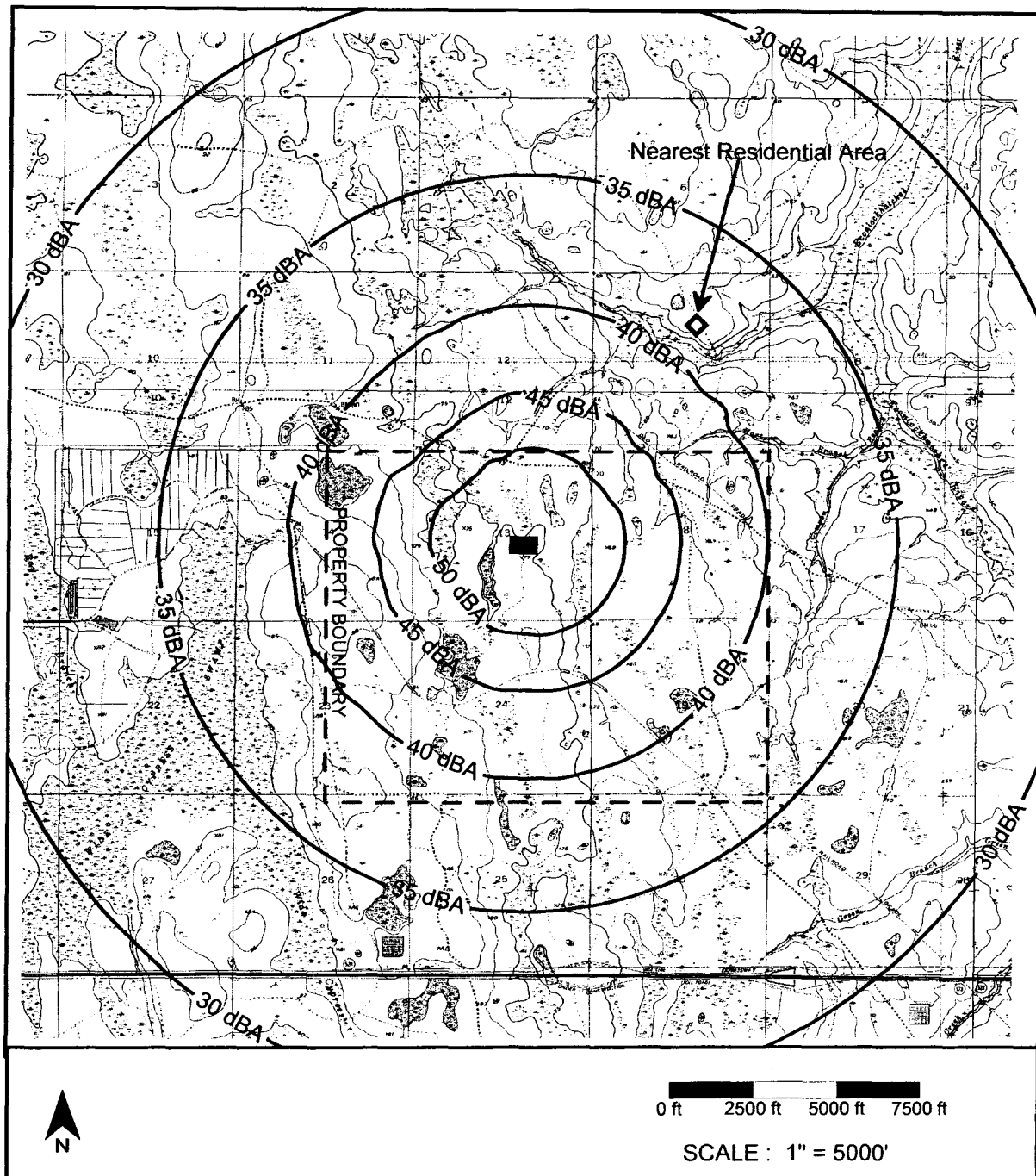


Figure 5.7-1.
STANDARD PACKAGED EQUIPMENT

Predicted A-weighted sound pressure levels (re: $20\text{e-}6$ Pa) during normal operation of the proposed facility. Sound pressure level results do not include the barrier effect of off-site buildings, structures, and intervening terrain.

5.7.4 Compliance with Noise Regulations

There are no federal or state noise regulations that apply to the proposed facility. Orange County has established a noise ordinance that is contained in Chapter 15, Article V of the Orange County Code. The code requires noise emissions associated with industrial facilities not to exceed 60 dBA daytime and 55 dBA nighttime at the nearest residences. Furthermore, the code requires the facility to not exceed specific sound levels in each of nine standard octave bands. The noise requirements and predicted sound level are contained in the Table 5.7-1.

The facility sound levels are projected to be approximately 39 dBA (daytime and nighttime) at the nearest residences. In addition, the facility noise emissions are anticipated to be below the noise criteria in each octave band. The facility noise emissions are projected to be fully compliant with the Orange County Code.

5.7.5 Noise Mitigation

The combined cycle unit equipment will include several noise mitigation features.

The combustion turbine generator, steam turbine generator, and much of the auxiliary equipment will be located within acoustic enclosures. These enclosures are constructed of heavy gauge metal panel, with acoustically sealed doors and silenced ventilation openings.

In addition, the combustion turbine inlet will be equipped with a silencer.

The HRSG equipment does not generate noise. The HRSG equipment will actually operate as a very effective exhaust silencer and will greatly mitigate the combustion turbine exhaust noise. However, a portion of the exhaust noise will pass through the boiler and exit the stack and also radiate through the boiler and duct walls. The noise radiated from the HRSG is included in the modeling. The HRSG is anticipated to provide sufficient exhaust silencing. No specific noise mitigation measures, beyond the inherent equipment noise attenuation, are anticipated for the HRSG equipment.

5.8 Changes in Nonaquatic Species Populations

5.8.1 Impacts

The operation of Stanton A is not expected to decrease the relative abundance of nonaquatic species in the vicinity of the facility. No wildlife habitat will be removed from the facility location. No changes in species diversity, composition, and dominance are expected to occur. No long-term changes in wildlife populations will result from the operation of Stanton A.

Table 5.7-1
Predicted Facility Noise Emissions versus Orange County Noise Criteria.

Frequency (Hz)	Residential		Projected Facility Sound Level
	Daytime (7 a.m. – 10 p.m.)	Nighttime (10 p.m. – 7 a.m.)	
31.5	75	72	52
63	74	71	50
125	67	65	48
250	63	57	44
500	56	51	37
1,000	51	45	26
2,000	47	39	25
4,000	45	34	20
8,000	40	32	18
Overall dBA	60 dBA	55 dBA	39 dBA

5.8.2 Monitoring

Mitigation monitoring plans, as approved under the Site Certification for Units 1 and 2 will also be followed for Stanton A. No changes are proposed in the management or monitoring plans with the addition of Stanton A.

5.9 Other Plant Operation Effects

The operating staff number will increase slightly with the addition of Stanton A. No significant impacts on area traffic are expected and no new offsite roads or road improvements will be required.

5.10 Landmarks, Sensitive Areas, and Archaeological Sites

There are no recorded historic, scenic, cultural, or natural landmarks located on the plant site. The nearest recognized sites are located in or near Orlando. The *National Register of Historic Places* currently lists the following sites located in Orange County, Florida:

- Orlando--Old Orlando Railroad Depot.
- Orlando--First Church of Christ Scientist.
- Orlando--The Tinker Building.
- Winter Park--The Parsonage.

The *National Register of Natural Landmarks* does not include any sites for Orange County, Florida.

An archaeological and historic survey of the Stanton Energy Center site was conducted in two stages. Sections 13 and 24, and the eastern halves of Sections 14 and 23 of Township 23 South, Range 31 east, initially were surveyed. When access later became available, the remainder of the site also was examined for the presence of archaeological and cultural resources. The site survey was conducted by personnel from the Florida Secretary of State, Division of Archives, History, and Records Management.

Four sites were found during the surveys. Three were prehistoric archaeological sites, and one was an historic hunting lodge from about the early 20th century. This lodge is located just off the site near the southwest corner of the proposed property line. The Division of Archives, History, and Records Management concluded that the sites did not represent significant archaeological or historical resources. A copy of a letter from Mr. L. Ross Morrell, Director, Division of Archives, History, and Records Management concerning the initial survey is presented as Figure 5.10-1.

The railroad corridor has been modified to include additional area southeast of Mud Lake, Lake Nona, and Red Lake. The Florida Department of State has reviewed the modification and has determined that no archaeological or historic sites have been



Secretary of State

STATE OF FLORIDA
THE CAPITOL
TALLAHASSEE 32304

GEORGE FIRESTONE
SECRETARY OF STATE

DIVISION OF ARCHIVES, HISTORY
AND RECORDS MANAGEMENT
L. Ross Morrell, Director
(904) 488-1480

March 13, 1981

In reply refer to:

Mr. John Scarry
Archaeology Supervisor
(904) 487-2333

Mr. George R. Savage
Black & Veatch Consulting Engineers
P. O. Box 8405
Kansas City, Missouri 64114

Re: Archaeological and Historical Survey
Econlockhatchee South Tract - Staunton Energy Center
Orange County, Florida

Dear Mr. Savage:

This agency recently surveyed those portions of the Econlockhatchee South Tract (The Staunton Energy Center property) which were accessible to the Orlando Utilities Commission. Specifically, we surveyed Sections 13 and 24 and the eastern halves of Sections 14 and 23 of Township 23 South, Range 31 East. We were unable to survey the remainder of the tract, i.e. that portion included in Sections 18 and 19 of Township 23 South, Range 32 East.

Four sites were located during the survey. Three of these were prehistoric archaeological sites; the final site is an historic hunting lodge dating to the first part of the 20th century. Based on the physical remains which constitute these sites, it is our opinion that they do not represent significant archaeological or historical resources. Therefore, construction of the proposed Staunton Energy Center will not adversely impact any significant archaeological or historical resources.

FLORIDA - STATE OF THE ARTS

Letter to Mr. Savage
March 13, 1981
Page Two

In accordance with the agreement between this agency and Black & Veatch, we will survey the remaining portions of the survey area as the Orlando Utilities Commission acquires access to them. Until that time, however, we cannot make an assessment of the archaeological and historical resources of that area.

Secretary of State George Firestone and I thank you for your cooperation in protecting the irreplaceable historic resources of Florida.

Sincerely,

A handwritten signature in dark ink, appearing to read 'L. Ross Morrell', written in a cursive style.

L. Ross Morrell, Director
Division of Archives, History
and Records Management

LRM/JFS/hs

recorded within the corridor modification. The Department of State also has concluded that the probability for significant, unrecorded sites to be present is low and that the project may proceed without further involvement of the Department of State. Figure 5.10-2 presents the pertinent documentation of this investigation.

5.11 Resources Committed

The SEC site includes 3,280 acres dominated by pine flatwoods with moderate cypress wetland areas. The Plant and associated onsite facilities have approximately 1,100 acres permitted for power development. Unit A will occupy approximately 60 acres within the previously certified site. The developed land may be mostly returned to its original use after the plant ceases operations.

The materials used to construct Stanton A 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 16.4 billion cubic feet of natural gas and 116.9 million gallons of No. 2 fuel oil (1,000 hours/year) will be consumed annually over the 30 year operating period.

5.12 Variances

It is not anticipated that any variances from applicable standards will be required for operation of the expanded facility.

5.13 References

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Armbruster, J. A., and C. L. Mulchi, 1984, "Response of Corn and Soybeans to Soil vs. Foliar-Applied Salts of Cooling Tower Origin," J. Environ. Qual. 13(2):278-282.

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George Firestone
Secretary of State
SYSTEMS ENG. DEPT.
LEGAL-ENV. GROUP
August 20, 1982

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ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - PROJECT 1

S.A. Ambruster	R.A. Fritz
F.C. Buschheit	D.D. Schultz
F.P. Chael	B.I. Unruh
F.F. Danner	K.E. Fells
S.H. Day	E.C. Windisch
C.W. Graham	P.H. Woodard
G.J. Moore	G. Savage

Received 8-31-82 File 12.1203
In Reply Refer to:

Ms. Juanita W. Crudele
Historic Sites Specialist
(904) 487-2333

Mr. E. C. Windisch
Black and Veatch Consulting Engineers
Post Office Box 8405
Kansas City, Missouri 64114

Re: Your Letter of August 4, 1982
Cultural Resource Assessment Request
Survey of Railroad Realignment, Stanton Energy Center
Unit 1, Orlando Utilities Commission, Orange County,
Florida

Dear Mr. Windisch:

As per your request we have reviewed the proposed realigned rail corridor to the Stanton Energy Center. A review of the Florida Master Site File indicates that no archaeological or historical sites are recorded within the project study area. Furthermore, a review of the information contained in the 1981 archaeological and historic site report by Randy Daniel and Paco de la Fuente for the originally proposed railroad corridor indicates that construction within the proposed realignment area - 300 feet on either side of the surveyed corridor - will have no impact on any significant archaeological resources and the project may proceed without further involvement with this agency.

If you have any questions concerning this matter, please do not hesitate to contact us.

Sincerely,

George W. Percy, Chief
Bureau of Historic Sites
and Properties

GWP:Ceb

cc: H. S. Oven

FLORIDA-State of the Arts

RFM-1

Figure 5.10-2

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6.0 Transmission Lines and Other Linear Facilities

6.1 Transmission Line

One new transmission line is proposed to connect the Stanton Energy Center Stanton A (Stanton A) with Orlando Utilities Commission existing Stanton Energy Center Substation No. 17 (Sub 17).

The proposed line will be installed on new structures for the entire length of the transmission line corridor. The proposed transmission line route is entirely within the existing Stanton Energy Center site and is shown on Figure 6.1-1.

6.1.1 Project Introduction

The proposed 230 kV transmission line will be a single circuit, heavy-duty, single-pole transmission line. The transmission line structures will be steel poles with drilled concrete pier foundations or self-supporting concrete poles. Both structure types will be capable of supporting a double circuit configuration.

In conjunction with the proposed transmission line, the existing OUC Sub 17 will be expanded to the west to accommodate the new 230 kV transmission line.

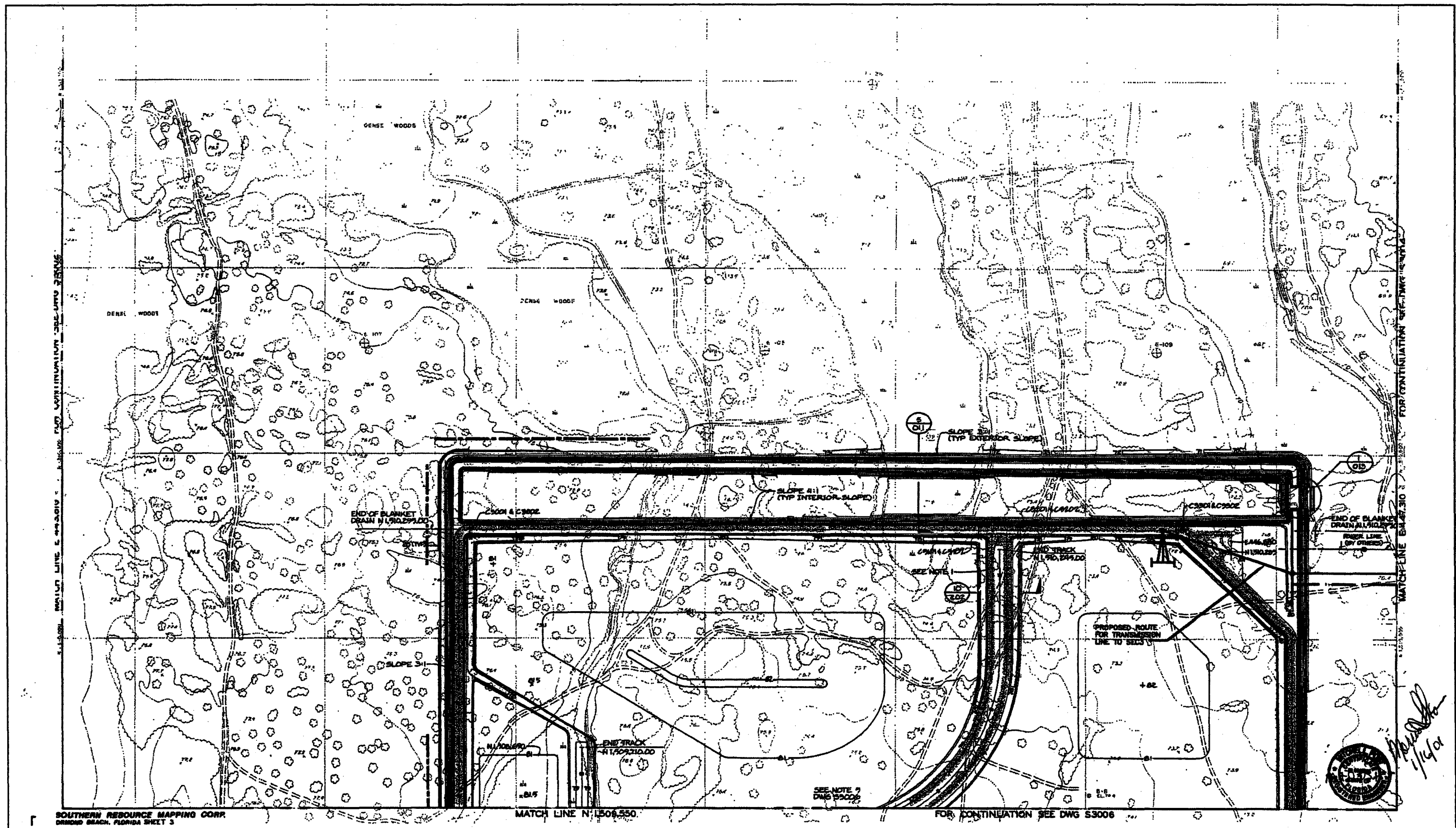
6.1.2 Corridor Location and Layout

The proposed route for the 230 kV transmission line will exit Stanton A and follow an easterly alignment to an existing access road. At this point, the line will turn north paralleling the access road a distance of approximately 1,400 feet. The line will then turn back to the east for approximately 800 feet, then turn to the north into a new substation bay at Sub 17. The total length of the transmission line is approximately 3,000 feet.

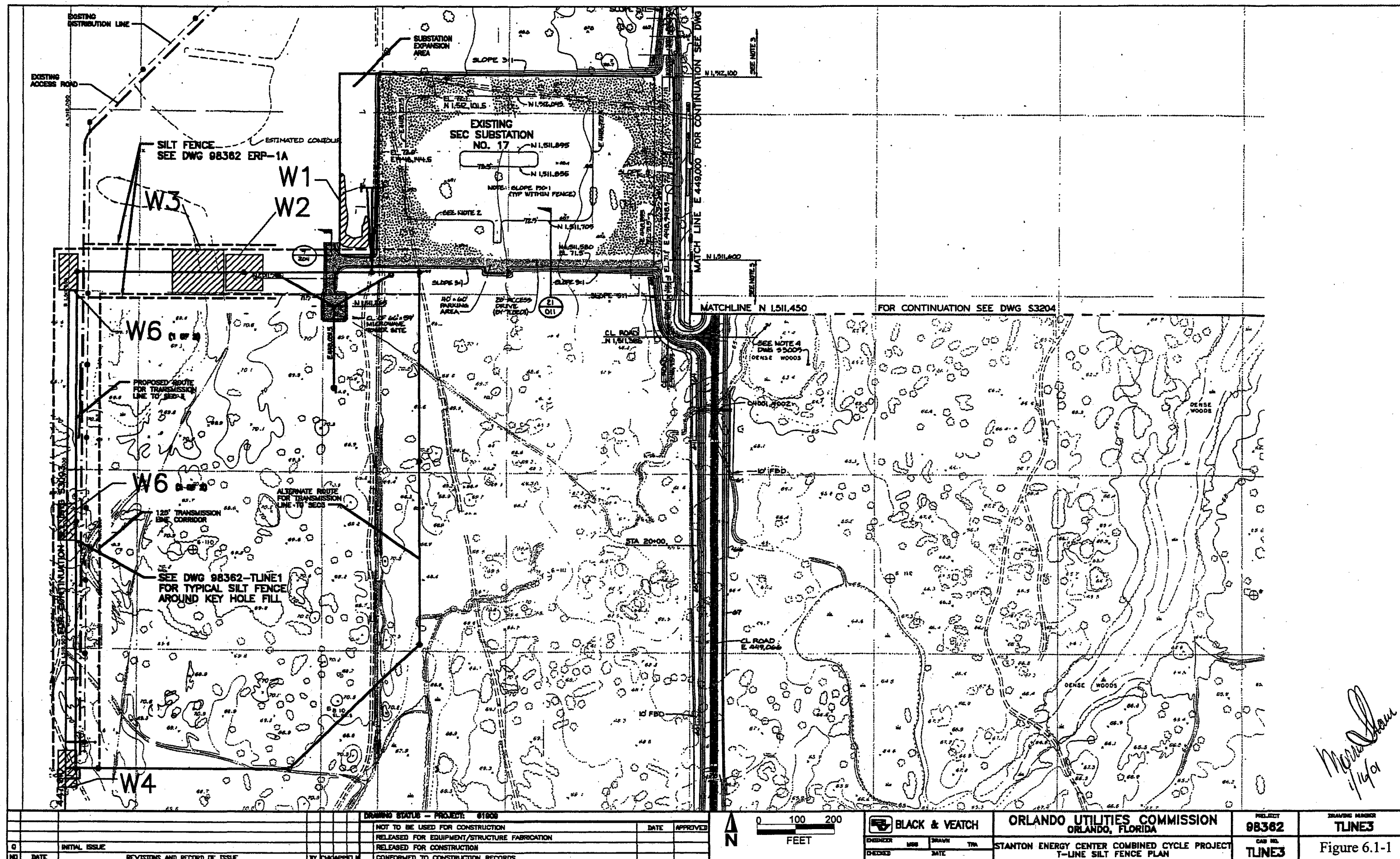
6.1.3 Transmission Line, Road, and Substation Design Characteristics

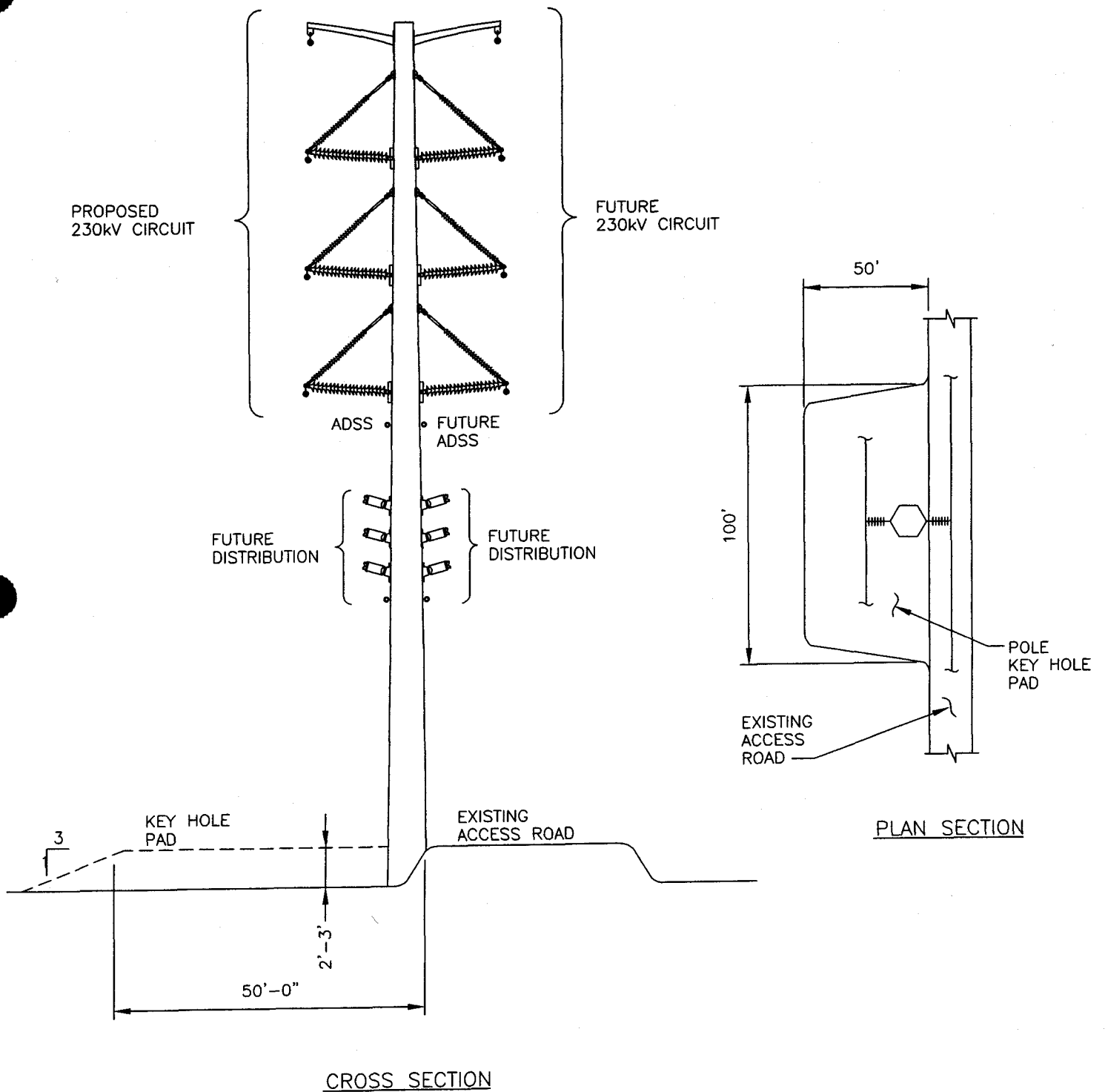
The 230 kV transmission line will be constructed using single-pole tubular steel structures or direct embedded concrete poles as shown on Figure 6.1-2. The tangent structures will be designed to support two 230 kV circuits; however, only one circuit will be installed. The structures will be spaced approximately 600 to 800 feet apart along the route. The transmission line conductors will be 1272 kcmil 39/19 ACSS/TW conductors. One fiber-optic shield wire and one ADSS fiber-optic cable will be installed on the structures for shielding, relaying, and communications.

The transmission 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 transmission



				DRAWING STATUS - PROJECT 01008						 BLACK & VEATCH		ORLANDO UTILITIES COMMISSION ORLANDO, FLORIDA		PROJECT 98362		DRAWING NUMBER TLINE2							
				NOT TO BE USED FOR CONSTRUCTION														DATE		APPROVED			
				RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION																			
				RELEASED FOR CONSTRUCTION																			
				CONFORMED TO CONSTRUCTION RECORDS																			
0		INITIAL ISSUE								DESIGNED		MOB		DRAWN		TFA		STANTON ENERGY CENTER COMBINED CYCLE PROJECT		CAB NO.		Figure 6.1-1	
NO		DATE		REVISIONS AND RECORD OF ISSUE		BY		CHK/APP/FLM		CHECKED				DATE				T-LINE SILT FENCE PLAN		TLINE2			





TYPICAL TRANSMISSION
TOWER STRUCTURES

Figure 6.1-2

line. The structures will vary in height along the route, depending on the span lengths and obstacles that must be crossed.

Access to the transmission line will be from existing roads, where practical. Construction of access roads is not anticipated. However, pole keyhole pads will be installed at several pole locations. The keyhole pads are necessary, not only for initial construction, but also for maintenance of the transmission line. Figure 6.1-2 also shows a cross section of the associated keyhole pad. The keyhole pad will be compacted native soil backfill with grass surface and side slope. Where necessary, a geotextile fabric liner will be installed to stabilize the keyhole pad. Corrugated metal pipe culverts are not anticipated since water will be allowed to flow around the keyhole pad.

OUC's Sub 17 will be expanded to the west to accommodate the new transmission line. The expansion will include site fill to bring the site up to the existing substation elevation. The site will be covered with well-graded crushed stone to 3 feet outside of the new fenced area. Structures will be galvanized tubular steel placed on drilled pier foundations similar in appearance to the existing structures.

Figure 6.1-1 shows where the construction of keyhole pads is anticipated along the route. Table 6.1-1 provides a summary cost estimate of the proposed and alternative transmission line alignments. Table 6.1-2 provides a summary cost estimate of the substation construction.

6.1.4 Cost Projections

The estimated total cost of the Stanton A 230 kV transmission line is summarized in Table 6.1-1.

6.1.5 Corridor Selection

Studies of OUC's electric transmission system showed that a connection from the Stanton A switchyard to SEC Sub 17 integrated very well with the existing system and is preferred to other possible connections or system upgrades for the addition of Stanton A.

One other route option was evaluated; however, this route would result in greater impacts because of potentially longer line lengths, and additional vegetation clearing, access road, and construction within wetland areas.

6.1.6 Sociopolitical Environment of the Transmission Line Corridor Area

The proposed electric transmission line lies entirely within the SEC property boundary. Neither the construction nor the operation of the new electric transmission line will therefore result in any significant sociopolitical impacts.

Table 6.1-1
Transmission Line Cost Estimate

Item	Description	Recommended Route, \$	Alternate Route, \$
1	Transmission Line Structures	348,634	348,634
2	Conductor, Insulators, Wire	90,511	95,874
3	Survey, Soil Borings	20,125	20,125
4	Construction Labor	833,129	984,170
5	Engineering	212,750	235,750
6	OUC Costs	<u>181,700</u>	<u>203,550</u>
		1,686,849	1,888,103

Table 6.1-2 Substation Cost Estimate		
Item	Description	Project Cost, \$
1	Equipment and Materials	1,491,691
2	SCADA Hardware	67,045
3	Survey, Soil Borings	13,800
4	Construction Labor	1,460,063
5	Engineering	553,495
6	OUC Costs	<u>438,150</u>
	Total	4,024,244

6.1.6.1 Governmental Jurisdictions. The proposed transmission line lies in an unincorporated area of Orange County.

6.1.6.2 Zoning and Land Use Plans. On August 11, 1981, the Board of County Commissioners of Orange County, Florida signed a resolution granting a special exception to permit the OUC electric power plant and associated facilities within an A-2 zoning district. This special exception applied to the entire SEC site. Since the proposed transmission line corridor lies entirely within SEC property, the special exception applies to the corridor as well. The transmission line is thus consistent with the SEC certification and the zoning and land use plans in Orange County, Florida.

6.1.7 Biophysical Environment of the Corridor Area

The following subsections describe the environment of the proposed 125 foot wide transmission line corridor proposed to connect the Stanton Energy Center Unit A (Unit A) with Orlando Utilities Commission existing SEC Substation No. 17 (Sub 17).

6.1.7.1 Land Use/Vegetation. The proposed transmission line route will be located entirely within the existing SEC boundary. The land between Unit A and Sub 17 is mostly undeveloped/native area dominated by pine flatwoods and cypress wetland vegetative communities. A detailed description of these communities is presented in Section 2.3.5. In addition to the undeveloped/native area, there is an access road that was once used as an alternative route to the SEC. The access road is now used to access electrical distribution lines, which are located adjacent to and east of the access road. This land was certified with SEC Unit 1 for land use compatibility on October 20, 1981, eliminating the need for further certification for the land use of the proposed electric transmission interconnection.

6.1.7.2 Affected Waters and Wetlands. This section describes the surface water bodies or wetlands that are crossed by the transmission line, and the significant drainage features that may be affected by this project.

The surface water bodies crossed by the corridor are limited to an artificial surface water (borrow ditch) and isolated cypress strand and herbaceous wetland. Approximately 0.4 acres of cypress strand will be cleared for the transmission line corridor and 0.57 acres of herbaceous wetland will be permanently filled to support the pole structures and associated keyhole pads. Refer to Figures 6.1-1 and 6.1-2 for location and description, respectively, of the keyhole pads. The approximate area covered by waters or wetlands in the 125 foot wide corridor is 7 acres. A breakdown of the estimated acreage of waters and wetland impacts in the corridor is presented in Table 6.1-3.

6.1.7.3 Ecology. The ecology of the SEC vicinity was addressed in Section 2.6 of the original SCA. The transmission line will be constructed entirely within SEC property.

Table 6.1-3 Wetland Impacts Within the SEC Electric Transmission Corridor		
Wetland Type	ft ² /acres	Impact Type
Artificial waters	10,000/0.23	Fill - Permanent
Cypress strand	17,500/0.4	Clear - Permanent
Herbaceous wetland	20,473/0.57	Fill - Permanent

6.1.7.4 Other Environmental Features. There are no other environmental features applicable to the proposed transmission line and associated 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, silt fence installation, clearing, foundation construction, structure assembly and erection, conductor and shield wire installation, and cleanup. These tasks will occur in the following sequence and will be separated, in time, by several days to several months.

The right-of-way centerline and edges, and structure 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." Silt fences are erected to define the construction area as well as to prevent soil and debris from leaving the construction area.

In wetlands and other 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 transmission structure foundations and keyhole fills. Stumps and root mat will be left in place except at structure foundation locations. There will be no need to demuck.

Fill material for keyhole fills will be hauled in by truck and spread with bulldozers to obtain suitable compaction. Culverts, if required, will be 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. Keypads 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 to prevent 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 Impacts on Waterbodies and Uses. The proposed transmission line and associated corridor are located more than 1 mile from the Econlockhatchee and Little Econlockhatchee Rivers and will have no impact on these surface waters. The proposed transmission line will have some impact on isolated wetland areas along the proposed route. Minor wetland dredge and fill will be necessary in a few locations in order to construct transmission pole foundations and keyhole pads. The expected locations of fill placement are shown on Figure 6.1-1. In addition, estimates of fill and clearing necessary for the transmission line are included in Table 6.1-3. The Joint Application form (ERP Form 40B-1.901(18)) for impacts to wetlands and surface waters is included in Appendix 10.4.4.

This application includes all currently available preliminary design information regarding the wetland impacts of the proposed transmission line. The ERP Form 40B-1.901(18) allows submittal of detailed wetland impact information either during the certification process or post-certification for later review.

6.1.8.3 Solid Wastes. Solid wastes generated during construction of the proposed transmission line will consist of construction material debris and cleared vegetation. Cleared vegetation and other combustible materials will be hauled to an acceptable area following applicable regulations regarding open burning. Noncombustible materials will be collected and disposed of at local landfills or other approved disposal sites.

6.1.8.4 Changes to Vegetation, Wildlife, and Aquatic Life. Approximately 0.4 acres of cypress strand will be cleared for the construction of the proposed transmission line. Changes to the landscape required to construct and operate the transmission line and associated corridor are consistent with the current use of the site. Construction of the transmission line and structure keyhole pads is expected to have minimal impact on wildlife and their habitat.

The proposed transmission route has been designed to avoid or minimize adverse impacts to the red-cockaded woodpecker, their habitat, and wetlands. Based on the *Progress Report on Red-Cockaded Woodpeckers for the Stanton Energy Center, 1999* (Delotelle & Guthrie, Inc., 2000), no cavity trees are located within, or in the vicinity of, the transmission line corridor. Therefore, no significant impacts on the red-cockaded woodpecker are anticipated as a result of the construction of the electric transmission line.

As shown in Table 6.1-3, an estimated 0.4 acres of cypress wetland will be cleared, and 0.57 acres of herbaceous wetland filled. These vegetative communities may be used as habitat by a variety of birds, small mammals, amphibians, and reptiles. Construction activities will displace wildlife from these areas. However, the disturbance resulting from development of the transmission line is anticipated to be minimal because

of the minimal acreage actually disturbed by the transmission construction. The proposed transmission line has been routed to minimize impacts on wetlands as much as possible.

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. OUC will inspect and maintain the transmission line and line right-of-way by the following activities:

- Emergency patrol by vehicle in the event of damage to the line by severe weather.
- Use of farm type tractors with mowing and brush-cutting attachments 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 transmission line corridor. 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 3 to 5 years. Only in a very unusual situation would treatment be required more frequently.

Burning is not normally required for maintenance of the transmission line corridor. When extensive vegetation removal within the corridor is necessary, as during construction, limited burning of cleared vegetation may occur. Pursuant to 5I-2, F.A.C., since the cleared corridor itself acts as a fire lane, no fire lanes are anticipated to be necessary.

6.1.9.2 Multiple Uses. There are no multiple uses planned for the proposed transmission line corridor.

6.1.9.3 Changes in Species Populations. No significant long-term changes in the populations of threatened, endangered, or species of special concern within the transmission line corridor are expected as a result of maintenance practices.

6.1.9.4 Effects of Public Access. Public access is generally not allowed on the SEC property; no new public access to the SEC property will result from the construction of the proposed transmission line. The entire transmission line and corridor will be

constructed within the current property boundary, which is controlled by gates at the fenced boundary site.

6.1.10 Other Post-Construction Effects

Other post-construction effects include impacts from electric and magnetic fields, audible noise, radio and television interference, and ozone. However, since the proposed line will be constructed entirely on SEC property, an analysis of these effects is not required as no offsite transmission facilities are required.

6.2 Natural Gas Pipeline

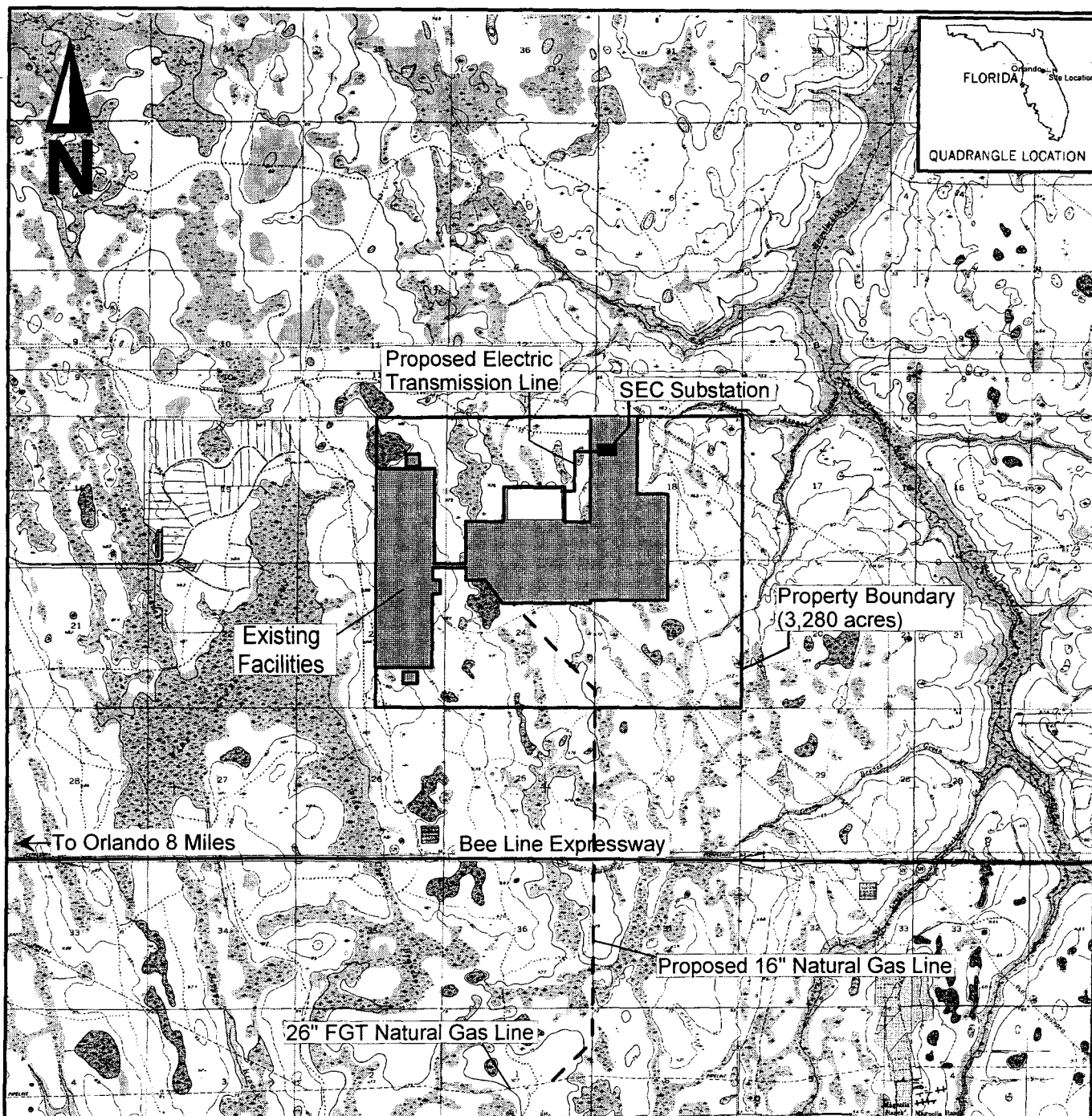
6.2.1 Project Introduction

Natural gas for the project will be delivered to Stanton A by a 4-1/2 mile long, 16 inch lateral to a Florida Gas Transmission (FGT) line in Orange County. The pipeline lateral will originate at the 26 inch FGT gas supply line, which is 2-1/2 miles south of the SEC, and will terminate at Stanton A. OUC owns a 300 foot wide corridor which contains a railroad spur, unimproved maintenance road, and a 230 kV transmission line. The proposed gas pipeline will be installed within this corridor, generally between the rail spur and the maintenance road. The origin of the pipeline is at the intersection of the FGT supply line (Figure 6.2-1). The actual right-of-way width required for the pipeline is a maximum of 75 feet for construction, of which 50 feet will be permanently maintained.

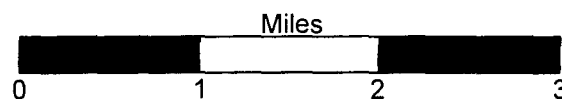
Starting from the connection to the FGT pipeline, the major components of the lateral will be as follows:

- A gas metering assembly at the connection.
- A scraper trap (a piping component located at either end of a pipeline to allow launching or receiving of internal cleaning or inspection devices into/from the main line).
- A buried 16 inch diameter gas transmission pipeline manufactured of high strength steel with sectionalizing block valves.
- A pressure regulating station and a gas metering assembly at the Stanton A site.

A Supervisory Control and Data Acquisition (SCADA) system will be used to monitor and operate the system and a cathodic protection system will be installed to protect the buried line against corrosion.



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)
 Property Boundary: Orange Co.; Sections 13, 24, E1/2 14, E1/2 23 of Township 23S, Range 31E; Sections 18, 19 of Township 23S, Range 32E



**Stanton Energy Center
 Property Location
 Figure 6.2-1**

6.2.2 Corridor Location and Layout

Figure 6.2-1 shows the pipeline route. From the FGT mainline, the pipeline proceeds north until it is about 40 feet from the railroad track. At that point, the pipeline will parallel the track to the north/northeast for about 1/4 of a mile and then run north as the track turns to the north. The pipeline will continue to parallel the track to the north for 2 miles, crosses under the Bee Line approximately 1 mile south of the SEC property boundary, and then turn northwest and follows the tracks for about 3/4 of a mile into the SEC. The pipeline will then cross the track and follow along the east side of the plant maintenance road as the road curves to the north, then the northwest, then back north. The pipeline will then head due east on the south side of the road for about 1/10 of a mile. At that point, the pipeline will cross under the road and will run between the coal storage area runoff pond and a driveway towards the north for 1/3 of a mile. The pipe will then pass under the east-west road between the existing units and the Stanton A site and turn to the west. The pipe will then turn north at the next road running north and follow the road to the future gas metering station.

6.2.3 Gas Pipeline Design Characteristics

The pipe will be manufactured of carbon-steel according to American Petroleum Institute standards. It will have a diameter of 16 inches and will be longitudinally welded at the mill. All facilities will be built in accordance with the requirements of the U.S. Department of Transportation (USDOT) (49 CFR, Part 192) as amended by the Materials Transportation Bureau, Office of pipeline Safety Operations. Pursuant to Chapter 368, F.S., the Florida Public Service Commission (PSC) has authority to regulate safety considerations for intrastate gas transmission and distribution pipelines that operate exclusively within Florida. Under that authority the PSC has adopted administrative rules, Chapter 25-12, Florida Administrative Code (F.A.C.), for gas pipeline safety, design, construction and operation. These PSC regulations adopt and expand the federal safety regulations particularly in the areas of pipeline welding and inspection and of drug testing of critical employees. The gas lateral pipeline connecting the project to a gas transmission pipeline will be subject to these PSC regulations.

The pipe will have a protective external coating. Such coating will be checked electrically for voids in the coating prior to shipping and prior to installation in the ground. The pipe will be installed to a depth of at least 30 inches below the surface. Burial will be deeper where required to pass beneath ditches, canals, and roads. Concrete coated pipe, concrete weights, and screw anchors will be used as necessary to locally control buoyancy.

A cathodic protection system will be installed to prevent corrosion. This system will be activated within 1 year following construction. The cathodic system will be monitored to insure continued protection.

A metering station will be located at the gas pipeline origin and at the gas pipeline termination point at Stanton A. No other nonpipe facilities will be used between these points.

6.2.4 Cost Projections

Pipeline cost projections on an average per foot basis is provided in Table 6.2-1(a), and on an average per mile basis in Table 6.2-1(b).

6.2.5 Corridor Selection Process

Only one route was developed and studied for the gas pipeline because the existing utility corridor is owned by OUC and runs directly south to the nearest FGT pipeline.

6.2.6 Sociopolitical Environment of the Corridor Area

The sociopolitical environment for the SEC area, which includes the utility corridor, is described in Section 2.2 of this SCA. The new pipeline will be located entirely on OUC owned property. This corridor received certification with regard to land use compatibility (as part of the initial SCA process) on October 20, 1981, and is zoned A-2.

The pipeline will cross the Bee Line Expressway (Florida State HWY 528) which will require conforming to the specifications outlined in the Florida Department of Transportation's (FDOT) "Utility Accommodation Guide" (FDOT, 1990). Approvals for crossing the Bee Line Expressway will be obtained from the FDOT and Orange County Expressway Authority through the site certification process. An FDOT Utility Crossing Permit Application is included in the Appendices in Section 10.4.

6.2.7 Bio-Physical Environment of the Corridor Area

The following subsections describe the environment of the proposed 50-foot wide SEC Natural Gas Pipeline corridor

6.2.7.1 Land Use/Vegetation. The proposed natural gas pipeline route will be located within existing corridors. Most of the pipeline route is in roads/highway right-of-way, but will also be installed in railroad right-of-way. Land use in the vicinity of the proposed natural gas pipeline corridor includes native habitats, utility/industrial, roads and highways, and the Florida Department of Correction's, Central Florida Reception Center-South Unit.

Table 6.2-1(a) Cost for Gas Pipeline Construction	
Gas Pipeline Construction Task	Cost
Pipe Installation	\$122 per foot
Right-of-Way Preparation	\$3 per foot
Gas Metering Stations	\$375,000 ea.
Total	\$3,750,000
Based on 4.5 mile pipeline length and 16 inch pipeline diameter.	

Table 6.2-1(b) Cost for Gas Pipeline Construction	
Gas Pipeline Construction Task	Cost
Pipe Installation	\$645,000 per mile
Right-of-Way Preparation	\$15,800 per mile
Gas Metering Stations	\$375,000 ea.
Total	\$3,750,000
Based on 4.5 mile pipeline length and 16 inch pipeline diameter.	

The vegetation in the proposed natural gas pipeline corridor is mostly maintained as lawn (i.e. grass) for maintenance and operation of the roads and railroad tracks now occupying the area. The new pipeline will follow much of this same route passing through areas adjacent to pine flatwoods, cypress strand, freshwater marsh, and unimproved pasture. A description of the pine flatwoods and cypress strand communities is presented in Section 2.3.5. The following communities were not included in Section 2.3.5.

Freshwater marshes are found in small, poorly drained depressions scattered throughout the corridor. Mesic, herbaceous species such as broomsedge bluestem (*Andropogon virginicus*) and bottlebrush threeawn (*Aristida spiciformis*) dominate these areas. Large islands of shrubs, such as peel bark St. Johns-wort, wax myrtle, and dahoon holly, can be found on drier locations. In addition, tree species such as swamp bay and pond pine can be encountered in isolated locations.

Small areas dominated by species typically occurring in unimproved pasture are encountered along the southern half of the proposed corridor. Most of these pastures have been cleared, rotary-cut, burned, or in some way altered to provide adequate forage for livestock. The typical vegetation includes many invasive native and nonnative grasses, as well as a large number of native perennial and annual herbs found throughout the pastures. At many localities, native species have persisted with diversity varying along water gradients and degrees of disturbance. At hydric sites common species include: bushy bluestem (*Andropogon glomeratus*), xyris (*Xyris* spp.), Carolina redroot (*Lachnanthes caroliana*), pickerelweed (*Pontederia cordata*), lachnocaulon (*Lachnocaulon* spp.), fimbry (*Fimbristylis* spp.), rhynchospora (*Rhynchospora* spp.), seedbox (*Ludwigia* spp.), and rhexia (*Rhexia* spp.). Common species that occur in the uplands include panicum (*Panicum* spp.), St. Johns wort (*Hypericum* spp.), cottony golden aster (*Chrysopsis gossypina*), small dogfennel (*Eupatorium capillifolium*), wand blackroot (*Pterocaulon virgatum*), Virginia buttonweed (*Diodia virginiana*), and lovegrass (*Eragrostis* spp.).

6.2.7.2 Affected Waters and Wetlands. The surface water bodies crossed by the corridor are limited to Green Branch and Turkey Creek and their associated wetlands. These two hydrological complexes drain to the northeast and are tributaries of the Econlockhatchee River drainage basin. Wetlands in the corridor include cypress strand and forested mixed wetlands, which are described in Section 2.3.5. The approximate area covered by waters or wetlands in the 50 foot corridor is 0.06 acre. A breakdown of the estimated acreage of waters and wetlands in the corridor is presented in Table 6.2-2.

Table 6.2-2 Wetland Impacts Within the SEC Natural Gas Pipeline Corridor		
Wetland Type	ft ² /acres	Impact Type
Forested mixed wetlands	2,760/0.06	Fill - Temporary
Cypress strand	8,110/0.17	Fill - Temporary
Cypress strand	8,750/0.20	No Impact

6.2.7.3 Ecology. Section 2.3.6 presents a general ecological overview of the sensitive species that occur or may potentially occur in the vicinity of the SEC. The proposed natural gas line corridor study area is located within the vicinity of the Power Park, and ecological issues within 5 miles are addressed in Section 2.3.6.

6.2.7.3.1 Important species. This section discusses the potential important species in the vicinity of the proposed natural gas pipeline. Important flora and fauna of the natural gas pipeline 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 gas pipeline corridor is based on state and federal endangered and threatened species lists (2000), available literature, and sensitive species surveys conducted in 1981.

Floristic elements considered “important” by federal and state agencies that may occur in the gas pipeline corridor are the same floristic elements that were considered in Section 2.3.6.

Wildlife species considered “important” by federal and state agencies that may occur in the gas pipeline corridor are the same species that were considered in Section 2.3.6. Several red-cockaded woodpecker colonies were observed in the vicinity of the corridor. However, no significant adverse impacts to the red-cockaded woodpecker are anticipated from the installation of the natural gas pipeline.

6.2.7.3.2 Existing stresses. Existing habitat stresses in the proposed corridor include railroad and automobile traffic. Cars and trains frequently pass the property on existing access roads and railroad tracks.

Barbed wire fences border the SEC Power Park boundary and the existing utility corridor. The corridor is gated at the intersection of the access road and SEC property boundary and along points where it connects with local roads and trails.

6.2.7.4 Other Environmental Features. No additional significant environmental features are known to occur in the proposed natural gas pipeline corridor.

6.2.8 Effect of Right-of-Way Preparation and Pipeline Construction

6.2.8.1 Construction Techniques. Pipeline construction activities differ slightly from pipeline to pipeline, but generally include the following, which are described in more detail below:

- Surveying and right-of-way preparation.
- Ditching/trenching.
- Installation.
- Testing.
- Right-of-way restoration.

Other specialized activities may take place, such as:

- Boring and installation of road, railroad, and stream crossings.
- Installation of mainline block valve assemblies.

Applicable Codes

The key regulatory document for the design and construction of the pipeline will be Minimum Federal Safety Standards for Gas Lines, Part 192, Title 49, CFR, implemented by the USDOT and referred to as 49 CFR, Part 192 hereafter. The PSC has adopted the USDOT standards.

Surveying and Right-of-Way Preparation

Following approval of the route, the entire route will be surveyed. The center line of the pipeline will be marked at about 200 foot intervals. Within the route staked by the surveying crew, the contractor personnel will clear the terrain to provide a work platform or working strip allowing unimpeded progress of the construction activities.

The 75 foot construction corridor will first be cleared of brush and timber in accordance with the contract specifications and permit or regulatory limitations. The stumps will be grubbed and all materials cleared will be disposed of in a manner consistent with the construction approvals and applicable state and local requirements. This may include upland burial onsite, burning, or hauling offsite. Generally, machetes, chain saws, bulldozers, backhoes, and trucks are the tools and equipment used during that operation.

Next, the topsoil layer within the route will be stripped where excavation will occur with a dozer or grader bermed to one side of the working strip. In both uplands and wetlands, the topsoil or upper 6 inches of soil will be saved to be spread back over the stripped area during restoration of the disturbed areas.

The work platform is then graded to provide smooth access to all equipment used in the following phases of construction.

The pipeline occupies only a small portion of the area necessary for the construction and possible future maintenance. Only 10 to 15 feet of area are needed to store the spoil excavated from the trench. For the 16 inch pipeline, the ditch bottom will be approximately 2 feet wide. Depending on the type of soil being excavated and type of ditching equipment used, the width of the trench at grade level may be only slightly wider than at the bottom, e.g., 6 feet, or it may be wider if unstable trench slopes are encountered.

The space adjacent to the trench is used to string the pipe joints on skids until ready for the welding operation. Working room is required on both sides of the pipe such that 10 to 12 feet must be reserved between the edge of the trench and the sideboom track. The width of the sideboom (also called pipelayer) for a 16 inch is approximately 12 feet with counterweight retracted and 16 feet or more when extended. Additional space is needed to the outside of the equipment for pickup trucks, lube truck, other side-booms and similar equipment to pass stationary equipment.

Trench Conditions

The trench excavation is called ditching and can be performed in a number of ways, based on the local conditions of the area crossed by the line. Wheel ditchers are the most convenient and effective way of opening the ditch.

For this pipeline, except in rocky areas if any are crossed along the route, the total depth of the trench will be about 4 to 5 feet.

Ditching for conventional drainage ditch crossing can be accomplished with backhoes or draglines. The choice of equipment will depend on the size of the ditch, water depth and current velocity, makeup of the channel bed and required trench depth. To control the water turbidity or to limit its increase as a result of construction activities, various methods are available as a function of site-specific conditions. For small waterways, as is the case for this installation, siltation barriers can be installed immediately downstream of the crossing. These siltation barriers consist of suspended fabric and/or hay bales.

To eliminate the disturbance to traffic brought on by using the open cut method of trenching across a roadway, boring techniques have been developed. The operation consists of drilling a hole horizontally under the road while inserting a pipe in that hole. The US DOT and counties regulate the minimum depth of cover between the top of the pipe and the road surface.

A boring machine is generally a motor driven auger equipped with a control panel and is mounted on a frame designed to straddle a pipe. A winch or hydraulic jacks provide the force applied to the auger and the pipe for horizontal progress.

Pipe Installation

Pipe installation, known as stringing pipe, can be accomplished just after the ditch has been opened or in other ways which also minimize the amount of time a trench is open. It essentially sets up the work for the actual assembly of the pipeline.

Since the welding operation is all-important in ensuring the structural integrity of the pipeline, it is performed by highly skilled personal. All welding personnel will be certified in the welding process associated with gas pipelines. The validity of the welding method (called the weld procedure) is verified and qualified following the requirements of API Standard 1104 for Welding Pipe Lines and Related Facilities.

Hydrostatic Testing

The entire pipeline and its associated facilities will be pressure tested to prove integrity. No evidence of leakage is allowed before the pipeline is authorized for operation. The records of all tests must be properly filed and maintained by the pipeline operator. Upon completion of all tests, the pipeline is ready for commissioning.

Part 192 of 49 CFR and project specifications establish stringent limits and requirements for the hydrotest. Both maximum and minimum levels are prescribed for test pressures as a function of the pipe physical characteristics (diameter, wall thickness and steel grade), the class location and the expected operating pressure. To satisfy all of these requirements, the range of required test pressures must be computed for each segment of the line. In any case, the minimum test pressure equals 110 percent of the maximum pressure at which the pipeline will be allowed to operate. A hydrostatic test program will be devised when the final design of the pipeline is completed. The water to be used for hydrostatic testing will be obtained from impounded water on the SEC and returned to this source following testing. No offsite surface or groundwater sources will be used for hydrostatic testing.

Land Restoration

During construction, topsoil will be saved to be spread back over the stripped area during the restoration of disturbed areas following pipe installation. Once the pipeline is buried in place, the stripped topsoil will be spread back in place to its original location and topography. Hydroseeding will be undertaken as necessary to quickly stabilize soils with a vegetation cover.

6.2.8.2 Impacts on Waterbodies and Uses. The proposed natural gas pipeline route is located more than a mile from the Econlockhatchee and Little Econlockhatchee Rivers and will have no impact on these surface waters. The proposed transmission line will have some impact on isolated wetland areas along the proposed route. Minor

wetland dredge and fill will be necessary in a few locations in order to install the pipeline. Estimates of fill necessary for the pipeline are included in Table 6.2-2. Cross sections showing pipeline locations within the proposed corridor are shown on Figure 6.2-2. The Joint Application form (ERP Form 40B-1.901(18)) for impacts to wetlands and surface waters is included in Appendix 10.4.4.

This application includes all currently available preliminary design information regarding the wetland impacts of the proposed natural gas line. The ERP Form 40B-1.901(18) allows submittal of detailed wetland impact information either during the certification process or post-certification for later review.

6.2.8.3 Solid Wastes. Solid wastes generated during construction of the proposed pipeline will consist of construction material debris and cleared vegetation. Cleared vegetation and other combustible materials will be hauled to an acceptable area and burned following applicable regulations regarding open burning. Noncombustible materials will be collected and disposed of at local landfills or other approved disposal sites.

6.2.8.4 Changes to Vegetation, Wildlife, and Aquatic Life. Construction of the natural gas pipeline is expected to have minimal impact on vegetation, wildlife, and aquatic life due to the temporary nature of the installation.

6.2.8.5 Impacts on Human Populations. All facilities of the natural gas pipeline installed in a state or county road right-of-way are to be designed and constructed in accordance with specifications outlined in FDOT's Utility Accommodation Guide. Construction would take approximately 2 to 3 months.

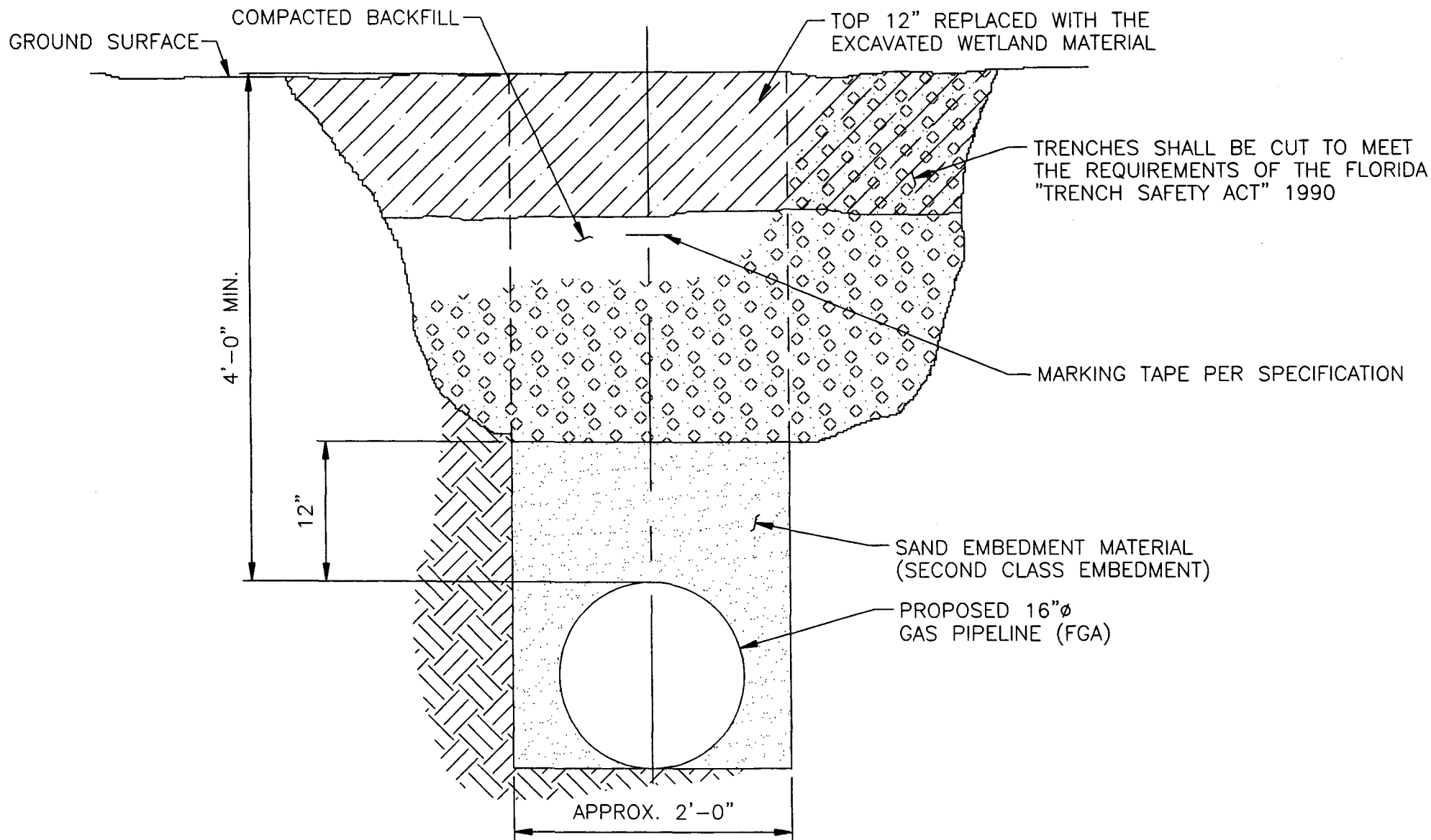
The pipeline will be installed in an existing utility corridor through areas with no human population. No impacts are expected.

6.2.8.6 Impact on Regional Scenic, Cultural, and Landmarks. No regional scenic, cultural, or natural landmarks have been identified within 0.5 mile of the pipeline route.

6.2.8.7 Impact of Archeological Historical Sites. No archeological or historical sites are located in the area of the pipeline route.

6.2.9 Post-Construction Impacts and Effects of Maintenance

Natural gas pipeline corridors 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.



LEGEND

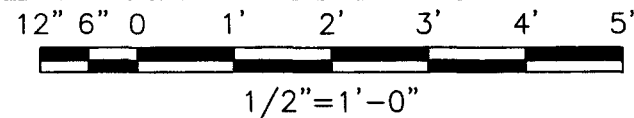


SAND EMBEDMENT

EXISTING SOIL



COMPACTED BACKFILL



TYPICAL GAS LINE TRENCH EXCAVATION

FIGURE 6.2-2

6.2.9.1 Maintenance. OUC will inspect and maintain the pipeline and right-of-way by the following activities:

- Emergency patrol by vehicle and/or aerial in the event of damage.
- Use of farm type tractors with mowing and brush-cutting attachments 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 pipeline corridor. 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 3 to 5 years. Only in a very unusual situation would treatment be required more frequently.

Burning is not normally required for maintenance of the pipeline corridor. When extensive vegetation removal within the corridor is necessary, as during construction, limited burning of cleared vegetation may occur. Since the cleared corridor itself acts as a fire lane, no fire lanes are anticipated to be necessary.

6.2.9.2 Multiple Uses. No multiple uses, other than potential utility uses, are planned for this corridor.

6.2.9.3 Changes in Species Populations. No significant long-term changes in the plant and animal populations of threatened, endangered, or species of special concern within the pipeline corridor are expected as a result of maintenance practices.

6.2.9.4 Effects of Public Access. The gas pipeline parallels existing linear facilities for its entire length and, except for publicly owned right-of-way crossings included in the larger utility corridor, is entirely located on OUC owned lands. No new access roads are to be constructed and public access to previously inaccessible areas will be limited.

7.0 Economic and Social Effects of Plant Construction and Operation

7.1 Socioeconomic Benefits

The Stanton Unit A Project (Stanton A) will provide benefits to Orange County, the region, and the State of Florida primarily by providing jobs that will increase the buying power of individuals and generate tax revenues. The Stanton Energy Center (SEC) 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 Stanton A is expected to create approximately 300 temporary jobs. As with all major construction projects, the labor force will change as construction progresses. Early in construction, laborers, carpenters, concrete workers, and operating engineers will be needed. Later, electricians, pipe fitters, boilermakers, and ironworkers will be hired. The anticipated workforce evolution is shown on Figure 7.1-1.

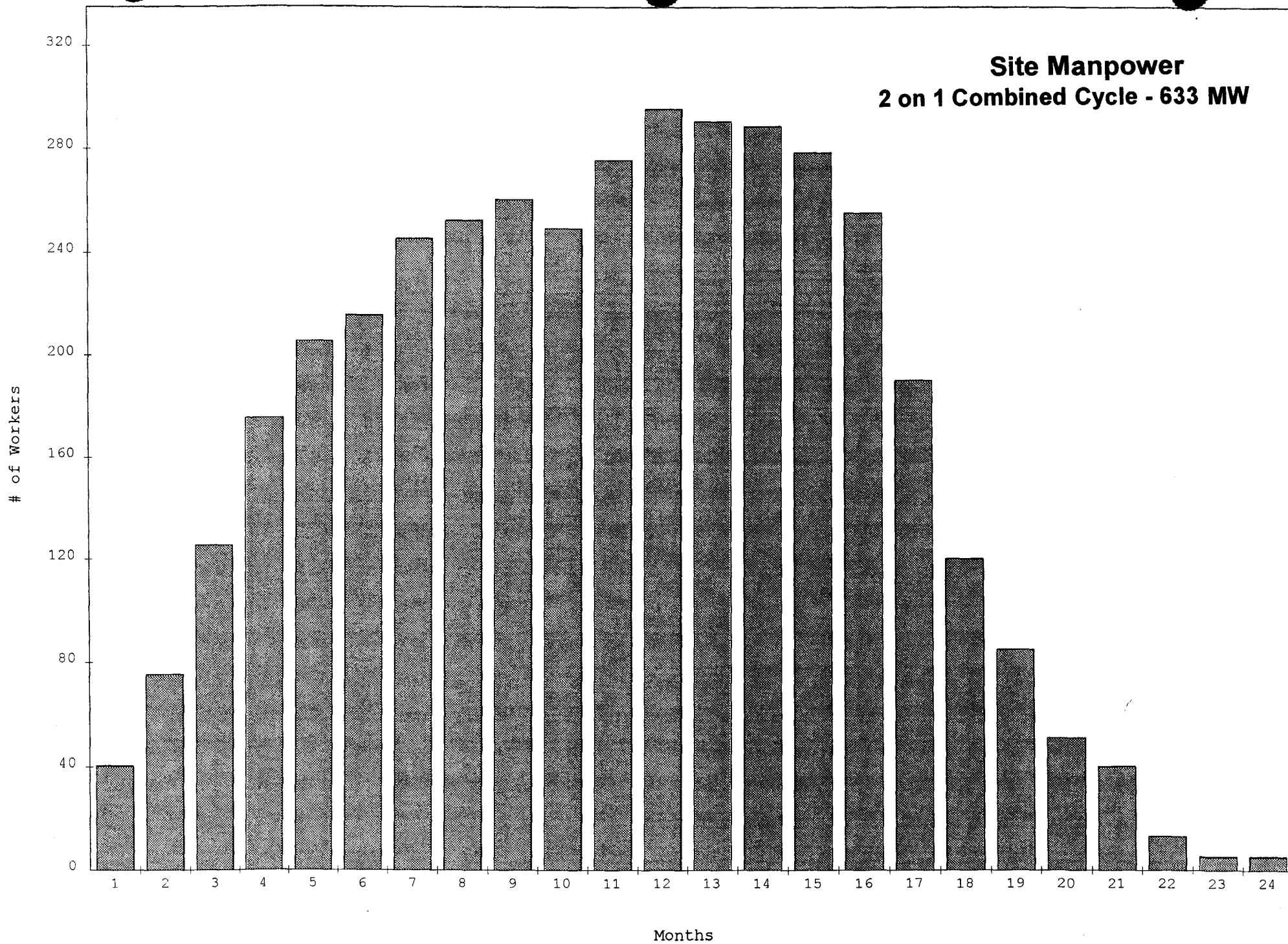
The construction workforce is expected to be primarily drawn from the impact area of Brevard, Osceola, Orange, Lake, and Seminole counties. As discussed above, it is anticipated that most of the workforce will commute daily from permanent residences within the impact area.

The estimated payroll for the construction workforce is \$28 million (in 2001 dollars). Distribution of this payroll would follow the workforce curve presented on Figure 7.1-1.

7.1.1.2 Permanent Jobs. It is estimated that the SEC will retain 30 full-time workers for the operation of Stanton A, with an estimated payroll of \$1,145,000. The current operational staff includes 180 individuals. Therefore, it is anticipated that beginning in late 2003 (the projected on-line date for the Project), the total operating SEC workforce salary will be in excess of \$10 million per year. Studies indicate that operational staff tend to live within 30 miles of the worksite (EPRI IV-2). Therefore, the benefits of these permanent positions will accrue in the impact area.

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 of 208 service positions ($300 \times 0.7 = 210$). Most of these service positions are typically of a short duration, lasting only so long as the construction workforce remains in the area. For operational employees, the multiplier has been found to be 0.8 (EPRI, 1982). Therefore, it is anticipated that possibly 16 service positions may be created as a result of the additional operational personnel ($30 \times 0.8 = 24$).

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 is planned, Stanton A will nonetheless contribute to the general creation and improvement of local transportation. This is anticipated through the increased tax revenue generated, 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 remain more than adequate to handle the anticipated weight and traffic count loads for the new Stanton A construction project.

7.1.5 Increased Knowledge of the Environment

Plant and wildlife surveys were completed prior to construction of Units 1 and 2. Mitigation monitoring plans for these units, as approved under the current Site Certification, will also be followed for Stanton A.

Monitoring for Units 1 and 2 has revealed no new information. It has, however, 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 site to coexist with a human population and industrial facility.

7.1.6 Increased Land Use Efficiency

Stanton A 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 SEC expansion and 20 additional operators and their families will not have any significant negative long-term impacts on these resources or services.

7.2.1 Temporary External Costs

Typical temporary external costs due to construction 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. However, OUC has owned the SEC property since 1983, with the intent and authorization to develop the property as an electrical power plant station. As described in other sections, there are no major construction impacts expected from development. OUC, KUA, FMFA, and Southern-Florida believe that the Project is an environmentally and socially responsible development.

7.2.1.1 Traffic Congestion. Some level 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 worksite. During Stanton A 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 lasting significant adverse impact on the roadways and intersections in the vicinity of the SEC.

Construction will occur during daylight hours, with the majority of workers onsite between 7 a.m. and 4 p.m. A late shift is anticipated, but this shift will have fewer workers. The main access point for the construction workforce and deliveries is the SEC entrance off of Alafaya Trail. The south access road, which connects with the Bee Line Expressway, will also be available during construction. The entrances are gated and access will continue to be controlled.

To further lessen the impact of the influx of construction workers on existing traffic patterns, OUC 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 carpooling 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 worksite, 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. The new construction of the SEC will not generate sufficient noise to negatively affect any local residents. The construction noise associated with Unit A is not anticipated to be significant. The majority of construction will be located on SEC property. The undeveloped surrounding area, as well as the vegetative buffer and physical distance to the nearest residences (nearly 1.5 miles), will all mitigate the intermittent disturbance. Equipment traveling to and from the SEC will unavoidably generate noise during transit, but this noise will not be significant in either level of intensity or duration.

7.2.1.3 Housing Impacts. No negative housing impacts will result from Stanton A 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 Stanton A 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 149 individuals. As mentioned in Subsection 2.2.7.1 under the heading Existing Housing Stock, the Orlando MSA alone had over 6,103 vacant rental units, over 92,200 hotel rooms, and over 40 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 multifamily housing units.

OUC, KUA, FMFA, and Southern-Florida 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 Stanton A. However, Stanton A will use the reclaimed water from the Orange County Easterly Water Reclamation Facility as cooling water makeup. Cooling water blowdown will be treated by a new brine concentration/crystallizer zero discharge system where most of the water is recovered for reuse. Potential sources of potable water supply for the facility include municipal potable water and treated well water. Systems already exist for supplying potable water from the existing wells. The existing service and demineralized water supply systems, which use well water as the source, will supply Stanton A service water and demineralized water requirements. An incremental groundwater allocation will also be requested for service/potable uses.

The construction contractors will be required to provide potable water for the Stanton A 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 Orange County landfill to handle the solid waste disposal needs of Stanton A construction. Since Orange County landfill is only 3 miles west of the site, the haulers will directly transfer the waste to the landfill without involving any transfer station. According to the Solid Waste Division of Orange County, there will be no impact from the proposed Stanton A on the current solid waste facility since Orange County landfill has sufficient capacity to handle the construction waste.

Orange County expects to have no problem arranging for the disposal of the solid waste generated during the subsequent operation of the SEC.

Sewer Service Impacts

Stanton A development will not impact the local sewer service. The new unit will include a dedicated septic tank/tile field system. Construction contractors will be required to provide temporary sanitary services for their employees.

Police Protection Impacts

Existing SEC fencing and security will continue to provide for the physical enclosure of secured areas and allow for the monitoring of incoming and outgoing traffic. The security fence will continue to enclose the main plant area and construction areas and allow only limited access. Therefore, police protection demand will not increase.

The combination of the size of the construction workforce and the duration of the construction phase will not cause any deterioration in the ability of the Orange County Sheriff's Department to provide routine patrol and protection services.

7.2.2 Long-Term External Costs

There may be long-term external costs resulting from operation of Stanton A as described in the following paragraphs. However, due to the remote location, self-reliant operation, 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. Potable water for Stanton A will be provided from an extension of the existing SEC service/potable water system, which is a permitted noncommunity public water system supplied by treated well water. In addition, the contractors will be required to supply potable water to their employees during construction. The design of Stanton A 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 existing SEC service water and demineralization water systems are capable of supplying the quality and quantity of water needed for the addition of Stanton A. Therefore, the incremental use of potable water and demineralized water due to Stanton A will not have significant impacts during the operational phase.

Negative Impacts on Potential Use of Contiguous Parcels

Since the SEC 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 the SEC property or the surrounding area. In addition, areas to the east and northeast of the Stanton A site are conservation areas. The north and northwest side of the SEC will continue to be the rural area. The area south of the SEC has been designated as industrial area, and the area west of the SEC has been designated as institutional area. Since the SEC already operates as an electric generating facility in a designated institutional area, Stanton A will not affect the potential use of this area. (Michael Rigby, Orange County Planning Department, July 2000.)

Negative Impacts on Local Recreational Activities

No access to local recreational activities is available through the SEC; therefore, Stanton A will not affect these activities.

Negative Impacts on Local Native Species

Stanton A construction will occur on SEC property that was prepared and used as a laydown area for the original facility. No critical habitat for federally listed species occurs within the proposed power plant site. No long-term changes in populations will result from the operation of Stanton A. OUC will continue implementation of the Joint Agency Mitigation Monitoring Plan at the SEC site.

Negative Impacts on Archaeological Sites

No significant archaeological sites exist on the SEC. Stanton A poses no threat to any other areas, whether of recreational, scenic, historic, cultural, natural, or archaeological value.

Negative Impacts on Alternative Land Uses

No alternative uses for the SEC have been proposed. The SEC has been designated for institutional use such as electricity generation by the Orange County Board of Commissioners.

Negative Impacts on Local Meteorological Conditions

Neither the construction or operation of Stanton A 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

As indicated in Sections 4.0 and 5.0, the noise of operation from the current SEC configuration does not have a significant negative impact on nearby residences. Furthermore, the additional noise generated by the operation of Unit A is expected to be imperceptible, and well within Orange County noise code guidelines.

There are currently no residential units within 1/2 mile of the construction site, and none are currently planned. As described previously, the closest residence is separated from the SEC by vegetation buffers. The vegetation will act to absorb or deflect sounds that otherwise may travel to the residential area.

Displacement of Persons for Construction Purposes

Since the SEC 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 construction or operation of Stanton A. 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 Project or otherwise.

Negative Impacts on Neighboring Property Values

Since the site has been zoned and developed as an 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 SEC. Since the surrounding areas are zoned for industrial and agricultural 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 Stanton A are expected to commute locally 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 300, 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 Stanton A is expected to be 30, which again is too low to adversely impact the ability of a local government from providing services.

Negative Impacts on Aesthetic or Scenic Values

Due to vegetative buffers and extensive setbacks, Stanton A development will not result in the deterioration of any local scenic or aesthetic values.

7.3 References

Socioeconomic Impacts of Power Plants, Electric Power Research Institute (EPRI), Report EA-2228, February, 1982.

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Florida Department of Labor and Employment Security, Florida Industry and Occupational Employment Projections to 2007.

Community Info. of Orlando, <http://www.realguides.com/community/ORFL>.

8.0 Site and Design Alternatives

8.1 Alternative Sites

Due to the availability and resources of the existing certified site, no alternative sites were considered for development of Stanton A.

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 Orange County Eastern Water Reclamation Facility for use in the cooling tower.

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 bio-fouling control alternatives include the following:

- Chlorination
- Sodium bromination
- Ozonation
- Ultraviolet radiation
- Mechanical cleaning

8.2.2.1 Alternative Biofouling Control Methods. Nonchlorine 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, the potential alternatives offer no environmental, operational, or cost-effective advantages relative to the chlorination method for biofouling control.

8.2.2.2 Proposed Biofouling Control Method. Chlorination using gaseous chlorine is the method of biocide treatment proposed for the Stanton A cooling tower. The gaseous chlorine will be stored in 1-ton containers. Chlorine will be withdrawn as a gas using water and a gas solution chlorinator. The solution will be fed through diffusers into the circulating water system. Biological growth will be controlled by 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. Presently, no municipal, community potable water supply is available at the SEC. Since a noncommunity public water system already exists for supplying potable water from the existing wells, extension of this system is the most viable alternative for potable water supply. The use of treated sewage effluent for potable water is not an acceptable alternative.

A new demineralizer system using reclaimed effluent from the Orange County facility would be a potential alternative water source to supply demineralized water. However, the existing demineralizer system using well water as its source has sufficient capability to supply Stanton A. A new extensive additional treatment system would be required if reclaimed effluent was used. Pretreatment methods such as clarification, multiple stages of 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 that can impact the reliability of the generating unit may develop.

Therefore, the use of treated effluent is not considered appropriate for plant use other than for cooling tower makeup. The existing service water and demineralized water systems are capable of supplying the quality and quantity of water needed for the addition of Stanton A.

8.2.3.2 Proposed Water Sources. The two proposed sources of water for the facility are well water and reclaimed effluent from the Orange County Eastern Water Reclamation Facility. The existing SEC service and demineralized water supply systems, which use well water as the source, will supply Stanton A service water and demineralized water requirements. Reclaimed water from the Orange County Eastern Water Reclamation Facility will be used as cooling tower makeup.

8.2.4 Sanitary Waste System Alternatives

Although the existing SEC sewage treatment facilities have the capacity to handle the Stanton A flow, the economics of piping/pumping the Stanton A sanitary wastewaters to the existing system are excessive compared to a relatively simple septic system.

8.2.5 Plant Wastewater System Alternatives

8.2.5.1 Process Wastewater Alternative Systems. It is planned to route the Stanton A oil/water separator effluent to the existing SEC recycle basin for use in the flue gas scrubber and ash handling systems. One potential alternative would be to discharge treated oil/water separator effluent directly to the cooling tower as a source of makeup. This option was dismissed since the water quality can be somewhat unpredictable and the water can be more beneficially used in the Units 1 and 2 ash and scrubber systems.

8.2.5.2 Storm Water Discharge Alternative System. Site drainage from oily drains will be routed through the oil/water separator before being transferred to the existing SEC recycle basin. Water from potentially oil contaminated areas will be collected in the containment areas. Oil will be skimmed from the collected water and trucked offsite. The remaining water will be checked before being drained to the recycle basin.

8.2.6 Process Wastewater Treatment Alternatives

8.2.6.1 Potential Alternative Systems. Presently, the Units 1 and 2 cooling tower blowdown and a small amount of other process wastewaters are routed to the SEC zero discharge system for recovery of water and disposal of the solids dissolved in the water. The zero discharge treatment system treats cooling tower blowdown for reuse at the SEC. Solid wastes produced from this system are disposed in the existing combustion waste landfill. Stanton A proposes to install a similar system to take advantage of the existing facilities and provide reuse water for selected SEC operations.

One potential alternative to using the zero discharge system is to transfer the waste to either an existing regional or new onsite percolation pond. There would be high additional costs associated with constructing a sufficiently large percolation pond. This alternative also presents additional environmental impacts that would require additional modeling, permitting, and monitoring. Use of the zero discharge system is the preferred wastewater treatment method.

8.2.6.2 Proposed Wastewater Treatment System. Cooling tower blowdown will be treated in a new brine concentrator/crystallizer system and reused in selected SEC operations. Existing Units 1 and 2 dispose of these wastes in this manner.

8.2.7 Solid Waste Disposal System

Additional solid wastes will be generated by the addition of Stanton A due to the increased amount of blowdown processed in the zero discharge system. The solids consist of the minerals present in the makeup water. Solids produced in the zero discharge system will be disposed in the SEC combustion waste landfill as are solids from Units 1 and 2. Trash and other solid wastes 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 be advised of or to provide information for the Stanton A project.

9.1 Federal

- **US Army Corps of Engineers**
Merritt Island, Florida
Elizabeth Bishop, (407) 452-8813
- **US Fish and Wildlife Service**
Jacksonville, Florida
Don Palmer, (904) 232-2580

9.2 State

- **Public Service Commission**
Tallahassee
Tom Ballinger, (850) 413-6680
Todd Bohrmann, (850) 413-6445
Jim Breman, (850) 413-6664
Michael Haff, (850) 413-6684
Paul Stallcup, (850) 413-6441
- **Department of Community Affairs**
Tallahassee
Paul Darst, (850) 488-4925
- **Department of Environmental Protection**
Power Plant Siting Coordination
Tallahassee
Buck Oven, (850) 487-0472
Steve Palmer, (850) 921-7250
Karen Skinner, (850) 487-0472

Air Resources Management Division, Bureau of Air Regulation

Tallahassee

Al Linero, (850) 921-9523

Cleve Holladay, (850) 921-8986

Alex Meng, (850) 921-9550

Joseph Kahn, (850) 921-9519

Jeff Koerner, (850) 414-7268

Christopher Carlson, (850) 921-9537

Michael Halpin, (850) 921-8986

Office of General Counsel

Scott Goorland, (850) 487-2339

Environmental Resource Permitting Division

Central District

Scott Wesson, (407) 893-3311

Industrial Wastewater

Central District

Eugene Elliott, (407) 893-5633

- **Fish and Wildlife Conservation Commission**

Vero Beach

Steve Lau, (561) 778-5094

- **St. Johns River Water Management District**

Orlando

James Hollingshead, (407) 897-4305

Mike McGovern, (407) 893-3532

- **Department of Labor and Employment Security**

Tallahassee

Jewel W. Holmes, (850) 488-1048, Office of Labor Market Statistics

- **East Central Florida Regional Planning Council**

Orlando

Greg Gulgowski, (407) 623-1075

9.3 Local

- **Orange County**

Zoning Department

Peggy Bishop, (407) 836-5525

Fire Rescue Department

Tom Wheeler, 407-836-9085

Sheriff's Department

Amanda Carlson, 407-836-4070, Human Resources

Planning Division of Orange County Administration Center

Michael Rigby/James Davis, 407-836-5600

Solid Waste Division

Suzanne Boroff, (407) 836-6612

**Growth Management and Environmental Resources Building
Division**

Bob Warbington, Director

Assistant County Attorney

Vivian Monaco

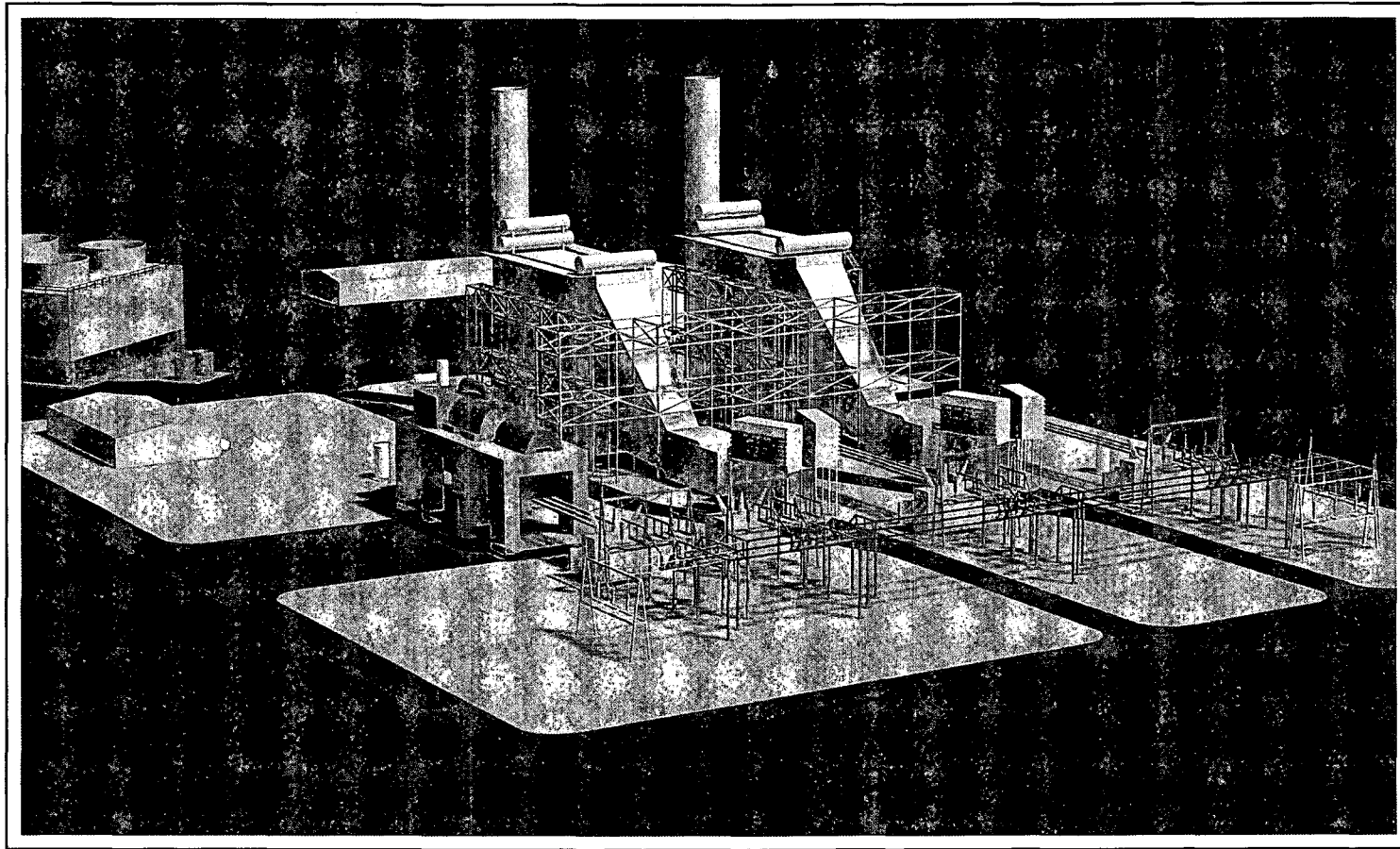
Transportation Planning

Mohammed Abdallah, Engineer

Supplemental Site Certification Application
Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A

Supplemental Site Certification Application

Appendices



Orlando Utilities Commission Curtis H. Stanton Energy Center Combined Cycle Unit A

B&V Project 98362

January 2001



Curtis H. Stanton Energy Center
Combined Cycle Unit A

Appendicies

Manual Number CHSEC - 001

Issued to Tasha Buford

Location _____

**Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A**

Supplemental Site Certification Application

B&V Project 98362

January 2001



10.0 Appendices

This section identifies the existing permits and approvals for Stanton Energy Center Units 1 and 2, and includes the major permit applications and approvals required to construct and operate Unit A.

10.1 Existing Federal Permits and Approvals

10.1.1 NPDES Permit

The Stanton Energy Center is designed as a zero discharge facility and, therefore, Units 1 and 2 have no requirement for a federal wastewater discharge permit. The same is true for Unit A.

10.1.2 Oil Pollution Prevention

OUC is required to comply with the EPA's oil pollution prevention regulations due to the amount of reserve fuel oil stored at the site for the operation of Units 1 and 2. The Spill Prevention, Control, and Countermeasures (SPCC) Plan was prepared for Units 1 and 2 in compliance with those regulations. Copies of the plan are available from OUC. This plan will be revised to incorporate Unit A facilities.

10.1.3 Certification of Compliance

The Power Plant and Industrial Fuel Use Act required OUC 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.

10.1.4 Federal Aviation Administration--Determination of No Hazard to Air Navigation

The FAA requires that structures over 200 feet in height or within a specified distance of an airport be marked and lighted in accordance with the standards of the FAA Obstruction Marking and Lighting Advisory Circular 70/7460-1F. Aeronautical Study No. 82-ASO-1904-OE was performed in 1982 to support the determination that the OUC site with structures exceeding 500 feet were not considered hazardous to air navigation in the vicinity.

10.2 Federal Permits and Approval
Applications

10.2 Federal Permit and Approval Applications

10.2.1 Environmental Resource Permit Application/404 Permit

The US Army Corps of Engineers and the US Fish and Wildlife Service will review the potential environmental impacts of the new onsite transmission line and natural gas pipeline. An Environmental Resource Permit application has been prepared to assist in this review, and is included in Section 10.4.

10.2.2 Prevention of Significant Deterioration (PSD) Permit Application

The Florida Department of Environmental Protection (FDEP) will review the PSD application in coordination with the USEPA. This application is included under separate cover as Appendix 10.7.

10.2.3 Certification of Compliance Statement

The Power Plant and Industrial Fuel Use Act requires Southern-Florida to certify that, with the installation of additional equipment, Unit A would be capable of firing coal (including gasified coal) or another alternate fuel as the primary energy source. Copies of the Certification of Compliance documents to be submitted for Unit A prior to construction are included herein.

10.2.4 Federal Aviation Administration--Notice of Construction or Alteration

At least 48 hours before the start of construction on Unit A, a Notice of Construction or Alteration must be filed with the FAA. This will inform the FAA that equipment with the potential for being over the height requirement will be onsite for construction activities. A copy of the application is included herein.

CERTIFICATION OF COMPLIANCE

SUGGESTED SUBMITTAL LETTER

Date, 2001

Office of Coal and Power Im/Ex
Office of Coal and Power Systems (FE-27)
Office of Fossil Energy
Forrestall Building, Room 4G-025
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Subject: Self-Certification under the Fuel Use Act

Attn: Director of the Office of Coal and Power Im/Ex

Gentlemen:

Pursuant to Section 201(d) of the Powerplant and Industrial Fuel Use Act of 1978, as amended (42 USC 8301(d)), Southern Company—Florida, LLC (“Southern-Florida”) hereby submits the attached Certification of Compliance attesting to the coal capability of the proposed combustion turbine unit addition at the Curtis H. Stanton Energy Center in Orange County, Florida. This unit, designated as Unit A, will be a nominal 633-megawatt combined cycle combustion turbine unit, constructed, owned, and operated by Southern-Florida, in conjunction with the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA), and the Orlando Utilities Commission (OUC). Additional information on the project can be obtained from Southern-Florida at P.O. Box 2641, Birmingham, AL 35921.

Very truly yours,

SOUTHERN COMPANY—FLORIDA, LLC

Charles D. McCrary
President

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FUELS PROGRAMS

IN THE MATTER OF: SOUTHERN COMPANY—FLORIDA, LLC

COAL CAPABILITY OF NEW ELECTRIC POWERPLANT
CERTIFICATION OF COMPLIANCE
PURSUANT TO THE POWERPLANT AND INDUSTRIAL FUEL USE ACT,
AS AMENDED

I, Charles D. McCrary, do hereby certify that I am President of Southern Company—Florida, LLC (Southern-Florida), an independent power producer operating under the laws of the State of Florida. Southern-Florida, in conjunction with the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA), and the Orlando Utilities Commission (OUC), is planning to construct, own, and operate the proposed Unit A addition to the Curtis H. Stanton Energy Center on property owned by OUC in Orange County, Florida. This unit will be a nominal 633-megawatt combined cycle combustion turbine unit. The unit is scheduled for commercial operation in October 2003.

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 8301(d)), Unit A at the Curtis H. Stanton Energy Center 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 Curtis H. Stanton Energy Center Unit A addition is attached to this Certification as Exhibit A.

IN WITNESS THEREOF, I have hereupon set my hand this _____ day of _____
2001.

Charles D. McCrary
President, Southern Company—Florida, LLC
P.O. Box 2641
Birmingham, AL 35921

SWORN AND SUBSCRIBED to me this _____ day of _____ 2001.

Notary of Public

My Commission Expires:

EXHIBIT A
CURTIS H. STANTON ENERGY CENTER UNIT A ADDITION DESCRIPTION

The proposed Stanton Unit A addition will be constructed, owned and operated by Southern Energy—Florida (Southern-Florida), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA), and the Orlando Utilities Commission (OUC). The nominal 633-megawatt combined cycle combustion turbine power plant will be operated as a base load facility. The Stanton Unit A addition site, located near Orlando, in Orange County, Florida, is owned by OUC.

The combustion turbine unit will be rated at approximately 633-megawatts. The primary fuel will be natural gas. No. 2 fuel oil will be stored onsite as backup fuel. The unit will be installed with modern pollution control devices to meet environmental quality standards. The unit could be converted to burn low Btu gas from a coal gasification facility.

The Curtis H. Stanton Energy Center Unit A is scheduled for commercial operation in October 2003. The net electricity generated will be supplied to the regional grid system.

NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION



U.S. Department of Transportation
Federal Aviation Administration

Failure To Provide All Requested Information May Delay Processing of Your Notice

Notice of Proposed Construction or Alteration

FOR FAA USE ONLY

Aeronautical Study Number

- OE

1. Sponsor (person, company, etc. proposing this action):

Attn. of: Charles D. McCrary
Name: Southern Company - Florida, LLC
Address: 270 Peach Tree Street, N.W.
Bin No. 935 - 11th Floor
City: Atlanta State: GA Zip: 30303
Telephone: _____ Fax: _____

2. Sponsor's Representative (if other than #1):

Attn. of: N/A
Name: _____
Address: _____
City: _____ State: _____ Zip: _____
Telephone: _____ Fax: _____

3. Notice of: ☒ New Construction ☐ Alteration ☐ Existing

4. Duration: ☐ Permanent ☒ Temporary (24 months, 0 days)

5. Work Schedule: Beginning October 2001 End October 2003

6. Type: ☐ Antenna Tower ☒ Crane ☐ Building ☐ Power Line ☐ Landfill ☐ Water Tank ☐ Other _____

7. Marking/Painting and/or Lighting Preferred:

☐ Red Lights and Paint ☐ Dual - Red and Medium Intensity White
☐ White - Medium Intensity ☐ Dual - Red and High Intensity White
☐ White - High Intensity ☐ Other _____

8. FCC Antenna Structure Registration Number (if applicable):

N/A

21. Complete Description of Proposal:

OUC's proposed Unit A at Stanton Energy Center will be a nominal 633 MW, combined cycle combustion turbine facility. Development of the Stanton Energy Center will require the onsite use of tall cranes for equipment movement and installation. There will not be any additional structures greater than 200 feet tall added to the facility.

Frequency/Power (kW)

Notice is required by 14 Code of Federal Regulations, part 77 pursuant to 49 U.S.C., Section 44718. Persons who knowingly and willingly violate the notice requirements of part 77 are subject to a civil penalty of \$1,000 per day until the notice is received, pursuant to 49 U.S.C., section 46301 (a).

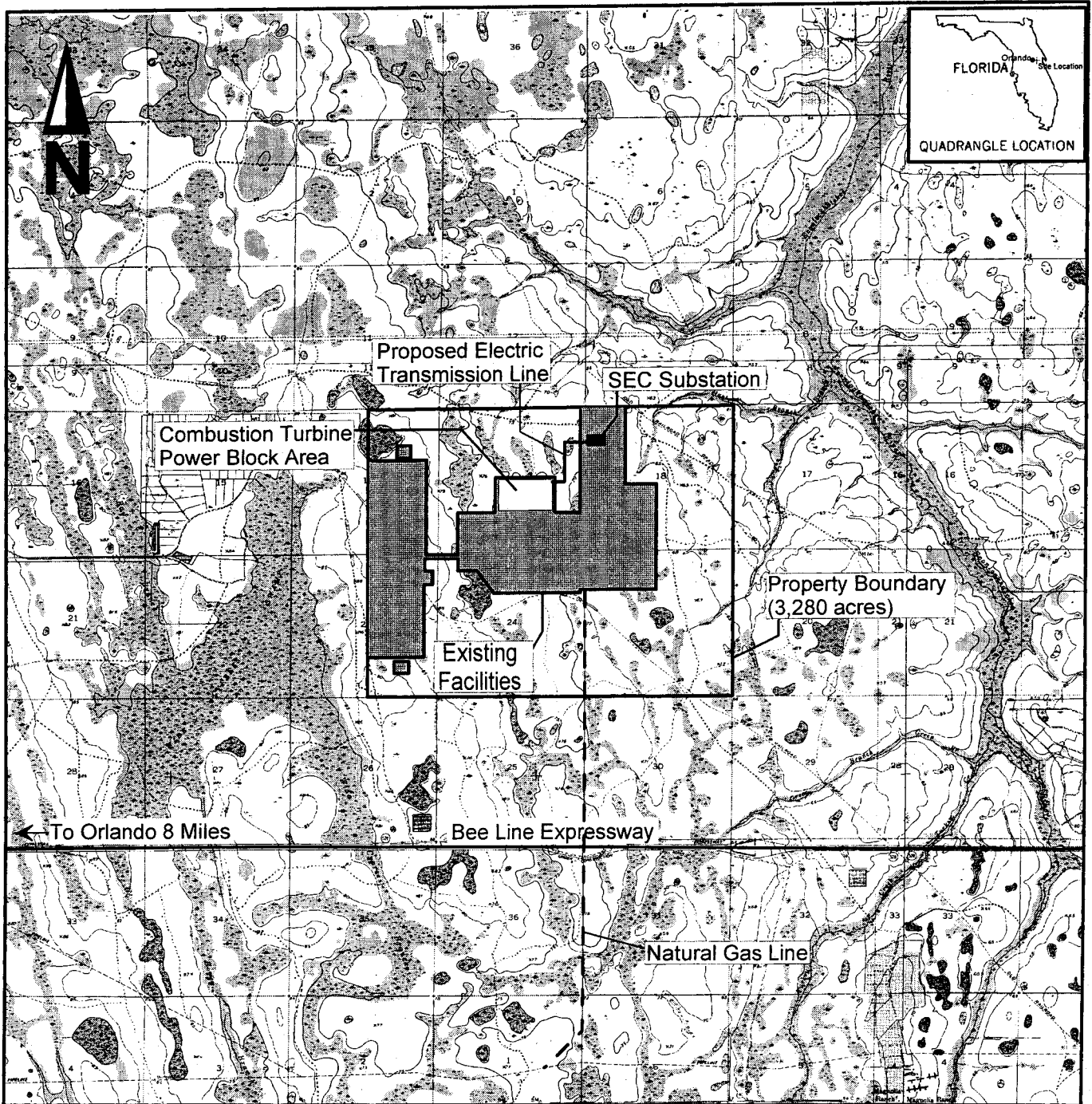
I hereby certify that all of the above statements made by me are true, complete, and correct to the best of my knowledge. In addition, I agree to mark and/or light the structure in accordance with established marking and lighting standards as necessary.

Date

Typed or Printed name and Title of Person Filing Notice

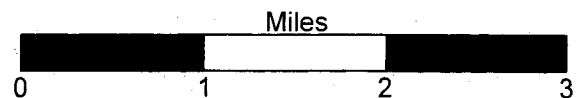
Signature

Charles D. McCrary, President



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Property Boundary: Orange Co.; Sections 13, 24, E1/2 14, E1/2 23 of Township 23S, Range 31E; Sections 18, 19 of Township 23S, Range 32E



Stanton Energy Center Property Location Attachment A

10.3 Existing State Permits

10.3.1 Title V Air Operation Permit

The existing Units 1 and 2 operate under FDEP issued Initial Title V Air Operation Permit No. 095013-001-AV. A copy of the Final Title V permit is included herein.

TITLE V AIR OPERATION PERMIT

Orlando Utilities Commission
Curtis H. Stanton Energy Center

Facility ID No.: 0950137
Orange County

Initial Title V Air Operation Permit
FINAL Permit No.: 0950137-001-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Initial Title V Air Operation Permit
FINAL Permit No.: 0950137-001-AV

Table of Contents

<u>Section</u>	<u>Page Number</u>
Placard Page.....	1
I. Facility Information	2 - 3
A. Facility Description.	
B. Summary of Emissions Unit ID Nos. and Brief Descriptions.	
C. Relevant Documents.	
II. Facility-wide Conditions.....	4 - 7
III. Emissions Unit(s) and Conditions	
A. Coal Fired Steam Generators (E.U. ID Nos. -001 and -002).....	7 - 20
B. Auxiliary Boiler (1 - 83 MMBtu/hr).....	21 - 22
C. Fly Ash Silos 1 and 2.....	23 - 24
D. Common Conditions.....	25 - 32
IV. Acid Rain Part	
A. Acid Rain, Phase II	33 - 34

Permittee:
Orlando Utilities Commission

FINAL Permit No.: 0950137-001-AV
Facility ID No.: 0950137
SIC Nos.: 4911
Project: Initial Title V Air Operation Permit

This permit is for the operation of the Stanton Energy Center. This facility is located at 5100 Alafaya Trail, Orlando, Orange County; UTM Coordinates: Zone 17, 484.00 km East and 3150.50 km North; Latitude: 28° 28' 50" North and Longitude: 81° 09' 40" West.

STATEMENT OF BASIS: This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:

Phase II Acid Rain Application/Compliance Plan received December 14, 1995
Phase II NO_x Acid Rain Application/Compliance Plan (Revised) Received August 17, 1999
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-3, TITLE V CONDITIONS (version dated 04/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE
SUMMARY REPORT- GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING
SYSTEM PERFORMANCE REPORT (40 CFR 60, July 1996)

Effective Date: January 1, 2000
Renewal Application Due Date: July 5, 2004
Expiration Date: December 31, 2004

Howard L. Rhodes, Director
Division of Air Resource
Management

HLR/sms/mh

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Each boiler/steam generator is a wall fired dry bottom unit. Unit Nos. 1 and 2 are fired with coal, with No. 6 fuel oil used for startup and flame stabilization. Each unit has their individual stacks. An auxiliary boiler, which serves both boilers and with a maximum heat input of 83 MMBtu/hour, is located at the facility. The auxiliary boiler is fired with No. 2 distillate fuel oil.

Also included in this permit are miscellaneous unregulated emissions units and insignificant emissions units and/or activities.

Based on the initial Title V permit application received on June 17, 1996, this facility is not a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Electric Generator No. 1
-002	Fossil Fuel Fired Steam Electric Generator No. 2
-003	Auxiliary Boiler
-004	Coal Transfer Baghouse
-005	Coal Crusher Building Baghouse
-006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
-007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
-008	Limestone Day Bin Baghouse
-009	Pebble Lime Receiving Hopper Baghouse
-010	Coal Reclaim Hopper Baghouse
-011	Flyash Exhauster Filter #1 Baghouse
-012	Flyash Exhauster Filter #2 Baghouse
-013	Flyash Exhauster Filter #3 Baghouse
-014	Flyash Exhauster Filter #4 Baghouse
-015	Flyash Silo Bin Vent Filter Baghouse
-016	Adipic Acid Storage Baghouse

Unregulated Emissions Units and/or Activities

- xxx Material Handling
- xxx Fuel Storage Tanks
- xxx Water Treatment
- xxx Unconfined emissions

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:

Table 1-1, Summary of Air Pollutant Standards and Terms

Table 2-1, Summary of Compliance Requirements

Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers

Appendix H-1, Permit History/ID Number Changes

These documents are on file with the permitting authority:

Phase II Acid Rain Application/Compliance Plan received December 14, 1995

Initial Title V Permit Application received June 17, 1996.

Phase II NO_x Acid Rain Application/Compliance Plan (Revised) received August 17, 1999.

These documents are on file with the USEPA:

Risk Management Plan submitted to the RMP Reporting Center received June 24, 1999.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-3, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}
2. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]
3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rule 62-296.320(4)(b)1. & 4., F.A.C.]
4. Prevention of Accidental Releases (Section 112(r) of CAA).
 - a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
 - b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
 - c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:

Cashier
Department of Community Affairs
State Emergency Response Commission
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.

[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.

[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

[Rule 62-296.320(1)(a), F.A.C.]

8. The following reasonable precautions shall be taken to prevent emissions of unconfined particulate matter at this facility.

- ◆ Maintenance of paved areas as needed,
- ◆ Regular mowing of grass and care of vegetation,
- ◆ Limiting access to plant property by unnecessary vehicles, and
- ◆ Additional or alternative activities may be utilized to minimize unconfined particulate emissions.

[Rule 62-296.320(4)(c)2., F.A.C.; and, proposed by applicant in the initial Title V permit application received June 14, 1996.]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.

[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

11. The permittee shall submit all compliance-related notifications and reports required of this permit to the Central District Office:

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155, Fax: 404/562-9164

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following Regulated Emissions Units.

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator # 1
-002	Fossil Fuel Fired Steam Generator # 2

Fossil fuel fired steam generator # 1 is a nominal 468 megawatt steam generator designated as Unit # 1. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Fossil fuel fired steam generator # 2 is a nominal 468 megawatt steam generator designated as Unit # 2. The emission unit is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization, as permitted herein, with a maximum heat input of 4286 MMBtu per hour.

Each boiler/steam generator, units #1 and #2, drives a turbine generator and both units have an individual 550 foot exhaust stack. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Combustion Engineering.

Each boiler/steam generator, units #1 and #2 are regulated under the federal Acid Rain Program, Phase II, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

{Permitting note(s): The emissions units are regulated under Acid Rain, Phase II; NSPS-40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7)(b)2, F.A.C.; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD); and Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT). Fossil fuel fired steam generator # 1 began commercial operation on May 12, 1987; and, fossil fuel fired steam generator # 2 began commercial operation on June 1, 1996.}

The following specific conditions apply to the emissions units listed above:

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

A.1. Capacity. The maximum permitted heat input rate for Unit No. 1 and 2 is 4286 MMBTU/hr. Testing of emissions shall be conducted with the emissions unit operating

at 90 to 100 percent of the maximum permitted heat input rate. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rule 62-4.160(2), and Rule 62-297.310(2), F.A.C.]

A.2. Methods of Operation - Fuels. Coal is permitted to be fired in Units No. 1 and 2. Coal shall not be burned in the unit unless both the electrostatic precipitator and limestone scrubber are operating properly except as provided under 40 C.F.R. 60.46a. The fuel oil to be fired in Units 1 and 2 and the auxiliary boiler shall be primarily "new oil", which means an oil which has been refined from crude oil and has not been used. On-site generated lubricating oil and used fuel oil which meets the requirements of 40 CFR 266.40 may also be burned. Landfill gas from the Orange County Landfill and Natural gas as supplied by commercial pipeline may be burned in Unit No. 1 and 2.

[Rules 62-4.070(3), 62-4.160(2), 62-210.200, and 62-213.440(1), F.A.C., PSD-FL-084]

A.3. Methods of Operation - Flue Gas Desulfurization System (FGD). No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting from the FGD system, if the bypass will cause overall SO₂ removal efficiency less than 90 percent (or 70 percent for mass SO₂ emission rates less than or equal to 0.6 lb/million Btu 30 day rolling average). The percentage and amount of flue gas bypassing the FGD system shall be documented and records kept for a minimum of two years available for Department's inspection. The flue gas scrubber shall be put into service during normal operational startup, and shutdown, when No. 6 fuel oil is being burned. The flue-gas desulfurization system and mist eliminators for Unit 2 will be maintained and operated in a manner consistent with good air pollution practice for minimizing emissions pursuant to the requirements of 40 C.F.R. 60.11(d).

[Rule 62-4.070(3), F.A.C., 40 CFR 60.40a, and Permit No. PSD-FL-084]

A.4. Hours of Operation. Units No. 1 & 2 are allowed to operate continuously (8760 hrs. /yr.).

[Rule 62-210.200, F.A.C., Definitions (PTE)]

Emission Limitations and Standards

A.5. Particulate matter emissions from Unit No. 1 shall not exceed 0.03 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. Particulate matter emissions from Unit No. 2 shall not exceed 0.02 lb/million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. This standard applies at all times except during periods of startup, shutdown, or malfunction.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(a); 40 CFR 60.46a(a); 40 CFR 60.46a(c)]

A.6. Based on the maximum permitted heat input rate listed in Specific Condition A.1., the particulate matter emissions from Unit No. 1 shall not exceed 124.1 lbs/hour and 543.5 tons/year. The particulate matter emissions from Unit No. 2 shall not exceed 85.7 lbs/hr and 375.4 tons/year.

[PSD-FL-084 and Rule 62-296.700(4)(b)1., F.A.C.]

A.7. Particulate matter emissions from Units No. 1 and 2 when combusting liquid fuel (No. 6 fuel oil) shall not exceed 0.03 lb/million Btu and 30 percent of potential combustion concentration (70 percent reduction).

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(b)(1)]

A.8. Visible emissions from Units No. 1 and 2 shall not exceed 20 (twenty) percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 (twenty-seven) percent opacity.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.42a(b)]

A.9. Sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.2 lb/million Btu (30 day rolling average) heat input or 1.2 lb/million Btu (2 hour emission rate) heat input. Additionally, sulfur dioxide emissions from Unit No. 1 when combusting solid fuel shall not exceed 1.14 lb/million Btu (3-hr average) heat input (4886 lbs/hr and 21,400 tons/year) and 10 percent of the potential combustion concentration (90 percent reduction) or 30 percent of the potential combustion concentration (70 percent reduction) when emissions are less than 0.60 lb/million Btu heat input.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1) and (2); PSD-FL-084]

A.10. Sulfur dioxide emissions from Unit No. 2 when combusting solid fuel shall not exceed 0.25 lb/million Btu (30 day rolling average) heat input; 0.67 lb/million Btu (24 hour emission rate) heat input or 0.85 lb/million Btu (3 hour emission rate) heat input. This corresponds to 3643 lbs/hr and 4,693 tons/year emission rate.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(a)(1); PSD-FL-084]

A.11. Sulfur dioxide emissions from Units No. 1 and 2 when combusting liquid fuel (No. 6 fuel oil) shall not exceed 0.80 lb/million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction).

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(b)(1)]

A.12. Compliance with a sulfur dioxide emission limitation and percent reduction requirements are both determined on a 30-day rolling average basis.

[Rule 62.204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(g)]

A.13. When different fuels are combusted simultaneously in Unit No. 1, the applicable standard of sulfur dioxide is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 0.60 lb/million Btu heat input

$$Es = \text{the lesser of } (0.80x + 1.20y)/100 \text{ or } 1.14 \text{ and } \%Ps = 10$$

- (2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 0.60 lb/million Btu heat input:

$$Es = \text{the lesser of } (0.80x + 1.20y)/100 \text{ or } 1.14 \text{ and } \%Ps = (10x + 30y)/100$$

where:

- Es = the sulfur dioxide emission limit (lb/million Btu heat input),
%Ps = the percentage of potential sulfur dioxide emission allowed.
x = the percentage of total heat input derived from the combustion of liquid fuel
y = the percentage of total heat input derived from the combustion of solid fuel

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(h); PSD-FL-084]

A.14. When different fuels are combusted simultaneously in Unit No. 2, the applicable standard of sulfur dioxide is determined by proration using the following formula:

- (1) If emissions of sulfur dioxide to the atmosphere are greater than 0.60 lb/million Btu heat input:

$$Es = \text{the lesser of } (0.80x + 1.20y)/100 \text{ or } 0.85 \text{ and } \%Ps = 10$$

- (2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 0.60 lb/million Btu heat input:

$$Es = \text{the lesser of } (0.80x + 1.20y)/100 \text{ or } 0.85 \text{ and } \%Ps = (10x + 30y)/100$$

where:

- Es = the sulfur dioxide emission limit (lb/million Btu heat input),
%Ps = the percentage of potential sulfur dioxide emission allowed.
x = the percentage of total heat input derived from the combustion of liquid fuel
y = the percentage of total heat input derived from the combustion of solid fuel

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.43a(h); PSD-FL-084]

A.15. Nitrogen dioxide emissions from Unit No. 1 when combusting bituminous coal shall not exceed 0.60 lb./million Btu heat input (30 day rolling average) nor 0.46 lb./million Btu heat input on an annual average. Nitrogen dioxide emissions from Unit No. 2 when combusting bituminous coal shall not exceed 0.17 lb./million Btu heat input. Nitrogen dioxide emissions from Units No. 1 and 2 when combusting liquid fuel shall not exceed 0.30 lb/million Btu heat input. These emission limits are based on a 30-day rolling average. These standards apply at all times except during periods of startup, shutdown, or malfunction. Ammonia slip from the NOx control system shall be limited to less than 30 ppmv, uncorrected. An ammonia monitoring protocol shall be submitted to EPA for review and approval prior to the operation of Unit 2.

{Permitting note: In accordance with 40 C.F.R. 70.6(a)(1)(ii), "where an applicable requirement of the Act is more stringent than an applicable requirement of the regulations promulgated under title IV of the Act, both provisions shall be incorporated in the permit and shall be enforceable by the Administrator." Unit 1 is required to meet the more stringent NOx limit of 0.46 pounds per MMBtu in addition to the 0.60 pounds per MMBtu PSD NOx limit.}

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(a); 40 CFR 60.46a(b); 40 CFR 60.46a(c)]

A.16. When liquid and solid fuels are combusted simultaneously in Unit No. 1, the applicable standard for nitrogen dioxides is determined by proration using the following formula:

$$En = [0.30 x + 0.60 y]/100$$

where:

En = the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (lb/million Btu heat input);

x = the percentage of total heat input derived from the combustion of liquid fuels

y = the percentage of total heat input derived from the combustion of solid fuels

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(c)]

A.17. When liquid and solid fuels are combusted simultaneously in Unit No. 2, the applicable standard for nitrogen dioxides is determined by proration using the following formula:

$$En = [0.30 x + 0.17 y]/100$$

where:

En = the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (lb/million Btu heat input);

x = the percentage of total heat input derived from the combustion of liquid fuels

y = the percentage of total heat input derived from the combustion of solid fuels

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.44a(c)]

A.18. Carbon monoxide (CO) emissions from Unit No. 2 shall not exceed 0.15 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, CO emissions shall not exceed 643 lb/hr (2816 TPY).

[PSD-FL-084]

A.19. Volatile Organic Compounds (VOC) emissions from Unit No. 2 shall not exceed 0.015 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, VOC emissions shall not exceed 64 lb/hr (282 TPY).

[PSD-FL-084]

A.20. Sulfuric acid mist (H₂SO₄) emissions from Unit No. 2 shall not exceed 0.033 lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, H₂SO₄ emissions shall not exceed 140 lb/hr (613 TPY).

[PPS PA 81-14/SA1]

A.21. Beryllium (Be) emissions from Unit No. 2 shall not exceed 5.2×10^{-6} lb./million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Be emissions shall not exceed 0.022 lb./hr (0.1 TPY).

[PPS PA 81-14/SA1]

A.22. Mercury (Hg) emissions from Unit No. 2 shall not exceed 1.1×10^{-5} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Hg emissions shall not exceed 0.046 lb/hr (0.2 TPY).

[PPS PA 81-14/SA1]

A.23. Lead (Pb) emissions from Unit No. 2 shall not exceed 1.5×10^{-4} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, Pb emissions shall not exceed 0.64 lb/hr (2.8 TPY).

[PPS PA 81-14/SA1]

A.24. Fluorides (F1) emissions from Unit No. 2 shall not exceed 4.2×10^{-4} lb/million Btu heat input. Based upon a heat input of 4286 million Btu/hr, F1 emissions shall not exceed 1.8 lb/hr (7.9 TPY).

[PPS PA 81-14/SA1]

Compliance provisions.

A.25. The sulfur dioxide emission standards in specific conditions A.9., A.10., A.11., A.13 and A.14., apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the following procedures in specific condition A.26. are implemented.

[Rule 62-296.800(7)(b)2., F.A.C.; 40 CFR 60.46a(c)]

A.26. During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Operating a *spare* flue gas desulfurization system module. The Department may at their discretion require Orlando Utilities Commission within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements of specific conditions A.9., A.10., A.11., A.13 and A.14. for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Department at least 30 days notice of the date and period of time over which the demonstration will be performed.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(d)]

A.27. Compliance with the sulfur dioxide emission limitations and percentage reduction requirements in specific conditions A.9., A.10., A.11., A.13 and A.14., and the nitrogen oxides emission limitations in specific conditions A.15., A.16 and A.17., is based on the *average emission rate* for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-day

average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(e)]

A.28. Compliance is determined by calculating the arithmetic average of all hourly *emission rates* for SO₂ and NO_x for the 30 successive boiler operating days, except for data obtained during startup and shutdown (SO₂ & NO_x), simultaneous combustion of different fuels (SO₂ & NO_x), malfunction (NO_x only), or emergency conditions (SO₂ only). Compliance with the percentage reduction requirement for SO₂ is determined based on the average inlet and average outlet SO₂ emission rates for the 30 successive boiler operating days. Compliance with the limits determined from specific conditions A.13., A.14., A.15. and A.16. (above) shall be determined by calculating the arithmetic average of all hourly *emission rates* for SO₂ and NO_x from any operating hours for the 30 prior boiler operating days where simultaneous combustion of different fuels occurred.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(g)]

A.29. If Orlando Utilities Commission has not obtained the minimum quantity of emission data as required in the following emission monitoring specific conditions A.30. through A.39, compliance of Units No. 1 and 2 with the sulfur dioxide and nitrogen oxides standards for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19, *Determination of Compliance When Minimum Data Requirement Is Not Met*.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.46a(h); 40 CFR 60, Appendix A, Method 19]

Emission Monitoring.

A.30. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. Opacity interference exists due to water droplets in the stack from the use of an FGD system, therefore the opacity is monitored upstream of the interference (at the inlet to the FGD system). This monitoring method has been approved by the Department through permitting actions.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(a), PSD-FL-084]

A.31. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions as follows:

- (1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
- (2) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19, Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates, may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required in the preceding specific condition A.31.(1).
- (3) Within 90 days of commencement of operations, the applicant will determine and submit to EPA and FDER the pH level in the scrubber effluent that correlates with 90% removal of the

SO₂ in the flue gas (or 70% for mass SO₂ emission rates less than or equal to 0.6 lb./MMBtu). Moreover, the applicant is required to operate a continuous pH meter equipped with and upset alarm to ensure that the operator becomes aware when pH value of the scrubber effluent rises above certain limited value. The value of the scrubber pH may be revised at a later date provided notification to EPA and FDER is made demonstrating that the minimum removal will be achieved on a continuous basis. Further, if compliance data show that higher FGD performance is necessary to maintain the minimum removal efficiency limit, a different pH value will be determined and maintained.

[PSD-FL-084, Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(b); 40 CFR 60, App. A, Mth.19]

A.32. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxide emissions discharged to the atmosphere.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(c)]

A.33. Orlando Utilities Commission shall calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain optimum air/fuel ratio parameters.

[PSD-FL-084, Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(d)]

A.34. The continuous monitoring systems required in specific conditions A.31., A.32., and A.33., shall be operated and record data during all periods of operation of Units No. 1 and 2 including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(e)]

A.35. Orlando Utilities Commission (OUC) shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, OUC shall supplement emission data with other monitoring systems approved by the Department, or the reference methods and procedures as described in Specific Condition A.37.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a (f)]

A.36. The 1-hour averages required under 40 CFR 60.13(h), *Monitoring Requirements*, are expressed in lbs/million Btu heat input and used to calculate the average emission rates required in specific conditions A.27. and A.28. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b), *Monitoring Requirements*. At least two data points must be used to calculate the 1-hour averages.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(g)]

A.37. When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in specific condition A.35., Orlando Utilities Commission shall use the following reference methods and procedures. Acceptable alternative methods and procedures are given in specific condition A.38.

- (1) Method 6 shall be used to determine the SO₂ concentration at the same location as the SO₂ monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.
- (2) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.
- (3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O₂ or CO₂ concentration at the same location as the O₂ or CO₂ monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.
- (4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in lb/million Btu heat input.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(h); 40 CFR 60, Appendix A, Methods 3B, 6, 7, and 19]

A.38. Orlando Utilities Commission shall use the following methods and procedures to conduct the monitoring system performance evaluations required under *40 CFR 60.13(c), Monitoring Requirements*, and the calibration checks required under *40 CFR 60.13(d), Monitoring Requirements*. Acceptable alternative methods and procedures are given in specific condition A.39.

- (1) Methods 6, 7, and 3B, as applicable, shall be used to determine O₂, SO₂, and NO_x concentrations
- (2) SO₂ or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N₂, as applicable) under 40 CFR 60 Appendix B, Performance Specification 2.
- (3) The span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Liquid.....	500
Solid.....	1,000
Combination.....	500y + 1,000z

where:

y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

- (4) All span values computed under the preceding specific condition A.38.(3) for burning combinations of fossil fuels are rounded to the nearest 500 ppm.
- (5) For affected facilities burning fossil fuel alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide

control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions oil fuel, alone or in combination with non-fossil fuel, the span value of the fuel fired.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(i); 40 CFR 60.13; 40 CFR 60 Appendix A, Methods 3B, 6, and 7; 40 CFR 60 Appendix B, Performance Specification 2.]

A.39. Orlando Utilities Commission may use the following as alternatives to the reference methods and procedures specified in conditions A.37. and A.38.:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under specific condition A.38., the conditions under 40 CFR 60.46(d)(1) apply; these conditions do not apply under specific condition A.37.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.47a(j); 40 CFR 60.46(d)(1), 40 CFR 60 Appendix A, Methods 3, 3A, 3B, 6, 6A, 6B, 6C, 7, 7A, 7C, 7D, and 7E]

Compliance determination procedures and methods.

A.40. In conducting the performance tests required in *40 CFR 60.8*, the owner or operator shall use as reference methods and procedures the methods in appendix A of 40 CFR 60 or the methods and procedures as specified in conditions A.41. through A.45., except as provided in *40 CFR 60.8(b)*. *40 CFR 60.8(f)* does not apply to specific conditions A.42 and A.43. for SO₂ and NO_x. Acceptable alternative methods are given in specific condition A.45. Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance. [Rule 62-204.800(7)(b)2., 62-210.300(2)(a)1., F.A.C.; 40 CFR 60.48a(a); 40 CFR 60.8]

A.41. Orlando Utilities Commission shall determine compliance with the particulate matter standards in specific conditions A.5., A.6., A.7 and A.8 as follows:

(1) The dry basis F factor (O₂) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5B shall be used after **wet** FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O₂ concentration. The O₂ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O₂ traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O₂ traverse points. If the grab sampling procedure is used, the O₂ concentration for the run shall be the arithmetic mean of all

the individual O₂ concentrations at each traverse point.

Orlando Utilities Commission

FINAL Permit No.: 0950137-001-AV

Curtis H. Stanton Energy Center

Page 17 of 34

(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.
[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(b); 40 CFR 60.11, 40 CFR 60 Appendix A, Methods 1, 3B, 5B, 9, and 19]

A.42. Orlando Utilities Commission shall determine compliance with the SO₂ standards in specific conditions A.9., A.10., A.11., A.13 and A.14. as follows:

(1) The percent of potential SO₂ emissions (%P_s) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_f)(100 - \%R_g)]/100$$

where:

%P_s = percent of potential SO₂ emissions, percent.
%R_f = percent reduction from fuel pretreatment, percent.
%R_g = percent reduction by SO₂ control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%R_f) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO₂ reduction (%R_g) of any SO₂ control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO₂ control device and the average SO₂ input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring systems specified in conditions A.31. and A.33. shall be used to determine the concentrations of SO₂ and CO₂ or O₂.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a (c); 40 CFR 60 43a; 40 CFR 60.47a(b) and (d); 40 CFR 60 Appendix A, Method 19]

A.43. Orlando Utilities Commission shall determine compliance with the NO_x standards in specific conditions A.15., A.16. and A.17. as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the NO_x emission rate.

(2) The continuous monitoring systems specified in specific conditions A.32. and A.33. shall be used to determine the concentrations of NO_x and CO₂ or O₂.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(d); 40 CFR 60.44a; 40 CFR 60.47a(c); 40 CFR 60.47a(d)]

A.44. Orlando Utilities Commission shall determine initial compliance with the CO, VOC, Be, Hg, Pb and Fl standards in specific conditions A.18., A.19., A.21., A.22., A.23., and A.24 respectively as follows:

- (1) EPA Method 10 for CO emissions.
- (2) EPA Method 18, 25, 25A or 25B for VOC emissions.
- (3) EPA Method 104 for Be emissions.
- (4) EPA Method 101A or 108 for Hg emissions.

Orlando Utilities Commission shall conduct annual compliance tests for particulates, NO_x, SO₂ and visible emissions.
[PPS PA 81-14/SA1]

A.45. Orlando Utilities Commission may use the following as alternatives to the reference methods and procedures specified in condition A.41:

(1) For Method 5 or 5B, Method 17 may be used at Units No. 1 and 2 if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F_c factor (CO₂) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of 40 CFR 60.46(d)(1). The CO₂ shall be determined in the same manner as the O₂ concentration.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.48a(e); 40 CFR 60.46(d)(1); 40 CFR 60 Appendix A, Methods 5, 5B, 17, and 19]

Reporting requirements.

A.46. For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be submitted to the Department.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(a)]

A.47. For sulfur dioxide and nitrogen oxides the following information shall be reported to the Department for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (lb/million Btu heat input) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification or not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup and shutdown (SO₂ & NO_x), simultaneous combustion of different fuels (SO₂ & NO_x), malfunction (NO_x only), emergency conditions (SO₂ only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, simultaneous fuel combustion, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

Orlando Utilities Commission
Curtis H. Stanton Energy Center
Page 19 of 34

FINAL Permit No.: 0950137-001-AV

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with 40 CFR 60 Appendix B, Performance Specifications 2 or 3.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(b); 40 CFR 60 Appendix B]

A.48. If the minimum quantity of emission data, as required by the emission monitoring specific conditions A.30. through A.39., is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of specific condition A.29. shall be reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(c); 40 CFR 60 Appendix A, Method 19]

A.49. If any sulfur dioxide standards under specific conditions A.9., A.10., A.11., A.13. or A.14. are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under specific condition A.26. were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J or lb/MMBtu) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(d); 40 CFR 60.43a; 40 CFR 60.46a(d)]

A.50. If fuel pretreatment credit is claimed toward the sulfur dioxide emission standards in specific conditions A.9., A.10., A.11., A.13. or A.14., Orlando Utilities Commission shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of specific condition A.42. and Method 19 (Appendix A of 40 CFR 60); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(e), 40 CFR 60.48a(c)]

A.51. For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(f)]

A.52. The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(g)]

A.53. For the purposes of the reports required under *40 CFR 60.7*, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under specific condition A.8. Opacity levels in excess of the applicable opacity standard and the date of such excesses shall be submitted to the Administrator each calendar quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(h)]

A.54. The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Department for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

[Rule 62-204.800(7)(b)2., F.A.C.; 40 CFR 60.49a(i)]

A.55. Samples of all fuel oil and coal fired in the boilers shall be taken and analyzed for sulfur content, ash content, and heating value. Accordingly, samples shall be taken of each fuel oil shipment received. Coal sulfur content shall be determined and recorded on a daily basis in accordance with EPA Reference Method 19. Records of all the analyses shall be kept for public inspection for a minimum of two years.

[PSD-FL-084]

Subsection B. This section addresses the following Regulated Emissions Unit.

E.U. ID No.	Brief Description
-003	Auxiliary Boiler

The auxiliary boiler is designated as Unit No. 3. The unit is a Babcock & Wilcox Model No. FM-2919 boiler. It is fired primarily with "new oil", which means an oil which has been refined from crude oil and has not been used. Only No. 2 fuel oil can be burned in the auxiliary boiler. This auxiliary boiler serves both Unit No. 1 and 2 boiler/steam generators.

{Permitting note: This emission unit is regulated under Rule 62-210.300, F.A.C., Permits Required.}

The following conditions apply to the Emission Unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Capacity. The maximum permitted heat input rate for Unit No. 3 is 83 MMBtu/hour.

{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rule 62-210.200(PTE), F.A.C.]

B.2. Methods of Operation. Fuel. The auxiliary boiler shall be fired on No. 2 fuel oil having a sulfur content less than 0.5 percent, by weight.

[Rule 62-4.160(2), F.A.C., Construction application request]

B.3. Hours of Operation. The emission unit may operate up to 150 hours/year.

[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

B.4. Emissions from the auxiliary boiler for burning No. 2 fuel oil shall not exceed the allowable emission limits listed in the following table:

Allowable Emission Limits

<u>Pollutant</u>	<u>lb/MMBtu</u>
PM	0.015
SO ₂	0.51
NO _x	0.16
Visible Emissions	20% Opacity

B.5. Compliance testing for PM, SO₂, NO_x, and visible emissions is not required if the unit operates for less than 400 hours annually.

[Rule 62-297.310(7)(a), F.A.C.]

B.6. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[PSD-FL-084]

Record keeping and Reporting Requirements

B.7. Documentation of the type, quantity, and analysis of the fuel oil used/received is required.

[PSD-FL-084]

B.8. Documentation on operating hours shall be kept in order to ensure that the source is operating less than 150 hours per year and is exempted from compliance testing as per specific condition B.5.

[PSD-FL-084, Rule 62-297.310(7)(a), F.A.C.]

Subsection C. This section addresses the following Regulated Emissions Units.

E.U. ID No.	Brief Description
-004	Coal Transfer Baghouse
-005	Coal Crusher Building Baghouse
-006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
-007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
-008	Limestone Day Bin Baghouse
-009	Pebble Lime Receiving Hopper Baghouse
-010	Coal Reclaim Hopper Baghouse
-011	Flyash Exhauster Filter #1 Baghouse
-012	Flyash Exhauster Filter #2 Baghouse
-013	Flyash Exhauster Filter #3 Baghouse
-014	Flyash Exhauster Filter #4 Baghouse
-015	Flyash Silo Bin Vent Filter Baghouse
-016	Adipic Acid Storage Baghouse

Descriptions

Fly Ash Silos handle fly ash from Steam Generators No. 1 and No. 2 respectively. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silos and then is gravity fed by tubing into totally enclosed tanker trucks. Particulate matter emissions generated by silo loading and unloading to a tanker truck is controlled by baghouses in addition to reasonable precautions. These units are subject to the applicable requirements under 40 C.F.R. 60 Subpart Y - Standards of Performance for Coal Preparation Plants, since Stanton has coal processing and conveying equipment (including breakers and crushers) and the facility commenced construction after October 24, 1974, per 40 C.F.R. §60.250.

{Permitting note: The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.}

The following conditions apply to the Emissions Units listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Hours of Operation. Fly Ash Silos are each allowed to operate continuously (8760 hrs./yr.) [Rule 62-210.200, F.A.C., Definition (PTE)]

Emission Limitations and Standards

C.2. Particulate emissions from fly ash handling system shall be limited to 0.02 gr./acf. A visible emission reading of 5% opacity or less may be used to establish compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr./acf emission limit is being violated. However, a visible emission reading greater than 5% opacity will require the permittee to perform a stack test for particulate emissions.

[PPS PA 81-14/SA1]

C.3. The following requirements shall be met to minimize fugitive dust emissions from the coal storage and handling facilities, the limestone storage and handling facilities, haul roads and general plant operations:

a. All conveyors and conveyor transfer points will be enclosed to preclude PM emissions (except those directly associated with the coal stacker/reclaimer and the emergency stockout facilities for which enclosure is operationally infeasible). All coal and limestone conveyors not underground or within buildings will be enclosed (roof and sides) with steel grating or concrete floors (except the stacker/reclaimer which will have windscreen protection);

b. Inactive coal storage piles will be shaped, compacted and oriented to minimize wind erosion.

c. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent except when adding, transferring and/or removing coal from the coal pile during which the opacity allowed shall be 20%.

d. The limestone handling receiver hopper will be equipped with water spray dust control facilities. Limestone conveyors not underground or within buildings will be enclosed with open grating floors (except where concrete floors are provided over roads or other facilities). Limestone day silos and associated transfer points will be maintained at negative pressures during filling operations with the exhaust vented to a control system. Lime will be handled with a totally enclosed pneumatic system. Exhaust from the lime silos during filling will be vented to a collector system.

e. The fly ash handling system (including transfer and silo storage) will be totally enclosed and vented (including pneumatic system exhaust) through fabric filters. Particulate emissions from fly ash handling system shall be limited to 0.02 gr./acf. A visible emission reading of 5% opacity or less may be used to establish compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr./acf emission limit is being violated. However, a visible emission reading greater than 5% opacity will require the permittee to perform a stack test for particulate emissions.

[PSD-FL-084]

Test Methods and Procedures

C.4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the Orlando Utilities Commission shall have formal compliance test conducted on each silo baghouse for opacity. Additionally, each baghouse shall be visually inspected on a daily basis to ensure that emissions are not visible. Records shall be maintained documenting that such inspections took place. Should emissions from a baghouse be visible, corrective action should be undertaken as well as conducting a Method 9 V.E. Records should include color, duration, and density of the plume of any abnormal visible emissions detected, as well as the cause and corrective action taken for any abnormal visible emissions.

{Permitting note: It is presumed that the threshold of visibility for opacity is equal to 5%.}

[Rule 62-297.310(7)(a)4., F.A.C., Rule 62-213.440, F.A.C.]

C.5. Compliance with the opacity limit listed in C.2 will be determined by EPA Reference Method 9. [PPS PA 81-14/SA1]

Subsection D. Common Conditions.

The following conditions apply to the Emissions Units ID -001 and -002:

40 CFR 60 Subpart A

D.1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.

[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

Notification and record keeping

D.2. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(1) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

[40 CFR 60.7(a)(4)]

D.3. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 CFR 60.7(b)]

D.4. Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

- (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
 - (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
 - (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- [40 CFR 60.7(c)(1), (2), (3), and (4)]

D.5. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

- (1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.
 - (2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.
- {See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance} (electronic file name: figure1.doc)*
- [40 CFR 60.7(d)(1) and (2)]

D.6. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

- (i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;
- (ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and
- (iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the

future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1)]

D.7. Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 **(five)** years following the date of such measurements, maintenance, reports, and records.

[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

Performance tests

D.8. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 CFR 60.8(c)]

Compliance with standards and maintenance requirements

D.9. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

[40 CFR 60.11(a)]

D.10. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).

[40 CFR 60.11(b)]

D.11. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

[40 CFR 60.11(c)]

D.12. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

[40 CFR 60.11(d)]

D.13. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of EPA Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he or she shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which EPA Method 9 data indicates noncompliance, the EPA Method 9 data will be used to determine opacity compliance.

[40 CFR 60.11(e)(5)]

Circumvention

D.14. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[40 CFR 60.12]

Monitoring requirements

D.15. For the purposes of 40 CFR 60.13, all continuous monitoring systems (CMS) required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
[40 CFR 60.13(a)]

D.16. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 60.8 and as described in 40 CFR 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 60.8 is conducted.
[40 CFR 60.13(c)(1)]

D.17. (1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

[40 CFR 60.13(d)(1) and (2)]

D.18. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13(e)(1) and (2)]

D.19. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.

[40 CFR 60.13(f)]

D.20. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

[40 CFR 60.13(g)]

D.21. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O₂ or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

[40 CFR 60.13(h)]

The following conditions apply to the Emissions Units ID -001 and -002:

Additional Limitations for On-Specification Used Oil

D.22. Used Oil. Burning of on-specification used oil is allowed at this facility in accordance with all other conditions of this permit and the following conditions:

a. On-specification Used Oil Allowed as Fuel: This permit allows the burning of used fuel oil meeting EPA "on-specification" used oil specifications, with a maximum sulfur content of 1.5 percent by weight for Units 1 and 2 and 0.5 percent by weight for the auxiliary boiler. The PCB concentration of used oil shall be less than 50 ppm. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility.

On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]

Arsenic shall not exceed 5.0 ppm;
Cadmium shall not exceed 2.0 ppm;
Chromium shall not exceed 10.0 ppm;
Lead shall not exceed 100.0 ppm;
Total halogens shall not exceed 1000 ppm;
Flash point shall not be less than 100 degrees F.

b. Quantity Limited: The maximum amount of on-specification used oil that can be burned at this facility shall be limited to 1.5 million gallons during each calendar year.

c. Used Oil Containing PCBs Not Allowed: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition. If the analytical results show that the used oil does not meet the specification for on-specification used oil, or that it contains a PCB concentration of 50 ppm or greater, the owner or operator shall:

- a. immediately notify the Central District Office in Orlando;
- b. provide the analytical results for the above parameters; and
- c. indicate the proposed means of disposal of the used oil.

f. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)]

- (1) The gallons of on-specification used oil generated and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
- (2) The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
- (3) Results of the analyses required above.
- (4) The total amount of lead emitted from burning used oil each month (calculated from the amount burned, the specific gravity of the used oil and the concentration of lead in the used oil), and the total amount of lead emitted in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)

g. Reporting Required: The owner or operator shall submit to Central District Office in Orlando, within thirty days of the end of each calendar quarter, the analytical results and the total amount of on-specification used oil generated and burned during the quarter.

Also, the owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year. [Rules 62-4.070(3) and 62-213.440, F.A.C., 40 CFR 279 and 40 CFR 761]

Section IV. This section is the Acid Rain Part.

Operated by: Orlando Utilities Commission
ORIS code: 0564

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions units listed below are regulated under Acid Rain Part, Phase II.

E.U. ID No.	Description
-001	Fossil Fuel Fired Steam Generator No. 1
-002	Fossil Fuel Fired Steam Generator No. 2

A.1. The Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these acid rain units must comply with the standard requirements and special provisions set forth in the application listed below:

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO₂) allowance allocations and nitrogen oxide (NO_x) limitations for each Acid Rain unit:

E.U. ID No.	EPA I.D.	Year	2000	2001	2002	2003	2004
-001	1	SO₂ allowances, under Table 2, 3, or 4 of 40 CFR 73	11290*	11290*	11290*	11290*	11290*
		NO_x limit	0.46 ⁺ lb./MMBtu	0.46 ⁺ lb./MMBtu	0.46 ⁺ lb./MMBtu	0.46 ⁺ lb./MMBtu	0.46 ⁺ lb./MMBtu
-002	2	SO₂ allowances, under Table 2, 3, or 4 of 40 CFR 73	0*	0*	0*	0*	0*
		NO_x limit	0.17 lb./MMBtu	0.17 lb./MMBtu	0.17 lb./MMBtu	0.17 lb./MMBtu	0.17 lb./MMBtu

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2, 3, or 4 of 40 CFR 73.

⁺This is an annual average.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirements of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.440(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62-214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.

[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: None.

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.

[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions – Applicable Requirements, F.A.C.]

Table 2-2, Summary of Compliance Requirements

Orlando Utilities Commission
Stanton Energy Center

FINAL Permit No.: 0950137-001-AV
Facility ID No.: 0950137

E.U. # -003		Auxiliary Boiler #3				CMS ²	See Permit Condition(s)
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date ¹	Min. Compliance Test Time		
Visible Emissions	F.O.	EPA Method 9	Annual	N/A	1 hour	No	B.5

E.U. # -004,-005,-006 and -007		Fly Ash Silo System				CMS ²	See Permit Condition(s)
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date ¹	Min. Compliance Test Time		
Visible Emissions	N/A	EPA Method 9	Annual	N/A	1 hour	No	C.2

1 - Frequency base date established for planning purposes only; see guidance memo and Rule 62-297.310, F.A.C.

2 - Continuous Monitoring System.

3 - EPA Method 17 may be used only if the stack gas exit temperature is less than 375 degrees F.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Table 1-1, Summary of Air Pollutant Standards and TermsOrlando Utilities Commission
Stanton Energy CenterFINAL Permit No.: 0950137-001-AV
Facility ID No.: 0950137**E.U. ID Nos. Brief Description**

-001		Fossil Fuel Fired Steam Generator #1							
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	Coal F.O.	8760	0.03 lb/MMBtu 0.03 lb/MMBtu			128.6	563.2	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.5, A.6 A.7
Visible Emissions	Coal F.O.	8760	20% Opacity					Rule 62-204.800(7)(b)2, F.A.C.	A.8
Sulfur Dioxide	Coal F.O.	8760	1.14 lb/MMBtu 0.80 lb/MMBtu			4886	21,400	Rule 62.204.800(7)(b)2, F.A.C. Rule 62.204.800(7)(b)2, F.A.C.	A.9, Sec IV-A2 A.11
Nitrogen Oxide	Coal F.O.	8760	0.46 lb/MMBtu 0.30 lb/MMBtu			1971	8,635	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.15, Sec IV-A2 A.15

-002		Fossil Fuel Fired Steam Generator #2							
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	Coal F.O.	8760	0.02 lb/MMBtu 0.03 lb/MMBtu			85.7	375.4	Rule 62.204.800(7)(b)2, F.A.C.	A.5, A.6 A.7
Visible Emissions	Coal F.O.	8760	20% Opacity					Rule 62.204.800(7)(b)2, F.A.C.	A.8
Sulfur Dioxide	Coal F.O.	8760	0.25 lb/MMBtu 0.80 lb/MMBtu			3643	4693	Rule 62.204.800(7)(b)2, F.A.C. Rule 62.204.800(7)(b)2, F.A.C.	A.10, Sec IV-A2 A.11
Nitrogen Oxide	Coal F.O.	8760	0.17 lb/MMBtu 0.30 lb/MMBtu			729	3191	Rule 62-204.800(7)(b)2, F.A.C. Rule 62-204.800(7)(b)2, F.A.C.	A.15, Sec IV-A2 A.15
Carbon Monoxide	Coal	8760	0.15 lb/MMBtu			643	2816	PSD-FL-084	A.18
VOC	Coal	8760	0.015 lb/MMBtu			64	282	PSD-FL-084	A.19
Sulfuric Acid Mist	Coal	8760	0.033 lb/MMBtu			140	613	PPS PA 81-14/SA1	A.20
Beryllium	Coal	8760	5.2×10^{-6} lb/MMBtu			0.022	0.1	PPS PA 81-14/SA1	A.21
Mercury	Coal	8760	1.1×10^{-5} lb/MMBtu			0.046	0.2	PPS PA 81-14/SA1	A.22
Lead	Coal	8760	1.5×10^{-4} lb/MMBtu			0.64	2.8	PPS PA 81-14/SA1	A.23
Fluorides	Coal	8760	4.2×10^{-4} lb/MMBtu			1.8	7.9	PPS PA 81-14/SA1	A.24

*Unit No.1 shall fire "new oil". Unit No.2 shall fire "new oil" as well as on-specification used fuel oil as per specific condition D.22.

** The "Equivalent Emissions" listed are for informational purposes only. Unit 1 NO_x emission limit is 0.60 lb/MMBtu on a 30-day rolling average, and 0.46 lb/MMBtu on an annual average.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Table 2-1, Summary of Compliance Requirements

Orlando Utilities Commission
Stanton Energy Center

FINAL Permit No.: 0950137-001-AV
Facility ID No.: 0950137

E.U. # -001	Fossil Fuel Fired Steam Generator #1						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date ¹	Min. Compliance Test Time	CMS ²	See Permit Condition(s)
PM Emissions	Coal	EPA Method 5B	Annual	N/A	6 hours	No	A.41(2)
Visible Emissions	Coal	EPA Method 9	Annual	N/A	1 hour	Yes	A.41(3)
Sulfur Dioxide	Coal	EPA method 6	Annual	N/A	1 hour	Yes	A.37(1)
Nitrogen Oxide	Coal	EPA Method 7	Annual	N/A	1 hour	Yes	A.37(2)

E.U. # -002	Fossil Fuel Fired Steam Generator #2						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date ¹	Min. Compliance Test Time	CMS ²	See Permit Condition(s)
PM Emissions	Coal	EPA Method 5B	Annual	N/A	6 hours	No	A.41(2)
Visible Emissions	Coal	EPA Method 9	Annual	N/A	1 hour	Yes	A.41(3)
Sulfur Dioxide	Coal	EPA Method 6	Annual	N/A	1 hour	Yes	A.37(1)
Nitrogen Oxide	Coal	EPA Method 7	Annual	N/A	1 hour	Yes	A.37(2)
Carbon Monoxide	Coal	EPA Method 10	Annual	N/A	N/A	No	A.44(1)
VOC	Coal	EPA Method 18	Annual	N/A	N/A	No	A.44(2)
Beryllium	Coal	EPA Method 104	Annual	N/A	N/A	No	A.44(3)
Mercury	Coal	EPA Method 101A	Annual	N/A	N/A	No	A.44(4)
Lead	Coal	EPA Method 12	Annual	N/A	N/A	No	A.44(5)
Fluorides	Coal	EPA Method 13A	Annual	N/A	N/A	No	A.44(6)

Table 1-2, Summary of Air Pollutant Standards and Terms

Orlando Utilities Commission
Stanton Energy Center

FINAL Permit No.: 0950137-001-AV
Facility ID No.: 0950137

E.U. ID Nos. Brief Description

-003		Auxiliary Boiler #3							
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
PM Emissions	F.O.	150	0.015 lb/MMBtu			1.2	0.1	Rules 62-4.160(2), F.A.C.	B.4
Visible Emissions	F.O.	150	20% Opacity					Rule 62-4.160(2), F.A.C.	B.4
Sulfur Dioxide	F.O.	150	0.51 lb/MMBtu			42.3	3.2	Rule 62-4.160(2), F.A.C.	B.4
Nitrogen Oxide	F.O.	150	0.16 lb/MMBtu			13.3	0.1	Rule 62-4.160(2), F.A.C.	B.4

-004, -005, -006, and -007		Fly Ash Silo System							
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/ hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
Visible Emissions	N/A	8760	5% Opacity					PPS PA 81-14/SA1	C.2

* The auxiliary boiler is fired primarily with No. 2 "new oil" having a sulfur content less than 0.5 percent, by weight.

** The "Equivalent Emissions" listed are for informational purposes only.

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

10.4 State Permit Applications

10.4 State Permit Applications

10.4.1 NPDES Permit Applications

Construction of Unit A will require an NPDES General Permit for Storm Water Discharges Associated with Construction Activities. This permit is issued by the FDEP. The Notice of Intent (NOI) to Use Generic Permit for Stormwater Discharge from Construction Activities that Disturb Five or More Acres of Land 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.

10.4.2 Prevention of Significant Deterioration (PSD) Permit Application

The construction and operation of Unit A will require an ATC/PSD permit. The PSD Air Permit Application is attached to this Supplemental Site Certification Application under separate cover as Appendix 10.7.

10.4.3 Title IV Acid Rain Permit Application

Modification of the existing Title IV Permit will be required with the addition of Unit A. As a new unit, the Acid Rain Permit modification will be submitted 24 months prior to operation.

10.4.4 Environmental Resource Permit Application

The construction, operation, and environmental impacts of the new onsite transmission line and natural gas pipeline will be reviewed during the certification process. An Environmental Resource Permit Application has been prepared to assist in this review. The application is included herein.

10.4.5 Application for Consumptive Uses of Water

Additional ground water withdrawals associated with the construction and operation of Unit A will be required. These additional withdrawals will be reviewed through completion and review of a SJRWMD Application Form 40C-2-1082-1. This application is included herein.

10.4.6 Industrial Wastewater Treatment System Permit Application

The existing industrial wastewater treatment and disposal system will require modification to incorporate the Unit A facilities. These additional treatment and disposal methods will be reviewed through completion and review of an FDEP Wastewater Application Form 2CG.

10.4.7 Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

The existing drinking water system will require an extension to serve the facilities associated with Unit A. This extension will be reviewed through completion and review of FDEP Form 62-555.900(7). The application is included herein.

10.4.8 Short-Term Dewatering Permit

The general construction contractor will be required to complete and submit a short-term dewatering permit for deep excavations (oil/water separator, false start drain tank).

10.4.9 FDOT Utility Permit

OUC is required to obtain a Utility permit from the Florida Department of Transportation (FDOT) to construct, operate and maintain a natural gas pipeline underneath the Bee Line Expressway in the Orlando Area. This activity will be reviewed through completion and submission of the FDOT Form 710-010-85. This application is included herein.

**NOTICE OF INTENT
TO USE
GENERIC PERMIT FOR STORMWATER
DISCHARGE FROM CONSTRUCTION
ACTIVITIES THAT DISTURB FIVE OR MORE
ACRES OF LAND**



**NOTICE OF INTENT
TO USE
GENERIC PERMIT FOR STORMWATER
DISCHARGE FROM CONSTRUCTION
ACTIVITIES THAT DISTURB FIVE OR MORE
ACRES OF LAND
(RULE 62-621.300(4), F.A.C.)**

This form is to be completed and submitted to the Department before use of the Generic Permit for Stormwater Discharge From Construction Activities that Disturb Five or More Acres of Land provided in Rule 62-621.300(4), F.A.C. The type of project or activity that qualifies for use of this generic permit, the conditions of the permit, and additional requirements to request coverage are specified in DEP Document 62-621.300(4)(a). Note that additional requirements for requesting coverage include submittal of the applicable generic permit fee pursuant to Rule 62-4.050, F.A.C. You should familiarize yourself with the generic permit and the attached instructions before completing this form. **Please print or type information in the appropriate areas below.**

I. IDENTIFICATION NUMBER:

Project ID: _____

II. APPLICANT INFORMATION:

A. Operator Name: Orlando Utilities Commission (OUC)		
B. Address: 500 South Orange Avenue		
C. City: Orlando	D. State: FL	E. Zip Code: 32802
F. Operator Status:	G. Responsible Authority: OUC	
	H. Phone No.: 407-423-9100	

III. PROJECT/SITE LOCATION INFORMATION:

A. Project Name: Curtis H. Stanton Energy Center		
B. Project Address/Location: 5100 South Alafaya Trail		
C. City: Orlando	D. State: FL	E. Zip Code: 32802
F. County: Orange	G. Latitude: 28 ° 29 ' 17 " Longitude: 81 ° 10 ' 3 "	
H. Is the site located on Indian lands? ☐ Yes ☒ No		I. Water Management District: St. Johns River
J. Project Contact: Frederick Haddad		K. Phone No.: 407-244-8732

IV. PROJECT/SITE ACTIVITY INFORMATION:

A. Other Existing Permits	ERP or 62-25 Permit No.: In Progress	Other (specify): Site Certification Order 81-14	
B. Has the SWPPP been prepared? ☐ Yes ☒ No		C. Is the SWPPP being submitted with this NOI? ☐ Yes ☒ No	
D. SWPPP Location	☐ Address in Part II above ☒ Address in Part III above ☐ Other address (specify below)		
E. SWPPP Address: Stanton Energy Center, 5100 South Alafaya Trail			
F. City: Orlando		G. State: FL	H. Zip Code: 32802
I. Construction Period	Start Date: October 2001	Completion Date: October 2003	J. Area Disturbed: Total: 110 AC Power Block: 60 AC Transmission Line: 9 AC Gas Line: 41 AC

V. DISCHARGE INFORMATION

A. MS4 Operator Name: Southern Company—Florida LLC
B. Receiving Water Name: Runoff will be contained in a collection basin or treated prior to discharge.

VI. CERTIFICATION¹:

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 and Official Title (Type or Print): Frederick F. Haddad, V.P. Power Resources, OUC
--

Signature: _____

Date Signed: _____

¹ Signatory requirements are contained in Rule 62-620.305, F.A.C.

ENVIRONMENTAL RESOURCE PERMIT APPLICATION

Table of Contents

1.0	Joint Environmental Resource Permit Application Forms
	• Section A • Section C • Section E
2.0	Figures, Drawings, and Aerial Photographs
	• Figure 1 Adjacent Property Owners • Figure 2 Property Location • Figure 3 Soil Survey • Figure 4 Existing Land Use Cover • Figure 5 Site Topography • Figure 6 FEMA Flood Insurance Rate Map • Figure 7 Proposed Land Use Cover • Figure 8 Regional Area Map
	• Drawing 98362-ERP-1 <i>Not used.</i> • Drawing 98362-ERP-1A Typical Staked Silt Barriers • Drawing 98362-ERP-2 Typical Gas Line Trench Excavation • Drawing 98362-ERP-3 Vicinity Map • Drawing 98362-ERP-4 Wetland Impact Areas • Drawing 98362-ERP-4A Wetland Impact Area (W5) • Drawing 98362-ERP-5 Typical Dewatering Detail
	• Drawing 98362-DS-S3300 Gas Pipeline Key Plan • Drawing 98362-DS-S3301 Gas Pipeline Plan and Profile – Sht 1 • Drawing 98362-DS-S3302 Gas Pipeline Plan and Profile – Sht 2 • Drawing 98362-DS-S3303 Gas Pipeline Plan and Profile – Sht 3 • Drawing 98362-DS-S3304 Gas Pipeline Plan and Profile – Sht 4 • Drawing 98362-DS-S3305 Gas Pipeline Plan and Profile – Sht 5 • Drawing 98362-DS-S3306 Gas Pipeline Plan and Profile – Sht 6 • Drawing 98362-DS-S3307 Gas Pipeline Plan and Profile – Sht 7 • Drawing 98362-DS-S3308 Gas Pipeline Plan and Profile – Sht 8 • Drawing 98362-DS-S3309 Gas Pipeline Plan and Profile – Sht 9 • Drawing 98362-DS-S3310 Gas Pipeline Typical Sections and Details • Drawing 98362-DS-S3311 Gas Pipeline Typical Sections and Details
	• Drawing 98362-TLINE1 Typical Transmission Profile • Drawing 98362-TLINE2 Transmission Line Silt Fence Plan • Drawing 98362-TLINE3 Transmission Line Silt Fence Plan
	• Aerial Photographs
Appendix A	Wildlife Report for Stanton Energy Center Combined Cycle Project
Appendix B	Stanton Energy Center Monitoring Well Data

Section 1.0

**Joint ERP
Application Forms**

SECTION A

FOR AGENCY USE ONLY

ACOE Application #
Date Application Received
Proposed Project Lat.
Proposed Project Long.

DEP/WMD Application #
Date Application Received
Fee Received \$
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

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 Sections 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 Sections 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: PA81-14
 - ☒ 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	B. ENTITY TO RECEIVE PERMIT (IF OTHER THAN OWNER)
Name Fredrick F. Haddad, Jr.	Name
Title and Company V.P. Power Resources, Orlando Utilities Commission	Title and Company
Address P.O. Box 3193	Address
City, State, Zip Orlando, Florida 32801	City, State, Zip
Telephone and Fax Telephone: (407) 658-6444 Fax: (407) 275-4120	Telephone and Fax
C. AGENT AUTHORIZED TO SECURE PERMIT	D. CONSULTANT (IF DIFFERENT FROM AGENT)
Name Mike Soltys	Name
Title and Company Black & Veatch Corporation	Title and Company
Address 11401 Lamar	Address
City, State, Zip Overland Park, Kansas 66211	City, State, Zip
Telephone and Fax Telephone: (913) 458-7563 Fax: (913) 458-2934	Telephone and Fax

PART 4: (Please provide metric equivalent for federally funded projects):

A. Name of Project, including phase if applicable: Stanton Energy Center Combined Cycle Unit A (Stanton A) Associated Facilities.

B. Is this application for part of a multi-phase project?
☐ yes ☒ no

C. Total applicant-owned area contiguous to the project?
3,445 ac.; 1,395 ha.

D. Total area served by the system: 0 ac.; 0 ha.

E. Impervious area for which a permit is sought: 0.57 ac.; 0.23 ha.

F. Volume of water that the system is capable of impounding:
0 ac. ft.; 0 m

G. What is the total area of work in, on, or over wetlands or other surface waters?
1.16 ac.; 0.47 ha. 50,530 sq. ft.; 4,700 sq. m.

H. Total volume of material to be dredged: 0 yd; 0 m

I. Number of new boat slips proposed: 0 wet slips; 0 dry slips

PART 5:

Project location (use additional sheets if needed):

County(ies) Orange (locations listed below indicate the location of impact areas)

Section(s) 13	Township 23S	Range 31E
Section(s) 18, 31	Township 23S	Range 32E
Section(s)	Township	Range

Land Grant name, if applicable:

Tax Parcel Identification Number: Multiple parcel numbers apply and can be provided upon request.

Street Address/Road or other location: Stanton Energy Center, 5100 Alafaya Trail

City, Zip Code, if applicable: Orlando, 32802

PART 6: Describe in general terms the proposed project, system, or activity.

Orlando Utilities Commission (OUC) is planning to expand the existing Stanton Energy Center by adding 633 MW (nominal) of generating capacity. The new unit (Stanton A) will consist of two natural gas fired combustion turbines in combination with two heat recovery steam generators and one steam turbine generator. A new electric transmission line and natural gas pipeline will be installed to support the Project.

The proposed 230 kV transmission line serving the new unit would be a single circuit, heavy-duty, single-pole transmission line, approximately 0.6 mile in length. The transmission line structures would be steel poles with drilled concrete pier foundations or self-supporting concrete poles, capable of supporting a double circuit configuration. The transmission line would interconnect to the existing SEC substation onsite after modifications to the substation are complete. Construction of the new transmission line and substation expansion would require clearing approximately 0.40 acre of cypress wetland strand and filling approximately 0.70 acre of herbaceous wetland/surface water.

Natural gas would be delivered to the Stanton Energy Center by a 4-1/2-mile long lateral to a Florida Gas Transmission (FGT) line in Orange County. The pipeline lateral will originate from the FGT gas supply line, and will terminate at Stanton A. OUC owns a 300-foot wide utility corridor which includes a railroad track, transmission line, and maintenance road. The proposed pipeline would be installed within this corridor. The actual corridor width required for the pipeline is a maximum of 75 feet for construction, of which 50 feet will be permanently maintained. Construction of the gas pipeline will require temporarily impacting 0.06 acre of herbaceous wetland across a drainage channel. The temporary impact consists of trenching activities required to install the pipeline. Excavated material will be used to backfill the trench within the wetland area and contours will be returned to the pre-construction grade.

There are no wetlands or protected species impacts associated with construction of the Stanton A power block. The storm water management system developed during Stanton Unit 1 construction would not require modification to serve Stanton A. No storm water management facilities would be constructed to serve the new transmission line, natural gas pipeline, or substation expansion installations. Post-development runoff patterns would remain consistent with pre-development patterns. Minor temporary and permanent impacts to wetlands would be required; no impacts to protected species are anticipated.

This ERP application requests work in wetlands within the substation expansion area and the electric transmission line and natural gas pipeline corridors (Project). These facilities will serve Stanton A.

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.

01/16/01 Site Visit

U.S. Army Corps of Engineers: Elizabeth Bishop

FFWCC: Steve Lau

Orlando Utilities Commission: Tom Tart

Southern-Florida: Michelle French

Black & Veatch: Mike Soltys

YVV&A: Tasha Buford

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	Date	No./Type of Application	Action Taken
<u>FDEP</u>	<u>12/14/82</u>	<u>Site Certification Application</u>	<u>Issued</u>
<u> </u>	<u> </u>	<u> </u>	<u> </u>
<u> </u>	<u> </u>	<u> </u>	<u> </u>

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 application) 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.

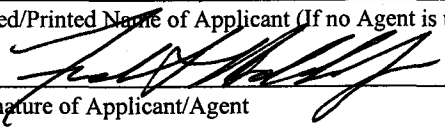
- | | |
|---|----|
| 1. | 2. |
| Please see attached Table A-1 and Figure 1 of this ERP. | |
| 3. | 4. |
| 5. | 6. |
| 7. | 8. |

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 relive 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.

Frederick F. Haddad, Jr., Orlando Utilities Commission

Typed/Printed Name of Applicant (If no Agent is used) or Agent (If one is so authorized below)


Signature of Applicant/Agent

1/17/01
Date

Vice President, Power Resources
(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 requirements 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.

Typed/Printed Name of Applicant

Signature of Applicant

Date

(Corporate Title if applicable)

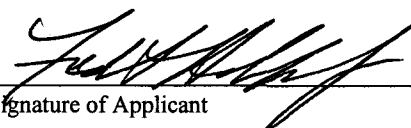
Please note: The applicant's original signature (not a copy) is required above.

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.

Frederick F. Haddad, Jr.

Typed/Printed Name of Applicant


Signature of Applicant

1/17/01
Date

Vice President, Power Resources
(Corporate Title if applicable)

**Table A-1
Surrounding Property Owners
Stanton Energy Center**

Parcel ID	Owner	Acres	Owner Address
12-23-31-0000-00-002	Redditt, John Cecil	120	4414 Calm Water Ct. Orlando, FL 32817
12-23-31-0000-00-005	Redditt, Adeline Ann	120	710 N. Dean Rd. Orlando, FL 32825
12-23-31-0000-00-001	Morgran Co., Inc.	854.9	15 McMurrich St. Suite 1104 Toronto, Canada M5R3
11-23-31-0000-00-001	Orange Co. BCC	640	P.O. Box 1393 Orlando, FL 32802
14-23-31-0000-00-008	Orange Co. BCC	320	P.O. Box 1393 Orlando, FL 32802
23-23-31-0000-00-005	Orange Co. BCC	160	P.O. Box 1393 Orlando, FL 32802
21-23-31-0000-00-002	Orange Co. BCC	2728.87	P.O. Box 1393 Orlando, FL 32802
25-23-31-0000-00-001	Orlando Business Park, LLC	629.7	1525 S. Andrews Ave. Suite 216 Ft. Lauderdale, FL 33316
30-23-32-0000-00-001	TIITF/DOC	609.08	3900 Commonwealth Blvd. Tallahassee, FL 32399
29-23-32-0000-00-002	Smith, W. Roger	509.5	601 Lake Harbor Cir. Orlando, FL 32809
20-23-32-0000-00-001	St. Johns River Water Management District	2,160	P.O. Box 1429 Palatka, FL 32178
07-23-32-0000-00-004	Avalon Associates of Delaware LP	914	13013 Founders Sq. Drive Orlando, FL 32828

Source: Orange County Property Appraiser (<http://pamap1.ocpafl.org>)

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 Stanton Energy Center Unit A (Stanton A) Associated Facilities
County Orange
Owner Orlando Utilities Commission
Applicant: Orlando Utilities Commission
Applicant's Address: P.O. Box 3193, Orlando, FL 32802

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.

A project location map is included as Figure 2.

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:

Unnamed, herbaceous wetlands occur within the proposed natural gas pipeline route, the electric transmission line corridor, and the substation expansion area. Unnamed cypress wetland occurs within the electric transmission line corridor. These wetlands are not Outstanding Florida Waters or Aquatic Preserves.

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.

Refer to Drawings 98362-ERP-2, 98362-ERP-3, 98362-TLINE1 through 98362-TLINE3, and 98362-DS-S3300 through 98362-DS-S3311 for plan, sections, and details of the proposed facilities.

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"):

The existing storm water system will remain in place to serve the proposed 60-acre industrial (Stanton A) development. The work requested herein involves installation of the new electric transmission line and natural gas pipeline and the expansion of the existing, onsite substation (Associated Facilities).

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 0.7 ac.; 0.06 excavated ac.;

other impacts 0.4 ac. (cleared)

6. Provide a brief statement describing any proposed mitigation for impacts to wetlands and other surface waters (attach additional sheets if necessary):

The proposed power block area was previously cleared for use as a laydown area during construction of Units 1 & 2. No wetlands exist in the Stanton A power block area.

The proposed project would temporarily impact 0.06 acre of herbaceous wetland, resulting from the installation of the natural gas pipeline. The pipeline trench would be excavated, backfilled with the original excavated material, and returned to original contours. Impacts associated with the installation of the natural gas pipeline are considered temporary. Therefore, no mitigation measures are proposed.

The electric transmission line route has been designed to minimize impacts to both cypress and herbaceous wetlands. However, construction of the new electric transmission line would require clearing approximately 0.40 acre of cypress wetland. No disturbance to soil structures in this 0.40-acre impact area is anticipated as a result of clearing activities. Rubber-tired vehicles and hand-clearing methods would be used for this clearing. Approximately 0.57 total acre of herbaceous wetland and surface water (0.34 and 0.23, respectively) would require filling to install the required transmission towers and associated keyhole pads. The electric transmission line route has been designed to follow, as much as practicable, an existing access road to minimize impacts to herbaceous wetland. Instead of constructing a new access road, pole keyhole pads would be constructed from the existing access road to the tower locations for construction and maintenance of the transmission line.

The existing SEC substation would require expansion to interconnect the electrical generation from Stanton A to the transmission system. Substation expansion would require filling approximately 0.13 acre of herbaceous wetland immediately west of the existing substation location.

Mitigation for the 1.10 acres of permanent impacts will be determined during post-submittal agency negotiations.

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.

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.*

Figure 3 is a map of the project area and vicinity delineating USDA/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.*

Aerials of the project area are provided in Section 2.0 of this ERP.

- 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.*

Appendix B of this ERP application provides data from monitoring wells on the SEC site. Additional reports (listed below) can be provided upon request.

- 1. Soil Investigation, Orlando Utilities Commission - Stanton Energy Center, Black & Veatch Project No. 8927, includes Phase I Soil Investigation.**
- 2. Laboratory Testing, Orlando Utilities Commission - Curtis H. Stanton Plant, Orlando, Florida, by Ardaman & Associates, Inc., September 10, 1980.**
- 3. Laboratory Testing, Orlando Utilities Commission - Curtis H. Stanton Plant, Orlando, Florida, August 6, 1981, by Ardaman & Associates, Inc.**
- 4. Laboratory and Field Materials Test Results, Orlando Utilities Commission - Stanton Energy Center Unit 2, Orlando, Florida, Black & Veatch Project No. 16805, by Universal Engineering Sciences, Inc., May 28, 1992 (Borings B-104 through B-119).**

- 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.*

Refer to response for Part I, Item C above.

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.*

Results of wildlife surveys for the project site are included as Appendix A of this ERP.

- 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.*

Water quantity and hydroperiod will be maintained in undisturbed areas by maintaining the existing drainage pattern. Water quality will be maintained during construction with silt fences. Silt fences will prevent sediment and construction debris from reaching wetlands adjacent to the proposed utility corridors. All waste materials will be removed and properly disposed at reasonable intervals. Materials such as fuels and similar products will be stored appropriately to avoid spills and incidental releases to the environment. Fugitive dust emissions will be controlled with water sprays. Storm water discharges during operation will be equal to pre-development runoff rates. Construction activities and personnel traffic will be confined to the proposed right-of-ways and substation expansion areas to maintain the integrity of adjacent habitat.

- C. *Provide a narrative description of any proposed mitigation plans, including purpose, maintenance, monitoring, and construction sequence and techniques, and estimated costs.*

Mitigation for the 1.1 acres of permanent impacts will be determined during post-submittal agency negotiations.

- 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.*

State (FAC 62-340) and Federal (1987 Corps Delineation Manual) wetland boundaries were delineated for the proposed electric transmission line corridor, the natural gas pipeline corridor, and the substation expansion area in November and December 2000. Jurisdictional wetland determinations were conducted by a Black & Veatch wetland specialist.

- E. *Impact Summary Tables:*

1. *For all projects, complete Tables 1, 2 and 3 as applicable.*

The Impact (Table 1) and Mitigation (Table 2) tables are included at the end of this Section E form.

2. *For docking facilities or other structures constructed over wetlands or other surface waters, provide the information requested in Table 4.*

No docking facilities proposed.

3. *For shoreline stabilization projects, provide the information requested in Table 5.*

The proposed project is not a shoreline stabilization project.

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;*

Project area boundary and total land area, including distances and orientation from roads or other land marks can be found in Figure 1, Adjacent Property Owners; Figure 2, Project Location; and Figure 8, Regional Area Map.

- 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.*

Existing land use and land cover, and onsite natural communities including wetlands and other surface waters, aquatic communities, and uplands are illustrated in Figure 4.

- 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 MRW and MLW. For docking facilities, indicate the distance to, location of, and depths of the nearest navigational channel and access routes to the channel.*

Refer to Figure 5, Site Topography, Drawings 98362-TLINE2 and 98362-TLINE3, and Drawings 98362-DS-S3300 through 98362-DS-S3310.

- 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;

A Flood Insurance Rate Map is included as Figure 6 of this ERP. The electric transmission line and the substation expansion area are entirely within Zone C, areas of minimal flooding. The natural gas pipeline corridor crosses both Zone A, areas of 100-year flood, and Zone C, areas of minimal flooding.

- 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;*

There are no wetlands or other surface waters within the power block area. Wetland boundaries associated with the linear facilities (natural gas and electric transmission lines) and the substation expansion area are indicated on Figure 4, Drawing 98362-ERP-4, and Drawing 98362-ERP-4A.

- 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.*

Proposed land use, land cover and natural communities, including wetlands and other surface waters, undisturbed uplands, aquatic communities, impervious surfaces, and water management areas are illustrated in Figure 7.

- G. Proposed impacts to wetlands and other surface waters, and any proposed connections/outfalls to other surface waters or wetlands;*

Proposed impacts to wetlands will consist of the following:

- **Filling 0.57 acre of herbaceous wetland/surface water within the electric transmission line corridor.**
- **Clearing 0.40 acre of cypress wetland strand within the electric transmission line corridor.**
- **Installing a natural gas pipeline in 0.06 acre of herbaceous wetland within the natural gas pipeline corridor.**
- **Filling 0.13 acre of herbaceous wetland within the substation expansion area.**

- H. Proposed buffer zones;*

The transmission line, natural gas pipeline, and substation expansion area are proposed entirely within Orlando Utilities Commission property; therefore no buffer zone is proposed.

- 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;*

The existing drainage patterns would remain unchanged since no storm water control system is associated with the electric transmission line, the natural gas pipeline, or the substation expansion area.

- J. Location of all water management areas with details of size, side slopes, and designed water depths;*

No storm water control facilities are associated with the electric transmission line, natural gas pipeline, or the substation expansion area.

- 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);*

No storm water control facilities are associated with the electric transmission line, natural gas pipeline, or the substation expansion area.

- L. Location, dimensions and elevations of all proposed structures, including docks, seawalls, utility lines, roads, and buildings;*

Location, dimensions, and elevations of the proposed transmission line, natural gas pipeline, and the substation expansion are illustrated on Drawings 98362-TLINE1, 98362-TLINE2, 98362-TLINE3, and Drawings 98362-DS-S3300 through 98362-DS-S3311.

- M. Location, size, and design capacity of the internal water management facilities;*

No storm water management facilities are associated with the electric transmission line, natural gas pipeline, or substation expansion area.

- 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;*

No rights-of-way or easements will be required for construction or operation of the electric transmission line, natural gas pipeline, or substation expansion area. No storm water control facilities are associated with the electric transmission line, natural gas pipeline, or substation expansion area.

- O. Receiving waters or surface water management systems into which runoff from the developed site will be discharged;*

Runoff would continue to drain to natural (existing) drainage patterns.

- 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;*

Erosion and sediment control measures will be installed as necessary during construction to retard erosion and control sediment deposition.

Before construction begins, silt fence or other appropriate control measures will be installed around the perimeter of the construction areas. Drawings 98362-ERP-1A, 98362-ERP-4A, 98362-DS-S3301 through 98362-DS-S3310, 98362-TLINE1, 98362-TLINE2, and 98362-TLINE3 show silt fence details and locations. Erosion control measures may also include minimizing fugitive dust through periodic spraying of water.

Construction Techniques

Several distinct tasks will be required for construction of the proposed transmission line. These will include surveying, silt fence installation, clearing, foundation construction, structure assembly and erection, conductor and shield wire installation, and cleanup. These tasks will occur in the following sequence and will be separated, in time, by several days to several months.

The right-of-way centerline and edges, and structure 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." Silt fences are erected to define the construction area as well as to prevent soil and debris from leaving the construction area.

In wetlands and other 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 transmission structure foundations and keyhole fills. Stumps and root mat will be left in place except at structure foundation locations. There will be no need to demuck.

Fill material for keyhole pads will be hauled in by truck and spread with bulldozers to obtain suitable compaction. Culverts, if required, will be 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. Key pads 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 to prevent 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.

Pipeline construction activities differ slightly from pipeline to pipeline, but generally include the following, which are described in more detail below:

- Surveying and right-of-way preparation.
- Ditching/trenching.
- Installation.
- Testing.
- Right-of-way restoration.

Other specialized activities may take place, such as:

- Boring and installation of road, railroad, and stream crossings.
- Installation of mainline block valve assemblies.

The key regulatory document for the design and construction of the pipeline will be Minimum Federal Safety Standards for Gas Lines, Part 192, Title 49, CFR, implemented by the USDOT and referred to as 49 CFR, Part 192 hereafter. The PSC has adopted the USDOT standards.

Following approval of the route, the entire route will be surveyed. The center line of the pipeline will be marked at about 200 foot intervals. Within the route staked by the surveying crew, the contractor personnel will clear the terrain to provide a work platform or working strip allowing unimpeded progress of the construction activities.

The 75 foot construction corridor will first be cleared of brush and timber in accordance with the contract specifications and permit or regulatory limitations. The stumps will be grubbed and all materials cleared will be disposed of in a manner consistent with the construction approvals and applicable state and local requirements. This may include upland burial onsite, burning, or hauling offsite. Generally, machetes, chain saws, bulldozers, backhoes, and trucks are the tools and equipment used during that operation.

Next, the topsoil layer within the route will be stripped where excavation will occur with a dozer or grader bermed to one side of the working strip. In both uplands and wetlands, the

topsoil or upper 6 inches of soil will be saved to be spread back over the stripped area during restoration of the disturbed areas.

The work platform is then graded to provide smooth access to all equipment used in the following phases of construction.

The pipeline occupies only a small portion of the area necessary for the construction and possible future maintenance. Only 10 to 15 feet of area are needed to store the spoil excavated from the trench. For the 16 inch pipeline, the ditch bottom will be approximately 2 feet wide. Depending on the type of soil being excavated and type of ditching equipment used, the width of the trench at grade level may be only slightly wider than at the bottom, e.g., 6 feet, or it may be wider if unstable trench slopes are encountered.

The space adjacent to the trench is used to string the pipe joints on skids until ready for the welding operation. Working room is required on both sides of the pipe such that 10 to 12 feet must be reserved between the edge of the trench and the sideboom track. The width of the sideboom (also called pipelayer) for a 16 inch is approximately 12 feet with counterweight retracted and 16 feet or more when extended. Additional space is needed to the outside of the equipment for pickup trucks, lube truck, other sidebooms and similar equipment to pass stationary equipment.

The trench excavation is called ditching and can be performed in a number of ways, based on the local conditions of the area crossed by the line. Wheel ditchers are the most convenient and effective way of opening the ditch.

For this pipeline, except in rocky areas if any are crossed along the route, the total depth of the trench will be about 4 to 5 feet.

Ditching for conventional drainage ditch crossing can be accomplished with backhoes or draglines. The choice of equipment will depend on the size of the ditch, water depth and current velocity, makeup of the channel bed and required trench depth. To control the water turbidity or to limit its increase as a result of construction activities, various methods are available as a function of site-specific conditions. For small waterways, as is the case for this installation, siltation barriers can be installed immediately downstream of the crossing. These siltation barriers consist of suspended fabric and/or hay bales.

To eliminate the disturbance to traffic brought on by using the open cut method of trenching across a roadway, boring techniques have been developed. The operation consists of drilling a hole horizontally under the road while inserting a pipe in that hole. The US DOT and counties regulate the minimum depth of cover between the top of the pipe and the road surface.

A boring machine is generally a motor driven auger equipped with a control panel and is mounted on a frame designed to straddle a pipe. A winch or hydraulic jacks provide the force applied to the auger and the pipe for horizontal progress.

Pipe installation, known as stringing pipe, can be accomplished just after the ditch has been opened or in other ways which also minimize the amount of time a trench is open. It essentially sets up the work for the actual assembly of the pipeline.

Since the welding operation is all-important in ensuring the structural integrity of the pipeline, it is performed by highly skilled personnel. All welding personnel will be certified in the welding process associated with gas pipelines. The validity of the welding method (called the weld procedure) is verified and qualified following the requirements of API Standard 1104 for Welding Pipe Lines and Related Facilities.

The entire pipeline and its associated facilities will be pressure tested to prove integrity. No evidence of leakage is allowed before the pipeline is authorized for operation. The records of

all tests must be properly filed and maintained by the pipeline operator. Upon completion of all tests, the pipeline is ready for commissioning.

Part 192 of 49 CFR and project specifications establish stringent limits and requirements for the hydrotest. Both maximum and minimum levels are prescribed for test pressures as a function of the pipe physical characteristics (diameter, wall thickness and steel grade), the class location and the expected operating pressure. To satisfy all of these requirements, the range of required test pressures must be computed for each segment of the line. In any case, the minimum test pressure equals 110 percent of the maximum pressure at which the pipeline will be allowed to operate. A hydrostatic test program will be devised when the final design of the pipeline is completed. The water to be used for hydrostatic testing will be obtained from impounded water on the SEC and returned to this source following testing. No offsite surface or groundwater sources will be used for hydrostatic testing.

During construction, topsoil will be saved to be spread back over the stripped area during the restoration of disturbed areas following pipe installation. Once the pipeline is buried in place, the stripped topsoil will be spread back in place to its original location and topography. Hydroseeding will be undertaken as necessary to quickly stabilize soils with a vegetation cover.

Q. Location, grading, design water levels, and planting details of all mitigation areas;

Mitigation for the 1.1 acres of permanent impacts will be determined during post-submittal agency negotiations.

R. Site grading details, including perimeter site grading;

The substation expansion will include site fill to bring the site up to elevation of the existing substation. The site will be covered with well-graded crushed stone to three feet outside of the new fenced area. The keyhole pads associated with the transmission tower structures will be brought up to the existing access road grade, as shown in Drawing 98362-TLINE1. The natural gas pipeline route will be returned to original grade upon completion of installation.

S. Disposal site for any excavated material, including temporary and permanent disposal sites;

Disposal site for excavated material will be within the Stanton A construction site area, north of the existing Units 1 and 2.

T. Dewatering plan details;

A short term dewatering permit will be secured for construction activities associated with the electric transmission line, natural gas pipeline, and substation expansion. A typical detail indicating the methodology to be utilized for dewatering activities is indicated on Drawing 98362-ERP-5. This detail incorporates the use of a well point system. Each and every dewatering system will be equipped with a primary and secondary (back-up) pump to ensure uninterrupted use of the system.

U. For marina facilities, locations of any sewage pumpout facilities, fueling facilities, boat repair and maintenance facilities, and fish cleaning stations;

Not applicable.

- 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.*

No offsite features will be impacted by the proposed construction.

- W. *For phased projects, provide a master development plan.*

Project development will require only one phase. Therefore, a master development plan is not required.

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:

- A. *Method for installing any pilings or seawall slabs;*

Not applicable.

- B. *Schedule of implementation of temporary or permanent erosion and turbidity control measures;*

Refer to Part III, Item P of this ERP.

- 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;*

Please refer to Part III, Item P of this ERP for a discussion of construction activities.

- 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;*

The fill material for the keyhole pads associated with the electric transmission line would be compacted native soil backfill with grass surface and side slope. Where necessary, a geotextile fabric liner would be installed to stabilize the keyhole pad. Transmission tower foundations would be concrete pads. Compacted native soil would be used as fill material for the substation expansion as well. The natural gas pipeline trench would be backfilled with the original, excavated material.

- E. *If dewatering is required, detail the dewatering proposal including the methods that are proposed to contain the discharge, methods of isolating dewatering area, and indicate the period dewatering structures will be in place (Note: a consumptive use or water use permit may be required);*

A short term dewatering permit application will be submitted requesting the authority to dewater prior to dewatering activities. All discharge from dewatering activities will be directed to existing drainage patterns.

- 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 will be used for transporting equipment and materials to and from the work site.

- G. *Demolition plan for any existing structures to be removed; and*

Construction of the electric transmission line, natural gas pipeline, and substation expansion will not require the demolition or removal of any existing structures.

- H. *Identify the schedule and party responsible for completing monitoring, record drawings, and as-built certifications for the project when completed.*

Orlando Utilities Commission will be responsible for identifying the schedule prior to construction and for identifying responsibility for completing monitoring, recording drawings, and as-built certifications for the project when completed.

V. Drainage Information

- A. *Provide pre-development and post-development drainage calculations, signed and sealed by an appropriate registered professional, as follows:*

Not applicable to the electric transmission line, natural gas pipeline, or substation expansion facilities.

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);*
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. *Runoff peak rates and volumes discharged from the system for each required design storm event(s);*
9. *Tail water history and justification (time and elevation); and*
10. *Pump specifications and operating curves for range of possible operating conditions (if used in system).*

B. *Provide the results of any percolation tests, where appropriate, and soil borings that are representative of the actual site conditions;*

Detailed subsurface conditions have been determined from the results of subsurface investigations completed for the existing SEC. These investigations included soil borings, installation of shallow piezometers, soil resistivity tests, and laboratory tests on selected samples. Data collected from these investigations is available (upon request) in the following four data reports:

1. Soil Investigation, Orlando Utilities Commission - Stanton Energy Center, Black & Veatch Project No. 8927, includes Phase I Soil Investigation.
2. Laboratory Testing, Orlando Utilities Commission - Curtis H. Stanton Plant, Orlando, Florida, by Ardaman & Associates, Inc., September 10, 1980.
3. Laboratory Testing, Orlando Utilities Commission - Curtis H. Stanton Plant, Orlando, Florida, August 6, 1981, by Ardaman & Associates, Inc.
4. Laboratory and Field Materials Test Results, Orlando Utilities Commission - Stanton Energy Center Unit 2, Orlando, Florida, Black & Veatch Project No. 16805, by Universal Engineering Sciences, Inc., May 28, 1992 (Borings B-104 through B-119).

C. *Provide the acreage, and percentages of the total project, of the following:*

1. *Impervious surfaces, excluding wetlands;*

Area of impervious surfaces:

Electric transmission line corridor = 0.57 acre;

Natural gas pipeline corridor = 0.0 acres;

Substation expansion area = 0.0 acres

Total = 0.57/173.8 acres = 0.3 %.

2. *Pervious surfaces (green areas, not including wetlands);*

Total pervious surfaces:

Electric transmission line corridor/substation expansion = 2.1 acres;

Natural gas pipeline corridor = 165 acres;

Total = 167.1/173.8 acres = 96.1 %.

3. *Lakes, canals, retention areas, other open water areas; and*

Borrow ditch:

Electric transmission line corridor = 0.64 acre;

**Natural gas pipeline corridor = 0.0 acres;
Total = 0.64/173.8 acres = 0.4%.**

4. *Wetlands.*

**Wetlands within transmission line corridor/substation expansion = 5.46 acres;
Wetlands within natural gas line corridor = 0.06 acre;
Total = 5.52/173.8 acres = 3.2%.**

D. *Provide an engineering analysis of floodplain storage and conveyance (if applicable), including:*

Not applicable.

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:*

1. *A description of the proposed stormwater treatment methodology that addresses the type of treatment, pollution abatement volumes, and recovery analysis; and*

Storm water treatment is not applicable to the electric transmission line, natural gas pipeline, or substation expansion. Storm water associated with these facilities will continue to drain to existing drainage patterns.

2. *Construction plans and calculations that address stage-storage and design elevations, which demonstrate compliance with the appropriate water quality treatment criteria.*

Not applicable to the electric transmission line, natural gas pipeline, or substation expansion facilities.

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.*

Not applicable.

VI. Operation and Maintenance and Legal Documentation

- A. *Describe the overall maintenance and operation schedule for the proposed system.*

No storm water facilities are associated with the electric transmission line, natural gas pipeline or substation expansion.

- 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.*

Not applicable.

- 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.*

Orlando Utilities Commission owns all project areas, therefore no easements apply.

- D. *Provide indication of how water and waste water service will be supplied. Letters of commitment from off-site suppliers must be included.*

Not applicable.

- 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.*

Please refer to Figures 1 and 2 of this ERP for property boundaries of the Curtis H. Stanton Energy Center. Construction of the electric transmission line and the substation expansion will occur entirely within the property boundary described in the above mentioned figures. Orlando Utilities Commission owns this property as well as the contiguous railroad and corridor in which the natural gas pipeline will be installed. Ownership documents can be provided upon request.

VII. Water Use

- A. *Will the surface water system be used for water supply, including landscape irrigation, or recreation.*

Not applicable.

- B. *If a Consumptive Use or Water Use permit has been issued for the project, state the permit number.*

Not applicable.

- 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.*

No Consumptive Use or Water Use permit will be required for this project.

- D. *Indicate how any existing wells located within the project site will be utilized or abandoned.*

Not applicable.

TABLE 1
Project Impact Summary

WL & SW ID	WL & SW TYPE	WL & SW SIZE (ac.) ON SITE	WL & SW ACRES NOT IMPACTED	PERMANENT IMPACTS TO WL & SW		TEMPORARY IMPACTS TO WL & SW		MITIGATION ID
				IMPACT SIZE (acres)	IMPACT CODE	IMPACT SIZE (acres)	IMPACT CODE	
W1	Herbaceous	0.13	0.0	0.13	F	N/A	N/A	M1
W2	Herbaceous	4.29	3.95	0.23	F	N/A	N/A	M1
W3	Cypress	0.40	0.0	0.40	O	N/A	N/A	M2
W4	Herbaceous	See W2.	See W2.	0.11	F	N/A	N/A	M1
W5	Herbaceous	0.06	0.06	0.00	N/A	0.06	O2	N/A
W6	Surface Water	0.64	0.41	0.23	F	N/A	N/A	M3 (if required)
Project Totals		5.52	4.42	1.10		0.06		

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 Florida Department of Transportation, "Florida Land Use, Cover and Forms Classification System," (September, 1985).

Impact Code 'O' = Clear Cut; Impact Code 'O2' = trench and backfill with original material. Impact ID's W2 and W4 occur within one, contiguous wetland area. See Drawings 98362-ERP-4 and 98362-ERP-4A for identification/location of WL ID's.

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
M1 (TBD)												
M2 (TBD)												
M3 (TBD)												
PROJECT TOTALS												

CODES (multiple entries per call 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

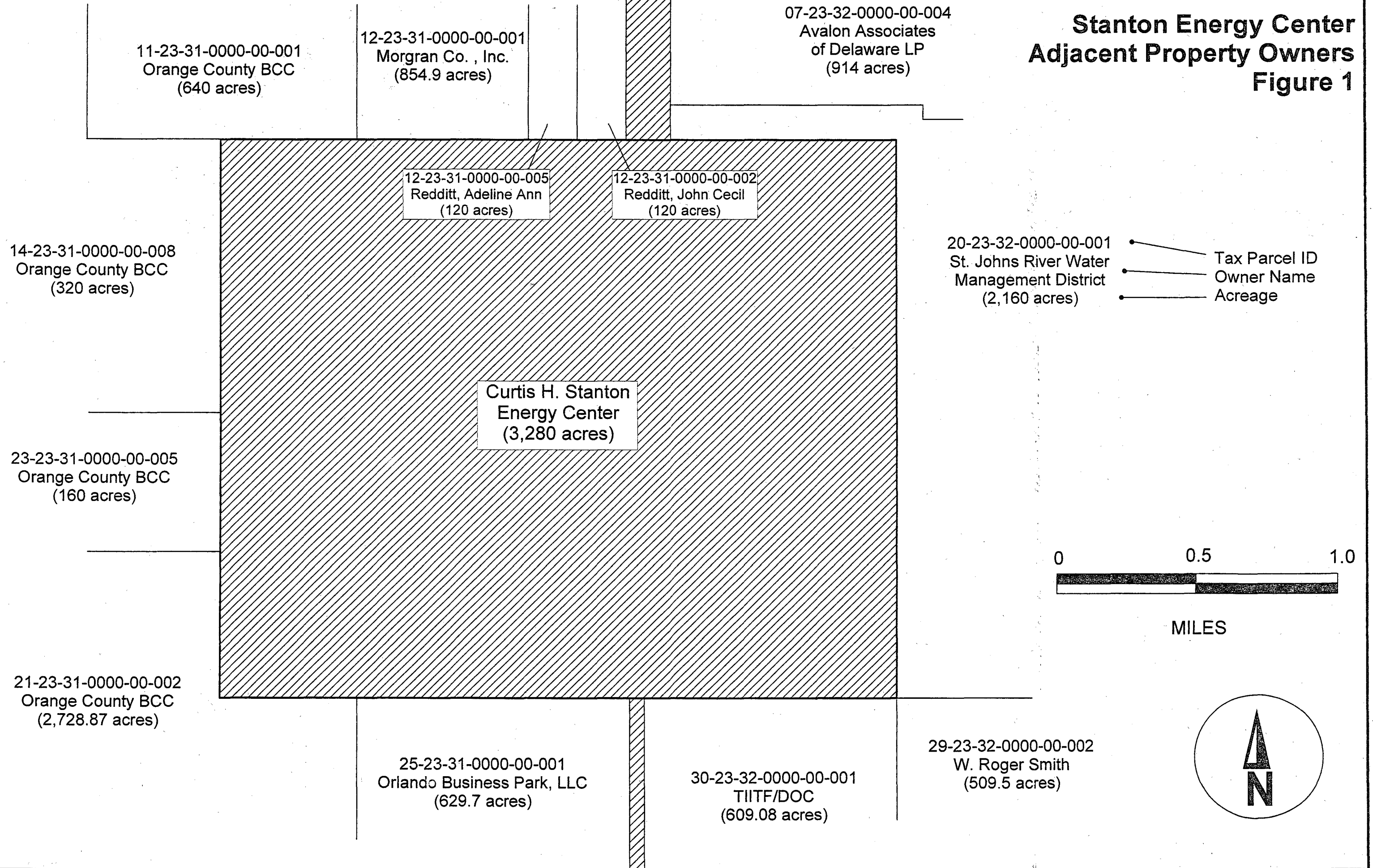
COMMENTS: TBD : Mitigation for wetland impacts will be determined during post-submittal agency negotiations.

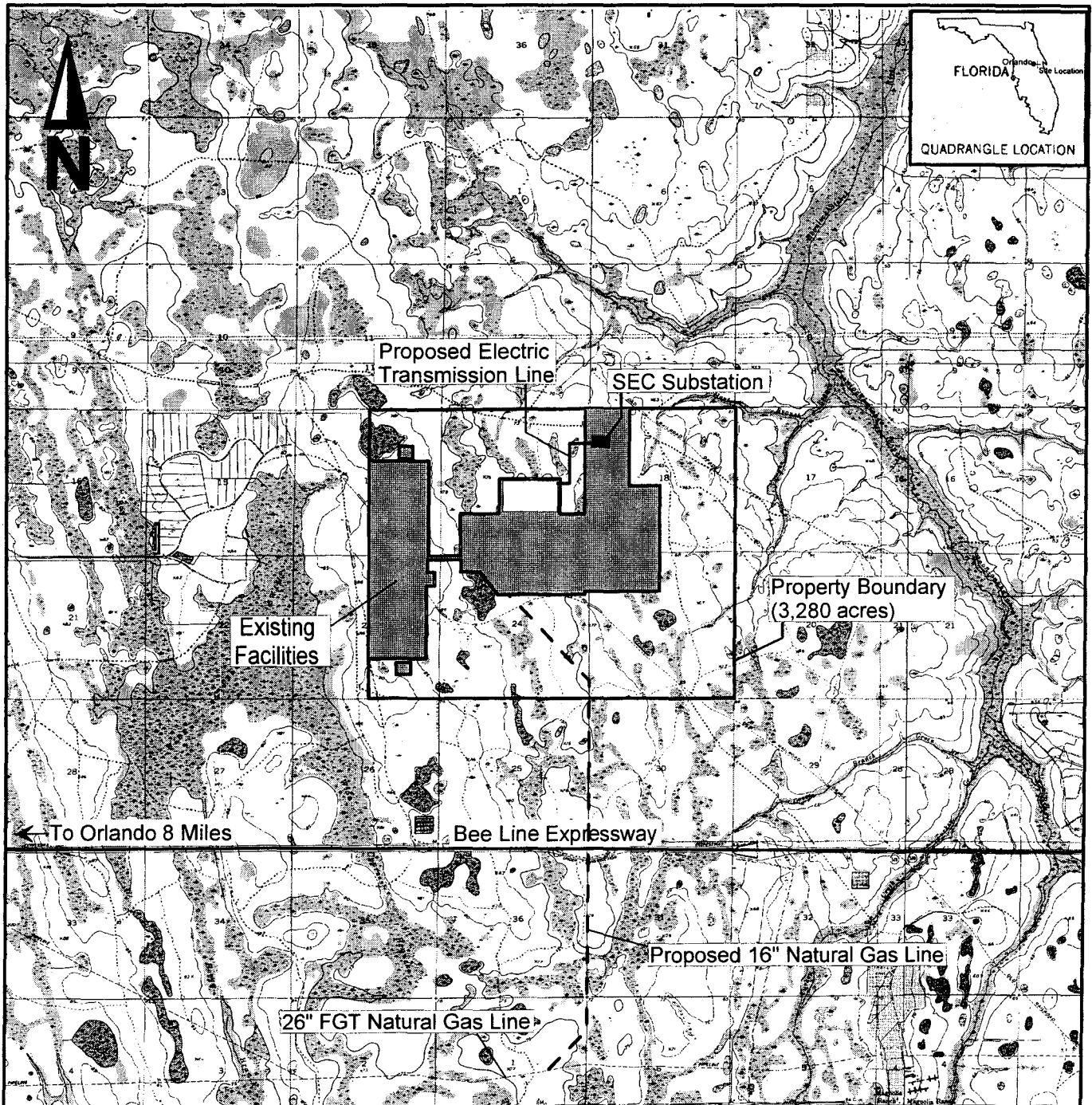
Classification is based on Florida Department of Transportation, "Florida Land Use, Cover and Forms Classification System," (September, 1985).

Section 2.0

Figures, Drawings, and Aerial Photographs

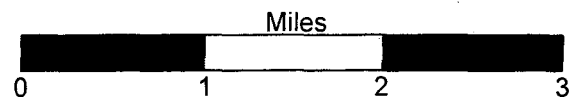
Stanton Energy Center Adjacent Property Owners Figure 1



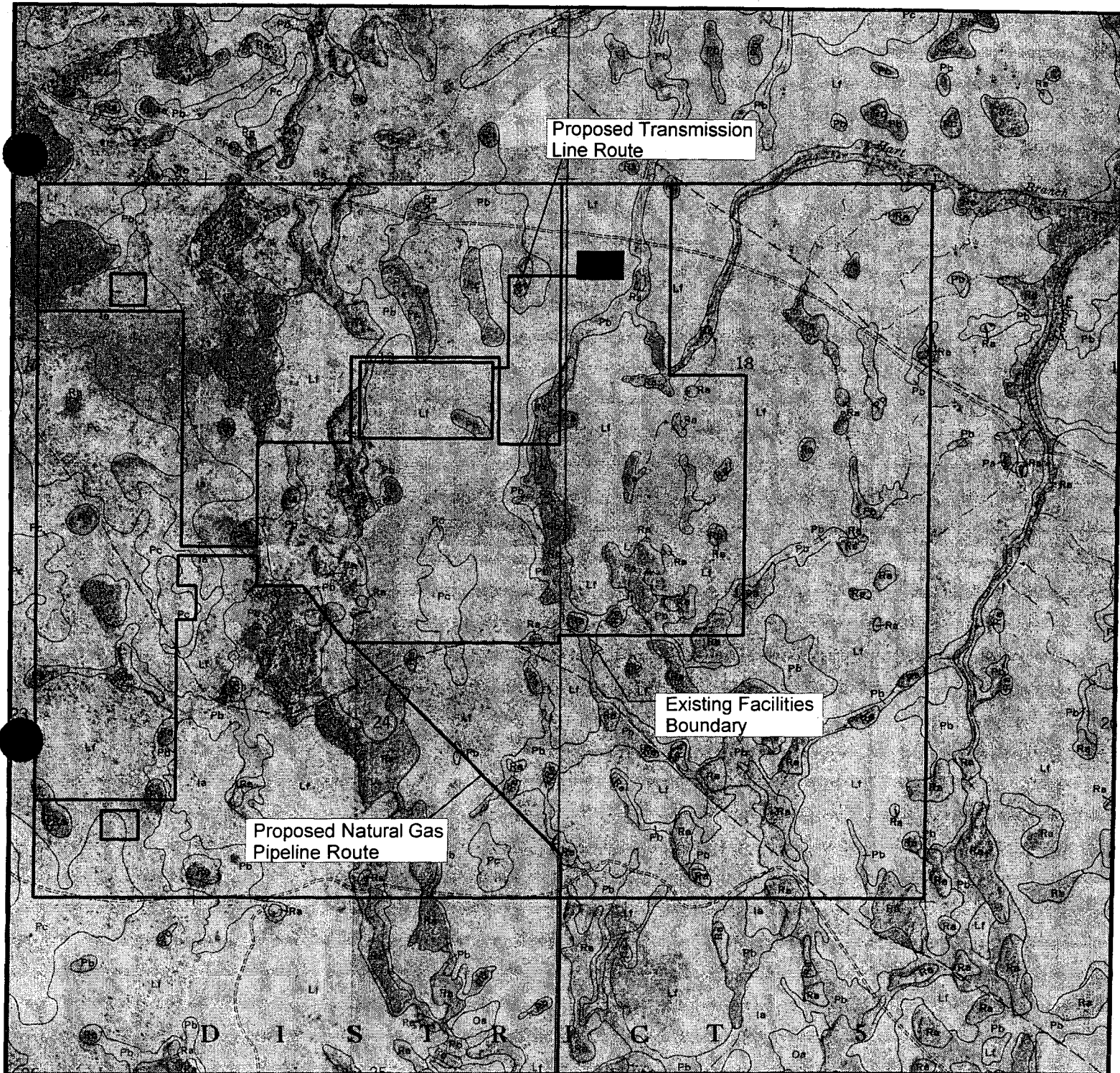


Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Property Boundary: Orange Co.; Sections 13, 24, E1/2 14, E1/2 23 of Township 23S, Range 31E; Sections 18, 19 of Township 23S, Range 32E



Stanton Energy Center
Property Location
Figure 2

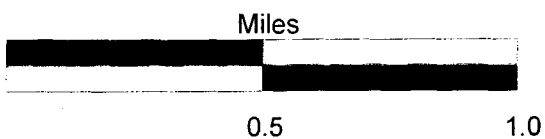


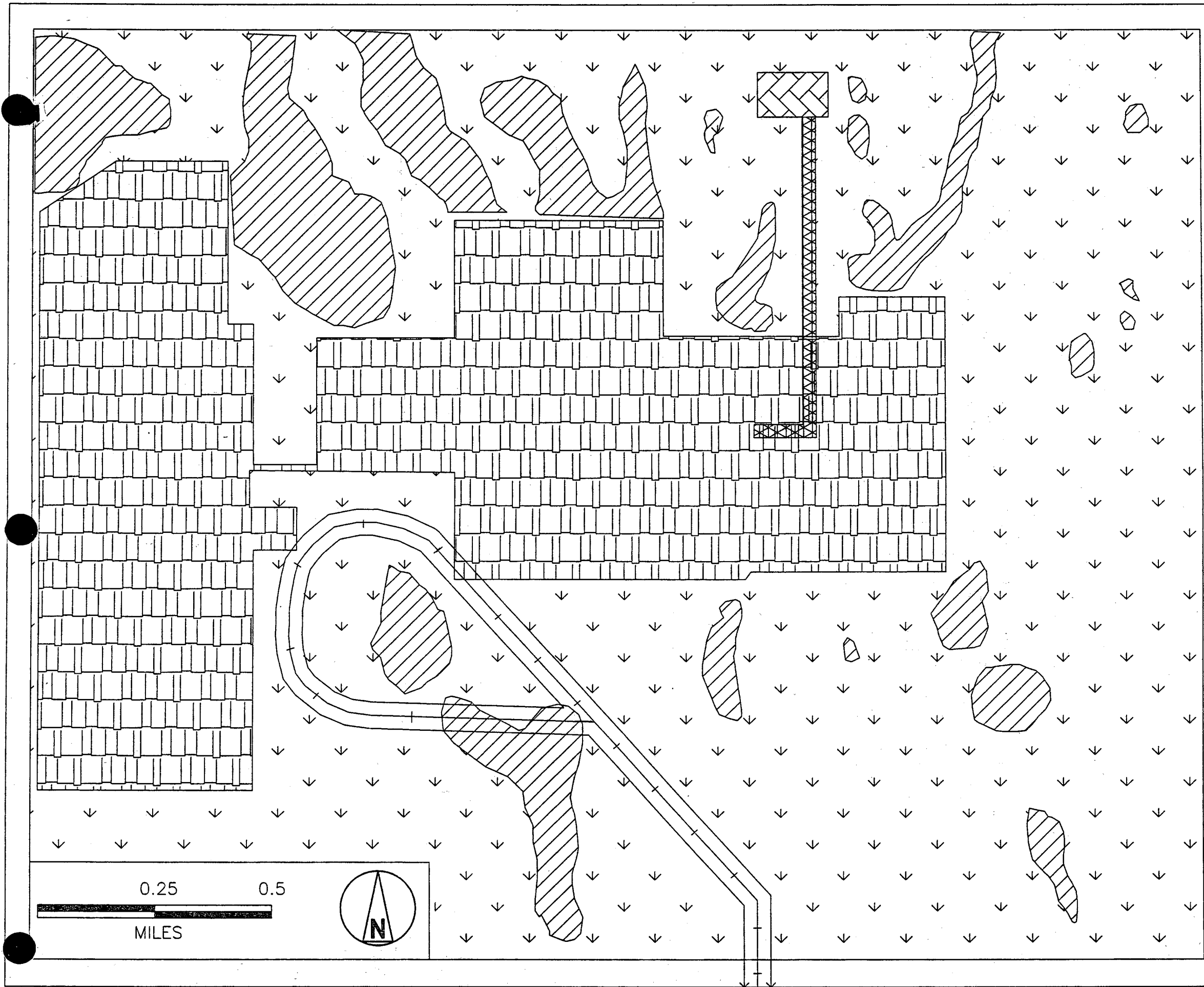
Ia - Immokalee fine sand
 Lf - Leon fine sand
 Pa - Pamlico muck
 Pb - Plummer fine sand

Pc - Pomello fine sand
 Ra - Rutlege fine sand
 Rc - Rutlege mucky fine sand
 Sa - St. Johns fine sand



Stanton Energy Center Soil Survey Figure 3





LEGEND

LAND COVER	ACRES	PERCENTAGE
411	1,779	51.5
621	342.5	9.9
812	~200	~6.0
831	1,100	31.9
8315	9.2	0.3
832	14.3	0.4

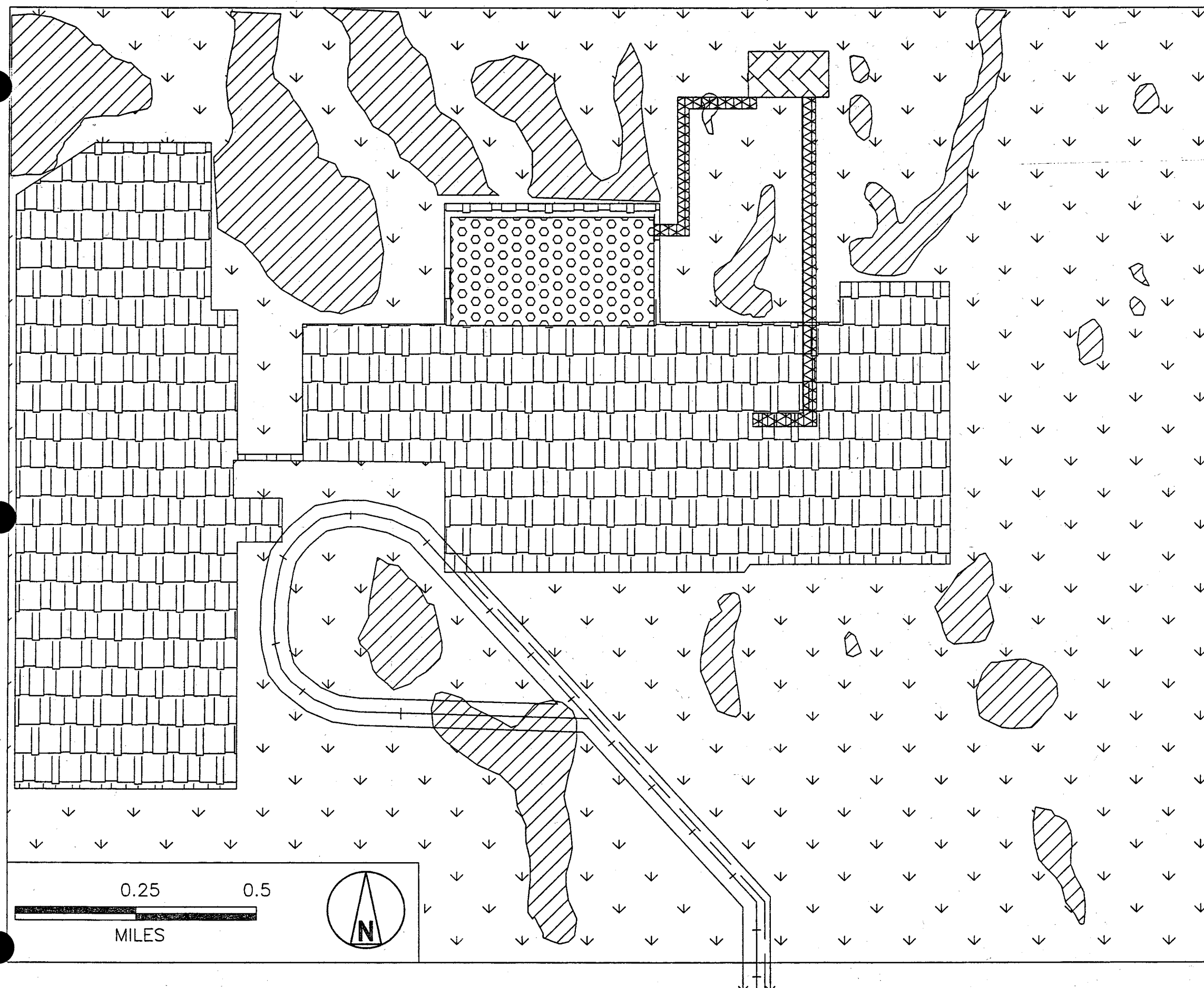
LAND COVER	SYMBOL
411	
621	
812	
831	
8315	
832	

LAND COVER	DESCRIPTION
411	PINE FLATWOODS
621	CYPRESS WETLAND
812	RAILROADS
831	ELECTRIC POWER FACILITIES
8315	SUBSTATIONS
832	ELECTRIC POWER TRANSMISSION LINES

EXISTING LAND USE COVER
STANTON ENERGY CENTER
FIGURE 4

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.



LAND COVER	ACRES	PERCENTAGE
411	1,771	51.3
621	342.1	9.9
812/817	~200	~6.0
831	1,040.00	30.2
8312	60.00	1.7
8315	10.4	0.3
832	21.5	0.6

LAND COVER	SYMBOL
411	
621	
812/817	
831	
8312	
8315	
832	

LAND COVER	DESCRIPTION
411	PINE FLATWOODS
621	CYPRESS WETLAND
812/817	RAILROADS/GAS LINE
831	ELECTRIC POWER FACILITIES (EPF)
8312	EPF, GAS TURBINES
8315	SUBSTATIONS
832	ELECTRIC POWER TRANSMISSION LINES

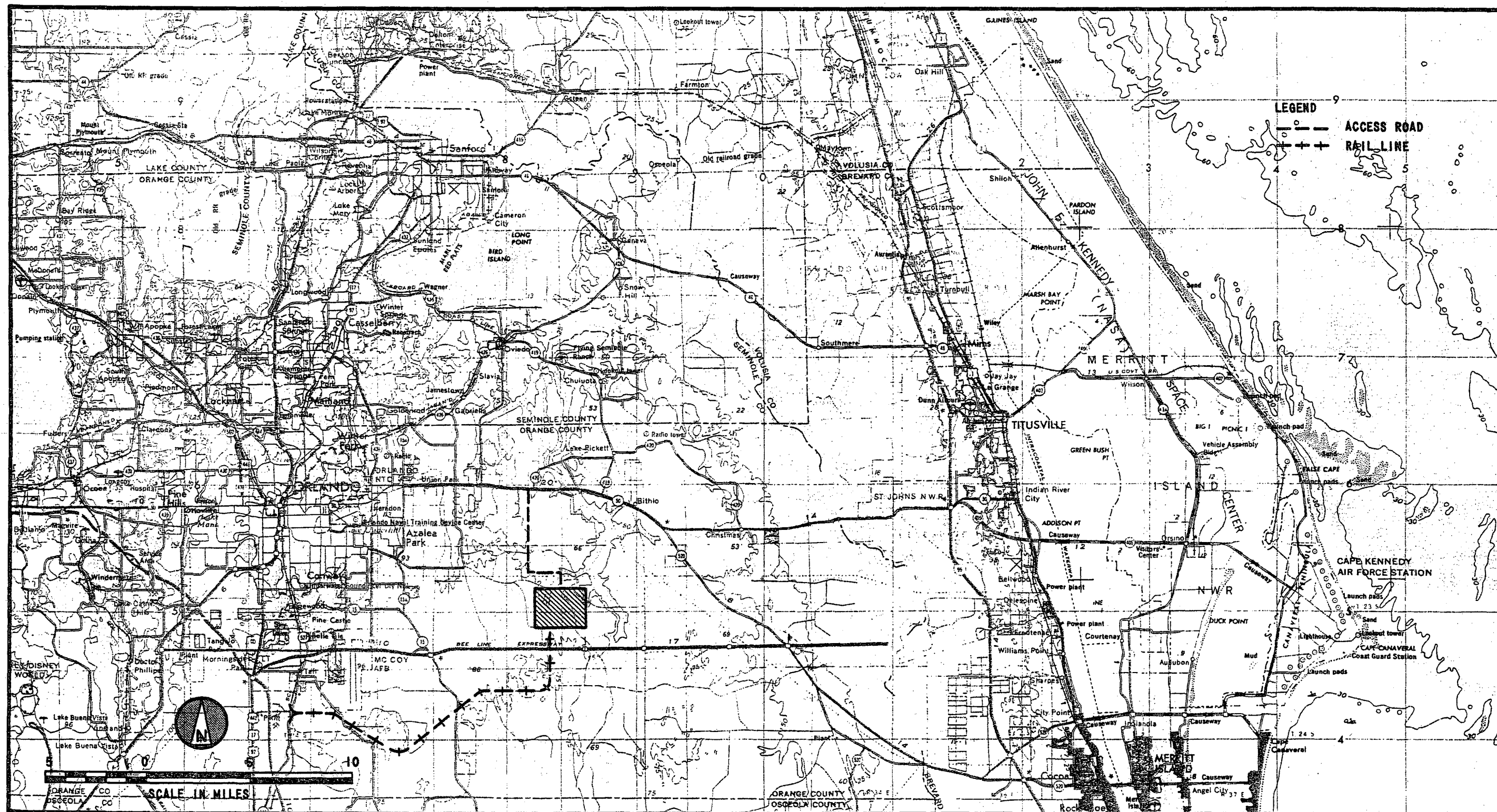
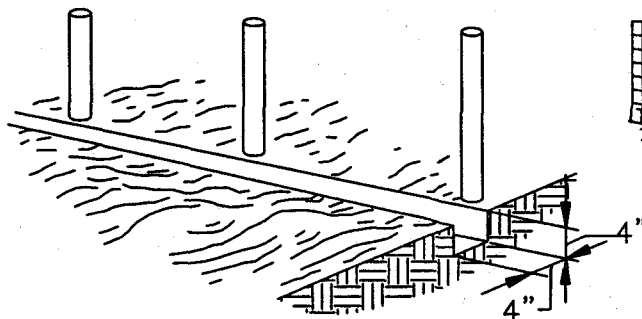


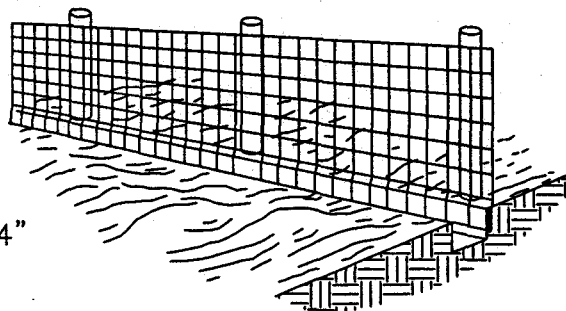
FIGURE 8

REGIONAL AREA MAP

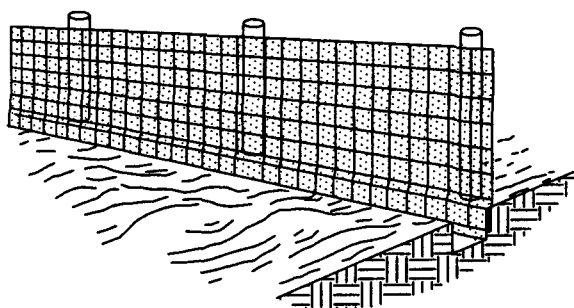
1. SET POSTS AND EXCAVATE A 4"X4" TRENCH UPSLOPE ALONG THE LINE OF POSTS.



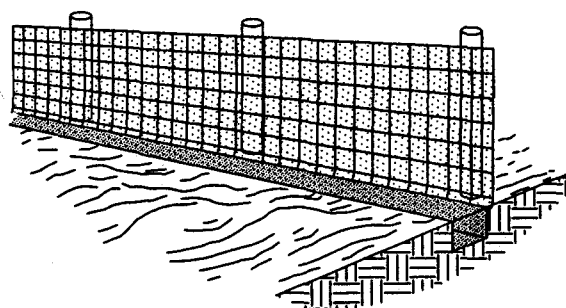
2. STAPLE WIRE FENCING TO THE POSTS.



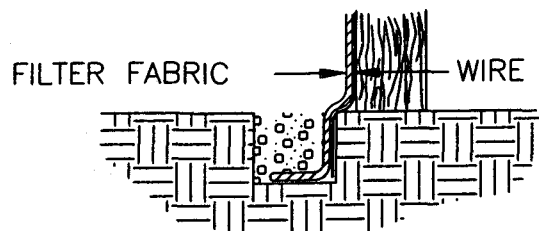
3. ATTACH THE FILTER FABRIC TO THE WIRE FENCE AND EXTEND IT INTO THE TRENCH.



4. BACKFILL AND COMPACT THE EXCAVATED SOIL.

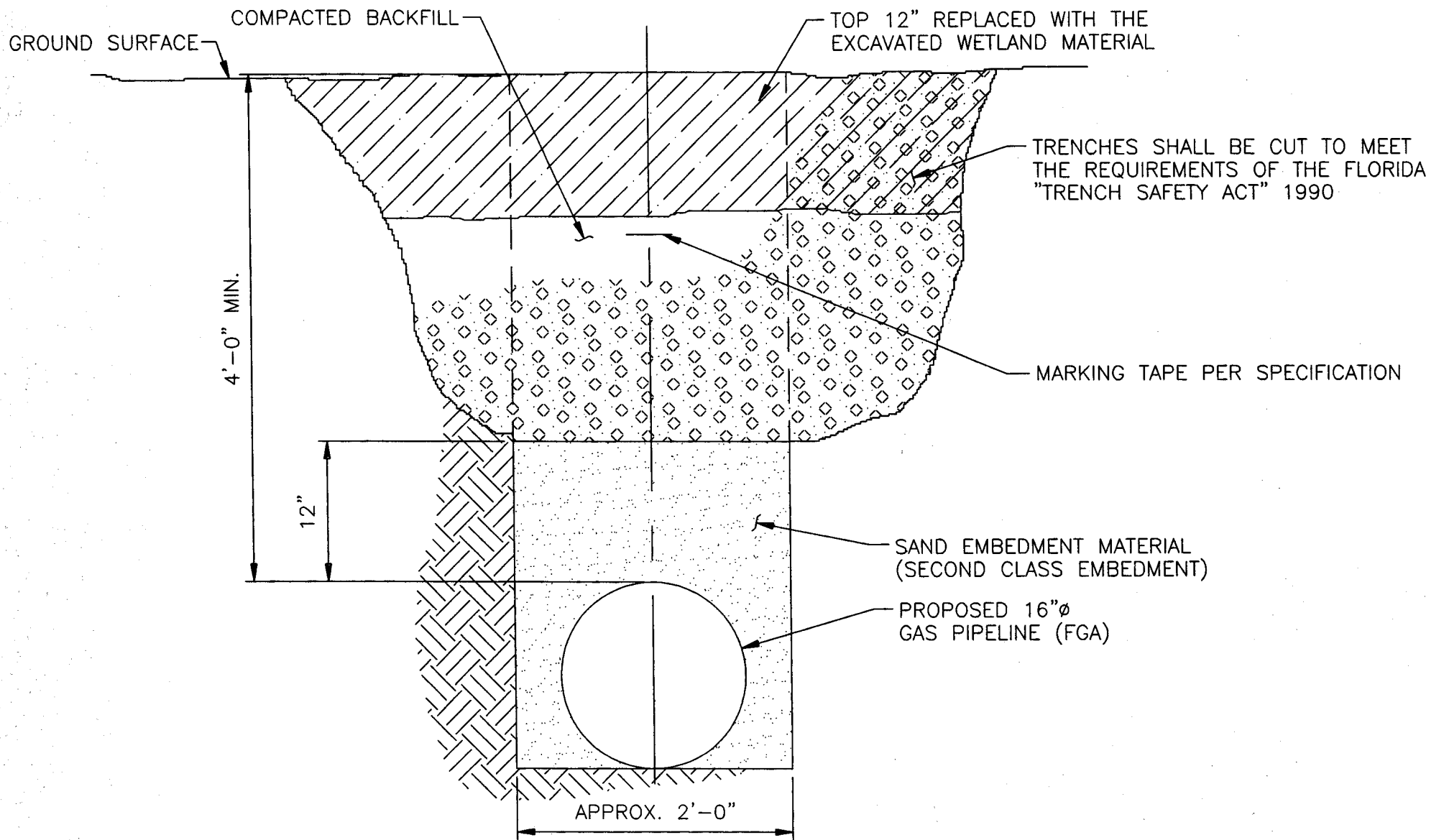


EXTENSION OF FABRIC AND WIRE INTO THE TRENCH



TYPICAL STAKED SILT BARRIERS
NO SCALE

DRAWING 98362-ERP-1A

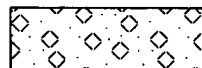


LEGEND

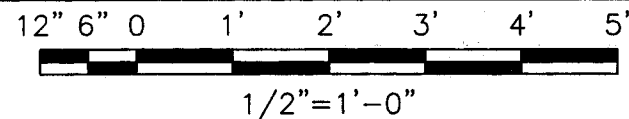


SAND EMBEDMENT

EXISTING SOIL

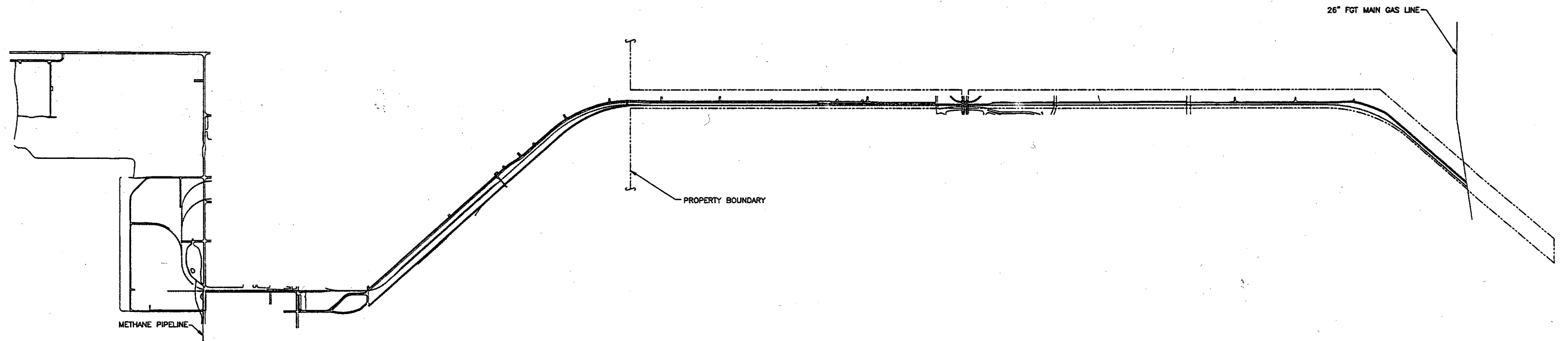


COMPACTED BACKFILL

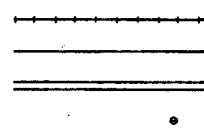


TYPICAL GAS LINE TRENCH EXCAVATION

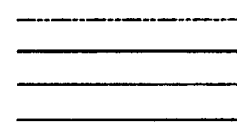
DRAWING 98362-ERP-2



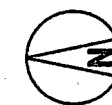
LEGEND



RAILROAD TRACKS
ROAD
DRIVEWAY/TRAIL
RAILROAD CROSSING SIGN



PROPERTY BOUNDARY
GAS PIPELINE
FGT MAIN GAS LINE
METHANE PIPELINE



VICINITY MAP
GAS PIPELINE GENERAL CONSTRUCTION
NO SCALE
DRAWING 98362-ERP-3

LEGEND



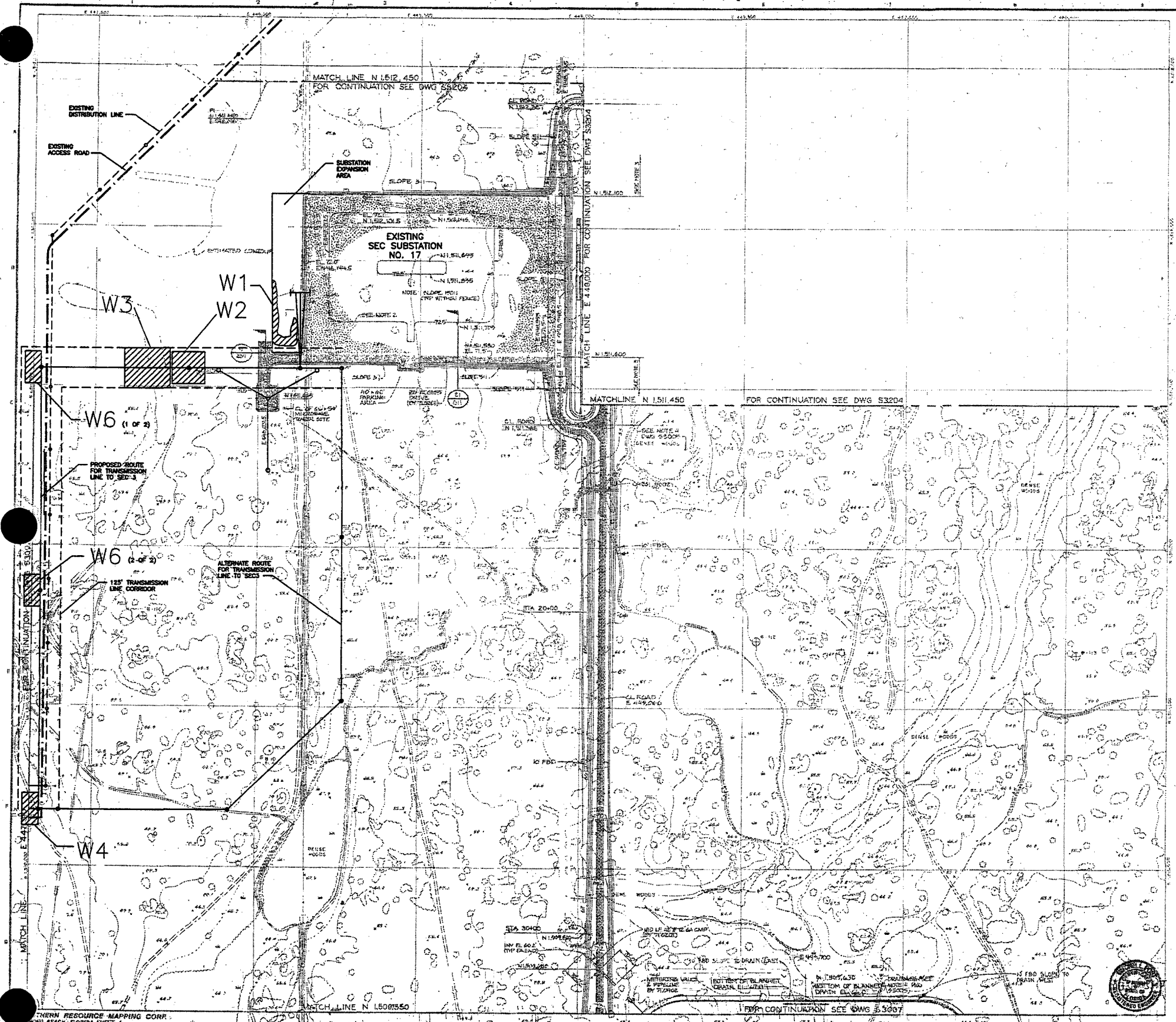
IMPACT AREA	DESCRIPTION
W1	HERBACEOUS WETLAND (0.13 ACRE)
W2	HERBACEOUS WETLAND (0.23 ACRE)
W3	CYPRESS WETLAND (0.40 ACRE)
W4	HERBACEOUS WETLAND (0.11 ACRE)
*W5	HERBACEOUS WETLAND (0.06 ACRE)
W6	SURFACE WATER (TOTAL = 0.23 ACRE)

* IMPACT AREA W5 IS SHOWN ON DRAWING 98362-ERP-4A.

STANTON ENERGY CENTER
COMBINED CYCLE PROJECT

WETLAND IMPACT AREAS

DRAWING 98362-ERP-4



NOTES

1. THE CONTOURS AS SHOWN FOR ROADS REPRESENT THE FIRST EVEN CONTOUR BELOW THE OUTSIDE EDGE OF ROAD SURFACE. REFER TO TYPICAL ROAD SECTIONS ON DWG 53000.
2. THE CONTOURS SHOWN FOR THE SUBSTATION AREA REPRESENT THE TOP OF TYPE 2 FILL SURFACE BY 100% AND DO NOT REPRESENT THE TOP OF CURBED ADJACENT SURFACE BY 75.00%. SEE SECTION U ON DWG 53001.
3. LIMITS OF SUBSTATION ACCESS ROAD SURFACING BY TYPED SUBSTATION AREA SURFACING BY OTHERS.
4. CMP SHALL BE SANDWICHED AND ASPHALT COATED BOTH SIDES.
5. HEAVY-DUTY WATERPROOFED PLYWOOD SHEETS SHALL BE PLACED OVER EACH END OF CMP PRIOR TO BACKFILLING.
6. CMP SECTIONS SHALL BE JOINED WITH STANDARD ASPHALT COATED CORRUGATED BANDS.

UNIT 2 CONTRACTOR NOTE:
DRAWING PROVIDED TO DEFINE EXISTING SITE CONDITIONS. ALSO SEE NOTES ON TITLE SHEET.

**SEC UNIT 2
RELEASED FOR CONST.**
10/1/02

**RELEASED FOR
CONSTRUCTION** *02/26/03*

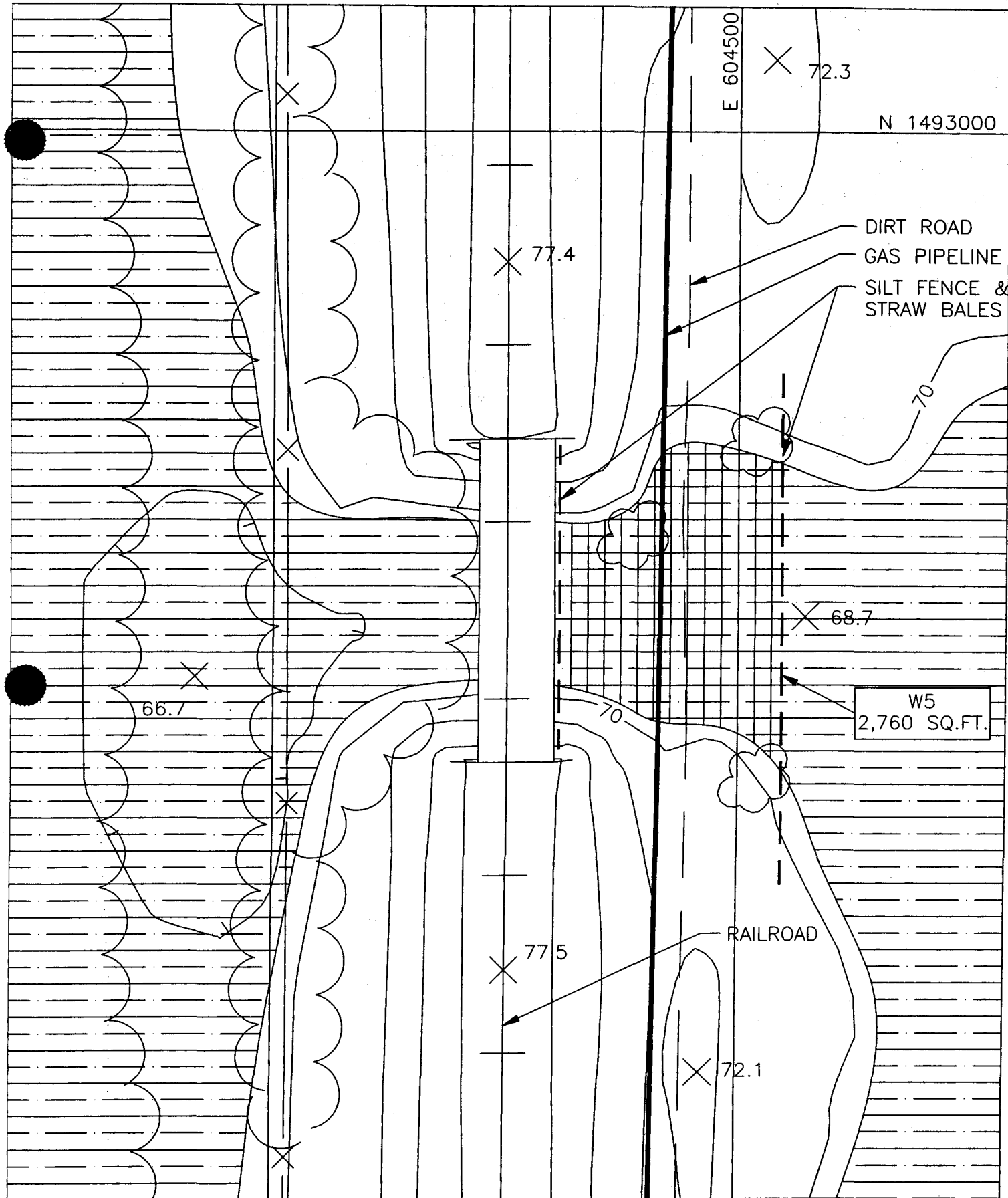
**BLACK & VEATCH
CONSULTING ENGINEERS**

**ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2
SITING - SITE GRADING - PLAN
AREA 3**

8927 - 1STF-S3004

3

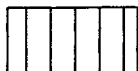
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LEGEND



WETLAND



IMPACTED WETLAND AREA

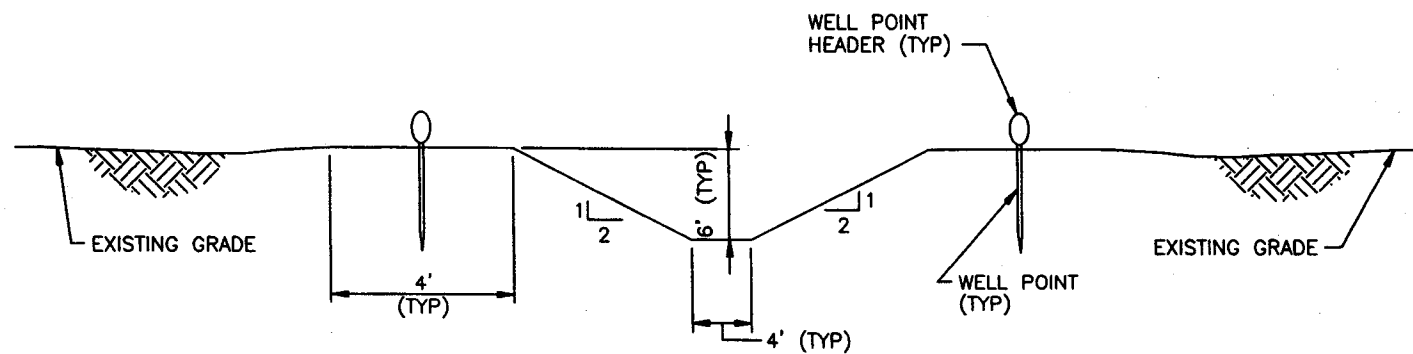


30' 20' 10' 0 30' 60'



1"=30'

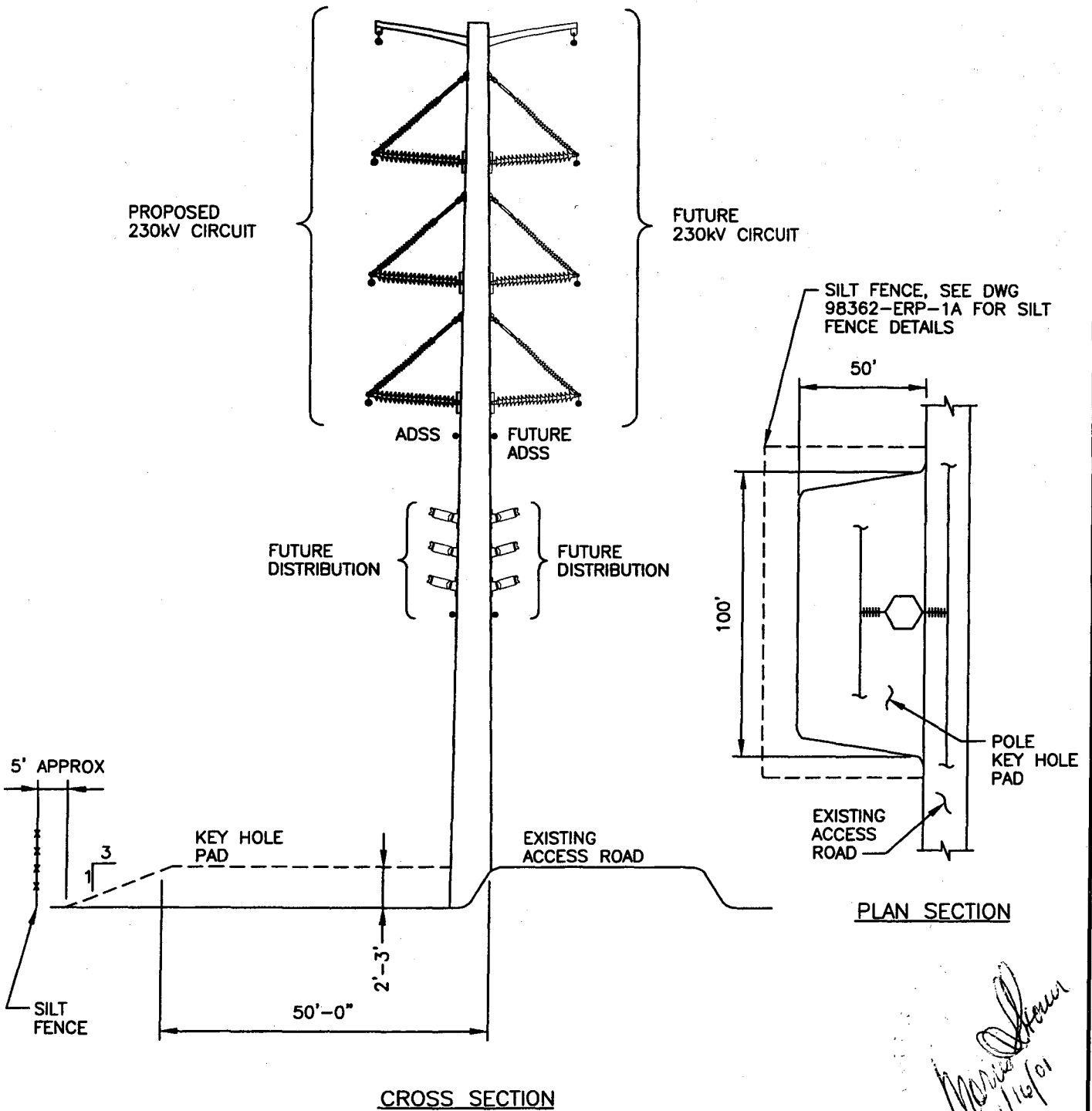
SEC COMBINED CYCLE PROJECT
WETLAND IMPACT AREA W5
DRAWING 98362-ERP-4A



NOTES

1. WELL POINTS ARE TIED INTO PUMP SYSTEMS THAT DISCHARGE INTO THE EXISTING DRAINAGE SYSTEM AFTER PASSING THROUGH HAY BALES AND SILT FENCE.

TYPICAL DEWATERING DETAIL
FIGURE 98362-ERP-5

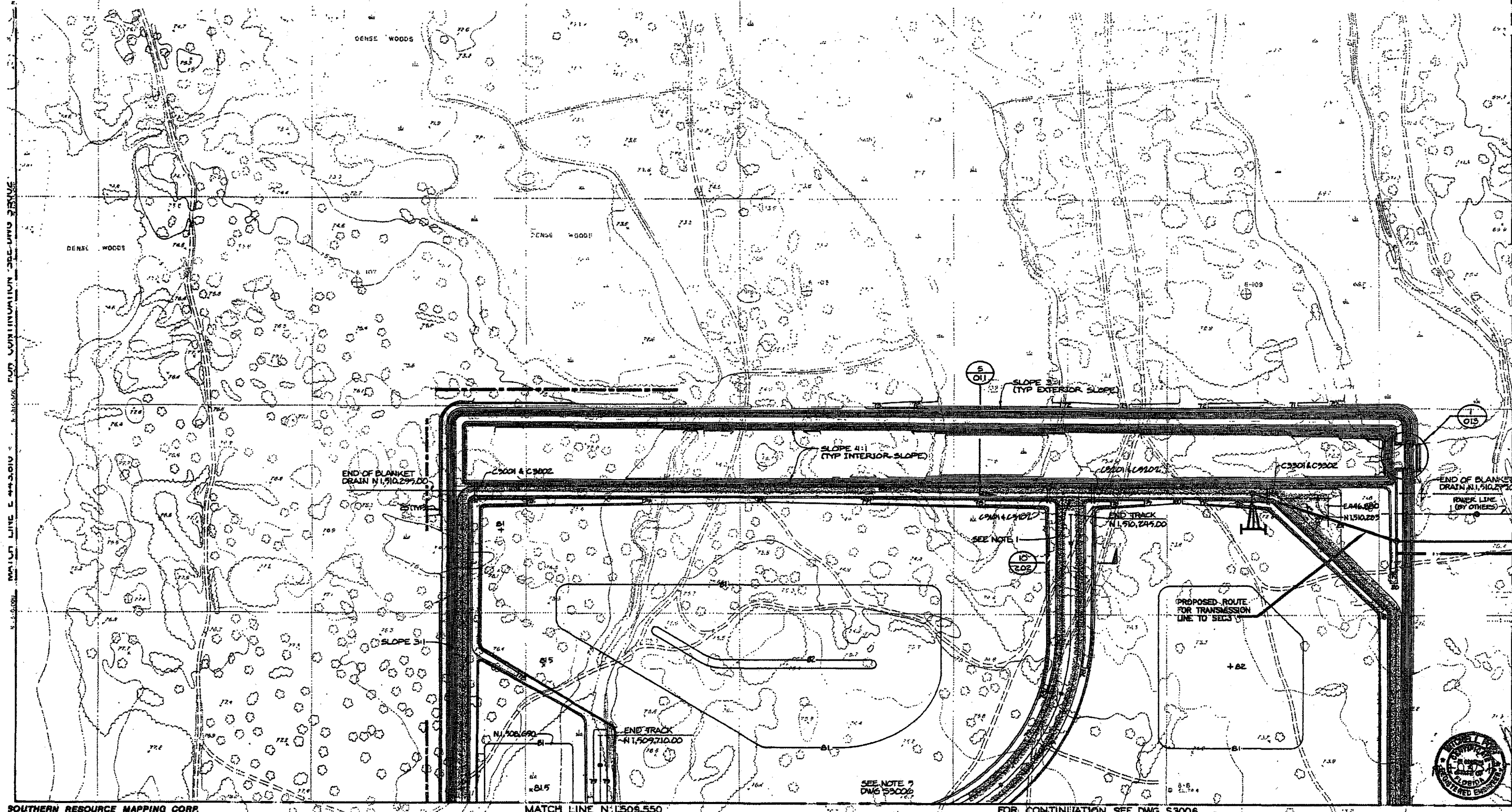


Handwritten signature and date: 1/14/01

 BLACK & VEATCH											
ENGINEER		DRAWN									
CHECKED		DATE		NO		DATE		REVISIONS AND RECORD OF ISSUE		BY	
										CHK	
										APP	
										FLM	
ORLANDO UTILITIES COMMISSION ORLANDO, FLORIDA								PROJECT 98362		DRAWING NUMBER TLINE1	
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TYPICAL TRANSMISSION PROFILE								CODE			
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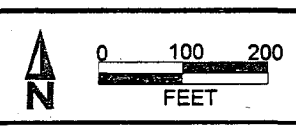


SOUTHERN RESOURCE MAPPING CORP.
DIAMOND BEACH, FLORIDA SHEET 3

MATCH LINE N:1509.550

FOR CONTINUATION SEE DWG S3006

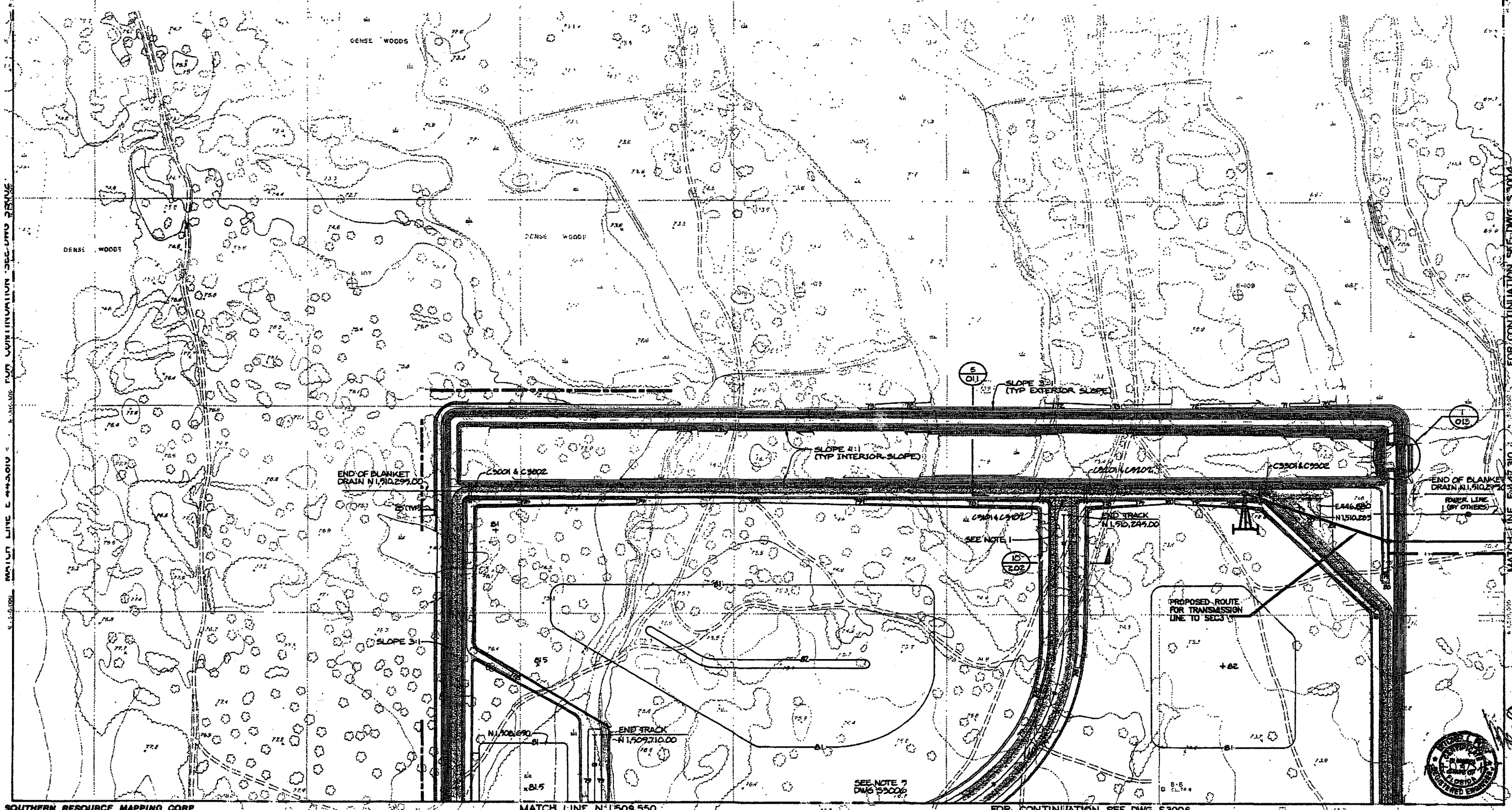
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RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION					
RELEASED FOR CONSTRUCTION					
CONFORMED TO CONSTRUCTION RECORDS					



BLACK & VEATCH
ENGINEER
DATE

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA
STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362	DRAWING NUMBER TLINE2
CAD NO. TLINE2	



SOUTHERN RESOURCE MAPPING CORP.
ORLANDO, FLORIDA SHEET 3

MATCH LINE N 1509.550

FOR CONTINUATION SEE DWG S3006

FOR CONTINUATION SEE DWG S3006

				DRAWING STATUS - PROJECT: 01805				 0 100 200 FEET		 BLACK & VEATCH		ORLANDO UTILITIES COMMISSION ORLANDO, FLORIDA		PROJECT 08362		DRAWING NUMBER TLINE2	
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Appendix A

Wildlife Report

For

**Stanton Energy Center
Combined Cycle Project**

Wildlife and Protected Species Observed at Stanton Energy Center

This report identifies endangered, threatened, and other sensitive species that have the potential to occur within 5 miles of SEC which might reasonably be expected to be affected by the construction and operation of Curtis H. Stanton Energy Center Combined Cycle Unit A (Stanton A). Sensitive species include animals listed as endangered or threatened by the USFWS; species listed by the FFWCC 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.

Endangered and threatened animal species were identified from both state listings and federal listings. Table A-1 shows those animal species that have been observed and that may potentially occur in the area and their current (2000) status. Field surveys for endangered, threatened, other sensitive species, and common species were conducted in 1981. No critical habitat for federally listed species occurs on SEC property. Protected species, which are known to occur on SEC property are discussed below.

Red-cockaded woodpeckers are characterized as inhabiting mature, open pine forests. During the 1981 study, 19 unreported colonies were located on or in the immediate vicinity of SEC property. During surveys, a total of 45 active cavity trees and 35 red-cockaded woodpeckers were observed. Twenty of these active cavity trees occur on SEC property and represent six colonies (refer to Figure A-1). During recent surveys (1999-2000), six colonies and twenty active cavity trees were observed on SEC property. Monitoring required by the Conditions of Certification for Units 1 and 2 will also be performed for Stanton A. The woodpecker habitat is currently managed with periodic prescribed burns. For a more complete discussion of these and other parameters concerning the red-cockaded woodpecker, copies of the *Joint Agency Mitigation Monitoring Plan* for the SEC and the *Progress Report on Red-Cockaded Woodpeckers for the Curtis H. Stanton Energy Center, 1999* can be provided upon request.

Kirtland's warbler may occur as a rare spring or fall transient throughout the southeastern United States. This warbler apparently breeds only in a restricted area of jack pine forest in southern Michigan (Mayfield, 1960). Winter habitat is confined to pinewoods, broadleafed scrub, and Australian pine. This species may occur occasionally in the area during spring and fall migration.

Originally, the Florida black bear ranged throughout Florida. Current populations are mainly centered in Apalachicola, Osceola, and Ocala National Forests, with remnant populations occurring in various parts of the state. According to Hamilton (1943) in

Mammals of the Eastern United States, secluded swamps and forests are areas of preferred habitation for bears. Major areas of occupied habitat within the region are located to the east along the St. John's River and to the north along the Wekiva River. No Florida black bears or bear tracks were observed in the SEC area. The habitat in this area does not appear suitable.

The Florida scrub jay is characteristic of oak scrub communities and is confined mainly to such habitats. Surveys for this bird, conducted in scrub oak communities within SEC boundaries, resulted in an estimate of 4 to 8 family units. Scrub jays were observed in areas adjacent to the Project site.

The eastern indigo snake occurs in peninsular Florida, in a few widely scattered areas of the Georgia Coastal Plain, and in parts of the Florida Panhandle. This snake occupies a wide variety of habitat types. In xeric habitats, the shelter provided by gopher tortoise burrows apparently is a critical factor for the survival of this snake. No indigo snakes were observed on SEC property, although one was sighted within the existing transmission corridor.

The range of the Sherman's fox squirrel is limited to peninsular Florida and, perhaps, southeastern Georgia. Longleaf pine/turkey oak forests seem to be the most frequently used habitat, but sand, scrub, bayheads, pine flatwoods, and borders of cypress swamps are also used. Although optimum habitat is not found onsite, fox squirrels do inhabit some pine flatwoods and various flatwood-wetland ecotones. Too few fox squirrels were sighted to estimate population levels, but two were sighted along the transmission line and four were observed on SEC property; two in pine flatwoods and two in cypress domes.

The gopher tortoise is locally distributed in the Coastal Plain from South Carolina and Florida to eastern Louisiana. In Florida, it may be encountered widely in northern sections with relict, scattered populations occurring in suitable habitats in the south. Preferred habitat consists of old field areas, longleaf pine sandhill, live oak hammock, and beach scrub, usually with abundant herbaceous cover of several types. A few burrows may occur in maintained pastures, mixed swamp, and hydric hammock, but generally these habitats are not utilized. Some important burrow symbionts, which may occur in these same habitats, include the pine snake, indigo snake, Florida mouse, and Florida gopher frog. Other commensals include a large number of invertebrates, eastern diamondback rattlesnake, and various mammals.

Populations of gopher tortoise on SEC property are centered mainly on the higher elevation in the western and south-central portion of the property. In these areas, an average of seven active burrows was recorded per mile of survey.

In the south, bald eagles typically nest estuaries, along large rivers, and around lakes. In Florida, nest sites are usually located in large pines, but also include cypress and mangrove. Bald eagles have been observed east of Project property and along the existing electrical transmission corridors. An eagle's nest was discovered in 2000 on the east side of the makeup pond.

Table A-1
Animals Observed Onsite

Scientific Name	Common Name
<i>Didelphis virginiana</i>	Virginia opossum
<i>Cryptotis parva</i>	Least shrew
<i>Scalopus aquaticus</i>	Eastern mole
<i>Pipistrellus subflavus</i>	Eastern pipistrelle
<i>Eptesicus fuscus</i>	Big brown bat
<i>Lasiurus borealis</i>	Red bat
<i>Lasiurus seminolus</i>	Seminole bat
<i>Lasiurus intermedius</i>	Northern yellow bat
<i>Nycticeius humeralis</i>	Evening bat
<i>Plecotus rafinesquii</i>	Rafinesque's big-eared bat
<i>Tadarida brasiliensis</i>	Brazilian free-tailed bat
<i>Dasypus novemcinctus</i>	Nine-banded armadillo
<i>Sylvilagus floridanus</i>	Eastern cottontail
<i>Sylvilagus palustris</i>	Marsh rabbit
<i>Oryzomys palustris</i>	Rice rat
<i>Reithrodontomys humulis</i>	Harvest mouse
<i>Peromyscus polionotus</i>	Old-field mouse
<i>Peromyscus gossypinus</i>	Cotton mouse
<i>Peromyscus nuttalli</i>	Golden mouse
<i>Sigmodon hispidus</i>	Cotton rat
<i>Neotoma floridana</i>	Eastern woodrat
<i>Sciurus carolinensis</i>	Gray squirrel
<i>Sciurus niger</i>	Fox squirrel
<i>Glaucomys volans</i>	Southern flying squirrel
<i>Vulpes vulpes</i>	Red fox
<i>Urocyon cinereoargenteus</i>	Gray fox
<i>Procyon lotor</i>	Raccoon
<i>Spilogale putorius</i>	Eastern spotted skunk
<i>Mephitis mephitis</i>	Striped skunk
<i>Lynx rufus</i>	Bobcat
<i>Sus scrofa</i>	Wild hog
<i>Odocoileus virginianus</i>	White-tailed deer
<i>Notophthalmus viridescens</i>	Peninsula newt

Table A-1
Animals Observed Onsite

Scientific Name	Common Name
<i>Scaphiopus holbrooki</i>	Eastern spadefoot toad
<i>Rana areolata</i>	Gopher frog
<i>Rana grylio</i>	Pig frog
<i>Rana utricularia</i>	Southern leopard frog
<i>Gastrophryne carolinensis</i>	Eastern narrow-mouth toad
<i>Bufo querecius</i>	Oak toad
<i>Bufo terrestris</i>	Southern toad
<i>Acris gryllus dorsalis</i>	Florida cricket frog
<i>Hyla cinerea cinerea</i>	Green treefrog
<i>Hyla femoralis</i>	Pine woods treefrog
<i>Hyla gratiosa</i>	Barking treefrog
<i>Hyla squirella</i>	Squirrel treefrog
<i>Pseudacris nigrita</i>	Chorus frog
<i>Limnaoedus ocularis</i>	Little grass frog
<i>Terrapene carolina bauri</i>	Florida box turtle
<i>Gopherus polyphemus</i>	Gopher tortoise
<i>Anolis sagrei</i>	Brown anole
<i>Anolis carolinensis</i>	Green anole
<i>Sceloporus undulatus</i>	Fence lizard
<i>Sceloporus woodi</i>	Florida scrub lizard
<i>Leiopisma laterale</i>	Ground skink
<i>Eumeces inexpectatus</i>	Southeastern five-lined skink
<i>Cnemidophorus sexlineatus</i>	Six-lined racerunner
<i>Ophisaurus ventralis</i>	Eastern glass lizard
<i>Ophisaurus longicauda</i>	Slender glass lizard
<i>Nerodia sipedon</i>	Banded water snake
<i>Virginia stripula</i>	Rough earth snake
<i>Storeria occipitomaculata</i>	Red-bellied snake
<i>Storeria dekayi</i>	Brown snake
<i>Heterodon platyrhinos</i>	Eastern hognose snake
<i>Heterodon simus</i>	Southern hognose snake
<i>Diadophis punctatus</i>	Ringneck snake
<i>Farancia abacura</i>	Mud snake
<i>Coluber constrictor</i>	Black racer

Table A-1
Animals Observed Onsite

Scientific Name	Common Name
<i>Pituophis melanoleucus</i>	Pine snake
<i>Masticophis flagellum</i>	Eastern coachwhip
<i>Opheodrys aestivus</i>	Rough green snake
<i>Elaphe obsoleta</i>	Rat snake
<i>Drymarchon corais couperi</i>	Indigo snake
<i>Lampropeltis elapsoides</i>	Scarlet kingsnake
<i>Lampropeltis getulus getulus</i>	Eastern kingsnake
<i>Cemophora coccinea</i>	Scarlet snake
<i>Tantilla relicta relicta</i>	Peninsula crowned snake
<i>Micrurus fulvius</i>	Eastern coral snake
<i>Agkistrodon piscivorus conanti</i>	Florida cottonmouth
<i>Sistrurus miliarius barbouri</i>	Dusky pigmy rattlesnake
<i>Crotalus adamanteus</i>	Eastern diamondback rattlesnake
<i>Bubulcus ibis</i>	Cattle egret
<i>Cathartes aura</i>	Turkey vulture
<i>Coragyps atratus</i>	Black vulture
<i>Accipiter striatus</i>	Sharp-shinned hawk
<i>Buteo jamaicensis</i>	Red-tailed hawk
<i>Buteo lineatus</i>	Red-shouldered hawk
<i>Circus cyaneus</i>	Marsh hawk
<i>Pandion haliaetus</i>	Osprey
<i>Falco sparverius</i>	American kestrel
<i>Colinus virginianus</i>	Bobwhite
<i>Charadrius vociferus</i>	Killdeer
<i>Zenaida macroura</i>	Mourning dove
<i>Columbina passerina</i>	Ground dove
<i>Caprimulgus carolinensis</i>	Chuck-will's widow
<i>Chordeiles minor</i>	Common nighthawk
<i>Colaptes auratus</i>	Common flicker
<i>Dryocopus pileatus</i>	Pileated woodpecker
<i>Centurus carolinus</i>	Red-bellied woodpecker
<i>Melanerpes erythrocephalus</i>	Red-headed woodpecker
<i>Sphyrapicus varius</i>	Yellow-bellied sapsucker
<i>Picoides villous</i>	Hairy woodpecker

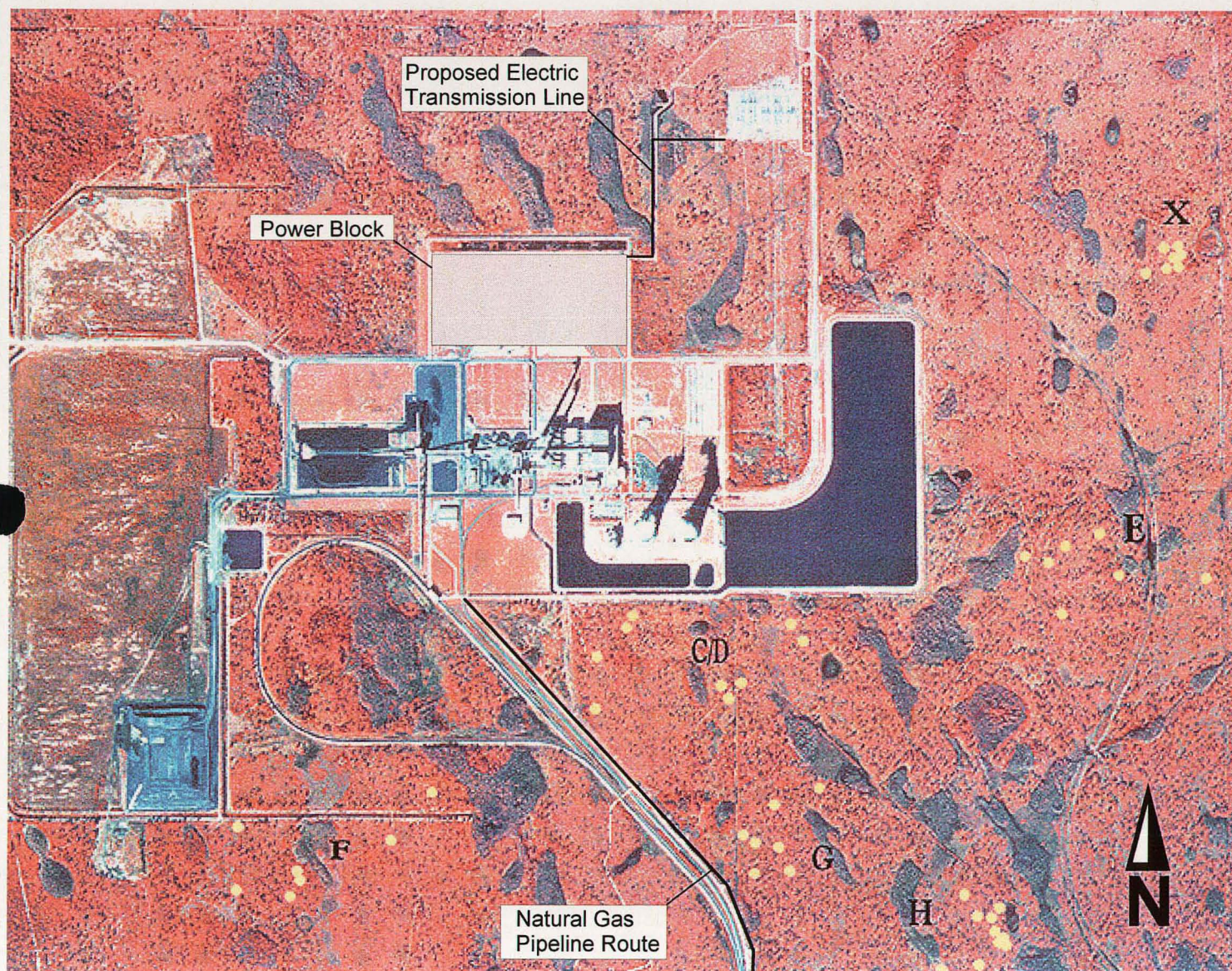
Table A-1
Animals Observed Onsite

Scientific Name	Common Name
<i>Picoides pubescens</i>	Downy woodpecker
<i>Picoides borealis</i>	Red-cockaded woodpecker
<i>Tyrannus tyrannus</i>	Eastern kingbird
<i>Myiarchus crinitus</i>	Great crested flycatcher
<i>Sayornis phoebe</i>	Eastern phoebe
<i>Iridoprocne bicolor</i>	Tree swallow
<i>Cyanocitta cristata</i>	Blue jay
<i>Corvus brachyrhynchos</i>	Common crow
<i>Corvus ossifragus</i>	Fish crow
<i>Parus carolinensis</i>	Carolina chickadee
<i>Parus bicolor</i>	Tufted titmouse
<i>Sitta pusilla</i>	Brown-headed nuthatch
<i>Regulus calendula</i>	Ruby-crowned kinglet
<i>Troglodytes aedon</i>	House wren
<i>Thryothorus ludovicianus</i>	Carolina wren
<i>Mimus polyglottos</i>	Mockingbird
<i>Dumetella carolinensis</i>	Gray catbird
<i>Turdus migratorius</i>	American robin
<i>Sialia sialis</i>	Eastern bluebird
<i>Poliophtila caerulea</i>	Blue-gray gnatcatcher
<i>Lanius ludovicianus</i>	Loggerhead shrike
<i>Vireo griseus</i>	White-eyed vireo
<i>Dendroica coronata</i>	Yellow-rumped warbler
<i>Dendroica pinus</i>	Pine warbler
<i>Dendroica discolor</i>	Prairie warbler
<i>Dendroica palmarum</i>	Palm warbler
<i>Geothlypis trichas</i>	Common yellowthroat
<i>Sturnella magna</i>	Eastern meadowlark
<i>Agelaius phoeniceus</i>	Red-winged blackbird
<i>Quiscalus major</i>	Boat-tailed grackle
<i>Quiscalus quiscula</i>	Common grackle
<i>Piranga rubra</i>	Summer tanager
<i>Cardinalis cardinalis</i>	Cardinal

Table A-1
Animals Observed Onsite

Scientific Name	Common Name
<i>Haliaeetus leucocephalus</i>	Bald eagle
<i>Carduelis tristis</i>	American goldfinch
<i>Pipilo erythrophthalmus</i>	Rufous-sided towhee
<i>Passerculus sandvicensis</i>	Savannah sparrow
<i>Aimophila aestivalis</i>	Bachman's sparrow
<i>Aphelocoma coerulescens</i>	Florida scrub jay
<i>Toxostoma rufum</i>	Brown thrasher
<i>Accipiter cooperii</i>	Cooper's hawk
<i>Meleagris gallopavo</i>	Turkey
<i>Philohela minor</i>	American woodcock
<i>Coccyzus americanus</i>	Yellow-billed cuckoo
<i>Otus asio</i>	Screech owl
<i>Bubo virginianus</i>	Great horned owl
<i>Strix varia</i>	Barred owl
<i>Caprimulgus vociferus</i>	Whip-poor-will
<i>Archilochus colubris</i>	Ruby-throated hummingbird
<i>Catharus guttatus</i>	Hermit thrush
<i>Catharus fuscescens</i>	Veery
<i>Vireo flavifrons</i>	Yellow-throat vireo
<i>Vireo solitarius</i>	Solitary vireo
<i>Vireo olivaceus</i>	Red-eyed vireo
<i>Minotilta varia</i>	Black and white warbler
<i>Protonotaria citrea</i>	Prothonotary warbler
<i>Parula americana</i>	Northern parula
<i>Dendroica dominica</i>	Yellow-throated warbler
<i>Setophaga ruticilla</i>	American redstart
<i>Pipilo erythrophthalmus</i>	Rufous-sided towhee
<i>Melospiza georgiana</i>	Swamp sparrow

Location of Red-Cockaded Woodpecker Clusters and Cavity
Trees (Yellow Spots), Curtis H. Stanton Energy Center, Orlando, Florida, 2000.



Source: Progress Report on Red-Cockaded Woodpeckers for the Curtis H. Stanton
Energy Center, 1999; DeLotelle & Guthrie, Inc.

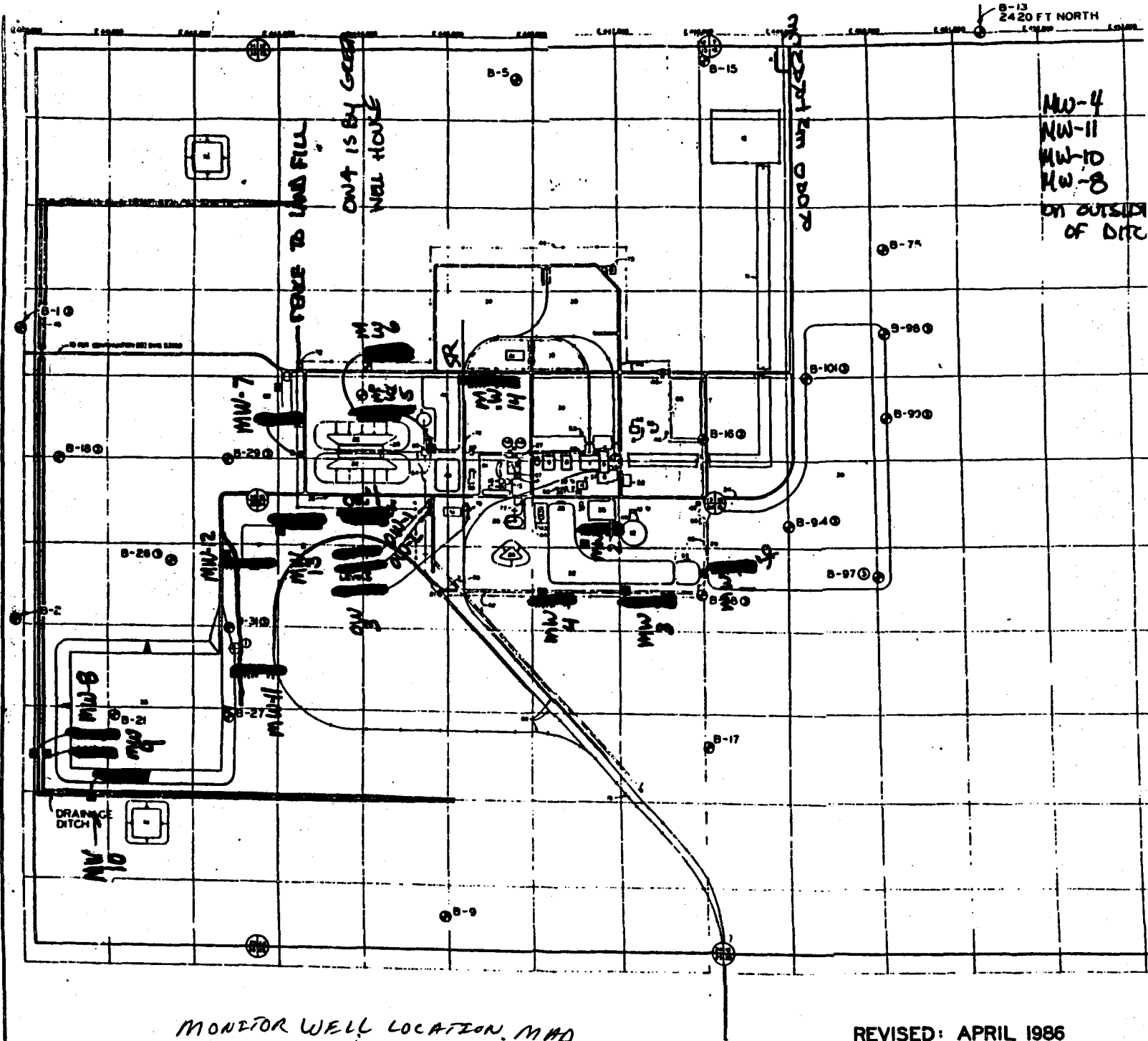
Figure A-1

Appendix B

Monitoring Well Data

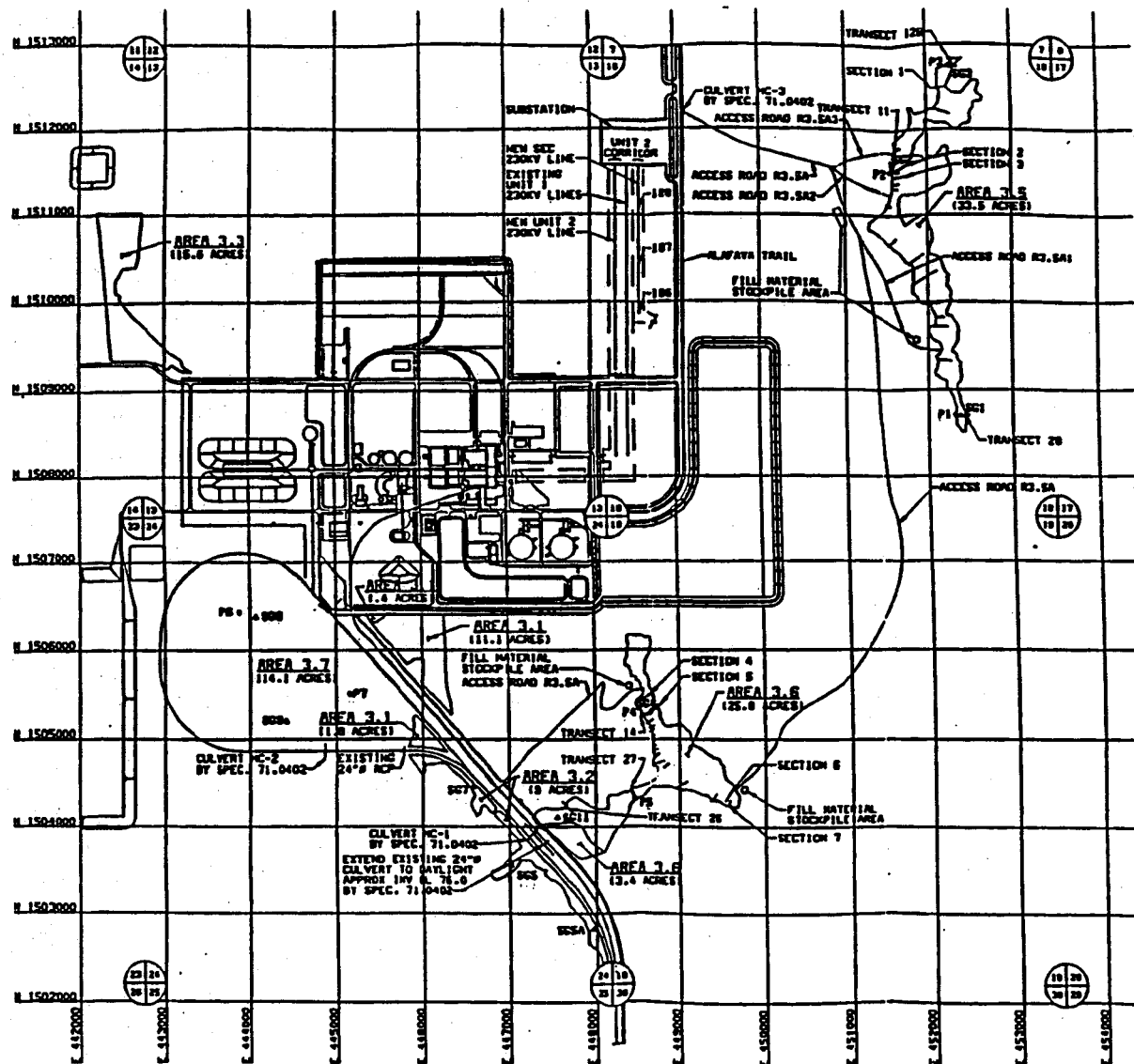
For

Stanton Energy Center



MONITOR WELL LOCATION. MHP

REVISED: APRIL 1986



MITIGATION SITE OVERALL PLAN

FIGURE 1

STAFF GAUGES & PIEZOMETER MAP

MW - 1

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	66.5	53	73	77
Nitrate	10	0.3	0.05	<0.050	<0.050
Total Phosphorus		0.32	0.68	0.34	0.35
Sulfate	250	<1.0	0.5		<0.50
Sulfite		<2.0	<1.0	<2.0	<2.0
Total Dissolved Solids	500	508	490	450	550
Aluminum	0.2	1.3	<0.050	0.37	0.24
Arsenic	0.05	<0.0050	<0.010	0.011	<0.010
Barium	2	0.28	0.33	0.24	0.29
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.010	<0.0050	<0.0050
Calcium		140	140	110	140
Chromium	0.1	<0.010	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	27	33	23	25
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		7.6	8.5	6.7	7.6
Manganese	0.05	0.03	0.036	0.026	0.029
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050
Potassium		1.8	1.8	1.3	1.4
Selenium	0.05	<0.0050	<0.020	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	18	18	15	19
Vanadium	0.049	<0.010	<0.010		<0.010
Zinc	5	<0.050	<0.010	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		7500 umhos/cm	750 umhos/cm	390 umhos/cm	800 umhos/cm
Field pH		6.15 Units	6.07 Units	6.1	6.2 pH Units
Field Temp		21.5 ^C	23.1^C	26.0 Deg C	22.1 Deg C
Color		100 pcu	40 pcu	75 pcu	80 pcu
Turbidity		179 NTU	64 NTU	44 NTU	41 NTU
Water Level		10.42 ft	10.53 ft	9.67 ft	8.63 ft
Gross Alpha		5.3+/-1.7 pCi/l	4.4+/-1.4 pCi/l	7.7+/-1.5 pCi/l	5.6+/-1.6 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 1

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	93	92	72	66
Nitrate	10	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.81	0.3	0.32	0.3
Sulfate	250	<0.50	<0.50	<0.50	<0.50
Sulfite		<2.0	<2.0	<2.0	<1
Total Dissolved Solids	500	680	600	580	660
Aluminum	0.2	0.57	0.098	0.59	0.47
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.38	0.31	0.31	0.31
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		160	150	150	130
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	36	28	28	26
Lead	0.015	<0.0050	<0.0050	0.0052	<0.0050
Magnesium		8.6	8.2	8.2	7.9
Manganese	0.05	0.033	0.042	0.029	0.025
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	0.0071	<0.0050	<0.0050	0.025
Potassium		2.2	1.9	2.3	1.5
Selenium	0.05	<0.010	<0.010	0.017	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	20	21	23	20
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	<0.010
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		917 umhos/cm	848 umhos/cm	874 umhos/cm	919 umhos/cm
Field pH		6.2 pH Units	6.0 pH Units	6.3 pH Units	5.9 pH Units
Field Temp		23.3 Deg C	26.2 Deg C	26.5 Deg. C	25.8 Deg. C
Color		300 pcu	250 pcu	250 pcu	120 pcu
Turbidity		120 NTU	30 NTU	15.9 NTU	8.14 NTU
Water Level		8.780 ft	10.5 ft	9.2 ft	9.89 ft
Gross Alpha		5.1+/-1.8 pCi/l	3.3+/- 1.8 pCi/l	3.2 +/-1.6 pCi/l	3.8 +/-1.4 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 1						
1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS						
PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4	
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	
Chloride	250	91	106	102	95.2	
Nitrate	10	<0.050	BDL	BDL	BDL	
Total Phosphorus		0.26	0.35	0.11	0.39	
Sulfate	250	<0.50	BDL	0.39	BDL	
Sulfite		64	1.28	0.64	1.92	
Total Dissolved Solids	500	590	621	535	589	
Aluminum	0.2	3.4	1.61	1.43	0.055	
Arsenic	0.05	<0.010	BDL	0.001	0.002	
Barium	2	0.33	0.336	0.329	0.316	
Beryllium	0.004	<0.0040	BDL	BDL	<0.001	
Cadmium	0.005	<0.0050	0.001	BDL	<0.001	
Calcium		130	167	143	137.1	
Chromium	0.1	0.0098	0.003	BDL	<0.002	
Copper	1	<0.010	0.02	0.02	<0.01	
Iron	0.3	34	1.1	26.5	24.5	
Lead	0.015	<0.0050	0.004	BDL	0.001	
Magnesium		9	7.86	8.1	8.07	
Manganese	0.05	0.048	0.05	0.03	0.04	
Molybdenum	0.035	<0.050	0.005	BDL	0.005	
Nickel	0.1	0.018	0.024	0.006	0.006	
Potassium		2	1.99	2.33	2.09	
Selenium	0.05	<0.010	BDL	BDL	BDL	
Silver	0.1	<0.010	0.001	0.001	<0.001	
Sodium	160	26	27	21	25	
Vanadium	0.049	<0.010				
Zinc	5	0.28	0.01	BDL	0.02	
Mercury	0.002	0.0005	BDL	BDL	BDL	
Conductivity		871 umhos/cm	946 Us	918 Us	870 us	
Field pH		5.7 pH Units	5.68 pH units	5.05 pH units	4.94 pH/units	
Field Temp		26.6 Deg. C	25.6 C	26.1 C	19.4 C	
Color		280 pcu	>30 CU	>30 CU	>30 CU	
Turbidity		39.4 NTU	48 NTU	26.0 NTU	.79NTU	
Water Level		10.3 ft	9.41 ft	8.17 ft	8.51 ft.	
Gross Alpha		5.0 +/-1.5 pCi/l	2.8 +/-2.8 pCi/l	10.8+/-1.7 pCi	34.8+/-5.1pCi/L	
GREEN - laboratory error						
RED - maximum contaminant level						
BDL - Below Detection Limit						

BDL - Below Detection Limit

MW - 1

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	98	99.8	91.3	
Nitrate	10	BDL	BDL	<0.10	
Total Phosphorus		0.61	0.47	0.32	
Sulfate	250	0.117	BDL	0.14	
Sulfite		3.2	4.8	4	
Total Dissolved Solids	500	529	542	663	
Aluminum	0.2	1	0.43	0.6	
Arsenic	0.05	0.006	0.003	0.006	
Barium	2	0.438	0.317	0.55	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		141.8	151	136.6	
Chromium	0.1	<0.002	0.002	BDL	
Copper	1	0.01	0.01	BDL	
Iron	0.3	37.3	27	26	
Lead	0.015	0.006	0.009	0.002	
Magnesium		8.36	8.75	9.74	
Manganese	0.05	0.03	0.05	0.06	
Molybdenum	0.035	<0.005	<.005	0.004	
Nickel	0.1	0.01	0.008	0.007	
Potassium		2.31	3.01	2.56	
Selenium	0.05	BDL	<0.001	0.007	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	29	27.5	24.9	
Vanadium	0.049		<.005		
Zinc	5	0.01	0.12	0.07	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		922 US	924.3 us	942 us	
Field pH		5.8 pH units	6.07 pH units	5.90 pH Units	
Field Temp			25.47 C	26.19 C	
Color		>30 CU	>30 CU	>30 CU	
Turbidity		30 NTU	50 NTU	46 NTU	
Water Level		9.1 ft.	10.67 ft.	8.81 ft.	
Gross Alpha		6.3-/+2pCi/l	4.4+/-2.8 pCi/L	4.5+/-2.8 pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
		value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).			

MW - 2

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	24.7	25	14	18
Nitrate	10	0.03	0.062	<0.050	<0.050
Total Phosphorus		0.81	1.2	0.38	0.21
Sulfate	250	39	37		38
Sulfite		<2.0	<1.0	<2.0	<2.0
Total Dissolved Solids	500	320	320	320	290
Aluminum	0.2	2.1	1.2	2.1	0.74
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010
Barium	2	0.17	0.25	0.21	0.26
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		83	94	61	82
Chromium	0.1	<0.010	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	3	2.7	2.6	2.7
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		2.9	4.5	4.6	5.1
Manganese	0.05	0.01	0.011	0.012	0.014
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050
Potassium		3.1	3.1	2.5	2.7
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	18	17	13	14
Vanadium	0.049	0.018	0.019		<0.010
Zinc	5	<0.050	<0.010	<0.010	<0.10
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		430 umhos/cm	490 umhos/cm	240 umhos/cm	490 umhos/cm
Field pH		6.36 Units	6.06 Units	5.9	6.3 pH Units
Field Temp		20.8 ^ C	23.6 ^ C	25.1 Deg C	23.6 Deg C
Color		50 pcu	30 pcu	25 pcu	10 pcu
Turbidity		46 NTU	91 NTU	0.24 NTU	12 NTU
Water Level		6.38 ft	5.52 ft	4.49 ft	2.93 ft
Gross Alpha		3.9+/-1.0 pCi/l	7.3+/-1.1 pCi/l	8.3+/-1.3 pCi/l	4.2+/-2.9 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 2						
1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS						
PARAMETER	FDEP	QTR 1	QTR 1 DUP	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	28	26	13	10	16
Nitrate	10	<0.050	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.88	0.56	0.29	0.28	0.42
Sulfate	250	46	45	8.6	9.2	29
Sulfite		<2.0	<2.0	<2.0	<2.0	2.6
Total Dissolved Solids	500	350	360	330	360	350
Aluminum	0.2	1.1	1.2	0.27	0.8	3.9
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Barium	2	0.31	0.31	0.13	0.12	0.16
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		88	88	120	130	87
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	3.3	3.6	0.87	0.75	1.7
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		4.7	4.7	2.2	1.9	3.3
Manganese	0.05	0.015	0.015	<0.010	0.011	0.011
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		3.2	3.1	2.2	2.5	2.9
Selenium	0.05	<0.010	<0.010	<0.010	0.011	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	14	14	9.4	11	14
Vanadium	0.049	0.014	0.015	<0.010	<0.010	<0.010
Zinc	5	<0.010	0.017	<0.010	<0.010	0.011
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		489 umhos/cm	489 umhos/cm	536 umhos/cm	602 umhos/cm	504 umhos/cm
Field pH		6.2 pH Units	6.2 pH Units	6.2 pH Units	6.8 pH Units	6.3 pH Units
Field Temp		23.6 Deg C	23.6 Deg C	24.9 Deg C	25.7 Deg. C	25.2 Deg. C
Color		200 pcu	200 pcu	15 pcu	50 pcu	80 pcu
Turbidity		67 NTU	72 NTU	8.7 NTU	9.03 NTU	25.1 NTU
Water Level		3.760 ft	3.760 ft	5.84 ft	4.58 ft	6.18 ft
Gross Alpha		5.9+/-2.2 pCi/l	6.5+/-2.0 pCi/l	<1.4+/-0.9 pCi	3.1 +/-1.2 pCi/	2.7 +/-1.0 pCi/l
GREEN - laboratory error						
RED - maximum contaminant level						

MW - 2

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	8	20.2	11.4	22.1
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.32	0.22	0.05	0.63
Sulfate	250	9.7	41.7	11.7	43.4
Sulfite		1	2.56	1.28	1.92
Total Dissolved Solids	500	340	324	371	265
Aluminum	0.2	<0.050	0.533	0.085	5.1
Arsenic	0.05	<0.010	BDL	BDL	<0.001
Barium	2	0.13	0.239	0.195	0.319
Beryllium	0.004	<0.0040	BDL	BDL	0.002
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		100	92	114	39.5
Chromium	0.1	<0.0050	0.003	0.003	0.002
Copper	1	<0.010	BDL	BDL	0.01
Iron	0.3	0.98	7.25	1.14	2.8
Lead	0.015	<0.0050	0.002	BDL	0.001
Magnesium		2.2	6.11	3	5.57
Manganese	0.05	<0.010	0.02	BDL	0.04
Molybdenum	0.035	<0.050	0.004	BDL	0.002
Nickel	0.1	<0.0050	0.012	BDL	0.006
Potassium		2.4	3.48	2.66	3.71
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	11	18	11.1	20
Vanadium	0.049	<0.010			
Zinc	5	0.011	0.01	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		589 umhos/cm	489 uS	611 Us	581 us
Field pH		6.6 pH Units	6.09 pH Units	6.21pH units	6.01 pH/units
Field Temp		25.7 Deg. C	26.2 C	23.9 C	18.6 C
Color		15 pcu	>30 CU	>30 CU	>30 CU
Turbidity		129 NTU	18 NTU	26 NTU	19.02 NTU
Water Level		6.84 ft	5.41 ft	4.39 ft	4.21 ft.
Gross Alpha		2.4 +/-1.0 pCi/l	3.6+/-2.8 pCi/l	6.6+/-2.3 pCi/l	7+/-2.4 pCi/L
GREEN - laboratory error					
RED - maximum contaminant level					
BDL - Below Detection Limit					

MW - 2

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	23.5	30.6	14.2	
Nitrate	10	0.045	BDL	<0.10	
Total Phosphorus		0.5	0.58	0.59	
Sulfate	250	41.7	52	12.9	
Sulfite		3.2	5	3	
Total Dissolved Solids	500	273	266	364	
Aluminum	0.2	3.42	1.4	1.32	
Arsenic	0.05	0.003	<0.001	0.001	
Barium	2	0.36	0.269	0.5	
Beryllium	0.004	0.001	0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		58.2	50.8	106	
Chromium	0.1	0.003	0.002	BDL	
Copper	1	<0.01	<0.01	BDL	
Iron	0.3	13.4	4	2.82	
Lead	0.015	0.005	0.002	0.002	
Magnesium		7	6.25	2.82	
Manganese	0.05	<0.02	0.03	0.02	
Molybdenum	0.035	<0.005	<0.005	0.003	
Nickel	0.1	0.002	<0.005	BDL	
Potassium		3.83		2.61	
Selenium	0.05	BDL	<0.001	0.005	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	21	22.4	11.5	
Vanadium	0.049		0.013		
Zinc	5	<0.01	0.09	0.04	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		469 US	472.4 us	601 us	
Field pH		5.79 pH units	5.88 pH units	6.46 pH units	
Field Temp			26.02 C	26.59 C	
Color		>30 CU	>30 CU	>30 CU	
Turbidity		14 NTU	20 NTU	17 NTU	
Water Level		5.4 FT	6.08 ft.	5.08 ft.	
Gross Alpha		4.4+/-2.2 pCi/l	.5+/-2.8 pCi/L	1.60+/-2.8pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 3

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 3 DUP	QTR 4	QTR 4 DUP
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	8.4	9.2	4.2	4.2	6.1	5.8
Nitrate	10	<0.02	0.05	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.07	0.034	0.059	0.06	0.035	0.029
Sulfate	250	<1.0	0.5			<0.50	<0.50
Sulfite		<2.0	<1.0	<2.0	<2.0	<2.0	<2.0
Total Dissolved Solids	500	160	190	160	170	92	150
Aluminum	0.2	0.18	0.11	0.13	0.12	0.11	0.1
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010	<0.010
Barium	2	0.055	0.056	0.046	0.046	0.051	0.051
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0050	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		50	56	44	43	37	37
Chromium	0.1	<0.010	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.10	<0.010	<0.010
Iron	0.3	0.48	0.05	0.36	0.36	0.42	0.41
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		1.3	1.6	1.3	1.3	1.4	1.4
Manganese	0.05	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		1.3	1.4	1	1	0.98	1
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	5.3	5.8	4.4	4.5	5.1	5.2
Vanadium	0.049	<0.010	<0.010			<0.010	<0.010
Zinc	5	<0.050	<0.010	<0.10	<0.010	<0.010	0.011
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		244 umhos/cm	270 umhos/cm	220 umhos/cm	220 umhos/cm	210 umhos/cm	220 umhos/cm
Field pH		6.34 units	6.17 Units	6.4	6.4	6.1 pH Units	6.1 pH Units
Field Temp		21.1 ^ C	22.4 ^ C	25.0 Deg. C	25.0 ^ C	23.8 Deg. C	23.9 Deg. C
Color		20 pcu	20 pcu	15 pcu	10 pcu	<5.0 pcu	5.0 pcu
Turbidity		7.10 NTU	7.1 NTU	0.82 NTU	0.70 NTU	0.44 NTU	0.53 NTU
Water Level		7.25 ft	6.67 ft	6.51 ft	6.51 ft	4.75 ft	4.75 ft
Gross Alpha		<1.7+/-1.2 pCi/l	1.7+/-0.8 pCi/l	<1+/-0.7 pCi/l	3.2 +/-0.8 pCi/l	<2+/- 1.5 pCi/l	<1.9+/-1.4 pCi/l
GREEN - laboratory error							
RED - maximum contaminant level							

MW - 3

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	13	6.7	1.6	6.1
Nitrate	10	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.21	<0.010	0.077	0.06
Sulfate	250	<0.50	<0.50	<0.50	<0.50
Sulfite		<2.0	<2.0	<2.0	1.3
Total Dissolved Solids	500	160	160	120	120
Aluminum	0.2	0.36	0.15	0.29	0.48
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.057	0.052	0.055	0.056
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		41	46	41	29
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.9	0.38	0.39	0.43
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		1.5	1.5	1.7	1.6
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		1.2	1.2	1.4	1.1
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	4.6	5.2	5.3	4.9
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	0.024
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		267 umhos/cm	233 umhos/cm	238 umhos/cm	183 umhos/cm
Field pH		6.1 pH Units	5.1 pH Units	6.2 pH Units	5.3 pH Units
Field Temp		22.9 Deg C	24.3 Deg C	26.1 Deg. C	25.4 Deg. C
Color		45 pcu	<5.0 pcu	50 pcu	20 pcu
Turbidity		13 NTU	4.0 NTU	1.74 NTU	3.63 NTU
Water Level		5.530 ft	7.17 ft	5.82 ft	6.53 ft
Gross Alpha		<2.3+/-1.6 pCi/l	3.2+/-1.7 pCi/l	2.3 +/-0.8 pCi/l	1.7 +/-0.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 3

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	5.6	7.44	6.93	6.87
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.011	0.22	0.22	BDL
Sulfate	250	0.53	1.25	0.4	1.63
Sulfite		2.6	3.2	1.3	1.92
Total Dissolved Solids	500	62	64	126	110
Aluminum	0.2	0.27	0.571	0.45	0.378
Arsenic	0.05	<0.010	0.001	0.001	<0.001
Barium	2	0.057	0.246	0.068	0.111
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		13	98.7	28.6	21.5
Chromium	0.1	<0.0050	0.001	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	0.63	6	0.49	0.38
Lead	0.015	<0.0050	0.002	BDL	0.001
Magnesium		1.5	6.14	2.04	1.95
Manganese	0.05	<0.010	0.02	BDL	BDL
Molybdenum	0.035	<0.050	0.005	BDL	0.003
Nickel	0.1	<0.0050	0.003	BDL	BDL
Potassium		0.81	3.61	1.26	1.38
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	4.8	5.8	5	5.4
Vanadium	0.049	<0.010			
Zinc	5	<0.010	BDL	BDL	0.01
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		159 umhos/cm	115 Us	190 Us	190 us
Field pH		5.3 pH Units	5.21 pH units	6.06pH units	5.96 pH units
Field Temp		24.6 Deg. C	25.2 C	24.5 C	19.1 C
Color		10 pcu	10 CU	>30 CU	18 CU
Turbidity		1.85 NTU	1.5 NTU	3.1 NTU	.39 NTU
Water Level		6.25 ft	5.96 ft	5.14 ft	4.92 ft
Gross Alpha		2.6 +/-1.0 pCi/l	0.3+/-0.6 pCi/l	7.0+/-1.7 pCi/l	1.3+/- .9 pCi/L
GREEN - laboratory error					
RED - maximum contaminant level					

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS							
PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 3 DUP	QTR 4	
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	
Chloride	250	13.8	14	15.5	15.6		
Nitrate	10	0.015	BDL	<0.10	<0.10		
Total Phosphorus		<0.05	0.05	0.007	0.05		
Sulfate	250	2.7	1.97	2.3	2.21		
Sulfite		2.6	3.6	2.8	2.8		
Total Dissolved Solids	500	90	77	90	92		
Aluminum	0.2	0.21	0.16	0.17	0.15		
Arsenic	0.05	<0.001	<0.001	0.004	0.001		
Barium	2	0.72	0.057	0.32	0.26		
Beryllium	0.004	<0.001	<0.001	<0.001	<0.001		
Cadmium	0.005	<0.001	<0.001	<0.001	<0.001		
Calcium		16.6	15.8	13.8	14.8		
Chromium	0.1	<0.002	0.002	BDL	0.005		
Copper	1	<0.01	<0.01	BDL	BDL		
Iron	0.3	0.63	0.66	0.46	0.52		
Lead	0.015	0.002	<0.001	0.001	0.001		
Magnesium		2.19	2	1.8	1.89		
Manganese	0.05	<0.02	0.03	BDL	0.02		
Molybdenum	0.035	<0.005	<0.005	0.006	0.003		
Nickel	0.1	<0.001	<0.005	BDL	BDL		
Potassium		1.11	1.11	1.26	1.37		
Selenium	0.05	BDL	0.09	0.057	0.008		
Silver	0.1	<0.001	<0.001	<0.001	<0.001		
Sodium	160	7.9	7.6	7.19	7.29		
Vanadium	0.049		<0.005				
Zinc	5	<0.01	8	0.04	0.04		
Mercury	0.002	BDL	<0.0005	BDL	BDL		
Conductivity		145 US	147.6 us	135 us	135 us		
Field pH		5.41 pH units	5.51 pH units	5.29 pH Units	5.29 pH units		
Field Temp			26.37 c	25.58 C	25.58 C		
Color		18 CU	8 CU	7 CU	8 CU		
Turbidity		2.1 NTU	1.6 NTU	1.9 NTU	2.3 NTU		
Water Level		5.34 FT	6.85 ft	5.25 ft.	5.25 ft.		
Gross Alpha		1.3+/-pCi/l	.8+/-2.8 pCi/L	<2.10+/-2.8pCi/l	1.6+/-2.8 pCi/L		
GREEN - laboratory error							
RED - maximum contaminant level							
value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).							

MW - 4

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	15.3	17	8.8	11
Nitrate	10	<0.02	0.084	<0.050	<0.050
Total Phosphorus		<0.01	0.017	0.011	0.018
Sulfate	250	<1.0	1.6		<0.50
Sulfite		<2.0	2.4	<2.0	<2.0
Total Dissolved Solids	500	48	66	50	58
Aluminum	0.2	0.61	0.31	0.48	0.3
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010
Barium	2	0.037	0.039	0.033	0.035
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		1.8	2.2	1.7	1.7
Chromium	0.1	<0.010	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.81	0.71	0.52	0.54
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		<1.0	1.1	0.89	0.86
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050
Potassium		<1.0	0.99	0.82	0.8
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	6.5	7.3	5.9	6.5
Vanadium	0.049	<0.010	<0.010		<0.010
Zinc	5	<0.050	<0.010	<0.010	0.015
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		60 umhos/cm	125 umhos/cm	60.0 umhos/cm	70.0 umhos/cm
Field pH		4.96 Units	4.67 Units	4.7	5.5 pH Units
Field Temp		20.3 ^ C	2.8 ^ C	24.5 Deg C	21.4 Deg. C
Color		10 pcu	10 pcu	<5.0 pcu	<5.0 pcu
Turbidity		7.20 NTU	10 NTU	2.1 NTU	1.2 NTU
Water Level		7.17 ft	7.01 ft	6.47 ft	4.23 ft
Gross Alpha		0.7+/-0.6 pCi/l	<1.4+/-0.9 pCi/l	1.1+/-0.6 pCi/l	1.6+/-0.8 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 4

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4	QTR 4 DUP
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	10	11	9.5	9.7	9.8
Nitrate	10	<0.050	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		<0.010	0.3	0.054	0.057	<0.05
Sulfate	250	0.68	2.3	0.61	<0.50	<0.50
Sulfite		<2.0	<2.0	<2.0	7	7.7
Total Dissolved Solids	500	57	48	25	54	49
Aluminum	0.2	0.4	0.32	0.31	0.3	0.29
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Barium	2	0.032	0.033	0.036	0.033	0.034
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		1.2	1.4	1.9	1.7	1.8
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.5	0.48	0.51	0.46	0.47
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		0.87	0.93	0.92	0.8	0.83
Manganese	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		0.75	0.91	1.1	0.84	0.82
Selenium	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	5.7	6.6	6.2	5.5	5.6
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	<0.010	0.013
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		66.0 umhos/cm	61.0 umhos/cm	62.0 umhos/cm	60.0 umhos/cm	60.0 umhos/cm
Field pH		5.3 pH Units	4.7 pH Units	5.0 pH Units	5.3 pH Units	5.2 pH Units
Field Temp		22.8 Deg C	23.2 Deg C	24.7 Deg. C	25.4 Deg. C	25.4 Deg. C
Color		15 pcu	<5.0 pcu	20 pcu	10 pcu	5.0 pcu
Turbidity		6.2 NTU	0.70 NTU	0.720 NTU	2.12 NTU	2.14 NTU
Water Level		5.010 ft	7.08 ft	5.81 ft	6.71 ft	6.71 ft
Gross Alpha		0.7 +/-0.4 pCi/l	0.8 +/-0.6 pCi/l	1.7 +/-0.7 pCi/l	1.2 +/-0.4 pCi/l	1.2 +/-0.4 pCi/l
GREEN - laboratory error						
RED - maximum contaminant level						

MW - 4

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	8.8	10.5	9.8	9.01
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		<0.010	0.06	BDL	BDL
Sulfate	250	1.6	0.93	0.7	239
Sulfite		2.6	4.5	2.5	1.92
Total Dissolved Solids	500	34	33	55	54
Aluminum	0.2	0.27	0.044	0.27	0.321
Arsenic	0.05	<0.010	0.002	BDL	<0.001
Barium	2	0.033	0.049	0.033	0.035
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		1.6	15.7	1.22	0.59
Chromium	0.1	<0.0050	BDL	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	0.5	0.42	0.5	0.52
Lead	0.015	<0.0050	0.001	BDL	BDL
Magnesium		0.85	1.51	0.95	1.37
Manganese	0.05	<0.010	BDL	BDL	0.02
Molybdenum	0.035	<0.050	0.007	BDL	BDL
Nickel	0.1	<0.0050	0.002	0.001	0.002
Potassium		0.69	0.99	1.07	1.02
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	5.5	6.9	5.16	5.8
Vanadium	0.049	<0.010			
Zinc	5	0.011	BDL	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		66.0umhos/cm	62 Us	60 Us	61 us
Field pH		5.5 pH Units	4.80 pH units	4.77pH units	4.71 pH units
Field Temp		25.1 Deg. C	25.3 C	23.7 C	19.1 C
Color		10 pcu	12 CU	12 CU	6 CU
Turbidity		1.62 NTU	1.0 NTU	1.0 NTU	.62 NTU
Water Level		6.63 ft	6.13 ft	4.89 ft	4.81 ft
Gross Alpha		1.4 +/-0.5 pCi/l	1.1 +/-0.9 pCi/l	2.3 +/-1.0 pCi/l	.6 +/- .6 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					
BDL - Below Detection Limit					

MW - 4

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	9.33	9.88	9.23	
Nitrate	10	BDL	BDL	<0.10	
Total Phosphorus		<0.05	<0.05	0.07	
Sulfate	250	2.86	2.36	2.22	
Sulfite		2.8	3.2	3.6	
Total Dissolved Solids	500	36	28	38	
Aluminum	0.2	0.46	0.21	0.15	
Arsenic	0.05	<0.001	0.001	0.001	
Barium	2	0.056	0.031	0.15	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		1.81	0.92	1.38	
Chromium	0.1	<0.002	<0.002	BDL	
Copper	1	<0.01	<0.02	BDL	
Iron	0.3	1.18	0.73	0.49	
Lead	0.015	0.002	0.002	0.001	
Magnesium		1.24	1		
Manganese	0.05	0.02	0.03	0.78	
Molybdenum	0.035	<0.005	0.005	BDL	
Nickel	0.1	0.002	0.005	BDL	
Potassium		1.14	0.98	1.03	
Selenium	0.05	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	6.6	6.5	6.49	
Vanadium	0.049		<0.005		
Zinc	5	0.01	0.09	0.02	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		54 US	52.6 US	53 us	
Field pH		4.4 pH units	4.64pH units	4.54 pH units	
Field Temp			30.43 C	25 C	
Color		6 CU	6 CU	8 CU	
Turbidity		1.5	1.5 NTU	1 NTU	
Water Level		5.55 ft	6.85 ft	5.45 ft.	
Gross Alpha		.6+/- .7 pCi/l	1.1+/-2.8 pCi/L	2.3+/-2.8pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).					

MW - 5

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	32.7	13	42	41
Nitrate	10	0.06	0.05	<0.050	<0.050
Total Phosphorus		0.01	0.012	0.011	0.024
Sulfate	250	74	75		90
Sulfite		<2.0	4.8	<2.0	<2.0
Total Dissolved Solids	500	212	250	230	200
Aluminum	0.2	1.2	1.3	1.1	1.1
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010
Barium	2	0.06	0.07	0.069	0.072
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		16	20	20	21
Chromium	0.1	<0.010	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	2.3	2.5	2.3	2.3
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		3.9	4.5	3.9	4.3
Manganese	0.05	<0.010	0.01	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050
Potassium		8.7	9.1	8.7	8.9
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	22	25	22	21
Vanadium	0.049	<0.010	<0.010		<0.010
Zinc	5	<0.050	0.026	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		272 umhos/cm	335 umhos/cm	245 umhos/cm	340 umhos/cm
Field pH		4.65 Units	4.25 Units	4.3	5.1 pH Units
Field Temp		19.8 ^ C	23.4 ^ C	24.8 Deg. C	22.4 Deg. C
Color		30 pcu	30 pcu	35 pcu	20 pcu
Turbidity		10.8 NTU	3.2 NTU	2.0 NTU	1.8 NTU
Water Level		8.40 ft	7.58 ft	6.49 ft	5.74 ft
Gross Alpha		10.3+/-2.2 pCi/l	8.6+/-1.1 pCi/l	8.9+/-0.9 pCi/l	8.7+/-2.1 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 5

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 2 DUP	QTR 3	QTR 3 DUP	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	51	51	44	13	34	38
Nitrate	10	<0.050	<0.050	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.01	<0.010	<0.010	0.054	<0.050	<0.05
Sulfate	250	98	120	120	38	100	100
Sulfite		<2.0	41	51	4	4	7.7
Total Dissolved Solids	500	200	230	240	300	290	280
Aluminum	0.2	1.3	1.3	1.3	1.3	1.3	1.4
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Barium	2	0.074	0.08	0.08	0.083	0.082	0.086
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		22	28	28	27	27	27
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	2.3	2.5	2.5	1.8	1.8	1.6
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		4.4	4.7	4.7	5.3	5.3	5.3
Manganese	0.05	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		10	9.7	10	12	11	10
Selenium	0.05	<0.010	<0.010	<0.010	0.011	0.01	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	19	22	22	17	17	15
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		330 umhos/cm	369 umhos/cm	364 umhos/cm	349 umhos/cm	347 umhos/cm	360 umhos/cm
Field pH		5.0 pH Units	4.5 pH Units	4.5 pH Units	5.0 pH Units	4.9 pH Units	5.3 pH Units
Field Temp		22.3 Deg C	24.7 Deg C	24.7 Deg C	25.4 Deg. C	25.5 Deg. C	25.6 Deg. C
Color		70 pcu	30 pcu	35 pcu	200 pcu	200 pcu	70 pcu
Turbidity		11 NTU	0.71 NTU	0.50 NTU	0.270 NTU	0.290 NTU	2.30 NTU
Water Level		6.230 ft	7.57 ft		6.54 ft	6.54 ft	7.92 ft
Gross Alpha		6.8+/-2.0 pCi/l	10.3+/-1.7 pCi	10.7+/-1.6 pCi	10.1 +/-1.3 pC	9.8 +/-1.3 pCi/l	5.0 +/-0.8 pCi/l
GREEN - laboratory error							
RED - maximum contaminant level							

MW - 5

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	25	33.2	34.6	34.3
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		<0.010	BDL	BDL	BDL
Sulfate	250	86	96.5	124.5	120
Sulfite		5.8	2.6	5.8	7.78
Total Dissolved Solids	500	200	232	251	275
Aluminum	0.2	1.5	0.222	1.32	1.87
Arsenic	0.05	<0.010	0.002	BDL	<0.001
Barium	2	0.078	0.03	0.092	0.837
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		27	1.36	30.1	29.4
Chromium	0.1	<0.0050	0.001	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	1.6	0.52	1.82	1.63
Lead	0.015	<0.0050	0.001	BDL	BDL
Magnesium		5.8	0.89	5.97	7.49
Manganese	0.05	<0.010	BDL	BDL	BDL
Molybdenum	0.035	<0.050	0.004	BDL	0.002
Nickel	0.1	<0.0050	0.001	BDL	0.003
Potassium		10	0.96	12.2	11.7
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	16	18	14	15
Vanadium	0.049	<0.010			
Zinc	5	<0.010	BDL	BDL	BDL
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		370 umhos/cm	364 Us	376 Us	394 us
Field pH		4.5 pH Units	4.53 pH units	4.79pH units	4.82 pH units
Field Temp		25.3 Deg. C	25.7 C	23.6 C	19.1 C
Color		60 pcu	>30 CU	>30 CU	>30 CU
Turbidity		0.790 NTU	3.0 NTU	2.0 NTU	1.24 NTU
Water Level		8.59 ft	7.89 ft	6.34 ft	6.88 ft
Gross Alpha		7.4 +/-1.3 pCi/l	8.3+/-2.2 pCi/l	6.4+/-1.8 pCi/l	10.1+/-2.2 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					
BDL - Below Detection Limits					

MW - 5							
2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS							
PARAMETER	FDEP	QTR 1	QTR 1 DUP	QTR 2	QTR 3	QTR 4	
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	
Chloride	250	37.8	35.3	13	31.2		
Nitrate	10	BDL	BDL	BDL	<0.10		
Total Phosphorus		0.06	<0.05	0.05	0.07		
Sulfate	250	121	151	140	145		
Sulfite		6	6	5	7		
Total Dissolved Solids	500	272	278	279	300		
Aluminum	0.2	1.6	2.4	1.4	1.9		
Arsenic	0.05	<0.001	<0.001	<0.001	0.001		
Barium	2	1.6	0.17	0.091	0.34		
Beryllium	0.004	<0.001	<0.001	<0.001	<0.001		
Cadmium	0.005	<0.001	<0.001	<0.001	<0.001		
Calcium		34.4	36.6	31.8	30.9		
Chromium	0.1	0.002	0.003	<0.002	BDL		
Copper	1	<0.01	<0.01	<0.01	BDL		
Iron	0.3	2.2	4.01	2.06	2.72		
Lead	0.015	0.001	0.002	0.001	0.002		
Magnesium		6.59	7.06	6.56	6.5		
Manganese	0.05	<0.02	<0.02	<0.02	BDL		
Molybdenum	0.035	<0.005	<0.005	<.005	BDL		
Nickel	0.1	0.001	0.001	<.005	0.001		
Potassium		11.2	12.1	8.31	13.8		
Selenium	0.05	BDL	BDL	<0.001	0.003		
Silver	0.1	<0.001	<0.001	<0.001	<0.001		
Sodium	160	20.1	20.4	21.4	21.5		
Vanadium	0.049			<0.005			
Zinc	5	0.02	0.02	0.09	0.04		
Mercury	0.002	BDL	BDL	<0.0005	BDL		
Conductivity		421 US	423 US	456.3 us	489 us		
Field pH		4.25 pH units	4.25 pH units	4.39 pH units	4.17 pH units		
Field Temp				26.41 C	25.94 C		
Color		>30 CU	>30 CU	40 CU	>30 CU		
Turbidity		7 NTU	2.5 NTU	15 NTU	17 NTU		
Water Level		7.63 FT	7.63 FT	8.94 ft	7.34 ft.		
Gross Alpha		8.2+/-2 pCi/l	12+/-2.4 pCi/l	9.6+/-2.8 pCi/L	1.40+/-2.8pCi/L		
GREEN - laboratory error							
RED - maximum contaminant level							
value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).							

value preceding the "U" indicates the limit of detection for that compound, based on the dilution (and moisture content if soil/sediment).

MW - 6

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 1 DUP	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	15.4	14.9	13	9.4	11
Nitrate	10	<0.02	<0.02	<0.050	<0.050	<0.050
Total Phosphorus		0.08	0.07	0.038	<0.010	0.018
Sulfate	250	<1.0	<1.0	<0.50		<0.50
Sulfite		<2.0	<2.0	<1.0	<2.0	<2.0
Total Dissolved Solids	500	48	48	50	42	34
Aluminum	0.2	2	2	0.49	1	0.49
Arsenic	0.05	<0.0050	<0.0050	<0.010	<0.010	<0.010
Barium	2	0.023	0.023	0.02	0.016	0.018
Beryllium	0.004	<0.0040	<0.0040	0.004	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		1.7	1.6	2.2	1.4	1.6
Chromium	0.1	<0.010	<0.010	<0.010	<0.0050	<0.0050
Copper	1	<0.010	<0.010	0.015	<0.010	<0.010
Iron	0.3	0.6	0.49	0.36	0.35	0.32
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		<1.0	<1.0	0.64	0.58	0.6
Manganese	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.010	<0.0050	<0.0050	<0.0050
Potassium		<1.0	<1.0	0.79	0.51	0.5
Selenium	0.05	<0.0050	<0.0050	<0.10	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	6.2	6.2	7.5	5.6	6.1
Vanadium	0.049	<0.010	<0.010	<0.010		<0.010
Zinc	5	<0.050	<0.050	<0.035	<0.010	<0.010
Mercury	0.002	<0.00010	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		53 umhos /cm	54 umhos/cm	58 umhos/cm	60.0 umhos/cm	65.0 umhos/cm
Field pH		4.96 Units	4.94 Units	4.22 Units	4.8	5.3 pH Units
Field Temp		21.1 ^ C	22.4 ^ C	26.8 ^ C	25.5 Deg. C	22.2 Deg. C
Color		150 pcu	40 pcu	20 pcu	10 pcu	10 pcu
Turbidity		27.0 NTU	11.8 NTU	12NTU	6.5 NTU	11 NTU
Water Level		8.33 ft	8.33 ft	7.83 ft	6.69 ft	6.09 ft
Gross Alpha		0.9+/-0.6 pCi/l	0.9+/-0.6 pCi/l	1.3+/-0.6 pCi/l	<0.6+/-0.4 pCi/l	1.4+/-0.7 pCi/l
GREEN - laboratory error						
RED - maximum contaminant level						

MW - 6

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	18	13	11	11
Nitrate	10	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.013	<0.010	<0.050	<0.05
Sulfate	250	<0.50	<0.50	0.63	<0.50
Sulfite		4.5 l	<2.0	<2.0	1.3
Total Dissolved Solids	500	70	48	54	62
Aluminum	0.2	0.61	0.98	0.71	1.4
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.022	0.019	0.019	0.019
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		1.7	1.4	1.6	1.9
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	1	0.39	0.37	0.39
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		0.69	0.67	0.71	0.66
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		0.59	0.55	0.86	0.55
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	6	6.6	6.1	6.3
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	0.026	<0.010	<0.010	0.015
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		64.0 umhos/cm	59.0 umhos/cm	60.0 umhos/cm	60.0 umhos/cm
Field pH		4.9 pH Units	4.4 pH Units	4.7 pH Units	4.7 pH Units
Field Temp		22.4 Deg C	26.5 Deg C	25.8 Deg. C	25.5 Deg. C
Color		75 pcu	<5.0 pcu	40 pcu	20 pcu
Turbidity		25 NTU	7.4 NTU	5.60 NTU	7.21 NTU
Water Level		6.210 ft	7.87 ft	6.14 ft	7.52 ft
Gross Alpha		0.8+/-0.5 pCi/l	1.2+/-0.6 pCi/l	1.2 +/-0.7 pCi/l	1.2 +/-0.4 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 6

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	10	12.5	12.3	11.9
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.029	BDL	BDL	BDL
Sulfate	250	<0.50	0.41	0.36	0.377
Sulfite		1.3	1.28		2.56
Total Dissolved Solids	500	26	50	69	60
Aluminum	0.2	0.74	1.17	10.4	0.88
Arsenic	0.05	<0.010	BDL	BDL	<0.001
Barium	2	0.019	0.016	0.032	0.023
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		1.7	31.4	1.1	0.59
Chromium	0.1	<0.0050	0.001	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	0.36	0.35	0.53	0.28
Lead	0.015	<0.0050	0.002	BDL	BDL
Magnesium		0.67	0.65	0.71	1.3
Manganese	0.05	<0.010	BDL	BDL	BDL
Molybdenum	0.035	<0.050	0.003	BDL	BDL
Nickel	0.1	<0.0050	0.002	0.002	0.001
Potassium		<0.50	0.65	0.84	0.64
Selenium	0.05	<0.010	BDL	0.002	BDL
Silver	0.1	<0.010	0.001	BDL	<0.001
Sodium	160	5.5	7	6.1	6.2
Vanadium	0.049	<0.010			
Zinc	5	<0.010	BDL	BDL	0.01
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		60.0umhos/cm	62 Us	62 Us	65 us
Field pH		4.5pH Units	4.13pH units	4.59 pH Units	4.62 pH units
Field Temp		26.3 Deg. C	25.5 C	25.1 C	4.69 C
Color		10 pcu	18 CU	15 CU	>30 CU
Turbidity		8.41 NTU	6.4 NTU	25.0 NTU	5.24 NTU
Water Level		8.58 ft	8.45 ft	6.06 ft	7.03 ft
Gross Alpha		1.0 +/-0.5pCi/l	1.0+/-0.8pCi/l	3.6+/-1.3pCi/l	2.1+/-1 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					
BDL - Below Detection Limit					

MW - 6

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	13	12.7	12.9	
Nitrate	10	0.026	BDL	<0.10	
Total Phosphorus		<0.05	<0.05	0.05	
Sulfate	250	0.624	0.124	0.66	
Sulfite		2	>2	<2.0	
Total Dissolved Solids	500	43	24	39	
Aluminum	0.2	0.44	0.35	0.4	
Arsenic	0.05	<0.001	<0.001	0.001	
Barium	2	0.027	0.02	0.2	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		1.17	1.46	2.06	
Chromium	0.1	<0.002	<0.002	BDL	
Copper	1	0.01	0.01	BDL	
Iron	0.3	0.43	0.33	0.39	
Lead	0.015	0.002	0.001	0.014	
Magnesium		0.88	0.87	0.77	
Manganese	0.05	<0.02	<0.02	BDL	
Molybdenum	0.035	<0.005	<0.005	BDL	
Nickel	0.1	<0.001	<.005	0.001	
Potassium		0.65	0.7	0.93	
Selenium	0.05	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	7.3	6.5	7.6	
Vanadium	0.049		<.005		
Zinc	5	0.02	0.09	0.03	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		67 uS	63.2 uS	65.5 uS	
Field pH		4.54 pH units	4.59 pH unit	4.49 pH units	
Field Temp			25.21 C	26.94 C	
Color		12 CU	12 CU	4 CU	
Turbidity		4 NTU	1.30 NTU	1.3 NTU	
Water Level		8.13 ft	9.58 ft	7.36 ft.	
Gross Alpha		.5+/- .6 pCi/l	1.4+/-2.8 pCi/L	0.90+/-2.8 pCi/L	
		3			
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound,					
based on the dilution(and moisture content if soil/sediment).					

MW - 7

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	10.7	12	5.9	7.9
Nitrate	10	<0.02	<0.050	<0.050	<0.050
Total Phosphorus		0.26	0.084	0.086	0.068
Sulfate	250	1.2	1.3		1.3
Sulfite		<2.0	<1.0	<2.0	<2.0
Total Dissolved Solids	500	60	62	48	62
Aluminum	0.2	2.5	1.7	1.5	1.1
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010
Barium	2	0.046	0.042	0.025	0.027
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		3	2.6	3.6	2.6
Chromium	0.1	<0.010	<0.010	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.48	0.47	0.29	0.26
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		<1.0	0.75	0.54	0.71
Manganese	0.05	<0.010	0.01	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050
Potassium		<1.0	0.8	0.72	0.7
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	4.3	5.6	3.5	4.3
Vanadium	0.049	<0.010	<0.010		<0.010
Zinc	5	<0.050	0.021	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		45 umhos/cm	55 umhos/cm	60.0 umhos/cm	60.0 umhos/cm
Field pH		5.15 Units	4.52 Units	4.9	5.0 pH Units
Field Temp		19.3 ^ C	24.5 ^ C	25.1 Deg C	21.4 Deg. C
Color		100 pcu	45 pcu	20 pcu	45 pcu
Turbidity		42.0 NTU	54 NTU	8.2 NTU	16 NTU
Water Level		3.84 ft	3.19 ft	2.01 ft	0.510 ft
Gross Alpha		2.1+/-0.8 pCi/l	2.3+/-0.7 pCi/l	0.9+/-0.6 pCi/l	1.8+/-0.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 7

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	7.2	8.8	7.1	8.6
Nitrate	10	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.14	0.076	0.091	0.22
Sulfate	250	0.96	1.3	1.5	<0.50
Sulfite		<2.0	<2.0	<2.0	2.6
Total Dissolved Solids	500	65	48	41	59
Aluminum	0.2	0.42	2.3	0.89	2.2
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.036	0.035	0.019	0.033
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		6.2	3.9	3	2.5
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.28	0.33	0.37	0.34
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		0.55	0.65	0.71	0.69
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		0.89	0.79	1	<0.50
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	3.6	4.3	6.1	3.9
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	<0.010
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		60.0 umhos/cm	52.0 umhos/cm	50.0 umhos/cm	52.0 umhos/cm
Field pH		5.1 pH Units	4.8 pH Units	5.0 pH Units	4.8 pH Units
Field Temp		24.2 Deg C	24.6 Deg C	25.3 Deg. C	24.6 Deg. C
Color		20 pcu	10 pcu	60 pcu	40 pcu
Turbidity		7.8 NTU	18 NTU	11.2 NTU	15.1 NTU
Water Level		1.250 ft	3.39 ft	6.14 ft	3.24 ft
Gross Alpha		<0.8+/-0.6 pCi	1.4+/-0.7 pCi/l	1.4 +/-0.8 pCi/	1.7 +/-0.4 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 7

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	7.6	10.5	8	8.26
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.056	0.11	BDL	0.09
Sulfate	250	1.1	2.21	1.1	1.38
Sulfite		2.6	2.6	2.6	3.84
Total Dissolved Solids	500	30	38	59	54
Aluminum	0.2	1.3	2.93	2.2	0.426
Arsenic	0.05	<0.010	0.001	BDL	<0.001
Barium	2	0.033	0.032	0.037	0.043
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		2.3	2	4	3.47
Chromium	0.1	<0.0050	0.001	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	0.33	0.4	0.3	0.2
Lead	0.015	<0.0050	0.003	BDL	BDL
Magnesium		0.73	0.89	0.54	1.27
Manganese	0.05	<0.010	BDL	BDL	BDL
Molybdenum	0.035	<0.050	0.003	BDL	BDL
Nickel	0.1	<0.0050	0.002	0.002	BDL
Potassium		0.58	0.81	1	0.99
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	4	5.7	4.2	4.5
Vanadium	0.049	<0.010			
Zinc	5	<0.010	0.01	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		52.0umhos/cm	57 Us	54 Us	51 us
Field pH		4.7pH Units	4.21pH units	4.92 pH Units	4.91 pH units
Field Temp		24.9 Deg. C	24.8 C	22.9 C	21 C
Color		15 pcu	20 CU	18 CU	10 CU
Turbidity		10.6 NTU	19 NTU	19 NTU	11NTU
Water Level		4.31 ft	4.29 ft	1.33 ft	2.19 ft
Gross Alpha		2.3 +/-0.6 pCi/l	1.8 +/-1.0 pCi/l	2.1+/-1.0 pCi/l	.9+/--.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					
BDL - Below Detection Limit					

MW - 7

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	8.75	8.38	8.9	
Nitrate	10	0.019	BDL	<0.10	
Total Phosphorus		0.21	0.16	0.13	
Sulfate	250	1.47	1.87	1.79	
Sulfite		2	2.6	0.32	
Total Dissolved Solids	500	44	32	40	
Aluminum	0.2	0.35	0.67	0.6	
Arsenic	0.05	<0.001	<0.001	BDL	
Barium	2	0.045	0.03	0.42	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		3.07	2.51	2.07	
Chromium	0.1	<0.002	<0.002	BDL	
Copper	1	<0.01	<0.01	BDL	
Iron	0.3	0.38	0.33	0.41	
Lead	0.015	0.002	0.001	0.004	
Magnesium		0.88	0.78		
Manganese	0.05	<0.02	<0.02	0.72	
Molybdenum	0.035	<0.005	<.005	BDL	
Nickel	0.1	0.001	<.005	BDL	
Potassium		0.85	0.96	1.15	
Selenium	0.05	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	4.5	4.1	4.95	
Vanadium	0.049		<.005		
Zinc	5	0.01	0.09	0.12	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		59 US	58.3 us	51 us	
Field pH		4.95 pH units	4.93 pH units	4.46 pH units	
Field Temp			24.19 C		
Color		18 CU	18 CU	22 CU	
Turbidity		6.1 NTU	6.4 NTU	6.7 NTU	
Water Level		3.95 FT	5.38 ft		
Gross Alpha		1.6+/- .9 pCi/l	1.5+/-2.5 pCi/L	1.80+/-2.8 pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).					

MW - 8

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	10.8	4.4	12	9.1
Nitrate	10	<0.02	<0.050	<0.050	<0.050
Total Phosphorus		<0.01	<0.010	0.015	0.018
Sulfate	250	<1.0	<1.0	<0.50	<0.50
Sulfite		<2.0	<0.50	<2.0	<2.0
Total Dissolved Solids	500	40	48	16	40
Aluminum	0.2	0.43	0.57	0.3	0.26
Arsenic	0.05	<0.0050	<0.10	<0.010	<0.010
Barium	2	0.012	<0.10	0.014	0.012
Beryllium	0.004	<0.0040	<0.10	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.10	<0.0050	<0.0050
Calcium		<1.0	1.2	0.58	0.35
Chromium	0.1	<0.010	<0.10	<0.0050	<0.0050
Copper	1	<0.010	<0.10	<0.010	<0.010
Iron	0.3	0.6	0.56	0.5	0.39
Lead	0.015	<0.0050	<0.10	<0.0050	<0.0050
Magnesium		<1.0	0.84	0.76	0.71
Manganese	0.05	<0.010	<0.10	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.10	<0.0050	<0.0050
Potassium		<1.0	<0.50	<0.50	<0.50
Selenium	0.05	<0.0050	<0.10	<0.010	<0.010
Silver	0.1	<0.010	<0.10	<0.010	<0.010
Sodium	160	5.5	8.3	5	5.3
Vanadium	0.049	<0.010	<0.10	<0.010	<0.010
Zinc	5	<0.050	<0.10	<0.010	<0.010
Mercury	0.002	<0.00010		<0.00050	<0.00050
Conductivity		42 umhos/cm	45 umhos/cm	50.0 umhos/cm	55.5 umhos/cm
Field pH		4.72 Units	4.36 Units	4.7	5.2 pH Units
Field Temp		22.3 ^ C	25.4 ^ C	24.3 Deg. C	22.1 Deg. C
Color		20 pcu	30 pcu	<5.0 pcu	15 pcu
Turbidity		3.30 NTU	3.8 NTU	0.14 NTU	0.26 NTU
Water Level		7.37 ft	7.63 ft	7.02 ft	6.24 ft
Gross Alpha		1.4+/-0.6 pCi/l	1.6+/-0.6 pCi/l	1.3+/-0.8 pCi/l	1.7+/-0.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 8

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	10	9.5	7.4	10
Nitrate	10	<0.050	<0.050	0.07	<0.050
Total Phosphorus		0.045	<0.010	0.076	<0.050
Sulfate	250	0.76	1.2	0.85	0.54
Sulfite		<2.0	<2.0	<2.0	1.9
Total Dissolved Solids	500	51	37	32	52
Aluminum	0.2	0.66	0.3	0.34	0.34
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.014	0.012	0.011	0.012
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		0.42	40	0.41	0.42
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.44	0.37	0.36	0.44
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		0.76	0.69	0.71	0.88
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		<0.50	<0.20	<0.50	<0.50
Selenium	0.05	0.022	<0.010	0.016	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	5.6	5.6	5.6	6.4
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	0.01	<0.010	<0.010	<0.010
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		51.0 umhos/cm	47.0 umhos/cm	45.0 umhos/cm	53.0 umhos/cm
Field pH		4.8pH Units	4.6 pH Units	4.9 pH Units	5.6 pH Units
Field Temp		23.0 Deg. C	24.5 Deg. C	24.9 Deg. C	29.4 Deg. C
Color		40 pcu	40 pcu	25 pcu	5.0 pcu
Turbidity		4.9 NTU	0.96 NTU	0.950 NTU	1.44 NTU
Water Level		6.900 ft	6.71 ft	5.56 ft	6.49 ft
Gross Alpha		1.7 +/- 0.7 pCi/l	2.0 +/- 0.9 pCi/l	1.7 +/- 0.8 pCi/l	1.9 +/- 0.9 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 8

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	17	16.7	9.4	12.4
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		<0.010	0.07	BDL	BDL
Sulfate	250	1.1	1.05	2.28	2.71
Sulfite		1.3	1.92	1.28	1.92
Total Dissolved Solids	500	64	43	53	63
Aluminum	0.2	0.46	0.354	0.28	0.387
Arsenic	0.05	<0.010	0.002	BDL	<0.001
Barium	2	0.022	0.014	BDL	0.022
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		0.57	1.04	0.83	2.83
Chromium	0.1	<0.0050	0.001	BDL	<0.002
Copper	1	<0.010	0.01	BDL	<0.01
Iron	0.3	0.78	0.92	0.39	0.52
Lead	0.015	<0.0050	0.001	BDL	BDL
Magnesium		1.7	1.42	0.94	1.92
Manganese	0.05	<0.010	BDL	BDL	0.03
Molybdenum	0.035	<0.050	0.003	BDL	BDL
Nickel	0.1	<0.0050	BDL	0.002	BDL
Potassium		<0.50	0.39	0.47	0.36
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	7.3	7.9	5.2	6.3
Vanadium	0.049	<0.010			
Zinc	5	0.011	0.01	BDL	0.01
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		81.0umhos/cm	76 Us	59 Us	60 us
Field pH		5.0 pH Units	5.09 pH units	5.70 pH units	5.44 pH units
Field Temp		25.1 Deg. C	24.7 C	24.4 CS	21.5 C
Color		10 pcu	20 PCU	20 PCU	12 CU
Turbidity		0.570 NTU	2.0 NTU	.75 NTU	.61 NTU
Water Level		7.56 ft	7.38 ft	6.44 ft	6.45 ft
Gross Alpha		2.5 +/-0.7 pCi/	0.3 +/-0.7 pCi/	2.7+/-1 pCi/L	1.2+/- .8 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 8

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	11.1	16.1	15.4	
Nitrate	10	0.009	BDL	<0.10	
Total Phosphorus		0.07	<0.05	0.05	
Sulfate	250	1.61	1.42	4.3	
Sulfite		2	3.6	4.8	
Total Dissolved Solids	500	34	26	39	
Aluminum	0.2	0.29	0.42	0.44	
Arsenic	0.05	<0.001	<0.001	0.001	
Barium	2	0.024	0.017	0.29	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		0.85	0.42	0.92	
Chromium	0.1	<0.002	<0.002	BDL	
Copper	1	<0.01	<0.01	BDL	
Iron	0.3	0.86	0.66	0.62	
Lead	0.015	0.002	0.001	BDL	
Magnesium		1.01	1.49	1.03	
Manganese	0.05	<0.02	<0.02	BDL	
Molybdenum	0.035	<0.005	<0.005	BDL	
Nickel	0.1	<0.001	<0.005	BDL	
Potassium		0.31	0.54	0.83	
Selenium	0.05	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	6.1	6.8	7.15	
Vanadium	0.049		<0.005		
Zinc	5	0.02	0.09	0.03	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		66 US	70.7 us	68 us	
Field pH		4.51 pH units	4.5 pH units	4.32 pH units	
Field Temp			25.24 C	25.9 C	
Color		14 CU	12 CU	8 CU	
Turbidity		2 NTU	.76 NTU	.7 NTU	
Water Level		6.98 FT	8.19 ft	11.95 ft.	
Gross Alpha		2.1+/-1 pCi/l	1.1+/-pCi/L	2.60+/-2.8 pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
		value preceding the "U" indicates the limit of detection for that compound,			
		based on the dilution(and moisture content if soil/sediment).			

MW - 9

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	10.3	3	9	7.7
Nitrate	10	<0.02	<0.050	<0.050	<0.050
Total Phosphorus		0.08	0.02	0.014	<0.010
Sulfate	250	3.2	<1.0	2.5	3
Sulfite		<2.0	3.2	<2.0	<2.0
Total Dissolved Solids	500	42	42	42	44
Aluminum	0.2	0.38	0.57	0.34	0.32
Arsenic	0.05	<0.0050	<0.10	<0.010	<0.010
Barium	2	0.012	<0.10	0.011	0.012
Beryllium	0.004	<0.0040	<0.10	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.10	<0.0050	<0.0050
Calcium		<1.0	1.3	0.42	0.44
Chromium	0.1	<0.010	<0.10	<0.0050	<0.0050
Copper	1	<0.010	<0.10	<0.010	<0.010
Iron	0.3	0.71	0.56	0.47	0.44
Lead	0.015	<0.0050	0.1	<0.0050	<0.0050
Magnesium		<1.0	1.1	1.1	1.1
Manganese	0.05	<0.010	<0.10	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.10	<0.0050	<0.0050
Potassium		<1.0	<0.50	<0.50	<0.50
Selenium	0.05	<0.0050	<0.10	<0.010	<0.010
Silver	0.1	<0.010		<0.010	<0.010
Sodium	160	4.9	7.3	4.2	4.6
Vanadium	0.049	<0.010	<0.10	<0.010	<0.010
Zinc	5	<0.050	<0.10	<0.010	<0.010
Mercury	0.002	<0.00010		<0.00050	<0.00050
Conductivity		48 umhos/cm	45 umhos/cm	50.0 umhos/cm	60.0 umhos/cm
Field pH		4.67 Units	4.56 Units	4.9	6.0 pH Units
Field Temp		22.7 ^ C	25.5 ^ C	26.0 Deg. C	22.7 Deg. C
Color		20 pcu	25 pcu	5.0 pcu	15 pcu
Turbidity		1.99 NTU	1.9 NTU	0.27 NTU	0.88 NTU
Water Level		6.06 ft	8.32 ft	7.77 ft	6.89 ft
Gross Alpha		1.0+/-0.6 pCi/l	1.0+/-0.6 pCi/l	0.7+/-0.6 pCi/l	1.8+/-0.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 9

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	8.8	9.5	7.7	8.6
Nitrate	10	<0.050	<0.050	0.07	<0.050
Total Phosphorus		0.056	<0.010	0.078	<0.050
Sulfate	250	2.5	1.2	2.5	2.1
Sulfite		<2.0	<2.0	<2.0	1.3
Total Dissolved Solids	500	19	37	41	49
Aluminum	0.2	0.96	0.3	0.4	0.72
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.013	0.012	0.012	0.01
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		0.45	0.4	0.54	0.51
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.57	0.37	0.5	0.49
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		1.2	0.69	1.1	1.1
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		0.54	<0.20	<0.50	<0.50
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	5.1	5.6	6.6	4.8
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	0.038
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		49.0 umhos/cm	47.0 umhos/cm	54.0 umhos/cm	61.0 umhos/cm
Field pH		5.2 pH Units	4.6 pH Units	5.6 pH Units	4.6 pH Units
Field Temp		23.3 Deg C	24.5 Deg C	25.4 Deg. C	26.0 Deg. C
Color		20 pcu	40 pcu	25 pcu	20 pcu
Turbidity		6.3 NTU	0.96 NTU	0.410NTU	3.64 NTU
Water Level		6.970 ft	6.71 ft	6.39 ft	7.34 ft
Gross Alpha		1.2+/-0.6 pCi/l	<1.0+/-0.7 pCi	1.5 +/-0.8 pCi/l	1.6 +/-0.8 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 9

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	7.3	8.27	5.6	8.79
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		<0.010	0.1	BDL	BDL
Sulfate	250	2.6	3.12	3.81	3.11
Sulfite		1.3	2.6	1.3	1.28
Total Dissolved Solids	500	28	34	51	52
Aluminum	0.2	0.31	0.373	0.488	0.431
Arsenic	0.05	<0.010	0.002	BDL	<0.001
Barium	2	0.022	0.009	0.007	0.011
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		0.44	1.74	0.08	3.31
Chromium	0.1	<0.0050	0.003	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	0.45	0.44	0.38	0.36
Lead	0.015	<0.0050	0.001	BDL	BDL
Magnesium		<0.050	0.95	0.84	1.8
Manganese	0.05	<0.010	BDL	BDL	BDL
Molybdenum	0.035	<0.050	0.008	BDL	BDL
Nickel	0.1	<0.0050	0.003	BDL	BDL
Potassium		<0.50	0.38	0.4	0.38
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	4.6	5.4	3.9	4.8
Vanadium	0.049	<0.010			
Zinc	5	<0.010	0.01	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		53.0umhos/cm	56 Us	40 Us	38 us
Field pH		5.3 pH Units	5.60 pH units	4.98 pH units	5.02 pH units
Field Temp		25.1 Deg. C	25.2 C	24.7	21.4 C
Color		15 pcu	18 CU	>30 CU	18 CU
Turbidity		1.01 NTU	1.5 NTU	2.5 NTU	2.98 NTU
Water Level		8.24 ft	7.98 ft	7.95ft	30.28 ft
Gross Alpha		1.1 +/-0.5 pCi/l	1.7 +/-0.9 pCi/l	1.8+/- .9 pCi/L	1.3+/- .8 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

	MW - 9	

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS									
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PARAMETER	FDEP	QTR 1	QTR 1 DUP	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	8.12	7.78	8.74	13	
Nitrate	10	0.017	0.01	BDL	<0.10	
Total Phosphorus		0.07	<0.05	<0.05	0.05	
Sulfate	250	2.41	2.32	2.27	7.43	
Sulfite		2.4	2.4	2.3	5	
Total Dissolved Solids	500	36	34	17	35	
Aluminum	0.2	0.28	0.28	0.29	0.6	
Arsenic	0.05	<0.001	<0.001	<0.001	0.001	
Barium	2	0.015	0.014	0.011	0.49	
Beryllium	0.004	<0.001	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	<0.001	
Calcium		0.48	0.48	0.3	0.84	
Chromium	0.1	<0.002	<0.002	<0.002	BDL	
Copper	1	<0.01	<0.01	<0.01	BDL	
Iron	0.3	0.5	0.49	0.41	0.83	
Lead	0.015	0.001	0.001	0.001	0.002	
Magnesium		0.88	1.03	1.09	1.89	
Manganese	0.05	<0.02	<0.02	<0.02	BDL	
Molybdenum	0.035	<0.005	<0.005	<0.005	BDL	
Nickel	0.1	<0.001	<0.001	<0.005	BDL	
Potassium		0.38	0.32	0.62	0.82	
Selenium	0.05	BDL	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	<0.001	
Sodium	160	5.3	5.4	5.2	6.72	
Vanadium	0.049			<0.005		
Zinc	5	0.03	0.01	0.1	0.1	
Mercury	0.002	BDL	BDL	<0.0005	BDL	
Conductivity		45 US	48 US	50.54 US	81.7 us	
Field pH		4.58 pH units	4.37 pH units	4.6 pH units	4.21 pH units	
Field Temp				24.17 C	25.95 C	
Color		18 CU	14 CU	16 cu	6 CU	
Turbidity		1.5 NTU	.7 NTU	.98 NTU	0.4	
Water Level		7.9 FT	7.9 FT	9.07 ft	10.9 ft.	
Gross Alpha		3.2+/-1.1 pCi/l	1.9+/- .9 pCi/l	1.5+/-2.8 pCi/L	2.1+/-pCi/L	
GREEN - laboratory error						
RED - maximum contaminant level						
		value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).				

MW - 10					
1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS					
PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	8.8	2.5	8.1	6.2
Nitrate	10	<0.02	<0.050	<0.050	<0.050
Total Phosphorus		<0.01	0.02	0.016	0.015
Sulfate	250	2.7	<1.0	1.9	2
Sulfite		<2.0	2.8	<2.0	<2.0
Total Dissolved Solids	500	38	42	34	56
Aluminum	0.2	0.29	0.35	0.25	0.21
Arsenic	0.05	<0.0050	<0.10	<0.010	<0.010
Barium	2	0.011	<0.10	<0.010	<0.010
Beryllium	0.004	<0.0040	<0.10	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.10	<0.0050	<0.0050
Calcium		<1.0	1.1	0.25	0.22
Chromium	0.1	<0.010	<0.10	<0.0050	<0.0050
Copper	1	<0.010	<0.10	<0.010	<0.010
Iron	0.3	0.96	0.61	0.46	0.41
Lead	0.015	<0.0050	<0.10	<0.0050	<0.0050
Magnesium		<1.0	0.74	0.61	0.56
Manganese	0.05	<0.010	<0.10	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.10	<0.0050	<0.0050
Potassium		<1.0	<0.50	<0.50	<0.50
Selenium	0.05	<0.0050	<0.10	<0.010	<0.010
Silver	0.1	<0.010	<0.10	<0.010	<0.010
Sodium	160	5.5	7.7	4.5	4.7
Vanadium	0.049	<0.010	<0.10	<0.010	<0.010
Zinc	5	<0.050	<0.10	<0.010	<0.010
Mercury	0.002	<0.00010		0.0005	<0.00050
Conductivity		40 umhos/cm	45 umhos/cm	45.0 umhos/cm	40.0 umhos/cm
Field pH		4.71 Units	4.37 Units	4.8	5.2 pH Units
Field Temp		21.3 ^ C	25.1 ^ C	24.5 Deg. C	20.9 Deg. C
Color		30 pcu	25 pcu	<5.0 pcu	10 pcu
Turbidity		2.90 NTU	1.7 NTU	0.13 NTU	<0.10 NTU
Water Level		5.99 ft	6.38 ft	5.65 ft	4.34 ft
Gross Alpha		1.8 +/-0.7 pCi/	1.4 +/-0.6 pCi/	<0.8 +/-0.6 pC	1.7 +/-0.7 pCi/
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 10

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	6.5	7.6	6.1	6.2
Nitrate	10	<0.050	<0.050	0.03	<0.050
Total Phosphorus		0.016	0.1	0.061	0.072
Sulfate	250	2.3	2.7	2.7	2.1
Sulfite		<2.0	<2.0	<2.0	1.3
Total Dissolved Solids	500	35	32	29	45
Aluminum	0.2	0.35	0.25	0.25	2.7
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.01	0.011	0.011	0.01
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	0.005	<0.0050
Calcium		0.25	0.25	0.27	0.34
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.47	0.47	0.46	0.45
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		0.64	0.71	0.7	0.68
Manganese	0.05	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		<0.50	<0.20	<0.50	<0.50
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	4.9	5.6	5.1	5.8
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	0.034
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		43.0 umhos/cm	48.0 umhos/cm	42.0 umhos/cm	43.0 umhos/cm
Field pH		4.6 pH Units	4.5 pH Units	4.8 pH Units	4.8 pH Units
Field Temp		23.1 Deg C	23.6 Deg C	25.0 Deg. C	24.2 Deg. C
Color		15 pcu	35 pcu	10 pcu	10 pcu
Turbidity		1.4 NTU	0.64 NTU	0.220 NTU	1.32 NTU
Water Level		4.940 ft	5.67 ft	4.96 ft	6.00 ft
Gross Alpha		0.7 +/-0.5 pCi/l	<1.1 +/-0.8 pCi	1.3 +/-0.7 pCi/l	0.7 +/-0.6 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 10

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	5.3	6.37	6.08	5.77
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.028	0.07	BDL	0.06
Sulfate	250	2.8	2.75	2.19	2.29
Sulfite		<0.64	1.28	0.64	0.64
Total Dissolved Solids	500	<20	23	40	37
Aluminum	0.2	0.4	0.232	0.23	0.273
Arsenic	0.05	<0.010	0.002	BDL	<0.001
Barium	2	<0.010	0.008	0.007	0.01
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		0.23	0.5	0.21	0.275
Chromium	0.1	<0.0050	0.002	BDL	<0.002
Copper	1	<0.010	0.01	BDL	<0.01
Iron	0.3	0.42	0.42	0.39	0.45
Lead	0.015	<0.0050	0.001	BDL	BDL
Magnesium		0.66	0.62	0.65	0.99
Manganese	0.05	<0.010	BDL	BDL	BDL
Molybdenum	0.035	<0.050	0.007	BDL	0.003
Nickel	0.1	<0.0050	0.001	0.002	BDL
Potassium		<0.50	0.3	0.37	0.22
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	4.3	5	4.4	4.6
Vanadium	0.049	<0.010			
Zinc	5	<0.010	BDL	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		44.0umhos/cm	43 Us	42 Us	40 us
Field pH		4.8 pH Units	4.89 pH units	4.80 pH units	4.76 pH units
Field Temp		24.1 Deg. C	24.3 C	22.4 C	21.7 C
Color		10 pcu	20 CU	4 CU	16 CU
Turbidity		1.33 NTU	0.85 NTU	.30 NTU	.40 Ntu
Water Level		6.42 ft	6.67 ft	5.82 ft	5.68 ft
Gross Alpha		0.9+/-0.4 pCi/l	1.9 +/-1.0 pCi/l	2.2+/-1pCi/L	1.5+/- .8 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 10

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	6.37	5.68	6.52	
Nitrate	10	BDL	BDL	<0.10	
Total Phosphorus		<0.05	<0.05	0.05	
Sulfate	250	2.44	2.91	2.72	
Sulfite		<2.01	<2	2	
Total Dissolved Solids	500	26	19	25	
Aluminum	0.2	0.27	0.21	0.17	
Arsenic	0.05	<0.001	<0.001	BDL	
Barium	2	0.011	0.009	0.4	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		0.44	0.18	0.6	
Chromium	0.1	<0.002	<0.002	BDL	
Copper	1	<0.01	<0.01	BDL	
Iron	0.3	0.58	0.4	0.39	
Lead	0.015	0.001	0.001	0.001	
Magnesium		0.65	0.87		
Manganese	0.05	<0.02	<0.02	0.59	
Molybdenum	0.035	<0.005	<.005	BDL	
Nickel	0.1	<0.001	<0.005	0.001	
Potassium		0.23	0.49	0.4	
Selenium	0.05	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	4.8	4.2	4.58	
Vanadium	0.049		<.005		
Zinc	5	0.01	0.1	0.03	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		42 US	41.7 US	42 us	
Field pH		4.51 pH units	4.62 pH units	4.13 pH units	
Field Temp			24.58	24.51 C	
Color		12 CU	10 CU	6 CU	
Turbidity		1.5 NTU	.5 NTU	0.49	
Water Level		6.4 FT	7.7 ft	6.7 ft.	
Gross Alpha		1.9+/- .9 pCi/l	1.6+/- pCi/L	2.4+/-2.8 pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).					

MW - 11

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 1 DUP	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	96.6	92.5	86	36	67
Nitrate	10	0.04	0.03	<0.050	<0.050	<0.050
Total Phosphorus		0.39	0.26	0.39	0.15	0.12
Sulfate	250	1.2	<1.0	<1.0	1.6	1.7
Sulfite		<2.0	<2.0	1.2	<2.0	<2.0
Total Dissolved Solids	500	248	232	250	170	250
Aluminum	0.2	4	4.3	1.1	0.4	0.39
Arsenic	0.05	<0.0050	<0.0050	<0.10	<0.010	<0.010
Barium	2	0.15	0.16	0.2	0.056	0.13
Beryllium	0.004	<0.0040	<0.0040	<0.10	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.10	<0.0050	<0.0050
Calcium		28	29	26	41	35
Chromium	0.1	<0.010	<0.010	<0.10	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.10	<0.010	<0.010
Iron	0.3	3.5	2.9	2.6	0.69	1
Lead	0.015	<0.0050	<0.0050	<0.10	<0.0050	<0.0050
Magnesium		2.6	2.6	2.5	1.2	1.8
Manganese	0.05	<0.010	<0.010	<0.10	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.010	<0.10	<0.0050	<0.0050
Potassium		3.6	3.7	<0.50	1.1	3
Selenium	0.05	<0.0050	<0.0050	<0.10	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.10	<0.010	<0.010
Sodium	160	31	32	32	11	23
Vanadium	0.049	<0.010	<0.010	<0.10	<0.010	<0.010
Zinc	5	<0.050	<0.050	<0.10	<0.010	<0.010
Mercury	0.002	<0.00010	<0.00010		<0.00050	<0.00050
Conductivity		330 umhos/cm	340 umhos/cm	310 umhos/cm	170 umhos/cm	390 umhos/cm
Field pH		5.53 Units	5.59 Units	5.12 Units	5.9	6.1 pH Units
Field Temp		21.6 ^ C	23.0 ^ C	25.1 ^ C	26.1 Deg. C	21.5 Deg. C
Color		50 pcu	50 pcu	150 pcu	30 pcu	30 pcu
Turbidity		37 NTU	27 NTU	46 NTU	5.8 NTU	2.7 NTU
Water Level		5.77 ft	5.77 ft	5.64 ft	4.96 ft	4.02 ft
Gross Alpha		1.2 +/-0.6 pCi/l	1.1 +/-0.6 pCi/l	3.9 +/-1.2 pCi/l	<1.3 +/-0.8 pC	<1.5 +/-1.0 pCi/l

GREEN - laboratory error

RED - maximum contaminant level

MW - 11

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	43	200	140	280
Nitrate	10	0.085	<0.050	0.04	<0.050
Total Phosphorus		0.32	0.056	<0.050	0.07
Sulfate	250	2.3	4.8	2.5	3.3
Sulfite		<2.0	<2.0	<2.0	1.9
Total Dissolved Solids	500	220	530	510	800
Aluminum	0.2	0.94	0.95	1	2.7
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.075	0.39	0.37	0.72
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		46	63	53	69
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.73	2.2	2	3.3
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		1.3	3.9	3	4.6
Manganese	0.05	<0.010	0.013	<0.010	0.015
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		2	10	8.3	17
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	12	50	40	66
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	0.018	0.022	<0.010	0.022
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		321 umhos/cm	681 umhos/cm	506 umhos/cm	934 umhos/cm
Field pH		6.1 pH Units	5.5 pH Units	5.1 pH Units	4.8 pH Units
Field Temp		24.1 Deg C	23.9 Deg C	33.8 Deg. C	25.2 Deg. C
Color		75 pcu	55 pcu	30 pcu	20 pcu
Turbidity		39 NTU	7.5 NTU	1.69 NTU	4.82 NTU
Water Level		4.610 ft	5.30 ft	4.24 ft	5.49 ft
Gross Alpha		<1.7+/-1.2 pCi	2.3+/-1.4 pCi/l	2.2 +/-0.7 pCi/l	<2.7+/-1.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 11

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	360	485	17.2	264
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.059	0.15	BDL	BDL
Sulfate	250	4.8	21.9	BDL	3.98
Sulfite		1.9	3.2	1.9	2.56
Total Dissolved Solids	500	780	1084	628	580
Aluminum	0.2	4.5	6.29	1.46	1.02
Arsenic	0.05	<0.010	0.002	BDL	<0.001
Barium	2	0.97	1.84	0.53	0.493
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		82	159	76.2	108.3
Chromium	0.1	<0.0050	0.003	BDL	<0.002
Copper	1	<0.010	0.01	BDL	<0.01
Iron	0.3	4.2	5.2	2.5	2.8
Lead	0.015	<0.0050	0.001	BDL	BDL
Magnesium		5.8	7.38	4.55	6.81
Manganese	0.05	0.02	0.02	BDL	0.02
Molybdenum	0.035	<0.050	0.004	BDL	0.002
Nickel	0.1	<0.0050	0.014	0.003	0.001
Potassium		25	41.4	15.2	11.2
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	80	120	55	54
Vanadium	0.049	<0.010			
Zinc	5	<0.010	0.01	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		1250umhos/cm	1762 Us	910 Us	900 us
Field pH		4.5 pH Units	4.31 pH units	5.22 pH units	5.14 pHunits
Field Temp		24.9 Deg. C	24.1 C	23.5 C	21 C
Color		5.0 pcu	20 CU	12 CU	14 CU
Turbidity		0.980NTU	5.4 NTU	5.5 NTU	.11 NTU
Water Level		6.11 ft	5.69 ft	4.73 ft	4.78 ft
Gross Alpha		11+/-2.6pCi/l	15.6+/-2.3 pCi	7.2+/-1.5 pCi/L	5.9+/-1.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

[illegible][illegible]

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 3 DUP	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	492	571	542	542	
Nitrate	10	BDL	BDL	<0.10	<0.10	
Total Phosphorus		0.11	0.08	0.08	0.1	
Sulfate	250	26.1	85.3	204	204	
Sulfite		2.6	2.4	3.7	3.7	
Total Dissolved Solids	500	1086	1007	1210	2085	
Aluminum	0.2	7.78	6.2	6.6	6.78	
Arsenic	0.05	<0.001	<0.001	0.001	0.002	
Barium	2	1.43	0.999	0.66	0.76	
Beryllium	0.004	0.001	<0.001	<0.001	<0.001	
Cadmium	0.005	0.001	<0.001	<0.001	0.001	
Calcium		148.1	162	193.8	205.2	
Chromium	0.1	<0.002	<0.002	BDL	BDL	
Copper	1	<0.01	<0.01	0.01	0.01	
Iron	0.3	5.96	4.9	5.56	4.5	
Lead	0.015	0.002	0.001	0.001	0.002	
Magnesium		7.47	9.56	7.7	7.77	
Manganese	0.05	0.02	<0.02	0.03	0.03	
Molybdenum	0.035	<0.005	<0.005	0.004	0.019	
Nickel	0.1	0.005	<0.005	0.006	0.004	
Potassium		42	37.1	43	42	
Selenium	0.05	BDL	<0.001	0.025	0.008	
Silver	0.1	<0.001	<0.001	<0.001	<0.001	
Sodium	160	108	116	115	120	
Vanadium	0.049		<0.005			
Zinc	5	0.03	0.11	0.04	0.04	
Mercury	0.002	BDL	<0.0005	BDL	BDL	
Conductivity		1838 US	1911 us	2085 us	2085 us	
Field pH		4.49 pH units	4.31 pH units	4.16 pH units	4.16 pH units	
Field Temp			23.85	25.82 C	25.82 C	
Color		8 CU	18 CU	12 CU	10 CU	
Turbidity		3 NTU	1.65 NTU	1.1 NTU	1.1 NTU	
Water Level		5.69 FT	7.46 ft	5.2 ft.	5.2 ft.	
Gross Alpha		31.1+/-4.3 pCi/l	13.2+/-2.8 pCi/L	6+/-2.8pCi/L	8.6+/-2.8pCi/L	
GREEN - laboratory error						
RED - maximum contaminant level						
		value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).				

MW - 12

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 3 DUP	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	67.8	38	39	39	45
Nitrate	10	0.05	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		<0.01	<0.010	0.012	0.011	0.021
Sulfate	250	210	75	22	22	44
Sulfite		<2.0	<1.0	<2.0	<2.0	<2.0
Total Dissolved Solids	500	414	180	100	86	150
Aluminum	0.2	8.1	2.1	1	1	1.2
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010
Barium	2	0.026	0.012	0.016	0.016	0.025
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		61	17	9.2	9.3	18
Chromium	0.1	<0.010	<0.010	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	2.8	1.4	0.69	0.7	0.66
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		2.4	1.2	2.3	2.3	2.1
Manganese	0.05	0.011	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		18	5.7	2.9	3	5.3
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	24	14	14	15	16
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.050	0.047	<0.010	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050	<0.00050
Conductivity		550 umhos/cm	238 umhos/cm	150 umhos/cm	160 umhos/cm	245 umhos/cm
Field pH		4.08 Units	4.07 Units	4.5	4.3	4.7 pH Units
Field Temp		22.8 ^ C	25.4 ^ C	25.0 Deg. C	25.8 Deg. C	21.5 Deg. C
Color		20 pcu	35 pcu	10 pcu	10 pcu	30 pcu
Turbidity		2.6 NTU	1.9 NTU	0.13 NTU	0.17 NTU	0.12 NTU
Water Level		10.14 ft	9.64 ft	9.23 ft	9.23 ft	7.73 ft
Gross Alpha		8.8 +/-0.8 pCi/	3.7 +/-0.8 pCi/	2.6 +/-0.6 pCi/	1.9 +/-0.5 pCi/	5.3 +/-1.1 pCi/
GREEN - laboratory error						
RED - maximum contaminant level						

MW - 12

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	280	180	66	190
Nitrate	10	0.1	<0.050	<0.050	<0.050
Total Phosphorus		0.011	<0.010	<0.050	<0.050
Sulfate	250	800	480	140	540
Sulfite		4.5 l	<2.0	<2.0	5.8
Total Dissolved Solids	500	1300	690	340	1100
Aluminum	0.2	1.8	13	4.2	16
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.095	0.037	0.054	0.069
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		240	120	4	180
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	4.8	3.4	1.6	4.3
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		6.7	4.4	3.3	6.7
Manganese	0.05	0.029	0.018	<0.010	0.026
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		64	31	13	49
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	91	44	28	75
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	0.043
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		1810 umhos/cm	1030 umhos/cm	462umhos/cm	1480 umhos/cm
Field pH		3.9 pH Units	4.6 pH Units	4.1 pH Units	4.2 pH Units
Field Temp		25.1 Deg C	26.9 Deg C	25.3 Deg. C	25.4 Deg. C
Color		25 pcu	10 pcu	50 pcu	20 pcu
Turbidity		0.25 NTU	0.24 NTU	0.160 NTU	1.67 NTU
Water Level		8.600 ft	9.81 ft	8.41 ft	9.73 ft
Gross Alpha		17.1+/-5.4 pCi	13.3+/-1.7 pCi	4.2 +/-1.0 pCi/	18.7 +/-4.1 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 12

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	67	107	262	207
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.028	0.06	BDL	BDL
Sulfate	250	310	11.7	809	147
Sulfite		2.6	2.56	3.2	3.84
Total Dissolved Solids	500	340	224	1458	1492
Aluminum	0.2	7.3	1.57	13.6	18.9
Arsenic	0.05	<0.010	0.001	BDL	<0.001
Barium	2	0.037	0.41	0.22	0.0781
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		48	10.3	224	253.9
Chromium	0.1	<0.0050	0.002	BDL	<0.002
Copper	1	<0.010	BDL	BDL	0.01
Iron	0.3	1.9	1.62	4	4.6
Lead	0.015	<0.0050	BDL	BDL	0.004
Magnesium		3.3	5.13	8.36	13.1
Manganese	0.05	0.011	0.02	0.02	0.04
Molybdenum	0.035	<0.050	0.004	BDL	0.002
Nickel	0.1	<0.0050	0.004	0.004	0.003
Potassium		15	3.46	48.5	61.7
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	31	48	110	88
Vanadium	0.049	<0.010			
Zinc	5	<0.010	BDL	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		593umhos/cm	417 Us	2304 Us	1750 us
Field pH		4.9 pH Units	4.27 pH units	4.15 pH units	4.06 pH units
Field Temp		25.6 Deg. C	25.2 C	23.3 C	21.1C
Color		5.0 pcu	20 CU	14 CU	16 CU
Turbidity		2.12 NTU	0.50 NTU	4.1 NTU	.41 NTU
Water Level		10.7 ft	10.24 ft	8.61 ft	8.77 ft
Gross Alpha		6.6+/-1.6pCi/l	1.1 +/-1.1 pCi/l	34.4+/-3.1 pCi/l	25.9+/-4.3 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 12

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	248	249	134	
Nitrate	10	BDL	BDL	<0.10	
Total Phosphorus		<0.05	0.05	0.05	
Sulfate	250	609	811	103	
Sulfite		2.6	2.5	4	
Total Dissolved Solids	500	1339	1424	383	
Aluminum	0.2	21.7	25	5.34	
Arsenic	0.05	<0.001	<0.001	0.001	
Barium	2	0.15	0.076	0.28	
Beryllium	0.004	0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		219.6	271	34.2	
Chromium	0.1	0.002	<0.002	BDL	
Copper	1	0.01	0.01	0.01	
Iron	0.3	6.27	6.8	2.22	
Lead	0.015	0.003	0.001	0.001	
Magnesium		10.4	19.4	7.37	
Manganese	0.05	0.04	0.04	0.02	
Molybdenum	0.035	<0.005	<0.005	0.002	
Nickel	0.1	0.004	<0.005	0.002	
Potassium		54.9	47.9	12.8	
Selenium	0.05	BDL	<0.001	0.003	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	94.6	88.2	60	
Vanadium	0.049		0.01		
Zinc	5	0.03	0.11	0.1	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		1999 US	2030 US	718.7 us	
Field pH		3.88 pH units	3.97 pH units	4.09 pH units	
Field Temp			24.4	27.04 C	
Color		18 CU	20 CU	8 CU	
Turbidity		6 NTU	2.05 NTU	4 NTU	
Water Level		10.15 FT	11.75 ft	9.42 ft	
Gross Alpha		23.6+/-3.8 pCi/	15.2+/-2.8 pCi/L	4.2+/-2.8 pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound,					
based on the dilution(and moisture content if soil/sediment).					

MW - 13

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4	QTR 4 DUP
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	32.1	26	20	29	29
Nitrate	10	<0.02	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.07	0.016	0.015	0.015	0.016
Sulfate	250	41	23		25	25
Sulfite		<2.0	<1.0	<2.0	<2.0	<2.0
Total Dissolved Solids	500	136	110	72	96	100
Aluminum	0.2	2.5	1.7	0.91	1.5	1.4
Arsenic	0.05	<0.0050	0.029	<0.010	<0.010	<0.010
Barium	2	0.044	<0.010	0.029	0.039	0.038
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		8.1	5.3	3.1	5.1	5.1
Chromium	0.1	<0.010	<0.010	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	1.4	0.85	0.74	0.96	0.96
Lead	0.015	<0.0050	<0.0050	<0.050	<0.0050	<0.0050
Magnesium		3.7	2.2	2.1	3.2	3.2
Manganese	0.05	0.02	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		1.9	1.4	0.86	1.2	1.2
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	10	9.4	9	11	11
Vanadium	0.049	<0.010	<0.010		<0.010	<0.010
Zinc	5	<0.050	0.11	<0.010	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050	<0.00050
Conductivity		200 umhos/cm	155 umhos/cm	120 umhos/cm	160 umhos/cm	165 umhos/cm
Field pH		4.26 Units	3.98 Units	4.1	4.4 pH Units	4.4 pH Units
Field Temp		24.1 ^ C	27.0 ^ C	26.4 Deg. C	21.9 Deg. C	21.9 Deg. C
Color		20 pcu	40 pcu	15 pcu	25 pcu	25 pcu
Turbidity		2.2 NTU	2.5 NTU	0.23 NTU	<0.10 NTU	<0.10 NTU
Water Level		8.13 ft	7.82 ft	7.07 ft	5.24 ft	5.24 ft
Gross Alpha		14.5 +/-0.8 pCi	11.4 +/-1.8 pCi	5.7 +/-1.6 pCi/l	10 +/-2.0 pCi/l	9.6 +/-2.0 pCi/l
GREEN - laboratory error						
RED - maximum contaminant level						

MW - 13

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4	QTR 4 DUP
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	38	43	41	40	41
Nitrate	10	0.16	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		<0.010	<0.010	0.068	<0.050	<0.050
Sulfate	250	28	41	13	16	15
Sulfite		<2.0	<2.0	<2.0	2.6	
Total Dissolved Solids	500	120	120	120	170	130
Aluminum	0.2	1.6	2.2	1.2	1.3	1.3
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Barium	2	0.049	0.053	0.06	0.054	0.054
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		5.7	7.9	3.7	4.5	4.5
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	1.3	1.4	0.99	1	1.1
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		4.5	4.2	3.3	3.4	3.4
Manganese	0.05	<0.010	0.01	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		1.5	1.7	1.2	1.3	1.2
Selenium	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	13	15	17	15	15
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010	<0.010
Zinc	5	0.01	0.011	<0.010	0.025	<0.010
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		200 umhos/cm	216 umhos/cm	187 umhos/cm	212 umhos/cm	
Field pH		4.0 pH Units	4.0 pH Units	5.2 pH Units	4.2 pH Units	
Field Temp		25.6 Deg C	25.2 Deg C	25.5 Deg. C	26.1 Deg. C	
Color		20 pcu	15 pcu	50 pcu	10 pcu	20 pcu
Turbidity		0.21 NTU	0.30 NTU	0.360 NTU	2.62 NTU	
Water Level		6.350 ft	7.95 ft	6.45 ft	7.82 ft	
Gross Alpha		6.9+/-1.1 pCi/l	11.0+/-2.1 pCi/l	8.1 +/-1.5 p Ci	7.9 +/-1.8 pCi/l	8.7 +/-1.9 pCi/l

GREEN - laboratory error

RED - maximum contaminant level

MW - 13

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	28	29.1	36.1	43.8
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		0.01	0.06	BDL	BDL
Sulfate	250	38	34	23.9	27.3
Sulfite		1.9	2.56	1.92	1.92
Total Dissolved Solids	500	64	102	125	143
Aluminum	0.2	1.9	1.86	1.36	1.91
Arsenic	0.05	<0.010	0.001	BDL	<0.001
Barium	2	0.046	0.42	0.064	0.073
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		7.1	9.42	6.87	5.87
Chromium	0.1	<0.0050	0.002	BDL	<0.002
Copper	1	<0.010	BDL	BDL	<0.01
Iron	0.3	1.2	1.01	1.08	1.16
Lead	0.015	<0.0050	BDL	BDL	0.001
Magnesium		3.4	2.96	3.53	5.69
Manganese	0.05	<0.010	BDL	BDL	BDL
Molybdenum	0.035	<0.050	0.004	BDL	BDL
Nickel	0.1	<0.0050	0.002	0.001	0.001
Potassium		1.1	1.38	1.71	1.36
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	BDL	<0.001
Sodium	160	13	14	15	22
Vanadium	0.049	<0.010			
Zinc	5	<0.010	BDL	BDL	0.02
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		210umhos/cm	199 Us	219 Us	210 us
Field pH		4.2 pH Units	5.84 pH units	4.17 pH units	4.07 pH units
Field Temp		25.7 Deg. C	25.6 C	25.1 C	21 C
Color		15 pcu	18 CU	20 CU	14 CU
Turbidity		2.84 NTU	0.45 NTU	.40 NTU	.34 NTU
Water Level		8.71 ft	8.72 ft	6.59 ft	6.94 ft
Gross Alpha		11.8+/-0.9pCi/l	5.6 +/-1.7 pCi/l	5.1+/-1.4 pCi/l	11.9+/-2.1 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 13

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	46.2	37.8	39.3	
Nitrate	10	BDL	BDL	<0.10	
Total Phosphorus		0.09	<0.05	0.07	
Sulfate	250	83	133	55.3	
Sulfite		2.3	3.2	3.3	
Total Dissolved Solids	500	199	214	146	
Aluminum	0.2	6.14	5.8	3.35	
Arsenic	0.05	<0.001	<0.001	0.001	
Barium	2	0.097	0.089	0.24	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		17.5	19.6	12.9	
Chromium	0.1	<0.002	<0.001	BDL	
Copper	1	<0.01	<0.01	0.01	
Iron	0.3	4.73	1.69	1.22	
Lead	0.015	0.002	0.001	0.001	
Magnesium		6.62	6.04	4.03	
Manganese	0.05	<0.02	<0.02	BDL	
Molybdenum	0.035	<0.005	<.005	0.003	
Nickel	0.1	0.002	<.005	0.001	
Potassium		3.07	3.21	2.19	
Selenium	0.05	BDL	<0.001	0.003	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	20.1	18.3	16.4	
Vanadium	0.049		<0.005		
Zinc	5	<0.01	0.09	0.02	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		380 US	404.6 US	284.6 us	
Field pH		3.79 pH units	3.91 pH units	3.89 pH units	
Field Temp			24.13	27.03 C	
Color		>30 CU	30 CU	16 CU	
Turbidity		7 NTU	.55 NTU	.65 NTU	
Water Level		8.3 FT	9.8 ft	7.8 ft.	
Gross Alpha		29.1+/-2.9 pCi/	14.5+/-2.8 pCi/L	8.4+/-2.8pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound, based on the dilution(and moisture content if soil/sediment).					

MW - 14

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	19.1	13	14	12
Nitrate	10	<0.02	0.05	<0.050	<0.050
Total Phosphorus		<0.01	0.028	0.06	0.015
Sulfate	250	2.4	3.6		8.2
Sulfite		<2.0	1	<2.0	<2.0
Total Dissolved Solids	500	380	380	440	550
Aluminum	0.2	0.38	<0.050	1.9	0.26
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010
Barium	2	0.085	0.092	0.089	0.088
Beryllium	0.004	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		110	120	110	110
Chromium	0.1	<0.010	<0.0050	0.017	<0.0050
Copper	1	0.014	<0.010	<0.010	<0.010
Iron	0.3	1.7	1.7	4.4	1.1
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		3.1	3.6	3.2	3.4
Manganese	0.05	0.017	0.016	0.013	0.014
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	0.013	<0.0050
Potassium		9.1	9.7	8.5	8.7
Selenium	0.05	<0.0050	<0.020	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	5.5	7.9	7.1	5.8
Vanadium	0.049	<0.010	<0.010		<0.010
Zinc	5	<0.050	0.038	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.00050	<0.00050
Conductivity		500 umhos/cm	520 umhos/cm	350 umhos/cm	600 umhos/cm
Field pH		6.69 Units	6.34 Units	6.6	6.7 pH Units
Field Temp		20.4 ^ C	23.8 ^ C	26.7 Deg. C	23.0 Deg. C
Color		150 pcu	170 pcu	550 pcu	80 pcu
Turbidity		12.3 NTU	16 NTU	170 NTU	30 NTU
Water Level		5.50 ft	4.47 ft	3.54 ft	2.71 ft
Gross Alpha		4.6 +/-1.3 pCi/l	3.7 +/-1.1 pCi/l	5.2 +/-1.7 pCi/l	<3.5 +/-2.9 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 14

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	16	19	11	16
Nitrate	10	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		0.014	<0.010	<0.050	<0.050
Sulfate	250	18	19	6.9	24
Sulfite		<2.0	61	<2.0	5.1
Total Dissolved Solids	500	450	390	410	480
Aluminum	0.2	0.17	0.23	0.53	0.36
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.091	0.085	0.06	0.11
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		130	140	120	130
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.55	0.26	0.55	0.73
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		3.7	3.8	5.1	4.5
Manganese	0.05	0.013	0.013	0.19	7.8
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		8.6	8.6	8.5	8.2
Selenium	0.05	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	5.3	5.5	8.6	7.8
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	0.012
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		586 umhos/cm	631 umhos/cm	597 umhos/cm	715 umhos/cm
Field pH		6.5 pH Units	6.2 pH Units	4.9 pH Units	4.9 pH Units
Field Temp		23.0 Deg C	26.4 Deg C	28.4 Deg. C	26.9 Deg. C
Color		180 pcu	70 pcu	180 pcu	100 pcu
Turbidity		30 NTU	19 NTU	11.5 NTU	4.09 NTU
Water Level		3.180 ft	4.63 ft	3.34 ft	4.71 ft
Gross Alpha		2.7+/-1.7 pCi/l	3.4+/-1.3 pCi/l	<1.5+/-0.9pCi/l	<2.0+/-1.2pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 14

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	13	23.3	22.7	28.7
Nitrate	10	<0.050	BDL	BDL	BDL
Total Phosphorus		<0.010	0.06	BDL	BDL
Sulfate	250	6.6	31.8	39.3	1.5
Sulfite		7	8.32	7.04	8.96
Total Dissolved Solids	500	410	509	491	435
Aluminum	0.2	<0.050	0.156	0.18	0.333
Arsenic	0.05	<0.010	0.001	BDL	<0.001
Barium	2	0.1	0.138	0.16	0.17
Beryllium	0.004	<0.0040	BDL	BDL	<0.001
Cadmium	0.005	<0.0050	BDL	BDL	<0.001
Calcium		120	155	117	98.7
Chromium	0.1	<0.0050	0.008	BDL	0.002
Copper	1	<0.010	0.01	BDL	<0.01
Iron	0.3	0.41	1.46	0.27	0.2
Lead	0.015	<0.0050	0.005	BDL	0.003
Magnesium		4	4.89	5.42	5.79
Manganese	0.05	0.018	0.02	BDL	0.04
Molybdenum	0.035	<0.050	0.005	BDL	0.002
Nickel	0.1	<0.0050	0.01	BDL	0.005
Potassium		8.6	8.92	1.03	13.8
Selenium	0.05	<0.010	BDL	BDL	BDL
Silver	0.1	<0.010	BDL	<0.001	<0.001
Sodium	160	8.4	14	8.4	14
Vanadium	0.049	<0.010			
Zinc	5	0.014	0.01	BDL	0.06
Mercury	0.002	<0.00050	BDL	BDL	BDL
Conductivity		681umhos/cm	735 Us	714 Us	725 us
Field pH		6.2 pH Units	5.63 pH units	6.17 pH units	6.19 pH units
Field Temp		24.5 Deg. C	25.9 C	26.4 C	19 C
Color		120 pcu	>30 CU	>30 CU	>30 CU
Turbidity		0.940NTU	10 NTU	6.8 NTU	3.12 NTU
Water Level		5.58 ft	8.47 ft	3.44 ft	3.98 ft
Gross Alpha		3.4+/-1.3 pCi/l	3.7 +/-2.5 pCi/l	6.5+/-1.5pCi/L	10.6+/-2.5 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

MW - 14

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	28.8	28.5	25.3	
Nitrate	10	0.029	BDL	<0.10	
Total Phosphorus		0.09	0.05	0.1	
Sulfate	250	46.5	50.8	45.1	
Sulfite		4.8	2.8	6	
Total Dissolved Solids	500	485	489	481	
Aluminum	0.2	1.6	0.33	3.24	
Arsenic	0.05	0.001	<0.001	0.001	
Barium	2	0.17	0.154	0.57	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		245.4	136	117.7	
Chromium	0.1	0.005	0.005	0.003	
Copper	1	0.02	0.01	0.01	
Iron	0.3	15.3	0.72	4.32	
Lead	0.015	0.002	0.002	0.001	
Magnesium		5.14	8.22	5.05	
Manganese	0.05	0.04	0.04	0.03	
Molybdenum	0.035	0.007	<.005	0.008	
Nickel	0.1	0.002	<.005	0.001	
Potassium		11.5	12.3	11.3	
Selenium	0.05	BDL	<0.001	0.005	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	12.3	13.7	12.8	
Vanadium	0.049		>.005		
Zinc	5	0.03	0.13	0.04	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		758 US	732.2 US	734 us	
Field pH		6.21 pH units	6.15 pH units	5.89 pH units	
Field Temp			26.4	26.94 C	
Color		>30	13 CU	>30 CU	
Turbidity		20 NTU	6.5 NTU	12	
Water Level		5.05 FT	6.2 ft	4.8 ft.	
Gross Alpha		8.1+/-2.9 pCi/l	3.2+/-2.8 pCi/l	5+/-pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound,					
based on the dilution(and moisture content if soil/sediment).					

0W - 4

1997 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 2 DUP	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	18.2	14	17	9.6	12
Nitrate	10	<0.02	0.1	0.18	<0.050	<0.050
Total Phosphorus		0.57	0.096	0.16	0.14	0.12
Sulfate	250	2.8	2.9	2.8		0.76
Sulfite		<2.0	3.2	3.2	<2.0	4.5 l
Total Dissolved Solids	500	100	82	88	78	82
Aluminum	0.2	4.6	0.16	0.21	5.8	1.7
Arsenic	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010
Barium	2	0.09	0.071	0.066	0.06	0.059
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0050	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		6.6	7.6	6.6	5.8	6.3
Chromium	0.1	<0.010	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010	<0.010
Iron	0.3	1	0.77	0.73	0.95	0.71
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		<1.0	0.86	0.78	0.66	0.81
Manganese	0.05	<0.010	<0.010	<0.010	<0.010	<0.010
Molybdenum	0.035	<0.010	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.010	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		1.5	1.4	1.5	1.1	1.2
Selenium	0.05	<0.0050	<0.010	<0.010	<0.010	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010	<0.010
Sodium	160	6.2	9.3	6.9	5.4	6.4
Vanadium	0.049	<0.010	<0.010	<0.010		<0.010
Zinc	5	<0.050	0.027	<0.010	<0.010	<0.010
Mercury	0.002	<0.00010	<0.0010	<0.0010	<0.00050	<0.00050
Conductivity		74 umhos/cm	105 umhos/cm	80 umhos/cm	80.0 umhos/cm	90.0 umhos/cm
Field pH		5.24 Units	4.83 Units	4.83 Units	4.8	5.1 pH Units
Field Temp		20.7 ^ C	24.2 ^ C	24.3 ^ C	25.8 ^ C	21.8 ^ C
Color		150 pcu	40 pcu	30 pcu	130 pcu	40 pcu
Turbidity		70.0 NTU	55 NTU	29 NTU	48 NTU	29 NTU
Water Level		6.28 ft	5.50 ft	5.50 ft	4.92 ft	8.37 ft
Gross Alpha		6.0 +/-1.2 pCi/l	5.1 +/-1.3 pCi/l	4.3 +/-1.2 pCi/l	3.9 +/-1.2 pCi/l	4.1 +/-1.2 pCi/l
GREEN - laboratory error						
RED - maximum contaminant level						

OW - 4

1998 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	39	12	10	10
Nitrate	10	<0.050	<0.050	<0.050	<0.050
Total Phosphorus		<0.010	0.13	0.18	0.15
Sulfate	250	14	8.3	16	9.4
Sulfite		5.5	51	5.0 l	9.6
Total Dissolved Solids	500	110	80	120	96
Aluminum	0.2	0.24	3.2	0.78	4
Arsenic	0.05	<0.010	<0.010	<0.010	<0.010
Barium	2	0.014	0.075	0.086	0.082
Beryllium	0.004	<0.0040	<0.0040	<0.0040	<0.0040
Cadmium	0.005	<0.0050	<0.0050	<0.0050	<0.0050
Calcium		0.11	8.9	9.7	8.4
Chromium	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Copper	1	<0.010	<0.010	<0.010	<0.010
Iron	0.3	0.2	0.99	1	1.1
Lead	0.015	<0.0050	<0.0050	<0.0050	<0.0050
Magnesium		1.2	0.92	1.1	0.99
Manganese	0.05	<0.010	<0.010	0.011	<0.010
Molybdenum	0.035	<0.050	<0.050	<0.050	<0.050
Nickel	0.1	<0.0050	<0.0050	<0.0050	<0.0050
Potassium		2.8	1.4	1.8	1.1
Selenium	0.05	<0.010	<0.010	0.017	<0.010
Silver	0.1	<0.010	<0.010	<0.010	<0.010
Sodium	160	12	7.6	8.3	7.1
Vanadium	0.049	<0.010	<0.010	<0.010	<0.010
Zinc	5	<0.010	<0.010	<0.010	<0.010
Mercury	0.002	<0.00050	<0.00050	<0.00050	<0.00050
Conductivity		110 umhos/cm	104umhos/cm	116 umhos/cm	108 umhos/cm
Field pH		5.0 pH Units	4.7 pH Units	4.9 pH Units	5.1 pH Units
Field Temp		24.6 Deg C	27.2 Deg C	24.8 Deg. C	24.6 Deg. C
Color		150 pcu	10 pcu	60 pcu	50 pcu
Turbidity		0.32 NTU	35 NTU	19.5 NTU	26.4 NTU
Water Level		4.600 ft	5.71 ft	4.46 ft	5.98 ft
Gross Alpha		4.0 +/-1.2 pCi/l	3.5 +/-1.2 pCi/l	4.3 +/-1.4 pCi/l	4.5 +/-0.7 pCi/l
GREEN - laboratory error					
RED - maximum contaminant level					

OW - 4

1999 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

PARAMETER	FDEP	QTR 1	QTR 1 DUP	QTR 2	QTR 3	QTR 4	QTR. 4 DUP.
	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Chloride	250	9.8	10	12.1	11.3	10.5	10.4
Nitrate	10	<0.050	<0.050	BDL	BDL	BDL	BDL
Total Phosphorus		0.066	0.053	0.14	0.05	BDL	BDL
Sulfate	250	3.9	4	6.89	16.4	23.7	24.7
Sulfite		7.7	7.7	10.2	7.04	6.4	6.4
Total Dissolved Solids	500	64	58	107	109	103	105
Aluminum	0.2	2.6	3.3	0.59	0.35	0.18	0.191
Arsenic	0.05	<0.010	<0.010	0.002	BDL	<0.001	<0.001
Barium	2	0.074	0.072	0.081	0.08	0.104	0.082
Beryllium	0.004	<0.010	<0.0040	BDL	BDL	<0.001	<0.001
Cadmium	0.005	<0.0050	<0.0050	BDL	BDL	<0.001	<0.001
Calcium		6.9	6.8	7.6	10.1	11.2	9.55
Chromium	0.1	<0.0050	<0.0050	0.006	BDL	0.002	0.002
Copper	1	<0.010	<0.010	0.01	BDL	<0.01	0.01
Iron	0.3	0.95	0.97	1.11	0.9	1.2	0.94
Lead	0.015	<0.0050	<0.0050	0.004	BDL	BDL	BDL
Magnesium		0.88	0.86	0.77	1.13	2.39	2.08
Manganese	0.05	<0.010	<0.010	BDL	BDL	0.02	0.02
Molybdenum	0.035	<0.050	<0.050	0.003	BDL	BDL	BDL
Nickel	0.1	<0.0050	<0.0050	0.004	BDL	BDL	BDL
Potassium		1.2	1.4	1.47	1.89	2.08	1.66
Selenium	0.05	<0.010	<0.010	BDL	BDL	BDL	BDL
Silver	0.1	<0.010	<0.010	BDL	BDL	<0.001	<0.001
Sodium	160	6.7	6.6	7.5	7.6	8.8	8.6
Vanadium	0.049	<0.010	<0.010				
Zinc	5	<0.010	<0.010	0.01	BDL	BDL	0.02
Mercury	0.002	<0.00050	<0.00050	BDL	BDL	BDL	BDL
Conductivity		94.0umhos/cm	94.0umhos/cm	98 Us	120 Us	115 us	115 us
Field pH		4.9 pH Units	4.9 pH Units	5.40 pH units	4.83 pH units	4.91 pH units	4.91 pH units
Field Temp		25.7 Deg. C	25.7 Deg. C	26.0 C	22.9 C	19 C	19 C
Color		50 pcu	25 pcu	>30 CU	>30 CU	12 CU	12 CU
Turbidity		225 NTU	22.5 NTU	65 NTU	5 NTU	.54 NTU	.54 NTU
Water Level		6.57 ft	6.57 ft	6.38 ft	4.45 ft	5.06 ft	5.06 ft
Gross Alpha		4.7+/-0.9 pCi/l	5.5+/-0.5 pCi/l	3.7 +/-1.4 pCi/l	1.1+/- .9 pCi/L	2.9+/-1.1 pCi/l	3.1+/-1.2 pCi/l
GREEN - laboratory error							
RED - maximum contaminant level							

OW - 4

2000 QUARTERLY GROUNDWATER ANALYTICAL RESULTS

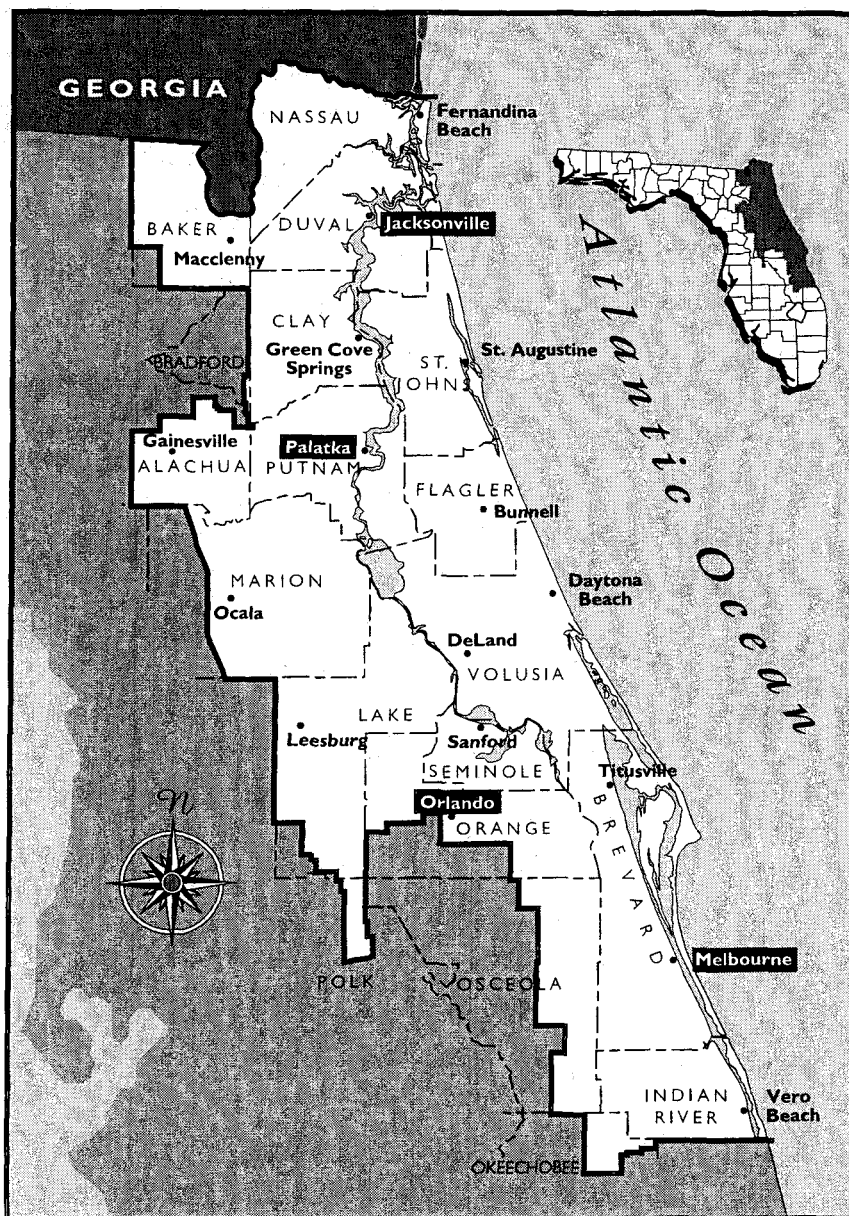
PARAMETER	FDEP	QTR 1	QTR 2	QTR 3	QTR 4
	mg/ l	mg/ l	mg/ l	mg/ l	mg/ l
Chloride	250	11.2	10.3	10.5	
Nitrate	10	BDL	BDL	<0.10	
Total Phosphorus		0.07	0.09	0.1	
Sulfate	250	32.6	42.7	45.8	
Sulfite		8	8	12	
Total Dissolved Solids	500	100	87	108	
Aluminum	0.2	0.98	0.11	0.028	
Arsenic	0.05	<0.001	<0.001	0.001	
Barium	2	0.11	0.104	0.45	
Beryllium	0.004	<0.001	<0.001	<0.001	
Cadmium	0.005	<0.001	<0.001	<0.001	
Calcium		11.8	0.92	13.7	
Chromium	0.1	<0.002	<0.002	BDL	
Copper	1	<0.01	0.01	0.01	
Iron	0.3	1.29	1.82	1.41	
Lead	0.015	0.001	0.001	0.002	
Magnesium		1.37	1.93	1.54	
Manganese	0.05	<0.02	<0.02	0.02	
Molybdenum	0.035	<0.005	<0.005	0.004	
Nickel	0.1	<0.001	<0.005	BDL	
Potassium		1.95	1.92	2.2	
Selenium	0.05	BDL	<0.001	0.001	
Silver	0.1	<0.001	<0.001	<0.001	
Sodium	160	10.3	9.7	10.2	
Vanadium	0.049		<.005		
Zinc	5	0.01	0.11	0.03	
Mercury	0.002	BDL	<0.0005	BDL	
Conductivity		152 US	158.5 US	163 us	
Field pH		4.9 pH units	4.87 pH units	4.71 pH units	
Field Temp			26.41	25.15 C	
Color		4 CU	12 CU	8 CU	
Turbidity		2.5 NTU	4.25 NTU	5 NTU	
Water Level		4.98 FT	7.74 ft	5.53 ft.	
Gross Alpha		2.8+/-1.1 pCi/l	1+/-2.8 pCi/L	2.70+/-2.8pCi/L	
GREEN - laboratory error					
RED - maximum contaminant level					
value preceding the "U" indicates the limit of detection for that compound,					
based on the dilution(and moisture content if soil/sediment).					

**PERMIT APPLICATION FOR
CONSUMPTIVE USES OF WATER**



St. Johns River Water Management District

PERMIT APPLICATION FOR CONSUMPTIVE USES OF WATER



Please mail to the nearest
District Service Center:
St. Johns River Water Management District

District Headquarters:

P. O. Box 1429
Highway 100 West
Palatka, Florida 32178
FAX: 904-329-4490

Jacksonville Service Center:

7775 Baymeadows Way
Suite 102
Jacksonville, Florida 32256
FAX: 904-730-6267

Orlando Service Center:

618 East South Street
Suite 200
Orlando, Florida 32801
FAX: 407-897-4354

Melbourne Service Center:

305 East Drive
Melbourne, Florida 32904
FAX: 407-722-5357

PERMIT APPLICATION FOR CONSUMPTIVE USES OF WATER



Permit Type: Individual CUP ☒ Secondary Use ☐ Standard General CUP ☐ Application is for: New use ☐ Renewal ☐ Modification of Existing Permit ☒

APPLICANT INFORMATION

ORGANIZATION NAME (please print all responses)

Orlando Utilities Commission

LAST NAME (please print all responses)

Haddad

FIRST NAME

Frederick

STREET NO.

STREET NAME

CITY

500 South Orange Ave

Orlando

STATE

ZIP

PHONE

FL

32802

4074239100

☐ Same as above

AGENT OR CONSULTANT

ORGANIZATION NAME (please print all responses)

BLACK & VEATCH

LAST NAME (please print all responses)

ROLLINS

FIRST NAME

MYRON

STREET NO.

STREET NAME

CITY

11401 LAMAR

OVERLAND

STATE

ZIP

PHONE

KS

66211

9134582000

Thomas B Tart

Thomas B Tart V.P.-OUC

1-16-01

APPLICANT'S NAME (Please print)

APPLICANT'S SIGNATURE

DATE

If a person other than applicant has completed this form, that person certifies by his signature below that he is acting as an authorized agent of the applicant and his signature will be certification that he is in fact the authorized agent.

AGENTS NAME (Please print)

AGENTS SIGNATURE

DATE

☒ Same as applicant

OWNER INFORMATION

LAST NAME (please print all responses)

FIRST NAME

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STREET NO.

STREET NAME

TYPE

CITY

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STATE

ZIP

PHONE

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SITE INFORMATION

COUNTY

O	R	A	N	G	E						
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ACRES OWNED

		3	2	8	0
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SECTION

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TOWNSHIP

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RANGE

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Sections 13 and 24, East 1/2 of Sections 14 and 23, T23S, R31E, Sections 18 and 19, T23S, R32E

PROJ. NAME

S	T	A	N	T	O	N	E	N	E	R	G	Y
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PROJECT ACRES

			6	0
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COUNTY PARCEL NO.

--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Multiple parcel numbers apply and will be provided upon request.

TYPE OF USE

DARKEN ALL THAT APPLY

AESTHETIC ☐ AGRICULTURAL ☐ AQUACULTURAL ☐ COOLING AND AIR CONDITIONING ☐

DEWATERING ☐ COMMERCIAL AND INDUSTRIAL ☒ ESSENTIAL ☒ FREEZE PROTECTION ☐

GOLF COURSE ☐ RECREATION AREA ☐ HOUSEHOLD TYPE ☒ LIVESTOCK ☐

NURSERY ☐ URBAN LANDSCAPE IRRIGATION ☐ WATER BASED RECREATION ☐

UNACCOUNTED FOR WATER ☐ OTHER ☐

Permit No.

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Additional amount requested for Unit A only.

AMOUNT REQUESTED

INCHES PER YEAR

MILLION GALLONS PER YEAR 115 mgd; 180 mgd including emergency cooling

MILLION GALLONS PER DAY 0.316 mgd

DATE OF START OF USE January 1, 2002

WATER USE MONITORING

All permittees are required to measure their water usage on a continuous basis. All users must report their use using form EN-50 to the District at the intervals specified in their permit. If used, meters must be 95% accurate, verifiable and installed according to manufacturers' specifications. Meters or alternative methods utilized by the water supplier to charge for the water may suffice as a water use monitoring tool.

Alternative methods must be 90% accurate and verifiable. All alternative methods must be approved in advance and in writing by District staff.

☐ Same as applicant

COMPLIANCE ENTITY

Consumptive Use Permits require the periodic submittal of data to the District. Please provide the name, address and phone number of the person who will be responsible for ensuring that the permitted conditions are met. Submittal of this information does not relieve the permit holder from the responsibility for compliance.

Name: Frederick F. Haddad, Orlando Utilities Commission

Address: 500 South Orange Avenue

Orlando, FL 32802

Phone Number: (407) - 244-8732

SECONDARY TYPE USE

Please supply information regarding the source(s) of water for your activities.

1. The name of the supplier of water. OUC-Stanton Energy Center
2. Is this source of water potable or non-potable? (circle one)
3. What percentage of your total water use is from this supplier? 100%
4. If 100% of your water use is not provided from the supplier, please indicate what uses are self supplied.
5. The applicant must also complete other packages which address the requested consumptive use identified in question 4.

See Attached

Description of Use Classes: Each permit shall be identified with one or more of the following use classifications:

- (a) **Aesthetic use** - the use of water for fountains, waterfalls, and landscape lakes and ponds where such uses are entirely ornamental and decorative.
- (b) **Agricultural use** - use of water for the commercial production of crops or the growing of farm products including, but not limited to, vegetables, citrus and other fruits, pasture, rice and sod.
- (c) **Aquacultural use** - the use or withdrawal of water for cultivation of animal and plant life in a water environment, including but not limited to food fish, aquatic bait, game fish, aquatic plants (i.e. watercress), alligators, tropical fish, shellfish, and turtles.
- (d) **Commercial and industrial process use** - the use of water essential to the production of the goods or services provided by a business establishment.
- (e) **Cooling and air conditioning use** - the use of water for heating or cooling, or for air conditioning.
- (f) **Dewatering use** - the removal of water from a specific area to facilitate mining or construction.
- (g) **Essential use** - the use of water strictly for fire fighting purposes, health and medical purposes and the use of water to satisfy federal, state or local public health and safety requirements.
- (h) **Freeze protection** - the periodic and infrequent use of water to protect agricultural and nursery crops from damage due to low temperatures.
- (i) **Golf course use** - water used to irrigate an establishment designed and used for playing golf.
- (j) **Household use** - the use of water for personal needs or for household purposes such as drinking, bathing, heating, cooking, sanitation or cleaning, whether the use occurs in a residence or in a business or industrial establishment.
- (k) **Livestock use** - the use of water for watering or washing of livestock.
- (l) **Nursery use** - the use of water on premises on or in which nursery stock is grown, propagated or held for sale or distribution or sold or reshipped.
- (m) **Recreation area use** - the use of water for the maintenance and support of intensive recreational areas such as, but not limited to, playgrounds, football, baseball, and soccer fields.
- (n) **Urban landscape irrigation** - the outside watering or sprinkling of shrubbery, trees, lawns, grass, ground covers, plants, vines, gardens and other such flora which are situated in such diverse locations as residential landscaping, recreational areas, cemeteries, public, commercial and industrial establishments, public medians and rights of way.
- (o) **Water based recreation use** - water used for public or private swimming and wading pools, including water slides. This term does not include pools specifically maintained to provide habitat for aquatic life.
- (p) **Water utility use** - water used for withdrawal, treatment, transmission and distribution by potable water systems.

SOURCES OF WATER

(Summary Data Sheet)

Please supply information regarding the source(s) of water for your activities. Include information regarding **all** wells/pumps on the property.

Table 1.
SUMMARY OF GROUND WATER SOURCES

Well or Pump Number	Wellfield or Facility Name	Casing Dia. (in)	Casing Depth (ft)	Total Depth (ft)	Operation Hrs/wk	Pump Capacity (in gpm)	Date Drilled	Existing or proposed (date)	Type of Use*
1	Stanton				168 ¹	850		Existing	(d)
2	Stanton				---1,2	850		Existing	(d)

1. One Continuous, One Spare 2. As needed for emergency cooling water backup or service
 * - See use descriptions on page 4. If more than one use type, show predominate use water supply.

Table 2
SUMMARY OF SURFACE WATER SOURCES

Pump Number	Pump Capacity (gpm)	Operation Hrs/wk	Acreage of Surface Water Body	Name of Source	Status (date if proposed)	Type of Use
N/A*						

*The only surface water withdrawal is from on-site holding ponds constructed for collection and distribution of process waters. No natural surface water sources are used for supply water.

PROPERTY CONTROL AND LOCATION

I. PROPERTY CONTROL

1. **Property Ownership** - Provide a copy of the excuted deed indicating the current owner of the property which is the subject of this application.
2. **Leased Property** - Provide a copy of the current lease, or a letter signed by the property owner describing the lease arrangement and the duration of the lease.

II. LOCATION MAPS

Provide a recent map (preferably a USGS topographic quadrangle, a map from a county plat directory, or survey map) indicating the following:

- (a) property boundaries (include approximate lengths of boundaries in feet); (public supply water uses please show service areas)
- (b) All existing and proposed withdrawal point locations. Indicate well number and casing size for ground water withdrawals, and pump number and maximum pump capacity for surface water withdrawals;
- (c) a north arrow;
- (d) a scale designation - all maps should have a minimum scale of 1 inch = 2,000 feet; and
- (e) labeled landmarks such as roads and political boundaries.

Please provide identification numbers and date permitted if you obtained or are in the process of obtaining any of the following permits for this project

Environmental Resource Permit (ERP)	In progress
-------------------------------------	-------------

EPA Ordered Environmental Impact Statements

Agricultural Discharge _____

FDEP Wastewater Site Identification No. _____

FDEP Public Water Supply (PWS) Identification No. _____

Site Certification Order PA81-14 (December 14, 1982)
Supplemental Site Certification was issued on December 17, 1991
(DOAH Case No. 91-1813EPP)

III. ADJACENT PROPERTY OWNERS

(not applicable to Secondary Users Permits)

Provide a complete list of adjacent property owners and mailing address as prescribed in Tables #3 and 4. Attach additional sheets as needed.

Name	Address	City	State	Zip Code
See Attached				

USE OF LOWEST ACCEPTABLE QUALITY WATER SOURCE

1. Are you proposing to use the most appropriate (lowest quality) source of water?
Yes, reasonable beneficial use information is included herein.
2. Is reclaimed water readily available as a source of water?
Yes, however, in the event of an emergency reclaimed water shortage due to pipeline interruption, treatment plant operation, or cooling water storage lake shortage, the use of groundwater is requested for Stanton A.

WATER CONSERVATION PLAN

A water conservation plan must be submitted with this application. Please refer to Section 12.0 and Appendix I, Applicant's Handbook, Consumptive Uses of Water, for information on how to prepare a plan and the plan components.

In progress.

**Table A-1
Surrounding Property Owners
Stanton Energy Center**

Parcel ID	Owner	Acres	Owner Address
12-23-31-0000-00-002	Redditt, John Cecil	120	4414 Calm Water Ct. Orlando, FL 32817
12-23-31-0000-00-005	Redditt, Adeline Ann	120	710 N. Dean Rd. Orlando, FL 32825
12-23-31-0000-00-001	Morgran Co., Inc.	854.9	15 McMurrich St. Suite 1104 Toronto, Canada M5R3
11-23-31-0000-00-001	Orange Co. BCC	640	P.O. Box 1393 Orlando, FL 32802
14-23-31-0000-00-008	Orange Co. BCC	320	P.O. Box 1393 Orlando, FL 32802
23-23-31-0000-00-005	Orange Co. BCC	160	P.O. Box 1393 Orlando, FL 32802
21-23-31-0000-00-002	Orange Co. BCC	2728.87	P.O. Box 1393 Orlando, FL 32802
25-23-31-0000-00-001	Orlando Business Park, LLC	629.7	1525 S. Andrews Ave. Suite 216 Ft. Lauderdale, FL 33316
30-23-32-0000-00-001	TIITF/DOC	609.08	3900 Commonwealth Blvd. Tallahassee, FL 32399
29-23-32-0000-00-002	Smith, W. Roger	509.5	601 Lake Harbor Cir. Orlando, FL 32809
20-23-32-0000-00-001	St. Johns River Water Management District	2,160	P.O. Box 1429 Palatka, FL 32178
07-23-32-0000-00-004	Avalon Associates of Delaware LP	914	13013 Founders Sq. Drive Orlando, FL 32828

Source: Orange County Property Appraiser (<http://pamap1.ocpafl.org>)

Table 3 - Ground Water Withdrawals

Withdrawal Amount	Property Owners to be Listed
less than 1,000,000 gallons maximum per day - and- less than 100,000 gallons per day annual average	None required
max day is between 1 and 5 million gallons -or- average day is between 100,000 and 500,000 gallons	All property owners within 600 feet of well or 100 feet of property boundary.
max day is between 5 and 10 million gallons -or- average day between 500,000 and 1,000,000 gallons	All property owners within 1,320 feet of each well or 200 feet of the property boundary.
max day exceeding 10 million gallons -or- average day exceeds 1,000,000 gallons	All property owners within 2,640 feet of the well, or 400 feet of the property boundary.

Table 4 - Surface Water Withdrawals

Withdrawal Amount	Property Owners to be Listed
surface area of the withdrawal lake is less than 80 acres	All riparian land owners on lake and those up to 600 feet downstream if the lake has an outlet
surface area of the withdrawal lake is greater than 80 acres	All riparian land owners up to 600 feet from the withdrawal point
Withdrawals from a stream and average daily pumpage is less than 5 million gallons	All riparian land owners up to 600 feet upstream and 1,320 feet downstream from the withdrawal point
Withdrawals from a stream and average daily pumpage is greater than 5 million gallons	All riparian land owners up to 1,320 feet upstream and 2,640 downstream from the withdrawal point

SECTION III

Applicant Checklist

Please verify that the following information has been provided as part of this application package:

- | | <u>Attached</u> |
|--|-----------------|
| 1. Appropriate Fee | \$ _____ |
| 2. Signature of Applicant and/or Agent | _____ |
| 3. Authorization from Owner for Agent
(if Agent is listed on application) | _____ |
| 4. Copy of Executed Deed or Lease Agreement | _____ |
| 5. Location Map | _____ |
| 6. List of adjacent land owners | _____ |
| 7. Completed Water Use Type Package* | _____ |
| 8. Water Conservation Plan | _____ |

*NOTE: Applications for Public Supply, Commercial/Industrial, Agricultural, Aquacultural, Nursery/Fem, Golf Course Irrigation, Dewatering, and Landscape Irrigation water uses must also include the supplemental water use package specific to each use type. Those applying for a **Secondary Use Permit** must complete and submit each of the supplemental water use packages that applies to their type use.

Additional Information in Support of Stanton A Consumptive Use Request

Section 373.223, F.S., provides a three-fold test for evaluating each proposed use: It must be a reasonable beneficial use, it must not interfere with any presently existing legal use of water, and it must be consistent with the public interest. The Applicant provides the following information to support and justify the amount of groundwater requested for use at Stanton A, an electric power generating facility:

I. Reasonable Beneficial Use

Section 373.019(4), F.S., defines "Reasonable Beneficial Use" as "the use of water in such quantity as is necessary: for economic and efficient utilization for a purpose and in a manner which is both reasonable and consistent with the public interest." Based upon the statutory guidance and the delineation of factors found in State Water Policy, the Governing Board has determined that the following criteria must be met in order for a use to be considered reasonable beneficial.

(a) The use must be in such quantity as is necessary for economic and efficient utilization. The quantity applied for must be within acceptable standards for the designated use.

The various plant systems for Stanton A will typically require three levels of water quality for operation. These levels are as follows.

- *High quality demineralized water*
- *Potable quality service water*
- *Reclaimed water*

High Quality Demineralized Water. *The following Stanton A water uses will require demineralized water quality to meet the manufacturers' requirements:*

- *Makeup to the Heat Recovery Steam Generators (HRSGs)*
- *Injection water for the control of NO_x emissions when using oil as fuel in the combustion turbines*
- *Injection steam for power augmentation in the combustion turbines*
- *Combustion turbine cleaning*

Manufacturers of the turbines and HRSGs place strict limitations on the water quality used in these units to ensure the units' safe operation and extend their life.

The existing facilities at Stanton Energy Center include a demineralizer system capable of producing 700,000 gpd, or 486 gpm. Average demineralized water demand for existing Units 1 and 2, as projected in the Unit 2 Site Certification Application, based on 95% capacity is 104,000 gpd, or 72 gpm. The additional anticipated annual average demand for demineralized water for Stanton A based on 95% capacity is approximately 222,000 gpd, or 154 gpm. This estimate for Stanton A is based on 1,000 hrs/yr firing the combustion turbines on oil, 1,000

hrs/yr of duct firing and 1,000 hrs/yr of steam injection for power augmentation. The hours per year used to determine the estimate for oil firing is consistent with the maximum allowed by the air permit.

Short-term peak demineralized water flow demands for Stanton A, such as occurs when firing on oil or using steam for power augmentation, will exceed the capability of the existing Units 1 and 2 demineralizer. These high demands are intermittent, however, and will be met by installation of a new demineralized water storage tank for Stanton A.

The water used to supply the demineralizer system is treated groundwater (service water) taken from the existing service water treatment system for Units 1 and 2, as described below.

Service Water Uses. In addition to supplying the demineralizer system, Stanton A will require service water, which is lime-softened, filtered, and chlorinated groundwater, for the following:

- Potable water supply
- Makeup to the inlet air evaporative coolers

Federal and State drinking water standards place limitations on the quality of water used for potable water. The existing service water system for Units 1 and 2 is a licensed non-community public water system. An extension to this system will supply Stanton A potable water users. The evaporative coolers require consistent quality water that will not cause excessive corrosion or fouling of the media used in the coolers.

It is estimated that 316,000 gpd, or 219 gpm, of additional groundwater will be required for Stanton A on an annual average basis. This estimate includes the water required to produce demineralized water.

The existing plant includes a 1,700 gpm water pretreatment system for treating well water to produce service water. The existing service water system will be adequate to serve Stanton A.

Reclaimed Water Uses. Water uses capable of directly using reclaimed water include the following:

- Cooling water for the steam cycle condenser and miscellaneous plant and equipment cooling
- Condensate transport water
- Combustion and steam turbine area washdown water

Stanton Energy Center has contracted with the Orange County Regional Water Reclamation Facility to supply reclaimed water to the site. For Stanton A, reclaimed water will be used primarily for makeup to the cooling towers, similar to existing Units 1 and 2.

(b) The use must be for a purpose which is both reasonable and consistent with the public interest.

The proposed consumptive use is that reasonably required to operate the electric power generating facility. The facility is reasonable and consistent with the public interest, as shown in the Supplemental Site Certification Application (SSCA) and the Joint Petition to Determine Need for Electrical Power Plant.

(c) The source of the water must be capable of producing the requested amounts of water. This capability will be based upon records available to the District at the time of evaluation. An eight of ten year capability will be considered acceptable.

Subsurface hydrology is discussed in section 2.3.2 of the Supplemental Site Certification Application.

(d) The environmental or economic harm caused by the consumptive use must be reduced to an acceptable amount. The methods for reducing harm include: reducing the amount of water withdrawn, modifying the method or schedule of withdrawal, or mitigating the damages.

See the response to (e) below.

(e) All available water conservation measures must be implemented unless the applicant demonstrates that implementation is not economically, environmentally or technologically feasible. Satisfaction of this criterion may be demonstrated by implementation of an approved water conservation plan as required in section 12.0 of Applicant's Handbook: Consumptive Uses of Water. Appendix I provides an outline of water conservation measures which the applicant may undertake to meet this requirement. Individual provisions in Appendix I are not requirements per se, and do not exclude alternative conservation measures the applicant may wish to propose to the District.

The following water conservation and reuse measures will be implemented in the Stanton A design.

- 1. Blowdown from the steam generators and miscellaneous condensed and collected steam losses will be collected and used to provide a portion of the makeup to the Stanton circulating water system.*
- 2. The plant is designed to maximize the cycles of concentration in the cooling tower to minimize cooling tower blowdown.*
- 3. The cooling tower will be equipped with drift eliminators to limit drift losses to less than 0.002% of circulating water flow.*
- 4. Blowdown from the cooling systems and the evaporative coolers will be collected and processed in a zero liquid discharge system. This system includes brine concentrator evaporators and crystallizers to remove solids from the water streams. The water recovered from this system will be routed to the Makeup Water Supply Storage Pond or to the existing cooling towers to offset a portion of the water requirements for the Stanton Site.*
- 5. A cascaded blowdown system will be used in the HRSG to normally limit the amount of makeup required by the HRSGs to less than 1% of the steam production rate.*

(f) When reclaimed water is readily available it must be used in place of higher quality water sources unless the applicant demonstrates that its use is either not economically, environmentally or technologically feasible.

In determining whether reclaimed water is readily available, the District will consider the following factors:

- (1) Whether a suitable source of reclaimed water exists;
- (2) Whether the source is offered to or controlled by the applicant,
- (3) Whether the applicant is capable of accessing the source; and
- (4) any other relevant information.

Reclaimed water was considered as a source of supply to meet Stanton A service and demineralized water requirements. Extensive additional treatment equipment would be required to allow reclaimed water to be used for these additional systems. The cost of this additional equipment is estimated as follows.

Additional Equipment Costs

<i>Softening and Clarification Equipment</i>	<i>\$1,000,000</i>
<i>Filtration Equipment, including dual media filters and ultrafiltration system</i>	<i>\$1,300,000</i>
<i>Reverse Osmosis System</i>	<i>\$700,000</i>
<i>Demineralizer</i>	<i><u>\$1,800,000</u></i>
<i>Total Estimated Installed Cost</i>	<i>\$4,800,000</i>

Operating Costs

<i>Chemicals</i>	<i>\$200,000</i>
<i>Additional operators</i>	<i>\$250,000</i>
<i>Maintenance and repairs</i>	<i>\$50,000</i>
<i>Sludge disposal</i>	<i><u>\$190,000</u></i>
<i>Total Estimated Annual Operating Costs</i>	<i>\$690,000</i>

Considering the high additional costs associated with treatment of reclaimed water and minimal impacts resulting from using groundwater, as discussed in the SSCA, it is not considered economic nor practical to use reclaimed water for these relatively minor uses. Treated groundwater is readily available from the existing service water and demineralized water systems for these uses. Groundwater will be used to supply less than ten percent of the makeup requirements for Stanton A.

(g) The lowest acceptable quality water source, including reclaimed water or surface water (which includes stormwater), which is addressed in paragraph 40C-2.301(4)(f), must be utilized for each consumptive use. To use a higher quality water source an applicant must demonstrate

that the use of all lower quality water sources will not be economically, environmentally, or technologically feasible. If the applicant demonstrates that use of a lower quality water source would result in adverse environmental impacts that outweigh water savings, a higher quality source may be utilized. This criterion shall not be used to require the use of lower quality sources for direct human consumption or human food preparation. Entities using water for these purposes and also for other purposes, such as irrigation, must evaluate the feasibility of using lower quality sources for such other purposes. However, it is possible that the unavailability of higher quality sources may necessitate the development of lower quality sources in order to meet projected demands, including the demands resulting from direct human consumption and human food preparation needs.

See response to (f) above.

(h) The consumptive use should not cause significant saline water intrusion or further aggravate currently existing saline water intrusion problems.

The proposed water use will not cause any saltwater intrusion. As discussed in Sections 2.3.2 and 5.3.2.5 of the SSCA, the depth to brackish groundwater within the SEC site is anticipated to be between 1,500 feet to 2,000 feet bgs, i.e., within the Lower Floridan Aquifer. The presence of the semiconfining layer within the Floridan Aquifer system prevents any major flow of water between the Upper and Lower Floridan aquifers. Maximum potentiometric head decreases in the semiconfining layer (Layer 4) are limited to 0.05 foot for the average groundwater usage, and 0.1 foot for the maximum groundwater usage conditions (maximum drawdowns correspond to the pumping well locations). Average and maximum groundwater usage are not considered to be sufficient to cause the required head changes to induce saltwater intrusion into the semiconfining unit from the Lower Floridan Aquifer.

(i) The consumptive use should not cause or contribute to flood damage.

Over 90 percent of the groundwater withdrawn will be consumed in the power generation process. The remaining waters will be treated and discharged onsite or reused at the Stanton site in other processes. The Stanton site will remain a zero-discharge facility, and therefore, should not cause or contribute to flood damage.

(j) The water quality of the source of the water should not be seriously harmed by the consumptive use.

The incremental withdrawals for Stanton A should not adversely impact the water quality of the source aquifer. As described in response (h) above, the proposed water use will not cause saltwater intrusion. The projected drawdowns are also indistinguishable from normal seasonal fluctuations.

(k) The consumptive use shall not cause or contribute to a violation of state water quality standards in receiving waters of the state, as set forth in chapters 62-3, 62-4, 62-302, 62-520, and 62-550, F.A.C., including any anti-degradation provisions of sections 624.242(1)(a) and (b), 62-4.242(2) and (3), and 62-302.300, F.A.C., and any special standards for Outstanding National Resource Waters set forth in sections 6:2,-4.242(2) and (3), F.A.C. A valid permit issued

pursuant to chapters 62-660 or 62-670, F.A.C., or section 62-4.240, F.A.C., or a permit issued pursuant to chapters 40C-4, 40C-40, 40C-42, or 40C-44, F.A.C., shall establish that this criterion has been met, provided the applicant is in compliance with the water quality conditions of that permit.

Stanton A will be a zero discharge unit, and will therefore not cause or contribute to a violation of state water quality standards in receiving waters of the state. Aquifer drawdowns are predicted only on the Stanton site as described in Section 5.3 of the SSCA.

II. Interference with Presently Existing Legal Uses

The use of water must not cause an interference with a legal use of water which existed at the time of the application for the initial consumptive use permit.

Interference with a legal use of water is defined as a decrease in the withdrawal capability of any individual withdrawal facility of a legal use of water which was existing at the time of the application for the initial permit such that the existing user experiences economic, health, or other type of hardship.

The area surrounding the SEC is currently rural and relatively undeveloped. No interference to existing legal uses due to the proposed withdrawals of ground water is anticipated.

Water supply wells installed in the region since construction of Units 1 and 2 are shown on Figure 2.3-13 of the SSCA. Three water supply wells have been installed within 1 mile of the SEC since 1992. The well owners and specific well information are summarized in Table 2.3-4 of the SSCA.

Table 2.3-5 of the SSCA shows average groundwater use in the SJRWMD for the year 1995, and projected 2020 conditions (Vergara, 1998). Orange County alone used 136.8 mgd of groundwater in 1996 and 19.2 mgd of surface water, about 11 percent of the total water use in the SJRWMD, and is projected to increase its use to 12 percent of the total water use by 2020.

The results of simulation described in Section 5.3 of the SSCA indicated that total plant operations will have negligible effect on the unconfined aquifer water levels and no impact on groundwater quality. No additional facilities that would affect the water table zone will be constructed for Stanton A operation. No water will be withdrawn from the unconfined aquifer.

Secondly, total plant operation will have negligible effect on the intermediate secondary artesian aquifer water levels and no impact on groundwater quality. No new facilities will be constructed that would affect the intermediate secondary artesian aquifer for Stanton A operation. No water will be withdrawn from the intermediate secondary artesian aquifer.

Lastly, the literature search conducted for the groundwater flow model, as well as the investigation of the site conducted by Black & Veatch, indicate that the Floridan Aquifer, the proposed groundwater source for the wells, acts as a confined aquifer in the SEC area. Therefore, withdrawal of groundwater from the aquifer will not affect the adjacent surface water bodies. Due to the confined nature of the aquifer, the proposed water use will not effect environmental features that have a direct or indirect relationship to wetland habitats for rare, endangered, or threatened species. The SEC 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.

The modeling performed indicates that the average daily groundwater flow will result in a drawdown at the pumping well of 2.5 feet, and a drawdown of 0.2 feet a radius of 1 mile from the pumping well. Figure 5.3-1 shows the model drawdown levels with distance away from the pumping well. The increased average daily groundwater flow will continue to have a minimal effect on the surrounding water supply wells.

For the maximum daily groundwater flow simulation with both wells pumping 614 gpm, the model indicates that, at the end of the 30 days, the drawdown in each of the pumping wells will be 3.0 feet. Drawdown at a radius of 1 mile away from the wells is estimated to be about 0.4 foot. Figure 5.3-2 shows the model drawdown levels with distance away from the pumping wells.

For the maximum daily groundwater flow simulation with one well pumping 850 gpm and the second well pumping 370 gpm, the model indicates that at the end of the 30 days, the drawdown at the well pumping 850 gpm will be 4.0 feet. Drawdown at a radius of 1 mile away from the wells is estimated to be about 0.4 foot. Figure 5.3-3 shows the model drawdown levels with distance away from the pumping wells.

The predicted drawdown in the vicinity of the pumping wells indicates that there will be no effects to existing domestic, irrigation, or other public water supply wells due to average or maximum groundwater withdrawals at the SEC. The 0.4 foot drawdown at a 1 mile radius observed for the maximum groundwater usage condition is a transient situation that will have no permanent effects on the groundwater levels. Groundwater levels will return to the original state once the units revert back to average groundwater usage.

In summary, groundwater withdrawal from the Floridan Aquifer at the SEC will have no adverse impacts on other legal users.

III. Public Interest

For purposes of this section, "public interest" means those rights and claims on behalf of people in general. In determining the public interest in consumptive use permitting decisions, the Board will consider whether an existing or proposed use is beneficial or detrimental to the overall collective well-being of the people or to the water resource in the area, the District and the State.

As shown in the Supplemental Site Certification Application and Joint Petition to Determine Need for Electrical Power Plant, the proposed consumptive use is consistent with the public interest.



COMMERCIAL/INDUSTRIAL TYPE USES

(Submit 2 copies of application, supplemental information drawings, calculations, etc.)

I. PROJECT DESCRIPTION

1. Type of business and/or operation, please describe:

The Curtis H. Stanton Energy Center is an electrical power plant currently composed of Units 1 and 2, both 450MW coal-fired units. The applicant proposes to add a third unit, which will be a nominal 633 MW combined cycle

combustion turbine unit.

- 2 Requested Water Use:

	Existing ² (mgd)	Proposed ² (mgd)	Proposed ² (mgd)	Proposed ² (mgd)
		5 years	10 years	15 years
Average Daily Use	0	0.316	0.316	0.316
Maximum Daily Use	0	2.45	2.45	2.45
Average Off-Site Discharge	--- ¹	--- ¹	--- ¹	--- ¹

*mgd - million gallons per day

3. Provide a graph (month vs mgd) or table summarizing monthly water use for the previous 3 years.
See Attached. Note: groundwater use only.
4. Provide a flow chart (schematic diagram) depicting the flow of all sources of water, use and eventual discharge.
See Attached.
5. Please provide a table projecting expected growth over the next 15 years. What is the reason for the expected growth?

See Attached.

II. WASTEWATER DISPOSAL

Describe in detail the flow of wastewater from the plant to its ultimate disposal. Also, provide the applicable Florida Department of Environmental Protection, Environmental Protection Agency permit numbers (EPA, FDEP) issued for discharge to surface waters. Attach daily flow amounts for effluent discharged to surface waters for the last 12 months. Include this information in the above requested schematic diagram.

See Attached.

¹ No wastewater discharged to offsite surface water sources.

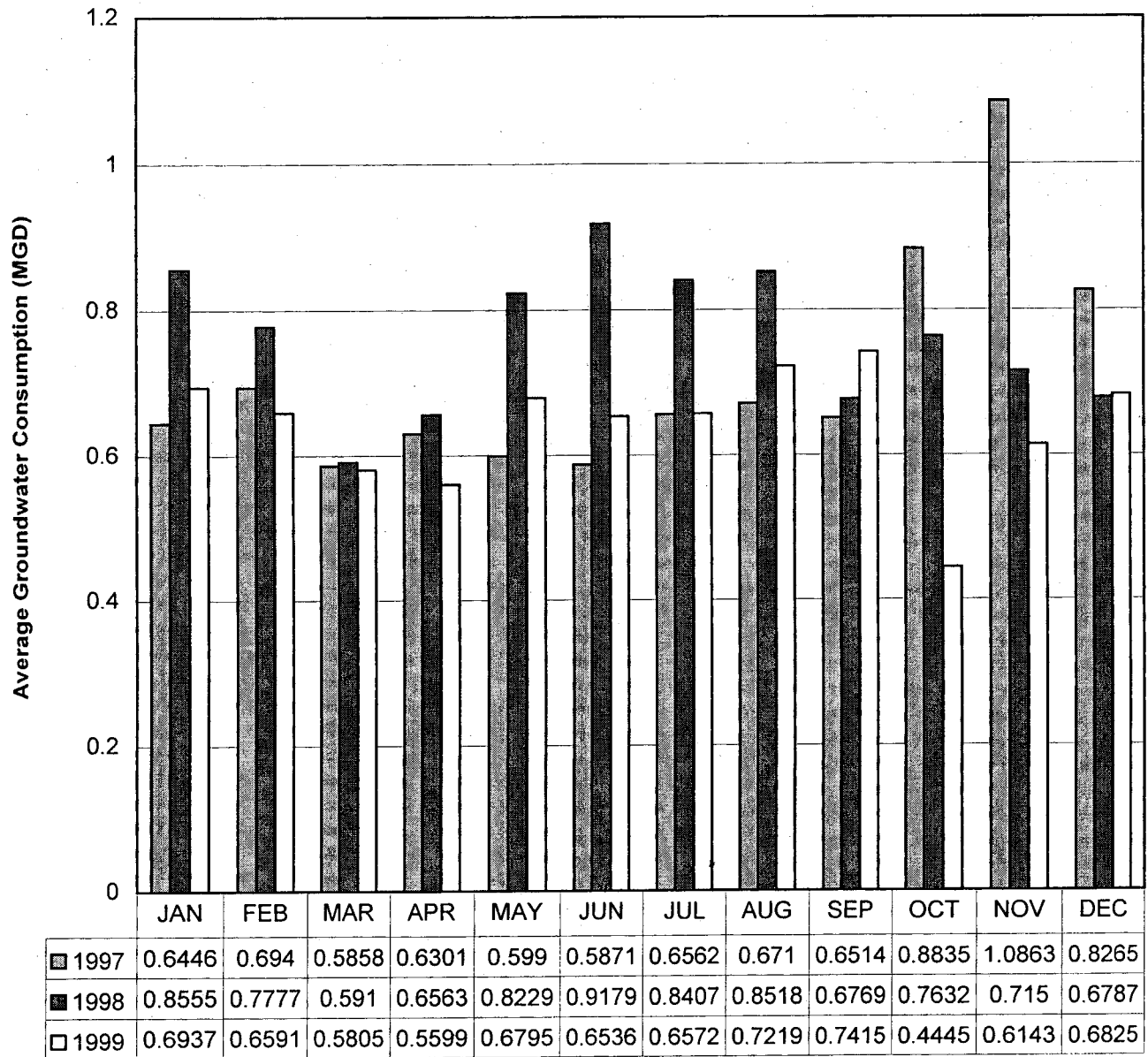
² Proposed use does not include additional water requirements that may result if further expansion of the facility is undertaken.

III. REUSE

1. Provide water quality data for effluent discharged from this facility during the last 12 months.
2. Provide the level of water quality required for each individual manufacturing and cooling process. Provide supporting documentation as to water quality and quantity limitation of reuse for each component of the process.

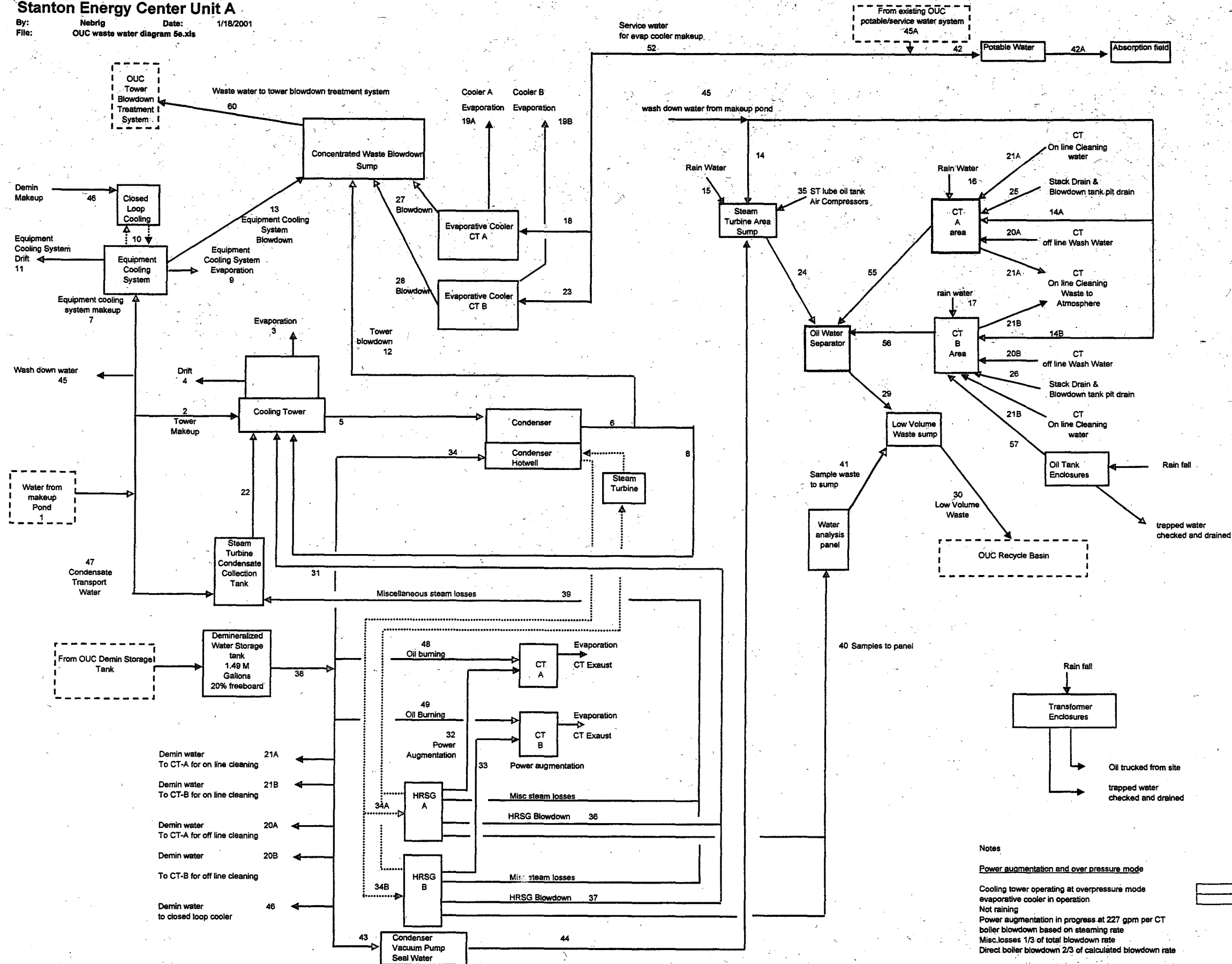
See Attached.

Stanton Energy Center Monthly Water Groundwater Use for 1997-1999



Stanton Energy Center Unit A

By: Nebrig Date: 1/18/2001
File: OUC waste water diagram 5e.xls



Line No.	Stream	Average Flow based on plant operation gpm	Max Flow Power Aug over press gpm
1	Makeup water from OUC makeup pond	2021.6	2778.8
2	Cooling tower makeup	1878.6	2628.8
3	Cooling tower evaporation	1724.5	2402.0
4	Cooling tower drift	2.4	2.5
5	Circulating water pump discharge	118750.0	125000.0
6	Condenser inlet	118750.0	125000.0
7	Equipment cooling system makeup	90.3	95.0
8	Condenser discharge after blowdown	118506.2	124659.0
9	Equipment cooling system evaporation	78.9	83.0
10	Closed loop cooling flow	9500.0	10000.0
11	Equipment cooling system drift	0.2	0.2
12	Cooling tower blowdown	243.8	341.0
13	Equipment cooling system blowdown	11.2	11.8
14	Makeup pond water to steam turbine area for wash down	0.2	0.0
14A	Makeup pond water to CT-A area	0.2	0.0
14b	Makeup pond water to CT-B area	0.2	0.0
15	Rain water to steam turbine area	0.1	0.0
16	Rain water to CT-A area	0.0	0.0
17	Rain water to CT-B area	0.0	0.0
18	Makeup water to CT-A evaporative cooler	26.1	27.4
19A	CT-A evaporative cooler evaporation	22.8	24.0
19B	CT-B evaporative cooler evaporation	22.8	24.0
20A	CT-A off line cleaning wash water	0.1	0.0
20B	CT-B off line cleaning wash water	0.1	0.0
21A	CT-A on line wash water	0.5	0.0
21B	CT-B on line wash water	0.5	0.0
22	Steam turbine collection tank to cooling tower basin	65.4	75.4
23	Water to CT-B evaporative cooler	26.1	27.4
24	Steam turbine area to oil water separator	0.3	0.0
25	CT-A stack drain and blowdown tank pit drain	0.0	0.0
26	CT-A stack drain and blowdown tank pit drain	0.0	0.0
27	CT-A evap cooler blowdown	3.3	3.4
28	CT-B evap cooler blowdown	3.3	3.4
29	Oil water separator to low volume sump	0.8	0.0
30	Low volume waste to OUC recycle basin	10.3	10.0
31	Total block boiler blow down	26.7	41.4
32	Power augmentation to CT A	25.9	227.0
33	Power augmentation to CT B	25.9	227.0
34	Makeup to Condenser Hotwell	101.2	525.7
34a	Makeup for losses at HRSG A	50.6	262.9
34b	Makeup for losses at HRSG B	50.6	262.9
35	Steam turbine lube oil tank and Air Compressors	0.0	0.0
36	HRSG A Blowdown to tower	13.4	20.7
37	HRSG B Blowdown to tower	13.4	20.7
38	Demin. water to process	154.0	525.7
39	Total HRSG miscellaneous losses	13.2	20.4
39A	HRSG A misc. losses	6.6	10.2
39B	HRSG B misc. losses	6.6	10.2
40	Water analysis panel waste	9.8	10.0
41	Panel waste to low volume sump	9.8	10.0
42	Potable water to block from potable water supply	0.6	0.0
42A	Sewage to treatment from block	0.6	0.0
43	Condenser vacuum pump seal water makeup	0.0	0.0
44	Condenser vacuum pump seal water waste	0.0	0.0
45	washdown water	0.6	0.0
45A	From existing OUC potable/service water system	52.7	54.9
46	Closed loop cooling water makeup	0.0	0.0
47	Condensate transport water	52.3	55.0
48	Demin water to CT-A during fuel oil burn	25.8	0.0
49	Demin water to CT-B during fuel oil burn	25.8	0.0
50	Spare		
51	Fire Protection water to site	0.0	0.0
52	Evap cooler makeup from OUC site	52.1	54.9
53	spare		
54	spare		
55	CT - A area sump to oil water separator	0.3	0.0
56	CT - B area sump to oil water separator	0.3	0.0
57	Oil storage tanks to CT - B area sump	0.0	0.0
58	Spare		
59	Spare		
60	Conc. Waste sump to OUC tower blowdown sump	261.5	359.7

Notes

Power augmentation and over pressure mode

Cooling tower operating at overpressure mode
evaporative cooler in operation
Not raining
Power augmentation in progress at 227 gpm per CT
boiler blowdown based on steaming rate
Misc. losses 1/3 of total blowdown rate
Direct boiler blowdown 2/3 of calculated blowdown rate

Blowdown

hot reheat	719782
Lp admission	20489
Main steam	803371
	1543622 #/hr
	30.87244 gpm

Average Flow Based on plant operation

operation factor	0.95
Normal operation a function of power factor and power aug. and oil burning	
power augmentation operation	1000 hours
oil burning	1000 hours
evaporative cooler in operation 12 hours per day	
Assume washdown of 100 gpm for 60 minutes per week (20 minutes per area)	
rain water	48.11 inches annual
steam turbine sump	1556 ft2
CT A sump	220 ft2
CTB sump	220 ft2
on line cleaning 780 gallons once per day exhausted to atmosphere.	
off line cleaning 2430 gallons once per month trucked from site	
assume 30 gallons per day per person, 30 persons/day	
1% boiler blowdown based on steaming rate	
Misc. losses 1/3 of total blowdown rate	
Direct boiler blowdown 2/3 of calculated blowdown rate	

I-5. Please provide a table projecting expected growth over the next 15 years. What is the reason for the projected growth?

Water use for existing Units 1 and 2 and proposed Unit A is predicted to remain fairly constant over the next 15 years. Variations in water use from year to year may result due to variations in load requirements or availability of the units. Water requirements at the facility may change if units are added or removed, but plans for such changes at the site do not exist at this time.

II. Describe in detail the flow of wastewater from the plant to its ultimate disposal. Also, provide the applicable Florida Department of Environmental Protection, Environmental Protection Agency permit numbers (EPA, FDEP) issued for discharge to surface waters. Attach daily flow amounts for effluent discharged to surface waters for the last 12 months. Include this information in the above requested schematic diagram.

Wastewaters produced at the Stanton Energy Center are recycled and reused within the process. Wastewater that has become too concentrated for further reuse in the process is treated by evaporative processes that reject dissolved solids from the wastewater. This results in recovery of a large portion of the water from the wastewater stream. The rejected solids are disposed of in on-site landfills, and the recovered water is used as makeup to the facility's cooling towers.

Due to the zero liquid discharge operation of the plant, no wastewaters are discharged from the plant to surface waters. For this reason, permits for discharge to surface waters are not required for the plant and information about the discharge to surface waters over the last twelve months does not exist.

III-1. Provide water quality data for effluent discharged from this facility during the last 12 months.

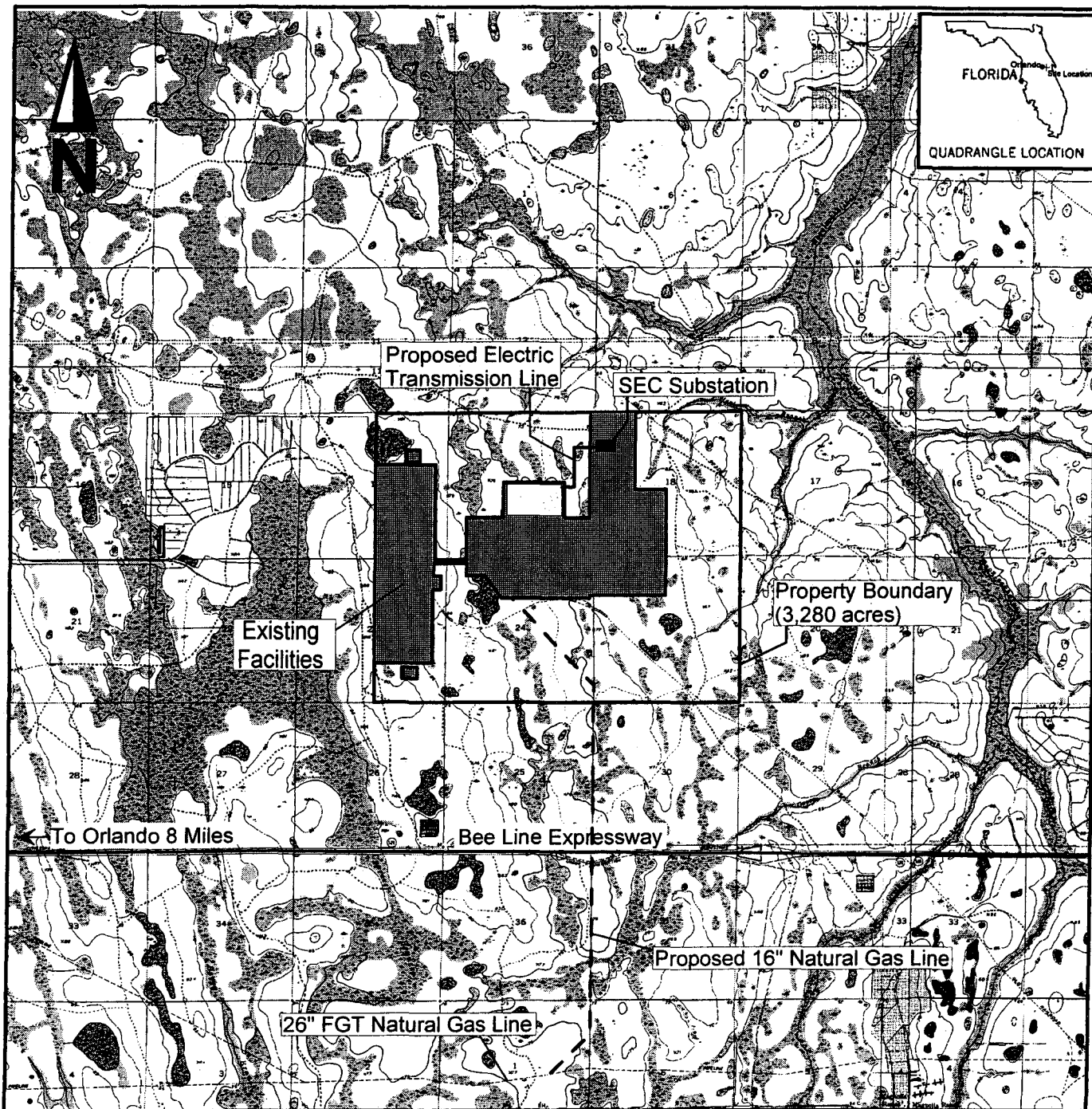
Stanton Energy Center is designed for recycle and reuse of wastewater streams. As such, there is no effluent discharge from the facility.

III-2. Provide the level of water quality required for each individual manufacturing and cooling process. Provide supporting documentation as to water quality and quantity limitation of reuse for each component of the process.

Water Use	Quality Requirements	Constituent	PPM
Makeup to Boilers/Heat Recovery Steam Generators	ABMA and ASME Suggested Water Chemistry Limits for High Pressure Boiler Feedwater EPRI Guidelines for Fossil Fuel Cycle Chemistry	Total Dissolved Solids	0.1
		Suspended Solids	1
		Dissolved Oxygen	<0.007
		Total iron (Fe)	≤0.01
		Total copper (Cu)	≤0.01
		Total hardness	ND
		pH	8.8-9.6
		Nonvolatile TOC	<0.2
		Oily Matter	<0.2
Cooling Tower Makeup	Circulating water limits per good engineering practice	Ca (as CaCO ₃)	<900
		SiO ₂ (as Si O ₂)	<150
		Mg(asCaCO3)xSiO2(as SiO2)	<35,000
		m-Alkalinity	<150
		Na + K	<0.5
		Ca	<1.0
		TDS	<5
Water injection for NOx Control	Demineralized Water per requirements of the	Demineralized water for NOx injection will be taken from the same source as the boiler	

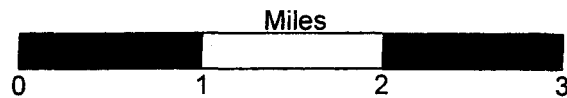
	combustion turbine manufacturer	feedwater, so the quality requirements will be the same.	
Makeup to Evaporative Coolers	Service Water Quality Requirements of the evaporative coolers manufacturer	Constituent	PPM
		Calcium Hardness (as CaCO ₃)	50-150
		Total Alkalinity (as CaCO ₃)	50-100
		Chlorides (as Cl)	<50
		Silica (as SiO)	<25
		Iron (as Fe)	<0.2
		Oil and Grease	<2.0
		Total Dissolved Solids	<500
		Suspended Solids	<5
		PH	7.0-8.5

Wastewater from all process components are recycled and reused to the extent practical. Wastewater that is too concentrated for further reuse is treated in an evaporative process to remove the dissolved solids. The recovered water from the evaporative process is recycled and reused in the cooling towers.



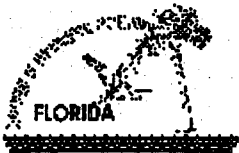
Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Property Boundary: Orange Co.; Sections 13, 24, E1/2 14, E1/2 23 of Township 23S, Range 31E; Sections 18, 19 of Township 23S, Range 32E



Stanton Energy Center Property Location Figure 2

**NOTIFICATION FOR USE OF THE GENERAL PERMIT FOR
CONSTRUCTION OF AN EXTENSION TO A PUBLIC DRINKING
WATER DISTRIBUTION SYSTEM**



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: Curtis H. Stanton Energy Center – Combined Cycle Unit A (Stanton A)

!Project Description: Stanton A proposed a 633 MW combined cycle combustion turbine power plant jointly owned by Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), Orlando Utilities Commission (OUC), and Southern Company – Florida, LLC. Bulk electricity is generated and sold to OUC, KUA, and FMPA customers. Stanton A will be provided potable water by an extension of the existing Units 1 and 2 non-community public drinking water system.

!Project Location

County: Orange Section: 13, 24, 18, 19, and eastern half of 14 and 23 Township: 235 Range: 31E and 32E

!Permittee

Utility/Company Name: Orlando Utilities Commission (OUC) Telephone No.: (407) 423-9100

Address: 500 South Orange Avenue

City: Orlando State: Florida Zip Code: 32802

!Public Water System Supplying Water for Project

System Name: Stanton Energy Center PWS Identification No.: 3484130

System Owner: Orlando Utilities Commission (OUC) Telephone No.: _____

Address: see above

City: _____ State: _____ Zip Code: _____

!Owner/Operator of Project After It Is Placed into Service

Utility/Company Name: OUC/Southern - Florida Telephone No.: _____

Address: _____

City: _____ State: _____ Zip Code: _____

!Professional Engineer in Responsible Charge of Designing Project

Name of Engineer: Rod Unruh

Firm Name: Black & Veatch Telephone No.: (913) 458-2000

Address: 11401 Lamar

City: Overland Park State: Kansas Zip Code: 66211

Notification for Use of the General Permit for Construction of an Extension to a Public Drinking Water Distribution System

Project Name: Curtis H. Stanton Energy Center – Combined Cycle Unit A

Permittee: Orlando Utilities Commission (OUC)

II. STATEMENT BY PERMITTEE

I, the undersigned owner or authorized representative* of OUC, 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.

by Thomas B. Jant OUC 1-16-01
Signature and Date Vice President

Fred Haddad
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 OUC, 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: Stanton Energy Center
- Construction Permit Number(s) for Plant and Date(s) Permit(s) Issued: Site Certification Order PA 81-14, 12/82
- Permitted Maximum Day Capacity of Plant:

- Maximum Day Flow at Plant as Recorded on Monthly Operating Reports During Past 12 Months:

by Thomas B. Jant V. President OUC
Signature and Date 1-16-01

Fred Haddad
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 OUC, 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.

by Thomas B. Jant V. Pres - OUC
Signature and Date 1-16-01

Fred Haddad
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: Curtis H. Stanton Energy Center – Combined Cycle Unit A

Permittee: OUC

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 "T," and the following requirements preceded by an "NA" are not applicable to this project.

- T (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.
- T (2) The plans or specifications include procedures for keeping existing water mains in service or for minimizing interruption of existing water service during construction.
- T (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.
- T (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.)
- T (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.
- T (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.
- T (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.
- T (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.)
- T (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.
- T (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.
- T (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.
- T (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: Curtis H. Stanton Energy Center – Combined Cycle Unit A

Permittee: OUC

- T (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.
- T (14) All tees, bends, plugs, and hydrants in new and relocated water mains are provided with reaction blocking or restrained joints to prevent movement.
- T (15) It is required that all new and relocated water mains be pressure tested and leakage tested in accordance with AWWA Standard C600.
- T (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.
- T (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.)
- T (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.
- T (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.
- T (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*.
- T (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: Curtis H. Stanton Energy Center – Combined Cycle Unit A

Permittee: OUC

- T (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.

Signature, Date, and Seal

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
Single-Family Home	0				0	0
Mobile Home	0				0	0
Apartment	0				0	0
Commercial, Institutional, or Industrial Facility*	1				.32 gpd	.895 gpd
Total	1				.32 gpd	.895 gpd

* Description of Commercial, Institutional, and Industrial Facilities and Explanation of Method Used to Estimate Average Day Water Demand for These Facilities:

The Facility is a new power plant unit at an existing power generating station. Potable uses were estimated at 1500 gpd based on 10 employees for three operating shifts with 50 gpd/person.

H Explanation of Method Used to Estimate Maximum Day Water Demand:

The maximum potable water estimate (1500 gpd) is based on the assumption of 10 staff per shift, three shifts per day with a consumption per person per shift of 50 gallons

2. Design/Projected Maximum Hour Water Demand for Proposed Altered/New Distribution Facilities Under this Project and Basis of Design/Projection: Maximum hour water demand is estimated, for potable water, to be 270 gallons, using the following basis: Toilets 40 gallons (5 stools at 7 gpf and 5 urinals at 1 gpf); Showers 200 gallons (5 minute showers at 8 gpm); Sinks 30 gallons (20 gallons for hand washing and 10 gallons for potable uses. Note: these are rough estimates.
3. 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: Projected fire demand—2500 gpm. No coincident draft anticipated, isolated system unable to be utilized for other uses.
4. Operating Pressure Range for Proposed Altered/New Distribution Facilities Under this Project:
5. 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.:

UTILITY PERMIT

STATE OF FLORIDA DEPARTMENT OF TRANSPORTATION
UTILITY PERMIT

FORM 710-010-85
UTILITIES
OGC - 01/99
Page 1 of 2

PERMIT NO.: _____ SECTION NO.: _____ STATE ROAD: 528 COUNTY: Orange

FDOT construction is proposed or underway. ☐ Yes ☒ No Financial Project ID: N/A
Is this work related to an approved Utility Relocation Schedule? ☐ Yes ☒ No If yes, Document Number: _____

PERMITTEE: Orlando Utilities Commission

ADDRESS: 500 South Orange Avenue TELEPHONE NUMBER: (407) 244 - 8732
PO Box 3193 Orlando, FL 32802

The above PERMITTEE requests permission from the State of Florida Department of Transportation, hereinafter called the FDOT, to construct, operate and maintain the following:

OUC Proposes to construct a natural gas pipeline underneath the Bee Line

Expressway in the Orlando area. A drawing set of the gas line in this area is included and can

be seen on drawing S3306. The pipeline will have 4 feet of cover, as seen on the typical cross-
section shown on drawing S3310

FROM: _____ TO: _____

Submitted for the PERMITTEE by: F. F. Haddad, VP-OUC _____
Name and Title (Typed or Printed Legibly) Signature Date

1. The PERMITTEE declares that prior to filing this application, the location of all existing utilities that it owns or has an interest in, both aerial and underground, are accurately shown on the plans and a letter of notification was mailed on _____ to the following utilities known to be involved or potentially impacted in the area of the proposed installation: None

2. The local Maintenance or Resident Engineer, hereafter referred to as the FDOT Engineer, shall be notified forty-eight (48) hours prior to starting work and again immediately upon completion of work. The FDOT's Engineer is _____, located at _____, Telephone Number _____. The PERMITTEE's employee responsible for Maintenance of Traffic is Vince Galluci, Telephone Number 407-658-6444 ext 3752 (This name may be provided at the time of the 48 hour notice prior to starting work).

3. All work, materials, and equipment shall be subject to inspection and approval by the FDOT Engineer.
4. All plans and installations shall conform to the requirements of the FDOT's Utility Accommodation Manual in effect as of the date this permit is approved by FDOT, and shall be made a part of this permit. This provision shall not limit the authority of the FDOT under Paragraph 8 of this Permit.
5. This PERMITTEE shall commence actual construction in good faith within _____ days after issuance of permit, and shall be completed within _____ days after the permitted work has begun. If the beginning date is more than 60 days from the date of permit approval, the PERMITTEE must review the permit with the FDOT Engineer to make sure no changes have occurred to the Transportation Facility that would affect the permitted construction.
6. The construction and maintenance of such utility shall not interfere with the property and rights of a prior PERMITTEE.
7. It is expressly stipulated that this permit is a license for permissive use only and that the placing of utilities upon public property pursuant to this permit shall not operate to create or vest any property right in said holder, except as provided in executed subordination and Railroad Utility Agreements.
8. Pursuant to Section 337.403(1), Florida Statutes, any utility placed upon, under, over, or along any public road or publicly owned rail corridor that is found by FDOT to be unreasonably interfering in any way with the convenient, safe, or continuous use, or maintenance, improvement, extension, or expansion, of such public road or publicly owned rail corridor shall, upon 30 days' written notice to the utility or its agent by FDOT, be removed or relocated by such utility at its own expense except as provided in paragraphs (a) and (b), and except for reimbursement rights set forth in previously executed subordination and Railroad Utility Agreements, and shall apply to all successors and assigns for the permitted facility.
9. It is agreed that in the event the relocation of said utilities are scheduled to be done simultaneously with the FDOT's construction work, the PERMITTEE will coordinate with the FDOT before proceeding and shall cooperate with the FDOT's contractor to arrange the sequence of work so as not to delay the work of the FDOT's contractor, defend any legal claims of the FDOT's contractor due to delays caused by the PERMITTEE's failure to comply with the approved schedule, and shall comply with all provisions of the law and the FDOT's current Utility Accommodation Manual. The PERMITTEE shall not be responsible for delay beyond its control.
10. In the case of non-compliance with the FDOT's requirements in effect as of the date this permit is approved, this permit is void and the facility will have to be brought into compliance or removed from the right of way at no cost to the FDOT, except for reimbursement rights set forth in previously executed subordination and Railroad Utility Agreements. This provision shall not limit the authority of the FDOT under Paragraph 8 of this Permit.
11. It is understood and agreed that the rights and privileges herein set out are granted only to the extent of the State's right, title and interest in the land to be entered upon and used by the PERMITTEE, and the PERMITTEE will, at all times, and to the extent permitted by law, assume all risk of and indemnify, defend, and save harmless the State of Florida and the FDOT from and against any and all loss, damage, cost or expense arising in any manner on account of the exercise or attempted exercises by said PERMITTEE of the aforesaid rights and privileges.

- During construction, all safety regulations of the FDOT shall be observed and the PERMITTEE must take measures, including placing and the display of safety devices that may be necessary in order to safely conduct the public through the project area in accordance with the Federal Manual on Uniform Traffic Control Devices, as amended for highways, the requirements of the Standard Application Package for railways, including flagging services and Railroad Protective Insurance or acceptable alternative, when applicable, and the FDOT's latest Roadway and Traffic Design Standards and Standard Specifications for Road and Bridge Construction, as amended. When a Utility deems it necessary to conduct Traffic Control activities and methods significantly different from those addressed in the above references, the Utility must submit an alternative plan signed and sealed by a qualified registered Florida professional engineer qualified to develop Traffic Control Planning in accordance with the provisions of the Utility Accommodation Manual, Chapter 8.
13. Should the PERMITTEE be desirous of keeping its utilities in place and out of service, the PERMITTEE, by execution of this permit acknowledges its present and continuing ownership of its utilities located between _____ and _____ within the FDOT's rights-of-way as set forth above. Whenever the PERMITTEE removes its facilities, it shall be at the Permittee's sole cost and expense. The

14. In the event contaminated soil is encountered by the Utility or anyone within the permitted construction limits, the Utility shall immediately cease work and notify the FDOT. The FDOT shall coordinate with the appropriate agencies and notify the PERMITTEE of any suspension or revocation of the permit until contamination assessment and remediation, as appropriate under Rule Chapters 62-770 and 62-730 Florida Administrative Code, has progressed to a state that all environmental regulatory agencies having jurisdiction have approved the site of the contamination for resumption of work.
15. During excavation operations, an on-site representative of the PERMITTEE may be required to perform the following activities with respect to their own facilities: physically expose or direct exposure of underground facilities, provide any necessary support to facilities and/or cover aerial facilities as deemed necessary to aid construction.
- Pursuant to Section 337.401(2), Florida Statutes, the permit shall require the permit holder to be responsible for damage resulting from the issuance of the permit. The Department may initiate injunctive proceedings as provided in s.120.69 to enforce provisions of this subsection or any rule or order issued or entered into pursuant thereto.
17. Pursuant to Section 337.402, Florida Statutes, when any public road or publicly owned rail corridor is damaged or impaired in any way because of the installation, inspection, or repair of a utility located on such road or publicly owned rail corridor, the owner of the utility shall, at his or her own expense, restore the road or publicly owned rail corridor to its original condition before such damage. If the owner fails to make such restoration, the authority is authorized to do so and charge the cost thereof against the owner under the provisions of s.337.404.
18. Special FDOT instructions:

It is understood and agreed that commencement by the PERMITTEE is acknowledgment and acceptance of the binding nature of all the above listed permit conditions and special instructions.

19. By the below signature, the Permittee hereby represents that no change to the FDOT's standard Utility Permit form, as incorporated by reference into Rule 14-46.001, for this Utility Permit has been made which has not been previously called to the attention of the FDOT (and signified to by checking the appropriate box below) by a separate attached written document showing all changes and the written and dated approval of the FDOT Engineer. Are there attachments reflecting change/s to the standard form? ☒ NO ☐ YES If Yes, _____ pages are attached.

PERMITTEE: Frederick F. Haddad, Jr. SIGNATURE: _____ DATE: _____
Name & Title of Authorized Permittee or Agent
(Typed or Printed Legibly)
V.P. Power Resources, OUC

APPROVED BY: _____ ISSUE DATE: _____
District Maintenance Engineer or Designee

UTILITY PERMIT FINAL INSPECTION CERTIFICATION

DATE: _____

DATE WORK STARTED: _____

DATE WORK COMPLETED: _____

INSPECTED BY: _____ (Permittee or Agent)

REMARKS (Brief summary of approved plans changes):

CHANGE APPROVED BY: _____ DATE: _____
District Maintenance Engineer or Designee

I the undersigned PERMITTEE do hereby CERTIFY that the utility construction approved by the above numbered permit was inspected and installed in accordance with the approved plans made a part of this permit and in accordance with the FDOT's current Utility Accommodation Manual. All plan changes have been approved by the FDOT's Engineer and are attached to this permit. I also certify that the work area has been left in as good or better condition than when the work was begun.

PERMITTEE: _____ SIGNATURE: _____ DATE: _____
Name & Title of Authorized Permittee or Agent
(Typed or Printed Legibly)

CC: District Permit Office
Permittee

10.5 Existing Local Permits

This section is not applicable for the Stanton A application because this is a supplemental SCA for a power plant site previously certified for ultimate capacity.

10.6 Local Permit Applications

10.6.1 Septic System Permit

An onsite septic system will be constructed for the Unit A facilities. The general construction contractor will be required to complete and submit an Onsite Sewage Disposal System Permit Application.

10.6.2 Certificate of Occupancy

A Certificate of Occupancy will be required to occupy the Unit A facilities. The Certificate is issued following approval of the building plans.

10.7 Prevention of Significant Deterioration (PSD) Permit Application

The construction and operation of Unit A 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

10.8 Site Subsurface Data

Three separate reports were prepared prior to construction of Units 1 and 2 describing the subsurface conditions at Stanton.

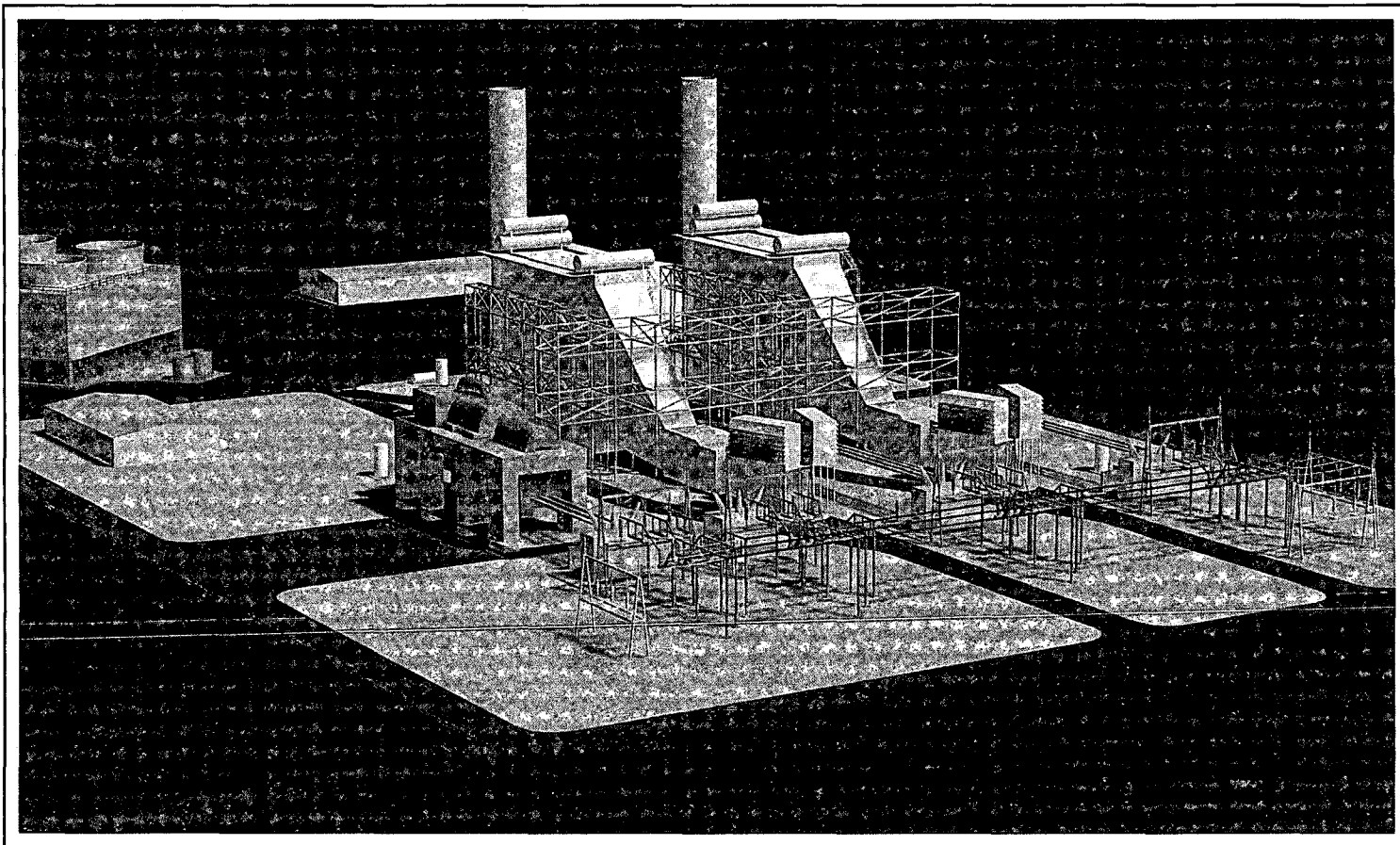
10.9 Ground Water Quality Data

Ground water quality monitoring reports from 1998 to 2000 are discussed in Subsection 2.3.2.1.

Supplemental Site Certification Application
Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A

Supplemental Site Certification Application

Appendix 10.7 – PSD Application



Orlando Utilities Commission Curtis H. Stanton Energy Center Combined Cycle Unit A

B&V Project 98362

January 2001



**Curtis H. Stanton Energy Center
Combined Cycle Unit A**

Appendix 10.7 - PSD Application

Manual Number CHSEC - 026

Issued to Stacey Anderson

Location _____

Appendix 10.7

**Prevention of Significant Deterioration
Air Permit Application
for the
Curtis H. Stanton Energy Center
Combined Cycle
Combustion Turbine Project**

Submitted by

**Orlando Utilities Commission
Kissimmee Utility Authority
Florida Municipal Power Authority
and
Southern Company-Florida, LLC**

**Prepared by
Black & Veatch**

**January 2001
Project No. 98362**

Contents

1.0 Introduction.....	1-1
2.0 Project Characterization.....	2-1
2.1 Project Location.....	2-1
2.2 Project Description.....	2-1
2.3 Project Emissions.....	2-3
2.3.1 Project Emissions.....	2-3
2.4 Maximum Potential-to-Emit	2-5
2.5 New Source Review Applicability.....	2-5
2.5.1 Prevention of Significant Deterioration	2-5
3.0 Best Available Control Technology.....	3-1
4.0 Air Quality Impact Analysis	4-1
4.1 Model Selection	4-1
4.2 Model Input and Options	4-1
4.2.1 Model Input Source Parameters.....	4-1
4.2.2 Land Use Dispersion Coefficient Determination.....	4-2
4.2.3 GEP Stack Height Determination	4-2
4.2.4 Model Defaults.....	4-2
4.2.5 Receptor Grid and Terrain Considerations	4-4
4.2.6 Meteorological Data.....	4-4
4.3 Model Results	4-4
4.3.1 Comparison to PSD Significant Impact Levels and Preconstruction Monitoring Requirements	4-6
5.0 Additional and Class I Area Impact Analyses	5-1
5.1 Model Selection and Inputs	5-1
5.1.1 CALPUFF Model Settings.....	5-3
5.1.2 Building Wake Effects.....	5-3
5.1.3 Receptor Locations	5-3
5.1.4 Meteorological Data Processing	5-3
5.1.4.1 CALMET Settings	5-3
5.1.4.2 Modeling Domain	5-3
5.1.4.3 Mesoscale Model Data.....	5-7
5.1.4.4 Surface Data Stations and Processing.....	5-7
5.1.4.5 Upper Air Data Stations and Processing.....	5-9
5.1.4.6 Precipitation Data Stations and Processing.....	5-9
5.1.4.7 Geophysical Data Processing.....	5-9

5.1.5 Facility Emissions	5-14
5.2 Class I Analyses	5-14
5.3 Regional Haze Analyses	5-14
5.3.1 Visibility	5-14
5.3.2 Background Visual Ranges and Relative Humidity Factors.....	5-16
5.3.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines	5-17
5.3.4 Visibility/Regional Haze Results.....	5-19
5.4 Deposition Analysis	5-19
5.5 Class I Impact Analysis	5-19
5.6 Commercial, Residential, and Industrial Growth	5-22
5.7 Vegetation and Soils	5-22
6.0 Hazardous Air Pollutants	6-1
6.1 Maximum Achievable Control Technology (MACT)	6-1
Determination	6-1
6.1.1 NESHAPs	6-1
6.1.2 Potential-To-Emit Hazardous Air Pollutants and MACT Applicability	6-1

Tables

Table 2-1	CTG/HRSG Maximum Emission Rates (lb/h)	2-6
Table 2-2	PSD Applicability	2-7
Table 4-1	Representative (<i>Enveloped</i>) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis	4-3
Table 4-2	ISCST3 Model Predicted Maximum Annual Concentrations of NO _x	4-7
Table 4-3	ISCST3 Model Predicted Maximum 1-Hour Concentrations of CO	4-8
Table 4-4	ISCST3 Model Predicted Maximum 8-Hour Concentrations of CO	4-9
Table 4-5	ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM ₁₀	4-10
Table 4-6	ISCST3 Model Predicted Maximum 24-Hour Concentrations of PM/PM ₁₀	4-11
Table 4-7	ISCST3 Model Predicted Maximum Annual Concentrations of SO ₂	4-12
Table 4-8	ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO ₂	4-13
Table 4-9	ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO ₂	4-14
Table 4-10	Comparison of Maximum Predicted Impacts With the PSD Class II Significant Impact Levels and the PSD De Minimis Monitoring Levels.....	4-15
Table 5-1	CALPUFF Model Settings.....	5-4
Table 5-2	CALMET Settings	5-6
Table 5-3	Meteorological Stations Used in the CALPUFF Analysis	5-10
Table 5-4	Hourly Precipitation Stations Used in the CALPUFF Analysis	5-12
Table 5-5	Stack Parameters and Pollutant Emissions Used in the CALPUFF Analysis	5-15
Table 5-6	Outline of IWAQM Refined Modeling Analyses	

Tables (Continued)

	Recommendations.....	5-18
Table 5-7	CALPUFF Refined Analysis Results on CNWR	5-20
Table 5-8	CNWR Sulfur and Nitrogen Deposition Results	5-21
Table 5-9	CNWR Class I Significant Impact Level (SIL) Results	5-23

Figures

Figure 2-1	Stanton Energy Center Property Location	2-2
Figure 2-2	Site Arrangement of the Brandy Branch Generation Station.....	2-4
Figure 4-1	Receptor Locations	4-5
Figure 5-1	Location of Stanton Energy Center with Respect to..... Chassahowitzka National Wildlife Refuge	5-2
Figure 5-2	Chassahowitzka National Wildlife Refuge Receptors.....	5-5
Figure 5-3	CALMET/CALPUFF Modeling Domain	5-8
Figure 5-4	Surface and Upper Air Meteorological Stations.....	5-11
Figure 5-5	Precipitation Stations	5-13

Attachments

Attachment 1 Operating Matrix

Attachment 2 Performance Data

Attachment 3 Potential-To-Emit (PTE), Enveloped Spreadsheet, and HAPs Analysis

Attachment 4 Best Available Control Technology

Attachment 5 Air Modeling Protocols

Attachment 6 Air Dispersion Modeling Files

1.0 Introduction

Orlando Utilities Commission (OUC), in conjunction with Kissimmee Utility Authority (KUA), Florida Municipal Power Authority (FMPA), and Southern-Florida, propose to construct and operate a 633 MW (nominal) electric generating unit at the existing Curtis H. Stanton Energy Center facility (hereinafter referred to as the "Project") near the city of Orlando, Florida in Orange County.

The Project will include the construction of two combined cycle combustion turbine (CCCT) units nominally rated at approximately 317 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a backup fuel. Each CCCT will be equipped with a heat recovery steam generator (HRSG) containing natural gas-fired duct burners. The two CCCT/HRSGs will feed a single, common steam turbine generator, this configuration is regularly referred to as a 2x1 configuration.

This report is a technical support document for the Prevention of Significant Deterioration (PSD) 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 (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project including a general description of the location, 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

The Project is located in east central Orange County, Florida. Figure 2-1 shows the general location of the Project, which is approximately 8 miles east of the city of Orlando. The approximate Universal Transverse Mercator (UTM) coordinates of the Project are 483,609 m East and 3,151,100 m North. The nearest Federal PSD Class I Area is the Chassahowitzka National Wildlife Refuge located approximately 140 kilometers (km) west-northwest of the Project.

The topography of the area is unpronounced and considered relatively flat.

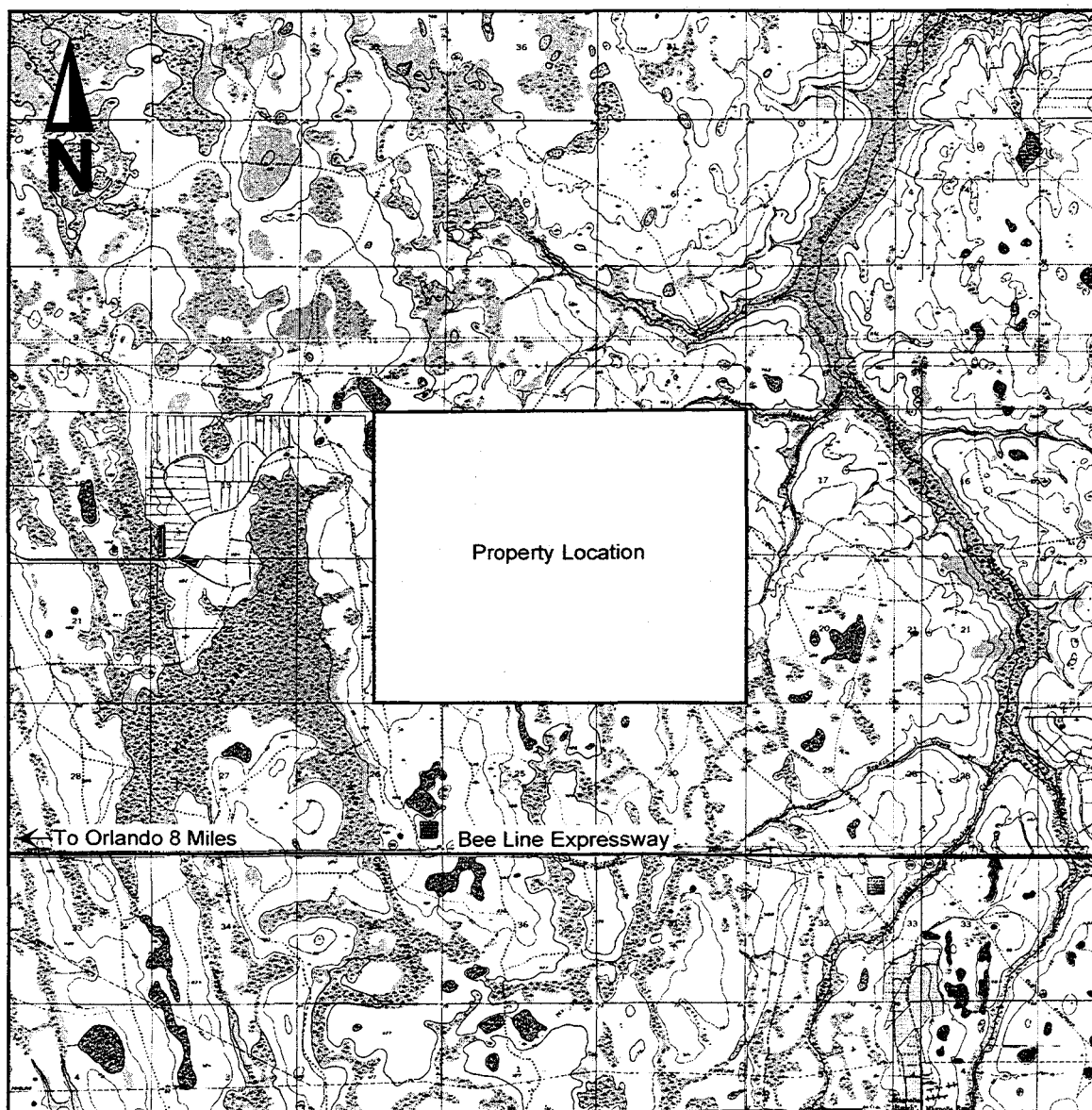
2.2 Project Description

The Project will be located at the existing Stanton Energy Center. The two CCCT units will be operated in a 2x1 configuration. Major equipment associated with each CCCT unit will consist of a General Electric (Model PG7241FA) combustion turbine generator, heat recovery steam generator (HRSG) with supplemental duct firing, steam generator, a 10-cell cooling tower, and a No. distillate fuel oil storage tank.

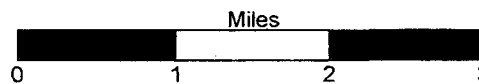
The project operation will consist of two CCCT/HRSGs capable of operating 8,760 hours while firing natural gas with the potential of 8,760 hours of natural gas duct firing and 1,000 hours of power augmentation, plus 1,000 hours of distillate fuel oil firing, as backup, per CCCT.

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 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.

Supplemental (duct) firing with natural gas will be used to increase the thermal energy of the combustion gases exhausting from each CCCT. The resulting high-pressure steam produced in each HRSG will be expanded through a single steam turbine. The rotating mechanical energy generated by the steam turbine will be converted into



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)



Stanton Energy Center Property Location

Figure 2-1

Site Location.srf

electrical energy via a shaft connected to an electrical generator. The exhaust gases will exit to the atmosphere after leaving the HRSG stack.

The CCCT/HRSG will also have the capability of augmenting of the power output by utilizing steam augmentation as the method used to increase power. Steam is injected into the combustor or combustor head end and increases overall mass flow into the CCCT/HRSG, and therefore, output. Steam injection can result in power increases of 15 to 18 percent by injection of up to 5 percent mass flow (of compressor inlet air) of steam into the compressor discharge.

A CCCT/HRSG operating matrix has been developed and is included in Attachment 1. A site arrangement showing the various emission units and structures/buildings at the Project is presented in Figure 2-2.

2.3 Project Emissions

This section discusses the potential-to-emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions will be generated from the following emission units:

- Two General Electric CCCT/HRSGs with supplemental firing.
- One, 10-cell linear mechanical draft cooling tower.
- One, No. 2 distillate fuel oil storage tank (approximately 1,680,000 gallons)

2.3.1 Project Emissions

Performance data for the CCCT/HRSG, based on vendor data from GE at design loads of 50, 75, and 100 percent, natural gas and distillate fuel oil firing, and ambient air temperatures of 19, 45, 60, 70, and 95° F, are provided in Attachment 2.

Ambient temperature data was selected based on meteorological data from Orlando, Florida. An ambient temperature of 19° F represents the lowest anticipated site temperature and maximum power generation. An ambient temperature of 70° F represents the average annual site temperature which is representative of the average heat input rate. An ambient temperature of 95° 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 for all loads and temperatures for combined cycle operation for natural gas and distillate fuel oil firing are presented in Table 2-1.



CENTER UNIT 1A HRSG STACK: E 602442'-0"
N 1510327'-0"
CENTER UNIT 1B HRSG STACK: E 602442'-0"
N 1510207'-0"
CENTER UNIT 2A HRSG STACK: E 602442'-0"
N 1509840'-0"
CENTER UNIT 2B HRSG STACK: E 602442'-0"
N 1509720'-0"

CENTER UNIT 1A	HRSG STACK:	E 1071425.2056
		N 3165216.3816
CENTER UNIT 1B	HRSG STACK:	E 1071427.0434
		N 3165179.7166
CENTER UNIT 2A	HRSG STACK:	E 1071432.6637
		N 3165067.5830
CENTER UNIT 2B	HRSG STACK:	E 1071434.5014
		N 3165030.9181

 DENOTES EQUIP. NO. - SEE D-PS-9000-2
 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=60'-0"

D-PS-9000-3 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SECTIONS

D-PS-9000-4 STANTON ENERGY CENTER - UNIT 3
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=400'-0"

CAD 9000-1D.DWG

AutoCad	SHW-14
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PRELIMINARY

*THIS DOCUMENT CONTAINS PROPRIETARY, CONFIDENTIAL, AND/OR TRADE SECRET INFORMATION OF THE SUBSIDIARIES OF THE SOUTHERN COMPANY OR THIRD PARTIES. IT IS INTENDED FOR USE ONLY BY EMPLOYEES OF, OR AUTHORIZED CONTRACTORS OF, THE SUBSIDIARIES OF THE SOUTHERN COMPANY. UNAUTHORIZED POSSESSION, USE, DISTRIBUTION, COPYING, DISSEMINATION, OR DISCLOSURE OF ANY PORTION HEREOF IS PROHIBITED.

Southern Company Services, Inc.
FOR

SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

[illegible]

2.4 Maximum Potential-to-Emit

The potential-to-emit (PTE) was estimated from the maximum hourly emission rate for each pollutant considering all ambient temperatures in combined cycle operation at 100 percent load. The PTE for each pollutant was based on specific scenarios within the performance data and calculated at 1,000 hours of power augmentation and duct firing using natural gas, 6,760 hours of duct firing using natural gas, and 1,000 hours of distillate fuel oil (0.05 percent sulfur) firing per CCCT. The PTE 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 PTE example calculations are 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 Project is in an attainment area with respect to all pollutants. As such, the PSD program will apply to the Project, as administered by the State of Florida under 62-212.400, FAC, Stationary Sources - Preconstruction Review, Prevention of Significant Deterioration.

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 Stanton Energy Center's new Project is classified as a major modification, having a PTE greater than 100 tpy for at least one regulated pollutant. Additionally, the estimated emission increases of NO_x, CO, PM/PM₁₀, and SO₂, and VOC resulting from the modification exceed the PSD significant emissions levels of 40, 100, 25/15, 40, and 40 tpy, respectively. Therefore, the Project emissions of NO_x, CO, PM/PM₁₀, and SO₂, and VOC are subject to PSD review as a major modification. The

Table 2-1
CTG/HRSG Maximum Emission Rates (lb/h)^a

Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NO _x	30.38	79.69
CO	142.51	71.00
PM/PM ₁₀	11.71	17.00
SO ₂	3.50	107.00
VOC	20.13	8.00
H ₂ SO ₄	0.43	13.05

^aMaximum pound per hour emission rates considering all loads (100, 75, and 50%), all temperatures (19, 45, 60, 70, and 95°F), and fuels for combined cycle operation.

^bH₂SO₄ emission rate based on a 10% conversion of SO₂ to SO₃ and a molecular ratio of 1.22 from SO₃ to H₂SO₄ (in the stack and SCR).

**Table 2-2
PSD Applicability**

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO _x	314.5 ^a	40	yes
CO	870.1 ^a	100	yes
PM/PM ₁₀	127.6 ^{a,b,c}	25/15	yes
SO ₂	134.1 ^{a,d}	40	yes
VOC	105.8 ^{a,e}	40	yes
H ₂ SO ₄	17.6 ^{a,f}	7	yes
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Total Fluorides	negl.	3	no
Lead	0.03 ^g	0.6	no
Mercury	0.004 ^g	0.1	no
Total HAPs	18.0 ^{g,h}	10/25	no

^aBased on maximum lb/h emission rate considering all temperature conditions for base load and assuming operating scenarios of 1,000 hours of power augmentation and duct firing on natural gas, 6,760 hours of duct firing on natural gas, and 1,000 hours of distillate fuel oil firing per CCCT.

^bAssumes front half PM/PM₁₀ emissions.

^cPM/PM₁₀ PTE include emissions from the cooling tower.

^dBased on 0.05% sulfur distillate fuel oil and 0.5 gr/100 scf sulfur natural gas.

^eVOC PTE includes emissions from the fuel oil storage tank.

^fH₂SO₄ emission rate based on a 10% conversion of SO₂ to SO₃ and a molecular ratio of 1.22 from SO₃ to H₂SO₄ for Natural Gas firing in addition to sulfur mist emissions presented in the performance data for Fuel Oil firing.

^gBased on AP-42 emission factors, assuming a conservative worst-case operating scenario of two CCCT/HRSGs operating 8,760 hours firing natural gas with 8,760 hours of natural gas duct firing and 1,000 hours of power augmentation, plus 1,000 hours of distillate fuel oil firing per CCCT.

^hHAPs calculation sheet is included Attachment 3.

Note: PTE example calculations are provided in Attachment 3.

PSD review includes a BACT analysis, air quality impact analysis, and an assessment of the Project's impact on general commercial and residential growth, soils and vegetation, and visibility, as well as a Class I impact analysis.

3.0 Best Available Control Technology

A summary of the best available control technology (BACT) analysis for the Project has been included below. Additionally, the detailed BACT for the Project has been included as Attachment 4.

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for the project. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for the BACT analysis are based on each CCCT/HRSG unit operating at three different operating conditions. These three conditions are 1) natural gas operation at full load with duct burner firing for 6,760 hours per year at an ambient temperature of 70°F, 2) natural gas firing with power augmentation for 1,000 hours per year at an ambient temperature of 70°F with the combustion turbine and duct burner firing at full load, 3) fuel oil firing of the combustion turbine-generator (CTG) unit at full load operation without duct firing for 1,000 hours per year at an ambient temperature of 70°F.

GE PG7241(FA) CCCT/HRSG Units:

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners with selective catalytic reduction (SCR) during natural gas firing and water injection with an SCR for fuel oil firing to achieve the following emission limits.

Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O₂.

Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O₂.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O₂ (without power augmentation) and 26.3 ppmvd at 15 percent O₂ (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O₂ during fuel oil firing.

Particulate (PM/PM₁₀) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O₂

(without power augmentation) and 6.3 ppmvd at 15 percent O₂ (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O₂ during fuel oil firing.

Sulfur Dioxide (SO₂) emissions -- BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate (PM/PM₁₀) emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

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, PM/PM₁₀, and SO₂). 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 OUC in a letter from Black & Veatch dated June 7, 2000. The agreed upon protocol was a result of an earlier meeting with FDEP on May 31, 2000 in which details of the analysis to be performed were discussed and approved. A copy of the protocol is presented in Attachment 5.

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3, Version 00101) air dispersion model was used to predict maximum ground level concentrations associated with the Project. 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 determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing the Project's proposed operating load range (i.e., 50, 75, and 100 percent loads) with a representative set of stack parameters and pollutant emission rates 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 were provided by Southern Company on November 17, 2000 and are presented in Table 4-1. A 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 Project was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the Project location, it was concluded that over 50 percent of the area surrounding the Project 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 (Coal Units 1 and 2) and proposed (CCCT/HRSG 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, Version 95086) 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 the Project is 64.05 m (210 ft). The actual modeled height for each stack is 48.768 m (160 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.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

Table 4-1
Representative (*Enveloped*) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis^a

CCCT/HRSG Operating Scenario	ISCST3 Source ID ^b	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO _x	CO	PM/PM ₁₀	SO ₂
Natural Gas	#STK16G	100	48.77	5.79	16.75	348.71	3.83	17.96	1.48	0.44
	#STK76G	75	48.77	5.79	13.49	347.59	2.42	5.04	1.13	0.35
	#STK56G	50	48.77	5.79	11.19	342.59	1.91	4.16	1.13	0.35
Distillate Fuel Oil	#STK16O	100	48.77	5.79	19.90	406.48	10.04	8.95	2.14	13.48
	#STK76O	75	48.77	5.79	16.94	400.93	8.01	7.43	2.14	10.84
	#STK56O	50	48.77	5.79	13.38	393.71	6.21	8.32	2.14	8.57
Annualized ^c	#STK16	100	48.77	5.79	16.75	348.71	4.52	N/A	1.54	1.93
	#STK76	75	48.77	5.79	13.49	347.59	3.06	N/A	1.25	1.55
	#STK56	50	48.77	5.79	11.19	342.59	2.40	N/A	1.25	1.29

^aRepresentative stack parameters and emission rates were provided by Southern-Florida on November 17, 2000 and January 11, 2001, and are contained in Attachment 2 and summarized for ISCST3 modeling in Attachment 3.

^bThe "#STK" character in the ISCST3 Source ID name refers to either 1STK, or 2STK, which refer to stack 1 or stack 2; 1,7, or 5 refer to 100, 75, or 50 percent load; 6 refers to a 160 foot stack; and G or O refer to natural gas or distillate fuel oil fired.

^cAnnualized emission rates at 100% load are based on the maximum lb/h emission rate considering all temperature conditions and assuming operating scenarios of 1,000 hours of power augmentation and duct firing on natural gas, 6,760 hours of duct firing on natural gas, and 1,000 hours of distillate fuel oil firing per CCCT. The annualized emission rates at 75 and 50% loads are based on the maximum lb/h emission rate considering all temperature conditions and assuming operating scenarios of 7,760 hours of duct firing on natural gas, and 1,000 hours of distillate fuel oil firing per CCCT. Other annualized stack parameters were based on the natural gas firing and the specific load worst-case exit velocity and temperature.

4.2.5 Receptor Grid and Terrain Considerations

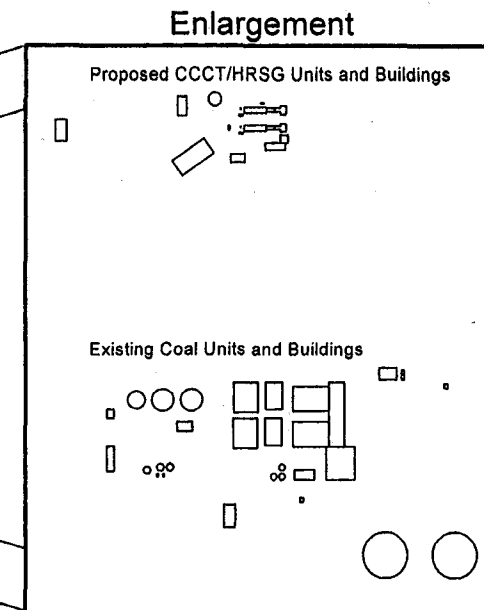
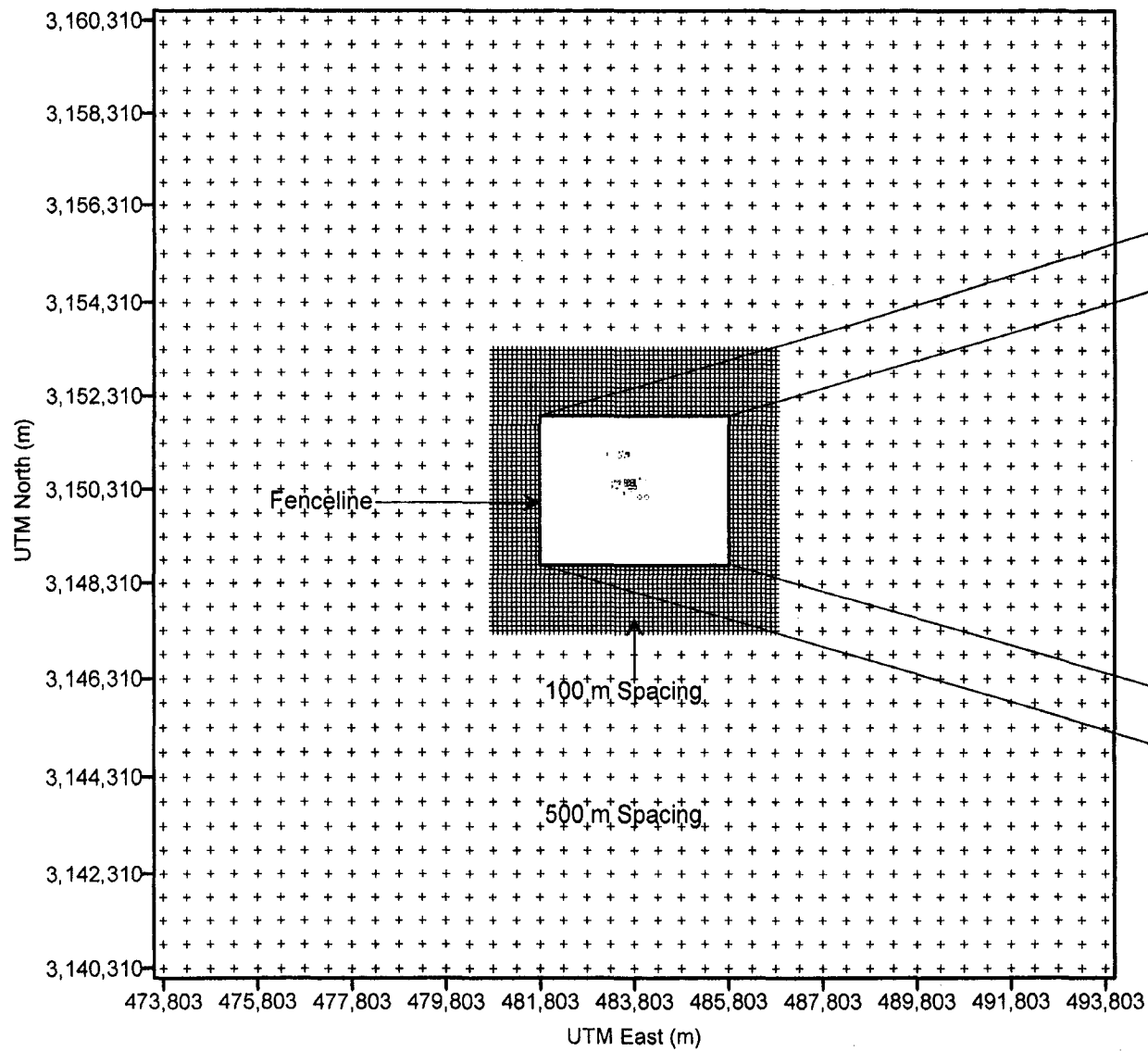
The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the Project was used. The rectangular grid network consists of 100 m spacing from the center of Stanton Energy Center out to 3 km, and then 500 m spacing from 3 to 10 km. Receptor spacing of 100 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors if the maximum predicted impacts occurred beyond the 100 m spacing. Figure 4-1 illustrates the nested rectangular grid, fenceline 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, Florida and Tampa, Florida, 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 Project's PTE exceeds the PSD significant emission thresholds for NO_x , CO, PM/PM₁₀, and SO₂. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x , CO, PM/PM₁₀, and SO₂ for each applicable averaging period. The modeled sources for NO_x (annual), PM/PM₁₀ (annual), and SO₂ (annual) included enveloped emissions over all loads and temperatures per fuel, and the final emission rate was calculated by combining these enveloped emissions to account for 1,000 hours per year firing distillate oil and 7,760 hours per year firing natural gas. Annual stack parameters were based on the worst-case, natural gas 100 percent load exit velocity and exit temperature. However, for CO (1-hour and 8-hour), PM/PM₁₀ (24-hour), and SO₂ (3-hour and 24-hour), the modeled sources included enveloped emissions per load and per fuel.



Receptor Locations

Figure 4-1

RECEPTORS.SRF

Tables 4-2 through 4-9 present the results for the 5 year (1987-1991) modeling analysis for each pollutant and applicable averaging period. The underlined concentrations in each table represent the maximum modeled predicted impacts in each case. Electronic copies of the modeled files are contained in Attachment 6.

4.3.1 Comparison to PSD Significant Impact Levels and Preconstruction Monitoring Requirements

Table 4-10 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the preconstruction monitoring requirements. As Table 4-10 indicates, the Project's maximum predicted concentrations are less than the PSD Class II significant impact levels 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. (µg/m ³)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1987	0.09	480,302.5	3,149,310.0
CC7		75		0.08	481,002.5	3,149,710.0
CC5		50		0.09	481,602.5	3,150,010.0
CC1		100	1988	0.09	480,902.5	3,149,610.0
CC7		75		0.08	481,402.5	3,149,910.0
CC5		50		0.08	481,785.0	3,150,120.0
CC1		100	1989	0.10	483,702.5	3,153,310.0
CC7		75		0.08	483,702.5	3,153,210.0
CC5		50		0.09	483,702.5	3,152,910.0
CC1		100	1990	0.11	481,002.5	3,149,510.0
CC7		75		0.10	481,402.5	3,149,810.0
CC5		50		<u>0.11</u>	481,785.0	3,150,020.0
CC1		100	1991	0.11	483,602.5	3,153,310.0
CC7		75		0.09	483,602.5	3,153,210.0
CC5		50		0.10	483,602.5	3,152,910.0

*CC=Combined Cycle; 1=100% Load; 7=75% Load; 5=50% Load

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)
Natural Gas Firing	1-Hour					
CCNG1		100	1987	<u>55.91</u>	483,702.5	3,152,010.0
CCNG7		75		16.02	483,702.5	3,152,010.0
CCNG5		50		13.79	483,620.0	3,151,920.0
CCNG1		100	1988	39.22	483,902.5	3,152,110.0
CCNG7		75		14.76	484,202.5	3,152,610.0
CCNG5		50		14.05	484,402.5	3,152,510.0
CCNG1		100	1989	34.77	483,420.0	3,151,920.0
CCNG7		75		11.32	483,720.0	3,151,920.0
CCNG5		50		15.79	483,902.5	3,152,510.0
CCNG1		100	1990	42.55	484,502.5	3,153,110.0
CCNG7		75		12.12	484,502.5	3,153,110.0
CCNG5		50		11.68	484,302.5	3,152,610.0
CCNG1		100	1991	36.36	483,520.0	3,151,920.0
CCNG7		75		15.32	482,802.5	3,153,010.0
CCNG5		50		14.28	485,402.5	3,152,210.0
Fuel Oil Firing	1-Hour					
CCFO1		100	1987	11.34	483,902.5	3,152,210.0
CCFO7		75		9.96	483,902.5	3,152,110.0
CCFO5		50		13.04	482,802.5	3,154,310.0
CCFO1		100	1988	13.43	483,520.0	3,151,920.0
CCFO7		75		14.75	483,902.5	3,152,110.0
CCFO5		50		17.11	483,902.5	3,152,110.0
CCFO1		100	1989	11.78	485,102.5	3,152,410.0
CCFO7		75		9.89	485,102.5	3,152,410.0
CCFO5		50		14.08	485,420.0	3,151,920.0
CCFO1		100	1990	12.01	483,002.5	3,152,310.0
CCFO7		75		11.01	484,502.5	3,153,310.0
CCFO5		50		13.94	484,402.5	3,153,210.0
CCFO1		100	1991	11.57	484,520.0	3,151,920.0
CCFO7		75		11.47	482,502.5	3,153,310.0
CCFO5		50		15.51	483,320.0	3,151,920.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-4
ISCST3 Model Predicted Maximum 8-Hour Concentrations of CO

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m³)	UTM Location	
					East (m)	North (m)
Natural Gas Firing	8-Hour	100	1987	12.77	483,802.5	3,152,110.0
CCNG1				4.41	485,820.0	3,150,300.0
CCNG7				4.82	485,820.0	3,150,300.0
CCNG5		100	1988	13.90	484,902.5	3,152,510.0
CCNG1				5.26	484,502.5	3,152,110.0
CCNG7				6.03	484,320.0	3,151,920.0
CCNG5		100	1989	14.11	481,302.5	3,150,810.0
CCNG1				4.92	481,702.5	3,150,910.0
CCNG7				5.22	484,402.5	3,152,110.0
CCNG5		100	1990	13.24	485,820.0	3,150,000.0
CCNG1				4.38	484,002.5	3,152,610.0
CCNG7				4.98	481,785.0	3,150,020.0
CCNG5		100	1991	<u>14.14</u>	483,602.5	3,152,910.0
CCNG1				4.88	483,602.5	3,152,710.0
CCNG7				5.29	483,720.0	3,151,920.0
Fuel Oil Firing		8-Hour	100	1987	3.19	484,685.0
CCFO1	3.09				484,685.0	3,148,700.0
CCFO7	4.41				486,302.5	3,150,110.0
CCFO5	100		1988	3.54	483,902.5	3,152,310.0
CCFO1				3.26	483,902.5	3,152,210.0
CCFO7				4.96	484,802.5	3,152,410.0
CCFO5	100		1989	3.33	485,302.5	3,153,210.0
CCFO1				3.28	485,102.5	3,152,910.0
CCFO7				4.84	481,002.5	3,150,810.0
CCFO5	100		1990	2.81	485,820.0	3,149,700.0
CCFO1				2.79	484,202.5	3,153,310.0
CCFO7				4.16	484,202.5	3,153,210.0
CCFO5	100		1991	3.08	483,602.5	3,153,310.0
CCFO1				3.19	483,602.5	3,153,310.0
CCFO7				5.04	483,720.0	3,151,920.0

* CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-5
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM₁₀

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m ³)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1987	0.03	480,302.5	3,149,310.0
CC7		75		0.03	481,002.5	3,149,710.0
CC5		50		0.05	481,602.5	3,150,010.0
CC1		100	1988	0.03	480,902.5	3,149,610.0
CC7		75		0.03	481,402.5	3,149,910.0
CC5		50		0.04	481,785.0	3,150,120.0
CC1		100	1989	0.03	483,702.5	3,153,310.0
CC7		75		0.03	483,702.5	3,153,210.0
CC5		50		0.05	483,702.5	3,152,910.0
CC1		100	1990	0.04	481,002.5	3,149,510.0
CC7		75		0.04	481,402.5	3,149,810.0
CC5		50		<u>0.06</u>	481,785.0	3,150,020.0
CC1		100	1991	0.04	483,602.5	3,153,310.0
CC7		75		0.04	483,602.5	3,153,210.0
CC5		50		0.05	483,602.5	3,152,910.0

*CC=Combined Cycle; 1=100% Load; 7=75% Load; 5=50% Load

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. ($\mu\text{g}/\text{m}^3$)	UTM Location	
					East (m)	North (m)
Natural Gas Firing	24-Hour	100	1987	0.38	484,202.5	3,152,910.0
CCNG1		75		0.39	485,820.0	3,150,200.0
CCNG7		50		0.54	485,820.0	3,150,200.0
CCNG5		100	1988	0.40	481,785.0	3,148,920.0
CCNG1		75		0.43	484,502.5	3,152,110.0
CCNG7		50		0.63	484,402.5	3,152,010.0
CCNG5		100	1989	0.44	481,785.0	3,150,120.0
CCNG1		75		0.41	481,785.0	3,150,120.0
CCNG7		50		0.55	484,202.5	3,153,210.0
CCNG5		100	1990	0.42	484,102.5	3,152,810.0
CCNG1		75		0.39	484,002.5	3,152,610.0
CCNG7		50		0.56	481,785.0	3,150,020.0
CCNG5		100	1991	0.41	485,820.0	3,150,300.0
CCNG1		75		0.45	483,802.5	3,152,510.0
CCNG7		50		<u>0.65</u>	483,720.0	3,151,920.0
Fuel Oil Firing	24-Hour	100	1987	0.25	484,685.0	3,148,700.0
CCFO1		75		0.31	487,802.5	3,149,310.0
CCFO7		50		0.47	486,702.5	3,149,810.0
CCFO5		100	1988	0.30	484,002.5	3,152,410.0
CCFO1		75		0.33	484,002.5	3,152,410.0
CCFO7		50		0.47	484,802.5	3,152,410.0
CCFO5		100	1989	0.31	481,202.5	3,149,810.0
CCFO1		75		0.36	481,402.5	3,149,910.0
CCFO7		50		0.49	481,402.5	3,149,910.0
CCFO5		100	1990	0.27	484,302.5	3,153,810.0
CCFO1		75		0.32	484,202.5	3,153,310.0
CCFO7		50		0.44	481,702.5	3,149,810.0
CCFO5		100	1991	0.27	486,102.5	3,149,910.0
CCFO1		75		0.34	483,720.0	3,151,920.0
CCFO7		50		0.55	483,720.0	3,151,920.0

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-7
ISCST3 Model Predicted Maximum Annual Concentrations of SO₂

ISCST Operating Scenario Source Code *	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m ³)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1987	0.04	480,302.5	3,149,310.0
CC7		75		0.04	481,002.5	3,149,710.0
CC5		50		0.04	481,602.5	3,150,010.0
CC1		100	1988	0.04	480,902.5	3,149,610.0
CC7		75		0.04	481,402.5	3,149,910.0
CC5		50		0.04	481,785.0	3,150,120.0
CC1		100	1989	0.04	483,702.5	3,153,310.0
CC7		75		0.04	483,702.5	3,153,210.0
CC5		50		0.05	483,702.5	3,152,910.0
CC1		100	1990	0.05	481,002.5	3,149,510.0
CC7		75		0.05	481,402.5	3,149,810.0
CC5		50		<u>0.05</u>	481,785.0	3,150,020.0
CC1		100	1991	0.04	483,602.5	3,153,310.0
CC7		75		0.05	483,602.5	3,153,210.0
CC5		50		0.05	483,602.5	3,152,910.0

*CC=Combined Cycle; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-8
ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO₂

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m ³)	UTM Location	
					East (m)	North (m)
Natural Gas Firing	3-Hour	100	1987	0.68	483,802.5	3,152,010.0
CCNG1		75		0.46	483,502.5	3,152,410.0
CCNG7		50		0.46	483,502.5	3,152,310.0
CCNG5		100	1988	0.55	483,220.0	3,151,920.0
CCNG1		75		0.45	484,502.5	3,152,110.0
CCNG7		50		0.48	484,320.0	3,151,920.0
CCNG5		100	1989	0.55	481,785.0	3,150,020.0
CCNG1		75		0.42	485,720.0	3,151,920.0
CCNG7		50		0.42	483,702.5	3,152,310.0
CCNG5		100	1990	0.57	481,785.0	3,149,820.0
CCNG1		75		0.44	481,602.5	3,151,310.0
CCNG7		50		0.43	481,785.0	3,151,220.0
CCNG5		100	1991	0.53	483,320.0	3,151,920.0
CCNG1		75		0.43	482,802.5	3,152,910.0
CCNG7		50		0.41	483,502.5	3,152,510.0
CCNG5						
Fuel Oil Firing	3-Hour	100	1987	8.06	483,402.5	3,153,210.0
CCFO1		75		7.87	483,402.5	3,153,110.0
CCFO7		50		8.15	483,402.5	3,152,810.0
CCFO5		100	1988	<u>8.91</u>	483,202.5	3,152,010.0
CCFO1		75		8.44	483,220.0	3,151,920.0
CCFO7		50		8.53	483,220.0	3,151,920.0
CCFO5		100	1989	8.29	485,820.0	3,149,300.0
CCFO1		75		7.31	486,502.5	3,152,210.0
CCFO7		50		7.65	486,002.5	3,152,010.0
CCFO5		100	1990	8.18	481,202.5	3,149,410.0
CCFO1		75		7.96	481,302.5	3,149,510.0
CCFO7		50		8.27	481,602.5	3,149,710.0
CCFO5		100	1991	8.34	486,802.5	3,149,710.0
CCFO1		75		7.61	483,302.5	3,152,110.0
CCFO7		50		7.71	483,302.5	3,152,010.0
CCFO5						

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-9
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO₂

ISCST Operating Scenario Source Code*	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m ³)	UTM Location	
					East (m)	North (m)
Natural Gas Firing	24-Hour	100	1987	0.11	484,202.5	3,152,910.0
CCNG1		75		0.10	485,820.0	3,150,200.0
CCNG7		50		0.11	485,820.0	3,150,200.0
CCNG5		100	1988	0.12	481,785.0	3,148,920.0
CCNG1		75		0.11	484,502.5	3,152,110.0
CCNG7		50		0.12	484,402.5	3,152,010.0
CCNG5		100	1989	0.13	481,785.0	3,150,120.0
CCNG1		75		0.10	481,785.0	3,150,120.0
CCNG7		50		0.11	484,202.5	3,153,210.0
CCNG5		100	1990	0.12	484,102.5	3,152,810.0
CCNG1		75		0.10	484,002.5	3,152,610.0
CCNG7		50		0.11	481,785.0	3,150,020.0
CCNG5		100	1991	0.12	485,820.0	3,150,300.0
CCNG1		75		0.11	483,802.5	3,152,510.0
CCNG7		50		0.13	483,720.0	3,151,920.0
CCNG5						
Fuel Oil Firing	24-Hour	100	1987	1.61	484,685.0	3,148,700.0
CCFO1		75		1.59	487,802.5	3,149,310.0
CCFO7		50		1.87	486,702.5	3,149,810.0
CCFO5		100	1988	1.89	484,002.5	3,152,410.0
CCFO1		75		1.69	484,002.5	3,152,410.0
CCFO7		50		1.88	484,802.5	3,152,410.0
CCFO5		100	1989	1.93	481,202.5	3,149,810.0
CCFO1		75		1.82	481,402.5	3,149,910.0
CCFO7		50		1.95	481,402.5	3,149,910.0
CCFO5		100	1990	1.67	484,302.5	3,153,810.0
CCFO1		75		1.63	484,202.5	3,153,310.0
CCFO7		50		1.78	481,702.5	3,149,810.0
CCFO5		100	1991	1.68	486,102.5	3,149,910.0
CCFO1		75		1.73	483,720.0	3,151,920.0
CCFO7		50		<u>2.20</u>	483,720.0	3,151,920.0
CCFO5						

*CC=Combined Cycle; FO=Distillate Fuel Oil; NG=Natural Gas; 1=100% Load; 7=75% Load; 5=50% Load

Table 4-10
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 ($\mu\text{g}/\text{m}^3$)	PSD De Minimis Monitoring Level ($\mu\text{g}/\text{m}^3$)
NO _x	Annual	0.11	1	14
CO	1-Hour	55.91	2,000	N/A
	8-Hour	14.14	500	575
PM/PM ₁₀	Annual	0.06	1	N/A
	24-Hour	0.65	5	10
SO ₂	Annual	0.05	1	N/A
	3-Hour	8.91	25	N/A
	24-Hour	2.20	5	13

*The maximum impacts per pollutant were the highest impact per scenario based on the five years of data (1987-1990), and are identified in Tables 4-2 through 4-9.

5.0 Additional and Class I Area Impact Analyses

As part of the air impact evaluation for the Project, the FDEP has requested that analyses of the Project's effect on the Chassahowitzka National Wildlife Refuge (CNWR) be performed. The CNWR is a Federal Prevention of Significant Deterioration (PSD) Class I area located in west central Florida approximately 140 km west-northwest of the Project. Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in these air analyses are regional haze, deposition, and Class I Significant Impact Levels (SILs). Figure 5-1 presents the locations of the Project with respect to the CNWR.

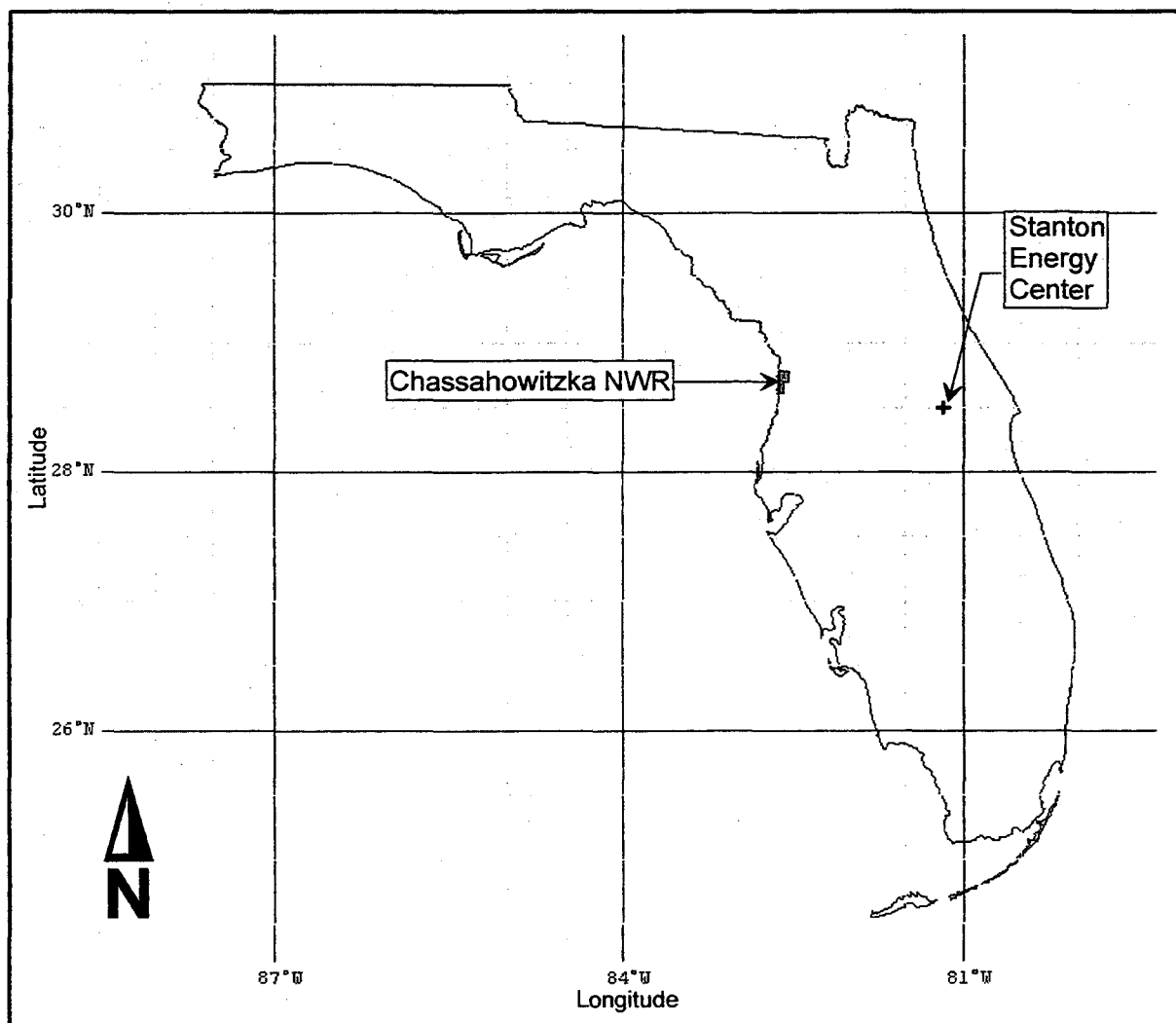
The air analyses closely follow those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I & II* reports dated April 1993 and December 1998, respectively, the *Draft Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* dated October 1999, as well as coordination with the FDEP who has communicated as necessary with the United States Fish and Wildlife Service (USFWS), which is the Federal Land Manager (FLM) for the area. The air analyses also followed a mutually agreed upon methodology discussed at a meeting with FDEP on May 31, 2000, submitted to FDEP on behalf of OUC in a letter from Black & Veatch dated August 30, 2000. A copy of the methodology submitted to FDEP is presented in Attachment 5.

This section includes a discussion of the meteorological and geophysical databases used in the analyses, the preparation of those databases for introduction into the modeling system, the air modeling approach, and the modeling results.

5.1 Model Selection and Inputs

The California Puff (CALPUFF, Version 5.4) air dispersion modeling system was used to determine the maximum ground level impacts of those PSD pollutants for which the Project is significant and which have applicable significant impact levels for a Class I area (i.e., NO_x , PM/PM_{10} , and SO_2).

CALPUFF is a non-steady state, Lagrangian, Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analyses. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs



Location of Stanton Energy Center
with Respect to
Chassahowitzka National Wildlife Refuge

Figure 5-1

Class I and Stanton.srf

that extract data from large databases and convert the data into formats suitable for input to CALMET. For the analyses, the processed data produced from CALMET was input to CALPUFF to assess pollutant specific impacts. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase I and II reports and Draft Phase I FLAG report. To model the emissions associated with the two CCCT/HRSGs at the Project and assess the AQRVs at the CNWR.

5.1.1 CALPUFF Model Settings

The CALPUFF settings contained in Table 5-1 were used for the modeling analyses.

5.1.2 Building Wake Effects

The CALPUFF analyses include the Project's building dimensions to account for the effects of building-induced downwash on the emission sources. As discussed in Section 4.2.3, dimensions for all significant building structures were processed with BPIP and included in the CALPUFF model input.

5.1.3 Receptor Locations

The CALPUFF analyses used an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the CNWR. Specifically, the array consists of 14 discrete receptors and was obtained from the FDEP via email from Alex Meng on June 20, 2000. The refined CALPUFF receptors for the CNWR are shown in Figure 5-2.

5.1.4 Meteorological Data Processing

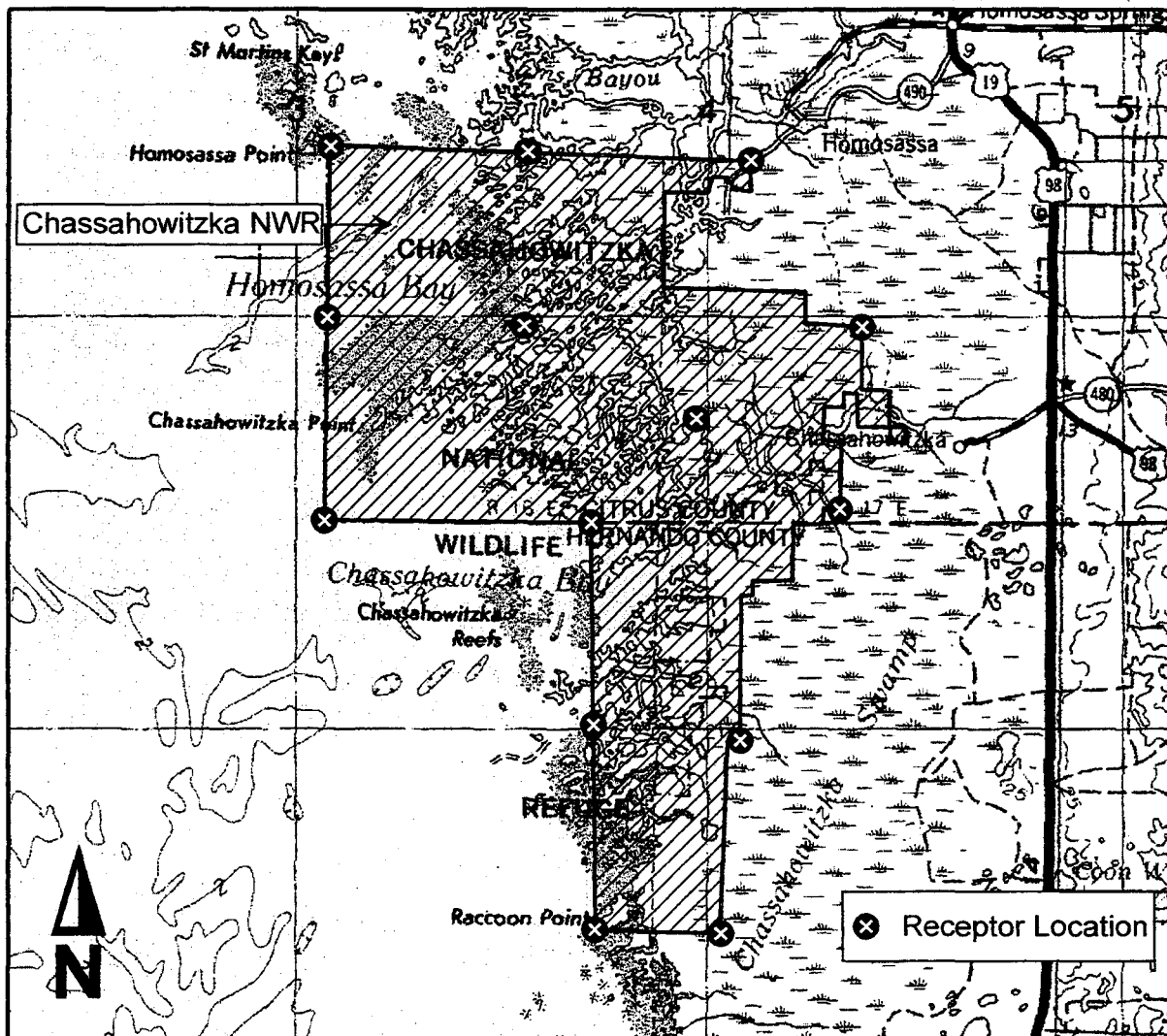
The CALPUFF analyses employed the California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.2) to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data used and processed in the CALMET model.

5.1.4.1 CALMET Settings The CALMET settings, including horizontal and vertical grid coverage, number of weather stations (sea surface, land surface, upper air, and precipitation), and resolution of prognostic mesoscale meteorological data, are contained in Table 5-2.

5.1.4.2 Modeling Domain A rectangular modeling domain extending 350 km in the east-west (x) direction and 290 km in the north-south (y) direction was used for the refined modeling analysis. The boundary of the domain is represented by the dashed line

Table 5-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO ₂ , SO ₄ , NO _x , HNO ₃ , and NO ₃ , and PM ₁₀
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Vertical Wind Shear, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	<u>Regional Haze:</u> Highest predicted 24-hour SO ₄ , NO ₃ and PM ₁₀ concentrations for the year. <u>Deposition:</u> Highest predicted annual, SO ₂ , SO ₄ , NO ₃ , NO _x , and HNO ₃ values in deposition units. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Ozone = 80 ppb; Ammonia =10 ppb



Chassahowitzka National Wildlife Refuge Receptors

Figure 5-2

Table 5-2
CALMET Settings

PARAMETER	SETTING
Horizontal Grid Dimensions	350 by 290 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	1 sea surface, 6 land surface, 3 upper air, 27 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 8 x 6 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

in Figure 5-3. The southwest corner of the domain is the origin and is located at 27 N degrees latitude and 83.5 W degrees longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. The size of the domain used for the modeling was based on the distances needed to cover the area from the Project to the receptors at the CNWR with an 80-km buffer zone in each direction.

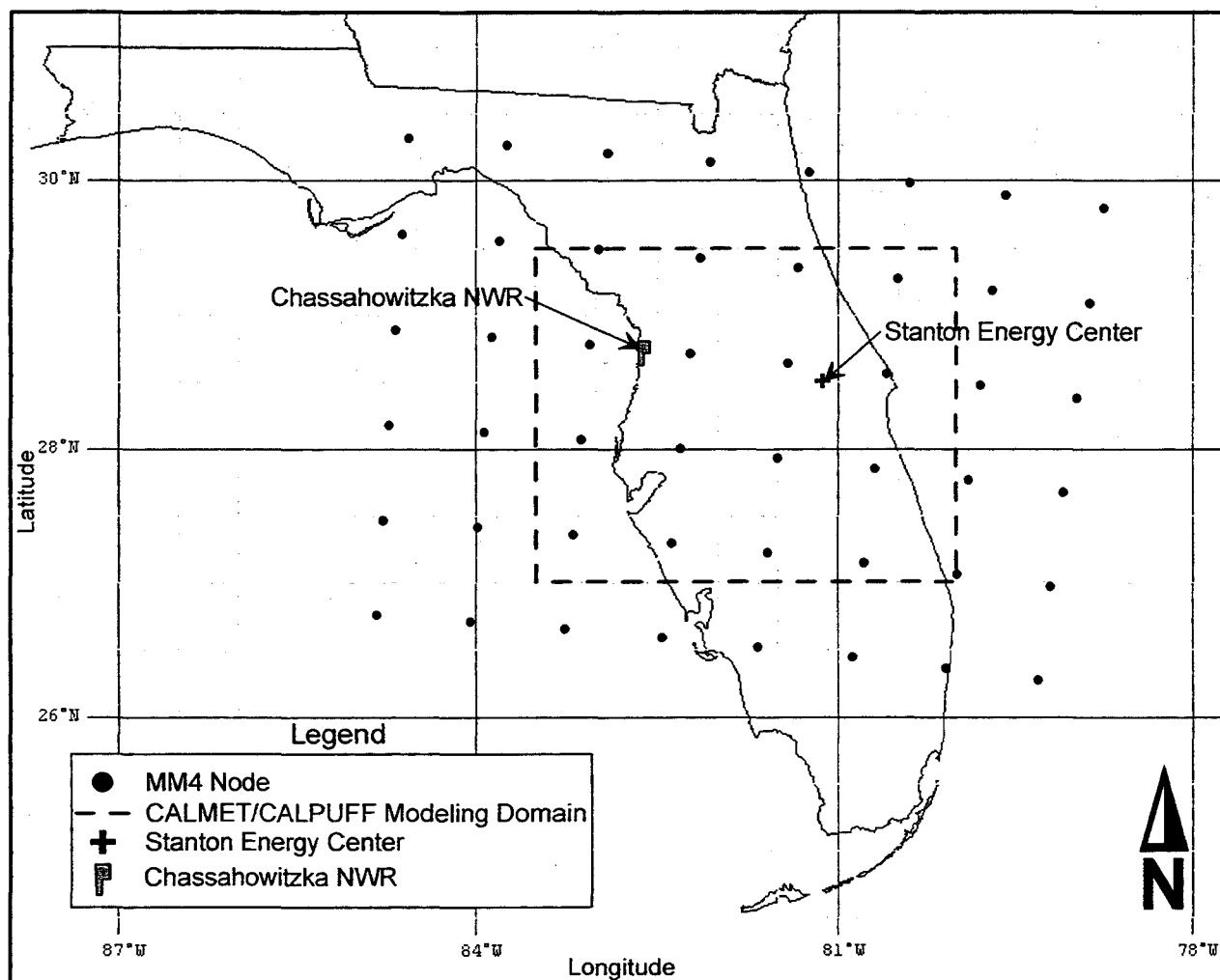
For the processing of meteorological and geophysical data, 70 grid cells were used in the x-direction and 58 grid cells were used in the y-direction. A 5-km grid spacing was used. The air modeling analyses were performed in the UTM coordinate system.

5.1.4.3 Mesoscale Model Data Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analyses used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

To apply a national MM4 dataset to the modeling domain, a sub-set domain was developed that fully enclosed the area of the modeling domain. The MM4 subset domain consisted of an 8 x 6-cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (49,10) to (56, 15). These data were processed to create a MM4.DAT file, for input to the CALMET model. The MM4 subset domain is represented by the MM4 node points in Figure 5-3.

The MM4 data set used in CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

5.1.4.4 Surface Data Stations and Processing The surface station data processed for the CALPUFF analyses consisted of data from six National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations for Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers, and Orlando. Because the modeling domain origin extends over water, C-Man station data from Venice is included



CALMET/CALPUFF Modeling Domain

Figure 5-3

Domain.srf

in the wind field. These data were processed by the FDEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. A summary of the surface station information and locations is presented in Table 5-3 and Figure 5-4, respectively. The land surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The sea surface station data include wind direction, wind speed, and air temperature.

The land surface weather station data for all stations but Gainesville was downloaded for the year 1990 from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD-ROM set. The surface data from Gainesville was processed from NCDC CD-144 format. The entire land surface data set was processed with the CALMET preprocessor utility program, SMERGE, to create one surface file, SURF.DAT.

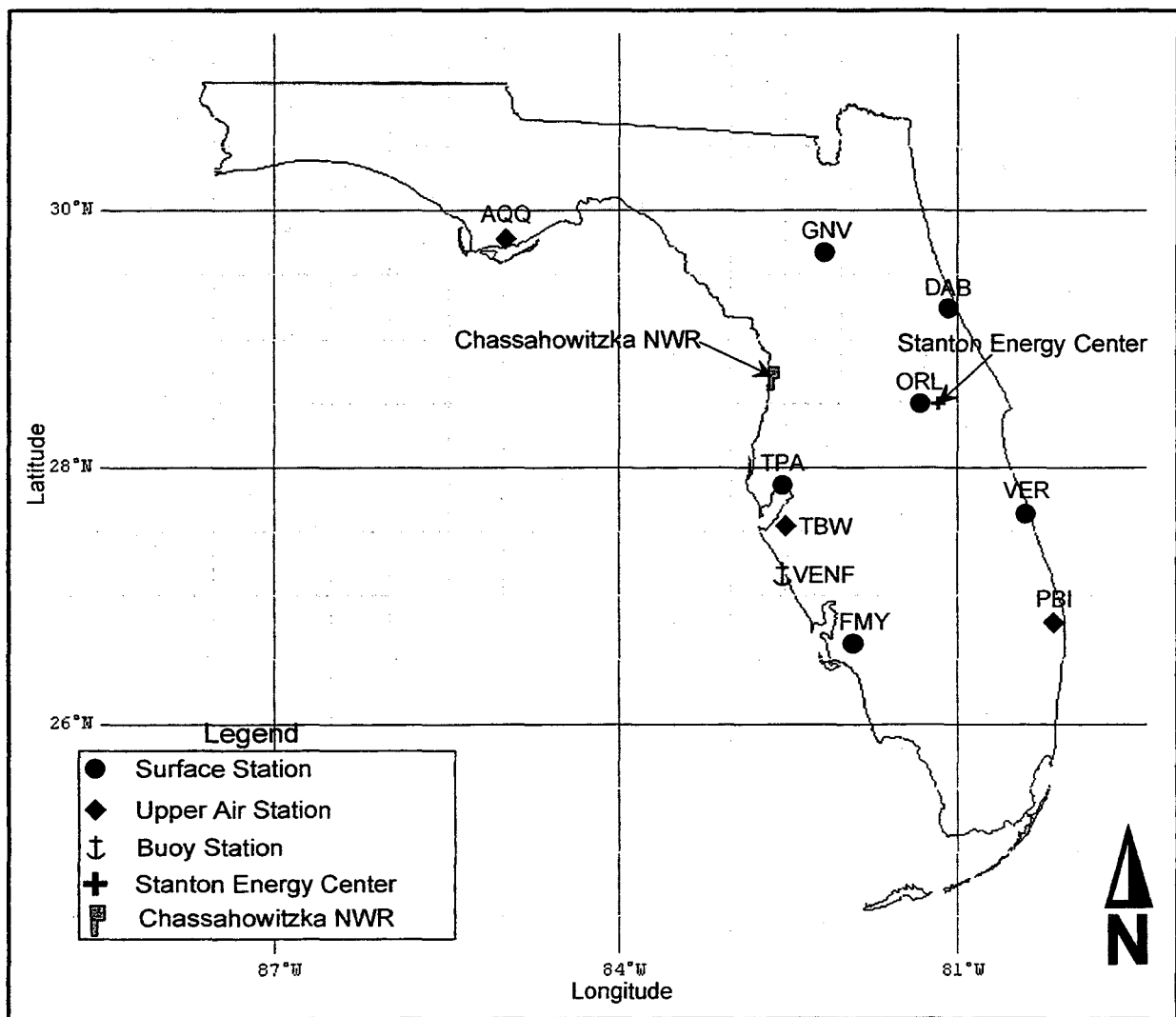
5.1.4.5 Upper Air Data Stations and Processing The analysis included three upper air NWS stations located in Ruskin, West Palm Beach, and Apalachicola. Data for these stations was obtained from the FDEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table 5-3 and Figure 5-4, respectively.

5.1.4.6 Precipitation Data Stations and Processing Precipitation data was processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations located within or just beyond the modeling domain (dashed rectangular box in Figure 5-3). They were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PEXTRACT and PMERGE were used to process the data into the format for the PRECIP.DAT file for use in CALMET. A listing of the precipitation stations used for the modeling analyses is presented in Table 5-4 and are shown in Figure 5-5.

5.1.4.7 Geophysical Data Processing Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS) web site. The DEM data was extracted for the modeling domain grid using the utility extraction program TERREL. Land-use data was obtained from the 1-degree USGS files and processed using the utility programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once processed, all of the land-use parameters were combined with the terrain

Table 5-3
Meteorological Stations Used in the CALPUFF Analysis

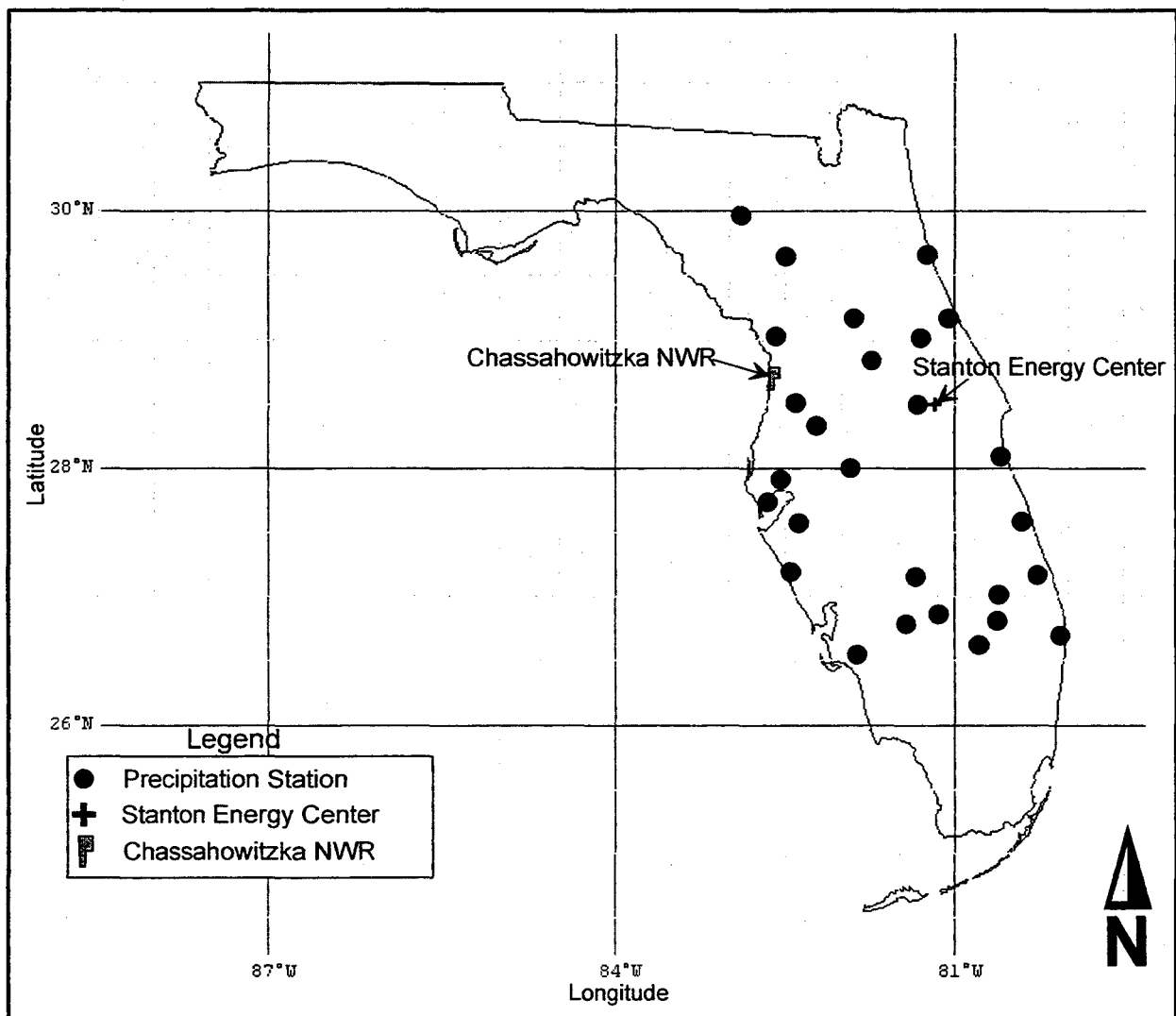
Station Name	Station Symbol ^a	WBAN Number	UTM Coordinates			Anemometer Height (m)
			Easting (km)	Northing (km)	Zone	
Surface Stations						
Daytona Beach, FL	DAB	12834	495.14	3,228.05	17	9.1
Fort Myers, FL	FMY	12835	413.65	2,940.38	17	6.1
Gainesville, FL	GNV	12816	377.40	3,284.12	17	6.7
Orlando, FL	ORL	12815	468.96	3,146.88	17	10.1
Tampa, FL	TPA	12842	349.20	3,094.25	17	6.7
Vero Beach, FL	VER	12843	557.52	3,058.36	17	6.7
Upper Air Stations						
Apalachicola, FL	AQQ	12832	110.00 ^b	3,296.00	16	N/A
Ruskin, FL	TBW	12842	349.20	3,094.28	17	N/A
West Palm Beach, FL	PBI	12844	587.87	2,951.42	17	N/A
Sea Stations						
Venice	VENF	N/A	356.20	2,994.80	17	7.3
^a Meteorological station location shown by station symbol on Figure 5-4.						
^b Equivalent Coordinate for Zone 17.						



Surface and Upper Air Meteorological Stations

Figure 5-4

Table 5-4 Hourly Precipitation Stations Used in the CALPUFF Analysis				
Station Name	Station Number	UTM Coordinates		
		Easting (km)	Northing (km)	Zone
Florida				
Belle Glade Hrcn Gt 4	80616	528.190	2,953.034	17
Branford	80975	315.606	3,315.955	17
Brooksville 7 SSW	81048	358.029	3,149.545	17
Canal Point Gate 5	81271	536.428	2,971.514	17
Daytona Beach WSO AP	82158	494.165	3,227.413	17
Deland 1 SSE	82229	470.780	3,209.660	17
Fort Myers FAA/AP	83186	413.992	2,940.710	17
Gainesville 11 WNW	83322	355.411	3,284.205	17
Inglis 3 E	84273	342.631	3,211.652	17
Lakeland	84797	409.871	3,099.178	17
Lisbon	85076	423.594	3,193.256	17
Lynne	85237	409.255	3,230.295	17
Marineland	85391	479.193	3,282.030	17
Melbourne WSO	85612	534.381	3,109.967	17
Moore Haven Lock 1	85895	491.608	2,967.803	17
Orlando WSO McCoy	86628	468.169	3,145.102	17
Ortona Lock 2	86657	470.174	2,962.267	17
Parrish	86880	366.986	3,054.394	17
Port Mayaca S L Canal	87293	538.044	2,984.440	17
Saint Leo	87851	376.483	3,135.086	17
St Lucie New Lock 1	87859	571.042	2,999.353	17
St Petersburg	87886	339.608	3,071.991	17
Tampa Wscmo AP	88788	348.478	3,093.670	17
Venice	89176	357.593	2,998.178	17
Venus	89184	467.266	3,001.224	17
Vero Beach 4 W	89219	554.268	3,056.498	17
West Palm Beach	89525	589.611	2,951.627	17



Precipitation Stations

Figure 5-5

information with the utility program MAKEGEO into a GEO.DAT file for input to CALMET. The land-use parameter values were based on annual averaged values.

5.1.5 Facility Emissions

As discussed in Section 2.3, performance data for the combustion turbines was based on vendor data at certain design ambient temperatures at base load operation, considering both natural gas and distillate fuel oil firing. The maximum pound per hour emission rates of the four representative ambient temperatures at base load operation for both natural gas and distillate fuel oil firing were considered for the modeling. Since distillate oil operation contains higher emission rates, it was assumed that the oil cases would produce the highest impacts and were therefore used in the modeling. The emission rates and stack parameters are listed in Table 5-5.

5.2 Class I Analyses

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the CNWR, including regional haze, deposition (both sulfur and nitrogen), and Class I SILs. The following analyses were performed as described below.

5.3 Regional Haze Analyses

A regional haze analysis was performed, using the CALPUFF modeling system, for the Class I area for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4 , NO_3 , and PM_{10} concentrations.

5.3.1 Visibility

Visibility is an AQRV for the CNWR. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances. According to Appendix W to Part 51, Guideline on Air Quality Models, long range transport is defined as distances beyond 50 km. Since all portions of the Class I area lie beyond 50 km from the Project, the change in visibility was analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current guidelines characterize a change in visibility by either of the following methods:

- Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
- Change in the light-extinction coefficient (b_{ext}).

Table 5-5
Stack Parameters and Pollutant Emissions Used in the CALPUFF Analysis

Stack No.	Easting (m)	Northing (m)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)*	Exit Temp (K)*	Pollutant Emission Rate (g/s)*		
							NO _x	SO ₂	PM ₁₀
1	438,609	3,151,119	48.77	5.79	19.90	406.48	10.04	13.48	2.14
2	438,609	3,151,082	48.77	5.79	19.90	406.48	10.04	13.48	2.14

*Assumes operation on distillate fuel oil at 100 percent load will yield worst-case impacts.

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm-1) = 3912 / vr(Mm-1)$$

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, 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.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by the percentage change in extinctions. The change is defined as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

where: b_{exts} is the extinction coefficient calculated for the source, and
 b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} 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_{extb} , or percent change in extinction. Based on the IWAQM Phase II guidance, if the change in extinction is less than 5 percent, no further analysis is required.

5.3.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual range of 65 km for the CNWR was obtained from the USFWS. The average relative humidity factor for each species' worst day was computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity was obtained by using Table 2.A-1 of Appendix 2.A of the Draft Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) were then used to determine the average relative humidity factor for that day (24-hour period).

5.3.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analyses followed the recommendations contained in the IWAQM Phase I and II Summary Reports and Recommendations for Modeling Long Range Transport Impacts, (EPA, 4/93 and 12/98). Table 5-6 summarizes the IWAQM recommendations. The typical calculation methodology used to compute the results of the regional haze analysis is illustrated below.

Calculation

Refined impacts are calculated as follows:

1. Obtain maximum 24-hour SO₄, NO₃, and PM₁₀ impacts, in units of micrograms per cubic meter (μg/m³).
2. Convert the SO₄ impact to (NH₄)₂SO₄ by the following formula:
 - $(\text{NH}_4)_2\text{SO}_4 \text{ (}\mu\text{g/m}^3\text{)} = \text{SO}_4 \text{ (}\mu\text{g/m}^3\text{)} \times \text{molecular weight } (\text{NH}_4)_2\text{SO}_4 / \text{molecular weight SO}_4$
 - $(\text{NH}_4)_2\text{SO}_4 \text{ (}\mu\text{g/m}^3\text{)} = \text{SO}_4 \text{ (}\mu\text{g/m}^3\text{)} \times 132/96 = \text{SO}_4 \text{ (}\mu\text{g/m}^3\text{)} \times 1.375$
3. Convert the NO₃ impact to NH₄NO₃ by the following formula:
 - $\text{NH}_4\text{NO}_3 \text{ (}\mu\text{g/m}^3\text{)} = \text{NO}_3 \text{ (}\mu\text{g/m}^3\text{)} \times \text{molecular weight NH}_4\text{NO}_3 / \text{molecular weight NO}_3$
 - $\text{NH}_4\text{NO}_3 \text{ (}\mu\text{g/m}^3\text{)} = \text{NO}_3 \text{ (}\mu\text{g/m}^3\text{)} \times 80/62 = \text{NO}_3 \text{ (}\mu\text{g/m}^3\text{)} \times 1.29$
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
$$b_{\text{exts}} = 3 \times \text{NH}_4\text{NO}_3 \times f(\text{RH}) + 3 \times (\text{NH}_4)_2\text{SO}_4 \times f(\text{RH}) + 1 \times \text{PM}_{10}$$
5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) obtained from the USFWS:
$$b_{\text{extb}} = 3.912 / \text{Visual range (km)}$$
6. Compute the change in extinction coefficients:
in terms of percent change of visibility:
$$\Delta\% = (b_{\text{exts}} / b_{\text{extsb}}) \times 100$$

Based on the predicted SO₄, NO₃, and PM₁₀ concentrations, the Project's emissions should then be compared to a 5 percent change in light extinction of the background levels.

Table 5-6
Outline of IWAQM Refined Modeling Analyses Recommendations*

Meteorology	<u>Refined CALPUFF</u> Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	<u>Refined CALPUFF</u> Within Class I area(s) of concern.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO ₄ , NO ₃ , and PM ₁₀ values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the supplied background extinction.

*IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 12/98).

5.3.4 Visibility/Regional Haze Results

The CALPUFF air modeling system was used to assess regional haze impacts at the Class I area from the Project. The results from the refined CALPUFF modeling at CNWR are presented in Table 5-7. The maximum predicted change is 0.81 percent. This impact is below the 5 percent change criteria indicating that the Project operation does not adversely impact the existing regional haze at the CNWR. Electronic copies of the modeled inputs and outputs are presented in Attachment 6.

5.4 Deposition Analysis

Deposition analyses were performed for the CNWR for both total sulfur and nitrogen. The analyses followed those procedures and methodologies set forth in the IWAQM Phase I Report. Specifically, deposition analyses were performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned (including output of both dry and wet deposition).
2. Perform individual CALPOST post-processor runs to output the maximum 24-hour average wet and dry deposition impacts of SO₂, SO₄, NO₃, NO_x, and HNO₃ in µg/m²/s units.
3. Apply the appropriate scaling factors to the above CALPOST runs to account for the conversion of micrograms to kilograms, square meters to hectares (ha), seconds to hours, and hours to a day. Thus, the CALPOST results are output in kg/hectare.
4. For sulfur deposition, sum the results of both the wet deposition and dry deposition values for the SO₂ and SO₄ CALPOST runs.
5. For nitrogen deposition, sum the results of both the wet deposition and dry deposition values for the NO₃, NO_x, and HNO₃ CALPOST runs.

The results of the sulfur and nitrogen deposition analyses for CNWR are presented in Table 5-8. Currently, there are no published threshold values for comparison, the values presented in the table are for review and evaluation by the FLM. However, it is assumed that these insignificant impacts are well below harmful levels.

5.5 Class I Impact Analysis

Ground-level impacts (in µg/m³) at the CNWR were calculated for the criteria pollutants that exceed PSD Significant Emission Levels (SELs) and also have PDS Class I significant increment levels to compare for each applicable averaging period (i.e.,

Table 5-7
CALPUFF Refined Analysis Results on CNWR

Item	Predicted Worst Days (Year – Day)		
	1990 – 085	1990 – 019	1990 – 019
<u>Maximum Predicted Conc. ($\mu\text{g}/\text{m}^3$)</u>			
SO ₄	0.023824	0.006075	0.006075
NO ₃	0.012852	0.018666	0.018666
PM ₁₀	0.012248	0.021756	0.021756
Average Relative Humidity Factor ^a	2.4	4.8	4.8
Background Visual Range ^b , V _r (km)	65	65	65
Background Extinction Coeff. (b_{extb}) (Mm^{-1})	60.2	60.2	60.2
<u>Source Extinction Coeff. (b_{exts}) (Mm^{-1})^c</u>			
(NH ₄) ₂ SO ₄	0.235858	0.120285	0.120285
NH ₄ NO ₃	0.119369	0.346740	0.346740
PM ₁₀	0.012248	0.021756	0.021756
Total (b_{exts}) (Mm^{-1})	0.37	0.49	0.49
Percent Change (%)	0.61	0.81	0.81

Table 5-8
CNWR Sulfur and Nitrogen Deposition Results

Pollutant	Dry Deposition ^a (kg/hectare)	Wet Deposition ^a (kg/hectare)	Total Deposition ^a (kg/hectare)
SO ₂	3.3889E-03	2.3031E-03	5.6920E-03
SO ₄	1.2061E-05	9.0206E-04	9.1412E-04
Total Sulfur ^b	3.4010E-03	3.2052E-03	6.6062E-03
NO ₃	5.7721E-06	2.8592E-04	2.9169E-04
NO _x	2.9132E-04	N/A ^d	2.9132E-04
HNO ₃	3.6589E-04	2.5640E-04	6.2229E-04
Total Nitrogen ^c	6.6298E-04	5.4232E-04	1.2053E-03

^aValues are computed from annual average model predicted impacts.

^bTotal sulfur is the sum of SO₂ and SO₄.

^cTotal nitrogen is the sum of NO₃, NO_x and HNO₃.

^dWet Deposition does not consider NO_x.

NO_x – Annual, PM₁₀ – Annual, PM₁₀ – 24 hour, SO₂ – Annual, SO₂ – 3 hour, and SO₂ – 24 hour). As noted in Section 2.5.1, CO also exceeded PSD SELs. However, there is no Class I increment for this pollutant and therefore it was not considered.

As in the regional haze analyses, CALPUFF was used for CNWR. For conservatism, the distillate fuel oil emission rates and stack parameters, from Table 5-5, were again assumed to yield the worst-case pollutant impacts and were therefore used in this analysis. Specifically, these short-term emission rates on oil were modeled in CALPUFF to yield both short-term and annual pollutant impacts at the Class I area. On an annual bases, the CALPUFF model conservatively assumed 8,760 hours of operation on oil although a maximum 1,000 hours of operation on fuel oil firing has been requested.

The results of this analysis, presented in Table 5-9, are compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I increment values. As the results in Table 5-9 demonstrate, there are no exceedances of the Class I SILs. Therefore, no further analyses are warranted.

5.6 Commercial, Residential, and Industrial Growth

The Project is at the Stanton Energy Center Facility near the city of Orlando within Orange County. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the Project.

It is anticipated that most of the labor force during the construction phase will commute from nearby communities. The electrical generating capacity created by the Project will not have a significant effect upon the industrial growth in the immediate area considering that the electrical generating capacity will be supplied 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 new, permanent jobs, which will be created by the Project. 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 the Project will be very small, compared to the overall population size of the surrounding area.

5.7 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 Project's impacts on soils and vegetation will be minimal.

The 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 NO₂, CO, PM/PM₁₀, and SO₂, below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

Table 5-9
CNWR Class I Significant Impact Level (SIL) Results

Pollutant	Impact ($\mu\text{g}/\text{m}^3$)	Class I Increment ($\mu\text{g}/\text{m}^3$)	Class I SIL* ($\mu\text{g}/\text{m}^3$)
NO _x – Annual	0.002	2.5	0.10
PM ₁₀ – Annual	0.001	4	0.16
PM ₁₀ – 24 Hour	0.022	8	0.32
SO ₂ – Annual	0.007	2	0.08
SO ₂ – 3 Hour	0.309	25	1.00
SO ₂ – 24 Hour	0.116	5	0.20

*Class I Significant Impact Levels calculated as 4 percent of the Class I Increment Levels.

The criteria pollutants, which triggered an additional impact analysis, include NO_x, CO, PM/PM₁₀, and SO₂. The modeled impacts were compared to the secondary NAAQS as the basis for assessing cumulative impacts. The results of the air dispersion modeling in Section 4.0 showed that the NO_x, CO, PM/PM₁₀, and SO₂ impacts are below the PSD Class II SILs and therefore are below the NAAQS. Because the Project's emissions do not even significantly impact the NAAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

6.0 Hazardous Air Pollutants

The following sections discuss the Project's hazardous air pollutant impact analyses.

6.1 Maximum Achievable Control Technology (MACT) Determination

The following section provides a discussion of the applicability of the National Emission Standards for Hazardous Air Pollutants (NESHAP) to the Project and the necessity of applying a Maximum Achievable Control Technology (MACT).

6.1.1 NESHAPs

Presently there is not a NESHAP that governs stationary gas turbines. Nonetheless, under the Requirements for Control Technology Determinations for Major Sources contained under Clean Air Act Sections 112(g) and 112(j) and codified under Title 40 Part 63 of the Code of Federal Regulations (40 CFR 63), any person who constructs a new major sources or major modification of Hazardous Air Pollutants (HAPs) may have to apply controls governed by a standard of MACT. To "construct a major source" means to "fabricate, erect, or install...a new process or production unit which in and of itself emits or has the potential-to-emit 10 tpy of any HAP or 25 tpy of any combination of HAP". The Project would be classified as a "process unit", thus it must be determined if the Project will have a potential-to-emit 10 tpy of any one HAP or 25 tpy of any combination of HAPs

6.1.2 Potential-To-Emit Hazardous Air Pollutants and MACT Applicability

The air toxics emission rates for the combustion turbine were estimated based on the EPA document Compilation of Air Pollutant Emission Factors (AP-42) factors from Section 3.1 – Stationary Gas Turbines and the duct burner emissions were estimated based on AP-42 Section 1.4 – Natural Gas Combustion for External Combustion Sources. Formaldehyde emission rates for both natural gas and distillate oil were taken from the AP-42 Section 3 Emission Factor Query. The analysis assumed a conservative worst-case operating scenario of two CCCT/HRSGs operating 8,760 hours firing natural gas with 8,760 hours of natural gas duct firing and 1,000 hours of power augmentation, plus 1,000 hours of distillate fuel oil firing per CCCT.

MACT applicability calculations were performed and are included in Attachment 3. As demonstrated in Attachment 3, no individual HAP has a potential to be emitted in excess of 10 tpy and no combination of HAPs has a potential to be emitted in excess of 25 tpy from the operation of the Project. The individual HAP with the greatest emissions

is Hexane with a potential-to-emit of 8.4 tpy. The potential-to-emit of all HAPs combined is 18.0 tpy for the Project. Because, the potential emissions of all HAPs, both individually and combined, are less than the major source levels, the NESHAP requirements are not applicable to the Addition and the need to apply MACT is not required.

Attachment 1
Operating Matrix

Table 1
Combustion Turbine Operating Scenarios

Natural Gas							
Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Power Augmentation	Duct Burner
1	19	100	X	X			
2	19	75	X	X			
3	19	50	X	X			
4	19	100	X	X			X
5	45	100	X	X			
6	45	75	X	X			
7	45	50	X	X			
8	45	100	X	X			X
9	60	100	X	X	X	X	X
10	70	100	X	X	X		
11	70	75	X	X			
12	70	50	X	X			
13	70	100	X	X	X		X
14	95	100	X	X	X		
15	95	75	X	X			
16	95	50	X	X			
17	95	100	X	X	X	X	X
18	95	100	X	X	X	X	X
19	95	100	X	X	X		X
Distillate Fuel Oil							
20	19	100	X	X			
21	19	75	X	X			
22	19	50	X	X			
23	45	100	X	X			
24	70	100	X	X	X		
25	95	100	X	X	X		

Attachment 2
Performance Data

GE Performance Data
Natural Gas Firing Only

Southern Co/OUC Project Gas Fuel Performance
Power Augmentation at 60F
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	BASE
Ambient Temp.	Deg F.	19.	19.	19.	60.
Ambient Relative Humid.	%	65.0	65.0	65.0	76.0
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280	280
Output	kW	188,800.	141,600.	94,400.	185,300.
Heat Rate (HHV)	Btu/kWh	10,080.	10,810.	12,930.	9,955.
Heat Cons. (HHV) X 10 ⁶	Btu/h	1,903.1	1,530.7	1,220.6	1,844.7
Exhaust Pressure Loss	inches Water	14.66	9.17	6.28	13.61
Exhaust Flow X 10 ³	lb/h	3847.	3006.	2463.	3687.
Exhaust Temp.	Deg F.	1077.	1132.	1182.	1101.
Exhaust Heat (HHV) X 10 ⁶	Btu/h	1190.0	991.8	853.1	1165.6
Steam Flow	lb/h	0.	0.	0.	121,170.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	12.
NOx AS NO2	lb/h	62.	50.	39.	77.
CO	ppmvd	9.	9.	9.	15.
CO	lb/h	31.	25.	20.	48.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	12.	10.	15.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.	3.
Particulates	lb/h	9.0	9.0	9.0	9.0
(PM10 Front-half Filterable Only)					

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.90	0.90	0.85
Nitrogen	75.07	75.02	75.12	70.32
Oxygen	12.77	12.61	12.91	11.59
Carbon Dioxide	3.77	3.84	3.70	3.72
Water	7.50	7.64	7.37	13.53

SITE CONDITIONS

Elevation	ft.	105.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 2 . 2 . 0 Opt: 11 724120300
GORDONSA 11/27/00 15:02 UOC nat gas 19-60F 11-27-00.dat

Southern Co/OUC Project Gas Fuel Performance
ESTIMATED PERFORMANCE PG7241S(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	45.	45.	45.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280
Output	kW	179,700.	134,800.	89,900.
Heat Rate (HHV)	Btu/kWh	10,190.	10,960.	13,170.
Heat Cons. (HHV) X 10 ⁶	Btu/h	1,831.1	1,477.4	1,184.
Exhaust Pressure Loss	inches Water	13.7	8.7	6.1
Exhaust Flow X 10 ³	lb/h	3689.	2926.	2412.
Exhaust Temp.	Deg F.	1106.	1149.	1198.
Exhaust Heat (HHV) X 10 ⁶	Btu/h	1151.5	963.5	833.0

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx as NO2	lb/h	60.	48.	38.
CO	ppmvd	15.	15.	15.
CO	lb/h	50.	40.	33.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
(PM10 Front-half Filterable Only)				

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.89
Nitrogen	74.65	74.63	74.74
Oxygen	12.65	12.59	12.90
Carbon Dioxide	3.77	3.80	3.66
Water	8.04	8.09	7.82

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Relative Humidity	%	76
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 2 . 1 . 1 Opt: 11 724120300
 GORDONSA 9/20/00 09:12 UOC nat gas 45F.dat

Southern Co/OUC Project Gas Fuel Performance
ESTIMATED PERFORMANCE PG7241S(FA)

Load Condition		BASE	75%	50%	BASE
Ambient Temp.	Deg F.	70.	70.	70.	70.
Evap. Cooler Status		On	Off	Off	On
Evap. Cooler Effectiveness	%	85			85
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280	280
Output	kW	169,100.	126,900.	84,600.	183,600.
Heat Rate (HHV)	Btu/kWh	10,375.	11,210.	13,450.	9,995.
Heat Cons. (HHV) X 10 ⁶	Btu/h	1,754.4	1,422.5	1,137.9	1,835.1
Exhaust Loss	in. H2O	12.6	8.3	5.9	13.4
Exhaust Flow X 10 ³	lb/h	3525.	2847.	2368.	3647.
Exhaust Temp.	Deg F.	1130.	1166.	1200.	1110.
Exhaust Heat (HHV) X 10 ⁶	Btu/h	1113.7	937.4	806.4	1161.4
Steam Flow	lb/h	0.	0.	0.	119,820.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	12.
NOx as NO2	lb/h	57.	46.	36.	76.
CO	ppmvd	15.	15.	15.	15.
CO	lb/h	48.	38.	32.	47.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	11.	9.	15.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8	3.
Particulates	lb/h	9.0	9.0	9.0	9.0
(PM10 Front-half Filterable Only)					

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.88	0.89	0.85
Nitrogen	73.70	73.83	73.96	69.82
Oxygen	12.40	12.48	12.86	11.42
Carbon Dioxide	3.77	3.75	3.57	3.73
Water	9.26	9.07	8.73	14.19

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Relative Humidity	%	77
Inlet Loss	in. H2O	4.
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 2.1.1 Opt: 11 724120300
 GORDONSA 9/20/00 09:10 UOC nat gas 70F.dat

Southern Co/OUC Project Gas Fuel Performance
ESTIMATED PERFORMANCE PG7241S(FA)

Load Condition		BASE	75%	50%	BASE
Ambient Temp.	Deg F.	95.	95.	95.	95.
Evap. Cooler Status		On	Off	Off	On
Evap. Cooler Effectiveness	%	85			85
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	21,021	21,021	21,021	21,021
Fuel Temperature	Deg F	280	280	280	280
Output	kW	160,800.	120,600.	80,400.	176,600.
Heat Rate (HHV)	Btu/kWh	10,530.	11,430.	13,660.	10,105.
Heat Cons. (HHV) X 10 ⁶	Btu/h	1,693.2	1,378.5	1,098.3	1,784.5
Exhaust Loss	in. H2O	11.8	8.1	5.7	12.6
Exhaust Flow X 10 ³	lb/h	3409.	2794.	2342.	3524.
Exhaust Temp.	Deg F.	1143.	1182.	1200.	1128.
Exhaust Heat (HHV) X 10 ⁶	Btu/h	1083.0	916.3	782.5	1135.3
Steam Flow	lb/h	0.	0.	0.	115,780.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	12.
NOx as NO2	lb/h	55.	45.	35.	74.
CO	ppmvd	15.	15.	15.	15.
CO	lb/h	45.	38.	32.	45.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	11.	9.	14.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8	2.8
Particulates	lb/h	9.0	9.0	9.0	9.0
(PM10 Front-half Filterable Only)					

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.89	0.88	0.83
Nitrogen	73.04	73.49	73.65	69.19
Oxygen	12.27	12.50	12.96	11.23
Carbon Dioxide	3.75	3.69	3.48	3.75
Water	10.07	9.44	9.03	15.01

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Relative Humidity	%	43
Inlet Loss	in. H2O	4.
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 2.1.1 Opt: 11 724120300
GORDONSA 9/20/00 09:11 UOC nat gas 95F.dat

GE Performance Data
Fuel Oil Firing Only

Southern Co/OUC Project Fuel Oil Performance
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	19.	19.	19.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	195,800.	146,800.	97,900.
Heat Rate (HHV)	Btu/kWh	10,560.	11,340.	13,310.
Heat Cons. (HHV) X 10 ⁶	Btu/h	2,067.6	1,664.7	1,303.
Exhaust Pressure Loss	inches Water	15.71	9.52	6.34
Exhaust Flow X 10 ³	lb/h	4003.	3060.	2468.
Exhaust Temp.	Deg F.	1054.	1139.	1193.
Exhaust Heat (HHV) X 10 ⁶	Btu/h	1192.6	1002.7	850.6
Water Flow	lb/h	130,720.	98,890.	68,730.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	336.	268.	208.
CO	ppmvd	20.	22.	30.
CO	lb/h	71.	59.	66.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	16.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	8.	6.	5.
SO2	ppmvw	12.0	13.0	12.0
SO2	lb/h	107.0	86.0	68.0
SO3	ppmvw	1.0	0.0	1.0
SO3	lb/h	7.0	6.0	4.0
Sulfur Mist	lb/h	11.0	9.0	7.0
Particulates	lb/h	17.0	17.0	17.0
(PM10 Front-half Filterable Only)				

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.87	0.86
Nitrogen	71.98	71.94	72.56
Oxygen	11.47	11.11	11.58
Carbon Dioxide	5.44	5.67	5.47
Water	10.26	10.42	9.53

SITE CONDITIONS

Elevation	ft.	105.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Relative Humidity	%	65
Application		Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less. FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value. Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2.2.0 Opt: 11 724120300
GORDONSA 11/27/00 14:57

OUC dist fuel 19F 11-27-00.dat

Southern Co/OUC Project Fuel Oil Performance
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	45.	70.	95.	19.
Ambient Relative Humid.	%	76.	77.	43.	65.
Evap. Cooler Status		Off	On	On	Off
Evap. Cooler Effectiveness	%		85	85	
Fuel Type		Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8
Output	kW	187,500.	178,500.	170,300.	195,800.
Heat Rate (HHV)	Btu/kWh	10,615.	10,700.	10,810.	10,560.
Heat Cons. (HHV) X 10 ⁶	Btu/h	1,990.3	1,910.	1,840.9	2,067.6
Exhaust Pressure Loss	inches Water	14.5	13.3	12.5	15.7
Exhaust Flow X 10 ³	lb/h	3825.	3646.	3517.	4003.
Exhaust Temp.	Deg F.	1083.	1113.	1131.	1054.
Exhaust Heat (HHV) X 10 ⁶	Btu/h	1151.0	1115.2	1086.0	1192.6
Water Flow	lb/h	124,780.	113,060.	103,400.	130,720.

EMISSIONS

NOx (FBN ≤ 0.015%)	ppmvd @ 15% O2	42.	42.	42.	42.
NOx as NO2	lb/h	324.	311.	300.	336.
NOx (FBN = 0.05%)	ppmvd @ 15% O2	56.	56.	56.	56.
NOx as NO2	lb/h	434.	416.6	401.9	450.1
CO	ppmvd	20.	20.	20.	20.
CO	lb/h	67.	64.	61.	71.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	14.	14.	16.
VOC	ppmvw	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.	7.	8.
SO2	ppmvw	12.0	12.0	12.0	12.0
SO2	lb/h	103.0	99.0	96.0	107.0
SO3	ppmvw	1.0	1.0	1.0	1.0
SO3	lb/h	7.0	7.0	6.0	7.0
Sulfur Mist	lb/h	11.0	10.0	10.0	11.0
Particulates	lb/h	17.0	17.0	17.0	17.0
(PM10 Front-half Filterable Only)					

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.84	0.84	0.85
Nitrogen	71.58	70.86	70.42	71.98
Oxygen	11.32	11.09	11.00	11.47
Carbon Dioxide	5.47	5.49	5.47	5.44
Water	10.78	11.72	12.27	10.26

SITE CONDITIONS

Elevation	ft.	105.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	13.0 @ ISO Conditions
Application		Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2.2.0 Opt: 11 724120300
GORDONSA 10/30/00 13:17

OUC dist fuel revB 10-30-00.dat

GE Performance Data
Emissions Data

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 1

Ambient temp (F) 19 Natural Gas
CT load (%) 100
Over pressure no
Power Augmentation no
Stack outlet (F) 185

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.77000	4.08640	14.35093	552080.46	12.77000	4.08640	14.35093	552080.46	12.77000	4.08640	14.35093	552080.46
carbon dioxide	3.77000	1.65880	5.82550	224107.06	3.77000	1.65880	5.82550	224107.06	3.77000	1.65880	5.82550	224107.06
water vapor	7.50000	1.35000	4.74103	182387.58	7.50000	1.35000	4.74103	182387.58	7.50000	1.35000	4.74103	182387.58
nitrogen	75.07000	21.01960	73.81825	2839788.21	75.07000	21.01960	73.81825	2839788.21	75.07000	21.01960	73.81825	2839788.21
argon	0.90000	<u>0.36000</u>	1.26428	48636.69	0.90000	<u>0.36000</u>	1.26428	48636.69	0.90000	<u>0.36000</u>	1.26428	48636.69
		28.47480	100.00000			28.47480	100.00000			28.47480	100.00000	
NOx	0.00100	0.00046	0.00161	62.00	0.00100	0.00046	0.00161	62.00	0.00039	0.00018	0.00063	24.13
carbon monoxide	0.00082	0.00023	0.00081	31.00	0.00082	0.00023	0.00081	31.00	0.00082	0.00023	0.00081	31.00
hydrocarbons CH4	0.00069	0.00011	0.00039	15.00	0.00069	0.00011	0.00039	15.00	0.00069	0.00011	0.00039	15.00
VOC	0.00014	0.00002	0.00008	3.00	0.00014	0.00002	0.00008	3.00	0.00014	0.00002	0.00008	3.00
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00023	9.00		0.00007	0.00023	9.00		0.00007	0.00023	9.00
ammonia, NH3									0.00111	0.00019	0.00066	25.47
Total				3847000.00				3847000.00				3847000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.80541				13.80541				13.80541			
carbon dioxide	4.07568				4.07568				4.07568			
nitrogen	81.15676				81.15676				81.15676			
argon	0.97297				0.97297				0.97297			
NOx	0.00108	10.78526	8.99447		0.00108	10.78526	8.99447		0.00042	4.19685	3.50000	
CO	0.00089	8.85932	7.38831		0.00089	8.85932	7.38831		0.00089	8.85932	7.38831	
VOC	0.00015	1.50037	1.25125		0.00015	1.50037	1.25125		0.00015	1.50037	1.25125	
ammonia, NH3									0.00120	11.99099	10.00000	

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 2

Ambient temp (F) 19 Natural Gas
CT load (%) 75
Over pressure no
Power Augmentation no
Stack outlet (F) 170

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.61000	4.03520	14.17571	426121.75	12.61000	4.03520	14.17571	426121.75	12.61000	4.03520	14.17571	426121.75
carbon dioxide	3.84000	1.68960	5.93559	178423.70	3.84000	1.68960	5.93559	178423.70	3.84000	1.68960	5.93559	178423.70
water vapor	7.64000	1.37520	4.83109	145222.70	7.64000	1.37520	4.83109	145222.70	7.64000	1.37520	4.83109	145222.70
nitrogen	75.02000	21.00560	73.79293	2218215.45	75.02000	21.00560	73.79293	2218215.45	75.02000	21.00560	73.79293	2218215.45
argon	0.90000	0.36000	1.26468	38016.41	0.90000	0.36000	1.26468	38016.41	0.90000	0.36000	1.26468	38016.41
		28.46560	100.00000			28.46560	100.00000			28.46560	100.00000	
NOx	0.00103	0.00047	0.00166	50.00	0.00103	0.00047	0.00166	50.00	0.00040	0.00018	0.00064	19.23
carbon monoxide	0.00085	0.00024	0.00083	25.00	0.00085	0.00024	0.00083	25.00	0.00085	0.00024	0.00083	25.00
hydrocarbons CH4	0.00071	0.00011	0.00040	12.00	0.00071	0.00011	0.00040	12.00	0.00071	0.00011	0.00040	12.00
VOC	0.00014	0.00002	0.00008	2.40	0.00014	0.00002	0.00008	2.40	0.00014	0.00002	0.00008	2.40
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00009	0.00030	9.00		0.00009	0.00030	9.00		0.00009	0.00030	9.00
ammonia, NH3									0.00113	0.00019	0.00068	20.30
Total				3006000.00				3006000.00				3006000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.65310				13.65310				13.65310			
carbon dioxide	4.15764				4.15764				4.15764			
nitrogen	81.22564				81.22564				81.22564			
argon	0.97445				0.97445				0.97445			
NOx	0.00111	11.14448	9.10137		0.00111	11.14448	9.10137		0.00043	4.28569	3.5	
CO	0.00092	9.15439	7.47612		0.00092	9.15439	7.47612		0.00092	9.15439	7.47612	
VOC	0.00015	1.53794	1.25599		0.00015	1.53794	1.25599		0.00015	1.53794	1.25599	
ammonia, NH3									0.00122	12.24484	10	

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 3

Ambient temp (F) 19 Natural Gas
CT load (%) 50
Full pressure no
Power Augmentation no
Stack outlet (F) 157

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.91000	4.13120	14.50592	357280.90	12.91000	4.13120	14.50592	357280.90	12.91000	4.13120	14.50592	357280.90
carbon dioxide	3.70000	1.62800	5.71641	140795.24	3.70000	1.62800	5.71641	140795.24	3.70000	1.62800	5.71641	140795.24
water vapor	7.37000	1.32660	4.65810	114729.10	7.37000	1.32660	4.65810	114729.10	7.37000	1.32660	4.65810	114729.10
nitrogen	75.12000	21.03360	73.85549	1819060.68	75.12000	21.03360	73.85549	1819060.68	75.12000	21.03360	73.85549	1819060.68
argon	0.90000	<u>0.36000</u>	1.26407	31134.08	0.90000	<u>0.36000</u>	1.26407	31134.08	0.90000	<u>0.36000</u>	1.26407	31134.08
		28.47940	100.00000			28.47940	100.00000			28.47940	100.00000	
NOx	0.00098	0.00045	0.00158	39.00	0.00098	0.00045	0.00158	39.00	0.00038	0.00018	0.00062	15.18
carbon monoxide	0.00083	0.00023	0.00081	20.00	0.00083	0.00023	0.00081	20.00	0.00083	0.00023	0.00081	20.00
hydrocarbons CH4	0.00072	0.00012	0.00041	10.00	0.00072	0.00012	0.00041	10.00	0.00072	0.00012	0.00041	10.00
VOC	0.00014	0.00002	0.00008	2.00	0.00014	0.00002	0.00008	2.00	0.00014	0.00002	0.00008	2.00
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00010	0.00037	9.00		0.00010	0.00037	9.00		0.00010	0.00037	9.00
ammonia, NH3									0.00109	0.00019	0.00065	16.03
Total				2463000.00				2463000.00				2463000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.93717				13.93717				13.93717			
carbon dioxide	3.99439				3.99439				3.99439			
nitrogen	81.09684				81.09684				81.09684			
argon	0.97161				0.97161				0.97161			
NOx	0.00106	10.58331	8.99071		0.00106	10.58331	8.99071		0.00041	4.11998	3.5	
CO	0.00089	8.91634	7.57459		0.00089	8.91634	7.57459		0.00089	8.91634	7.57459	
VOC	0.00016	1.56036	1.32555		0.00016	1.56036	1.32555		0.00016	1.56036	1.32555	
ammonia, NH3									0.00118	11.77138	10	

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 4

Ambient temp (F) 19 heat input MMBtu/lb (HHV) 498.9 Natural Gas
CT load (%) 100
Over pressure yes
Power Augmentation no
Stack outlet (F) 178

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.77000	4.08640	14.35093	552080.46	10.74747	3.43919	12.12700	469133.00	10.74747	3.43919	12.12700	469133.00
carbon dioxide	3.77000	1.65880	5.82550	224107.06	4.70628	2.07076	7.30176	282468.59	4.70628	2.07076	7.30176	282468.59
water vapor	7.50000	1.35000	4.74103	182387.58	9.30101	1.67418	5.90337	228371.87	9.30101	1.67418	5.90337	228371.87
nitrogen	75.07000	21.01960	73.81825	2839788.21	74.35386	20.81908	73.41060	2839889.06	74.35386	20.81908	73.41060	2839889.06
argon	0.90000	0.36000	1.26428	48636.69	0.89138	0.35655	1.25725	48636.72	0.89138	0.35655	1.25725	48636.72
		28.47480	100.00000			28.35977		99.99998		28.35977		99.99998
NOx	0.00100	0.00046	0.00161	62.00	0.00162	0.00075	0.00263	101.91	0.00048	0.00022	0.00079	30.38
carbon monoxide	0.00082	0.00023	0.00081	31.00	0.00199	0.00056	0.00196	75.90	0.00199	0.00056	0.00196	75.90
hydrocarbons CH4	0.00069	0.00011	0.00039	15.00	0.00261	0.00042	0.00147	56.91	0.00261	0.00042	0.00147	56.91
VOC	0.00014	0.00002	0.00008	3.00	0.00050	0.00008	0.00028	10.98	0.00050	0.00008	0.00028	10.98
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00023	9.00		0.00008	0.00030	11.49		0.00008	0.00030	11.49
ammonia, NH3								58.51	0.00138	0.00024	0.00083	32.08
Total				3847000.00				3868500.00				3868500.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.80541				11.84960				11.84960			
carbon dioxide	4.07588				5.18890				5.18890			
nitrogen	81.15676				81.97871				81.97871			
argon	0.97297				0.98279				0.98279			
NOx	0.00108	10.78526	8.99447		0.00179	17.90709	11.74185		0.00053	5.33773	3.5	
CO	0.00089	8.85932	7.38831		0.00219	21.91024	14.36674		0.00219	21.91023	14.36674	
VOC	0.00015	1.50037	1.25125		0.00055	5.54798	3.63786		0.00055	5.54798	3.63786	
ammonia, NH3									0.00153	15.25067	10	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Revised 11/15/00

Case 5

Ambient temp (F) **45**
CT load (%) **100**
Over pressure no
Power Augmentation no
Stack outlet (F) **181**

Natural Gas

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.65000	4.04800	14.24750	525590.31	12.65000	4.04800	14.24750	525590.31	12.65000	4.04800	14.24750	525590.31
carbon dioxide	3.77000	1.65880	5.83838	215377.77	3.77000	1.65880	5.83838	215377.77	3.77000	1.65880	5.83838	215377.77
water vapor	8.04000	1.44720	5.09362	187903.73	8.04000	1.44720	5.09362	187903.73	8.04000	1.44720	5.09362	187903.73
nitrogen	74.65000	20.90200	73.56751	2713905.32	74.65000	20.90200	73.56751	2713905.32	74.65000	20.90200	73.56751	2713905.32
argon	0.89000	<u>0.35600</u>	1.25299	46222.86	0.89000	<u>0.35600</u>	1.25299	46222.86	0.89000	<u>0.35600</u>	1.25299	46222.86
		28.41200	100.00000			28.41200	100.00000			28.41200	100.00000	
NOx	0.00100	0.00046	0.00163	60.00	0.00100	0.00046	0.00163	60.00	0.00039	0.00018	0.00063	23.21
carbon monoxide	0.00138	0.00039	0.00138	50.00	0.00138	0.00039	0.00138	50.00	0.00138	0.00039	0.00138	50.00
hydrocarbons CH4	0.00072	0.00012	0.00041	15.00	0.00072	0.00012	0.00041	15.00	0.00072	0.00012	0.00041	15.00
VOC	0.00014	0.00002	0.00008	3.00	0.00014	0.00002	0.00008	3.00	0.00014	0.00002	0.00008	3.00
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00024	9.00		0.000	0.000	9.00		0.00007	0.00024	9.00
ammonia, NH3								38.10	0.00111	0.00019	0.00066	24.51
Total				3689000.00				3689000.00				3689000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.75598				13.75598				13.75598			
carbon dioxide	4.09961				4.09961				4.09961			
nitrogen	81.17660				81.17660				81.17660			
argon	0.96781				0.96781				0.96781			
NOx	0.00109	10.92415	9.04814		0.00109	10.92415	9.04814		0.00042	4.22568	3.50000	
CO	0.00150	14.95568	12.38733		0.00150	14.95568	12.38733		0.00150	14.95528	12.38700	
VOC	0.00016	1.57035	1.30067		0.00016	1.57035	1.30067		0.00016	1.56954	1.30000	
ammonia, NH3									0.00121	12.07337	10.00000	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Revised 11/15/00

Case 6

Ambient temp (F) 45 Natural Gas
CT load (%) 75
Over pressure no
Power Augmentation no
Stack outlet (F) 170

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.59000	4.02880	14.17923	414884.13	12.59000	4.02880	14.17923	414884.13	12.59000	4.02880	14.17923	414884.13
carbon dioxide	3.80000	1.67200	5.88455	172181.86	3.80000	1.67200	5.88455	172181.86	3.80000	1.67200	5.88455	172181.86
water vapor	8.09000	1.45620	5.12505	149958.86	8.09000	1.45620	5.12505	149958.86	8.09000	1.45620	5.12505	149958.86
nitrogen	74.63000	20.89640	73.54417	2151902.50	74.63000	20.89640	73.54417	2151902.50	74.63000	20.89640	73.54417	2151902.50
argon	0.90000	0.36000	1.26701	37072.65	0.90000	0.36000	1.26701	37072.65	0.90000	0.36000	1.26701	37072.65
		28.41340	100.00000			28.41340	100.00000			28.41340	100.00000	
NOx	0.00101	0.00047	0.00164	48.00	0.00101	0.00047	0.00164	48.00	0.00039	0.00018	0.00063	18.54
carbon monoxide	0.00139	0.00039	0.00137	40.00	0.00139	0.00039	0.00137	40.00	0.00139	0.00039	0.00137	40.00
hydrocarbons CH4	0.00073	0.00012	0.00041	12.00	0.00073	0.00012	0.00041	12.00	0.00073	0.00012	0.00041	12.00
VOC	0.00015	0.00002	0.00008	2.40	0.00015	0.00002	0.00008	2.40	0.00015	0.00002	0.00008	2.40
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00009	0.00031	9.00		0.00009	0.00031	9.00		0.00009	0.00031	9.00
ammonia, NH3								30.47	0.00112	0.00019	0.00067	19.58
Total				2926000.00				2926000.00				2926000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.69818				13.69818				13.69818			
carbon dioxide	4.13448				4.13448				4.13448			
nitrogen	81.19900				81.19900				81.19900			
argon	0.97922				0.97922				0.97922			
NOx	0.00110	11.02477	9.05920		0.00110	11.02477	9.05920		0.00043	4.25939	3.5	
CO	0.00151	15.09343	12.40248		0.00151	15.09343	12.40248		0.00151	15.09407	12.403	
VOC	0.00016	1.58481	1.30226		0.00016	1.58481	1.30226		0.00016	1.58206	1.3	
ammonia, NH3									0.00122	12.16969	10	

Case 7

Natural Gas

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.90000	4.12800	14.52028	350229.20	12.90000	4.12800	14.52028	350229.20	12.90000	4.12800	14.52028	350229.20
carbon dioxide	3.66000	1.61040	5.66460	136630.11	3.66000	1.61040	5.66460	136630.11	3.66000	1.61040	5.66460	136630.11
water vapor	7.82000	1.40760	4.95125	119424.09	7.82000	1.40760	4.95125	119424.09	7.82000	1.40760	4.95125	119424.09
nitrogen	74.74000	20.92720	73.61164	1775512.73	74.74000	20.92720	73.61164	1775512.73	74.74000	20.92720	73.61164	1775512.73
argon	0.89000	0.35600	1.25223	30203.87	0.89000	0.35600	1.25223	30203.87	0.89000	0.35600	1.25223	30203.87
		28.42920	100.00000			28.42920	100.00000			28.42920	100.00000	
NOx	0.00097	0.00045	0.00158	38.00	0.00097	0.00045	0.00158	38.00	0.00038	0.00017	0.00061	14.70
carbon monoxide	0.00139	0.00039	0.00137	33.00	0.00139	0.00039	0.00137	33.00	0.00139	0.00039	0.00137	33.00
hydrocarbons CH4	0.00074	0.00012	0.00041	10.00	0.00074	0.00012	0.00041	10.00	0.00074	0.00012	0.00041	10.00
VOC	0.00015	0.00002	0.00008	2.00	0.00015	0.00002	0.00008	2.00	0.00015	0.00002	0.00008	2.00
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00011	0.00037	9.00		0.00011	0.00037	9.00		0.00011	0.00037	9.00
ammonia, NH3								24.13	0.00108	0.00018	0.00064	15.52
Total				2412000.00				2412000.00				2412000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.99436				13.99436				13.99436			
carbon dioxide	3.97049				3.97049				3.97049			
nitrogen	81.08049				81.08049				81.08049			
argon	0.96550				0.96550				0.96550			
NOx	0.00106	10.56274	9.04648		0.00106	10.56274	9.04648		0.00041	4.08662	3.5	
CO	0.00151	15.06977	12.90654		0.00151	15.06977	12.90654		0.00151	15.06797	12.905	
VOC	0.00016	1.59831	1.36888		0.00016	1.59831	1.36888		0.00016	1.59962	1.37	
ammonia, NH3									0.00117	11.67607	10	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are Input)
3.5ppm NOx (natural gas), w/o CO catalyst

Revised 11/15/00

Case 8

Ambient temp (F) **45** heat input MMBtu/lb (HHV)
CT load (%) **100**
Over pressure **yes**
Power Augmentation **no**
Stack outlet (F) **175**

523.7 Natural Gas

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.65000	4.04800	14.24750	525590.31	10.44518	3.34246	11.81490	438518.28	10.44518	3.34246	11.81490	438518.28
carbon dioxide	3.77000	1.65880	5.83838	215377.77	4.79229	2.10861	7.45350	276641.87	4.79229	2.10861	7.45350	276641.87
water vapor	8.04000	1.44720	5.09362	187903.73	10.00091	1.80016	6.36321	236174.99	10.00091	1.80016	6.36321	236174.99
nitrogen	74.65000	20.90200	73.56751	2713905.32	73.88083	20.68663	73.12300	2714011.33	73.88083	20.68663	73.12300	2714011.33
argon	0.89000	0.35600	1.25299	46222.86	0.88079	0.35232	1.24537	46222.78	0.88079	0.35232	1.24537	46222.78
		28.41200	100.00000			28.29018	99.99998			28.29018	99.99998	
NOx	0.00100	0.00046	0.00163	60.00	0.00169	0.00078	0.00275	101.90	0.00049	0.00023	0.00080	29.76
carbon monoxide	0.00138	0.00039	0.00136	50.00	0.00264	0.00074	0.00262	97.13	0.00264	0.00074	0.00262	97.13
hydrocarbons CH4	0.00072	0.00012	0.00041	15.00	0.00281	0.00045	0.00159	58.99	0.00281	0.00045	0.00159	58.99
VOC	0.00014	0.00002	0.00008	3.00	0.00054	0.00009	0.00031	11.38	0.00054	0.00009	0.00031	11.38
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00024	9.00		0.00009	0.00031	11.62		0.00009	0.00031	11.62
ammonia, NH3								58.09	0.00141	0.00024	0.00085	31.43
Total				3689000.00				3711570.00				3711570.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.75598				11.60587				11.60587			
carbon dioxide	4.09961				5.32482				5.32482			
nitrogen	81.17660				82.09064				82.09064			
argon	0.96781				0.97867				0.97867			
NOx	0.00109	10.92415	9.04814		0.00188	18.76028	11.98213		0.00055	5.47991	3.5	
CO	0.00150	14.95568	12.36733		0.00294	29.37979	18.76478		0.00294	29.37980	18.76478	
VOC	0.00016	1.57035	1.30067		0.00060	6.02326	3.84704		0.00060	6.02327	3.84704	
ammonia, NH3									0.00157	15.65688	10	

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 9

Ambient temp (F) 60 Natural Gas
CT load (%) 100
Full pressure yes Duct Burner Heat Input MMBtu/hr (HHV) 452.8
Power Augmentatory yes
Stack outlet (F) 178

CT Emissions				Duct Burner Discharge				Stack Exhaust				
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.59000	3.70880	13.33592	491695.45	9.72849	3.11312	11.23470	416415.3	9.72849	3.11312	11.23470	416415.3
carbon dioxide	3.72000	1.63680	5.88553	216999.33	4.58697	2.01827	7.28358	269966.6	4.58697	2.01827	7.28358	269966.6
water vapor	13.53000	2.43540	8.75709	322874.00	15.14336	2.72580	9.83696	364607.9	15.14336	2.72580	9.83696	364607.9
nitrogen	70.32000	19.68960	70.79890	2610355.59	69.69872	19.51564	70.42860	2610443	69.69872	19.51564	70.42860	2610443
argon	0.85000	0.34000	1.22256	45075.62	0.84247	0.33699	1.21613	45075.98	0.84247	0.33699	1.21613	45075.98
		27.81060	100.00000			27.70982		99.99997		27.70982		99.99997
NOx	0.00126	0.00058	0.00209	77.00	0.00184	0.00085	0.00305	113.224	0.00047	0.00022	0.00078	29.04
carbon monoxide	0.00129	0.00036	0.00130	48.00	0.00346	0.00097	0.00349	129.504	0.00346	0.00097	0.00349	129.50
hydrocarbons CH4	0.00071	0.00011	0.00041	15.00	0.00248	0.00040	0.00143	53.0352	0.00248	0.00040	0.00143	53.0352
VOC	0.00014	0.00002	0.00008	3.00	0.00082	0.00013	0.00047	17.4896	0.00082	0.00013	0.00047	17.49
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00024	9.00		0.00008	0.00030	11.264		0.00008	0.00030	11.264
ammonia, NH3								61.78	0.00135	0.00023	0.00083	30.67
Total				3687000.00				3706510				3706510
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.40349				11.46461				11.46461			
carbon dioxide	4.30207				5.40555				5.40555			
nitrogen	81.32300				82.13702				82.13702			
argon	0.98300				0.99281				0.99281			
NOx	0.00146	14.60174	11.53299		0.00217	21.68519	13.64508		0.00056	5.56231	3.5	
CO	0.00150	14.95392	11.81115		0.00407	40.74814	25.64016		0.00407	40.74814	25.64016	
VOC	0.00016	1.63558	1.29184		0.00096	9.63036	6.05976		0.00096	9.63036	6.05976	
ammonia, NH3									0.00159	15.89231	10	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Revised 11/15/00

Case 10

Ambient temp (F) 70 Natural Gas
CT load (%) 100
Over pressure no
Power Augmentation no
Stack outlet (F) 178

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.40000	3.96800	14.03231	494638.87	12.40000	3.96800	14.03231	494638.87	12.40000	3.96800	14.03231	494638.87
carbon dioxide	3.77000	1.65880	5.86613	206780.99	3.77000	1.65880	5.86613	206780.99	3.77000	1.65880	5.86613	206780.99
water vapor	9.26000	1.66680	5.89442	207778.24	9.26000	1.66680	5.89442	207778.24	9.26000	1.66680	5.89442	207778.24
nitrogen	73.70000	20.63600	72.97649	2572421.28	73.70000	20.63600	72.97649	2572421.28	73.70000	20.63600	72.97649	2572421.28
argon	0.87000	0.34800	1.23066	43380.63	0.87000	0.34800	1.23066	43380.63	0.87000	0.34800	1.23066	43380.63
		28.27760	100.00000			28.27760	100.00000			28.27760	100.00000	
NOx	0.00099	0.00046	0.00162	57.00	0.00099	0.00046	0.00162	57.00	0.00039	0.00018	0.00063	22.26
carbon monoxide	0.00138	0.00039	0.00136	48.00	0.00138	0.00039	0.00136	48.00	0.00138	0.00039	0.00136	48.00
hydrocarbons CH4	0.00070	0.00011	0.00040	14.00	0.00070	0.00011	0.00040	14.00	0.00070	0.00011	0.00040	14.00
VOC	0.00014	0.00002	0.00008	2.80	0.00014	0.00002	0.00008	2.80	0.00014	0.00002	0.00008	2.80
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00026	9.00		0.000	0.000	9.00		0.00007	0.00026	9.00
ammonia, NH3								36.34	0.00111	0.00019	0.00067	23.51
Total				3525000.00				3525000.00				3525000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.66542				13.66542				13.66542			
carbon dioxide	4.15473				4.15473				4.15473			
nitrogen	81.22107				81.22107				81.22107			
argon	0.95878				0.95878				0.95878			
NOx	0.00110	10.95473	8.96143		0.00110	10.95473	8.96143		0.00043	4.27851	3.50000	
CO	0.00152	15.15542	12.39777		0.00152	15.15542	12.39777		0.00152	15.15541	12.39777	
VOC	0.00015	1.54712	1.26561		0.00015	1.54712	1.26561		0.00015	1.54712	1.26561	
ammonia, NH3									0.00122	12.22430	10	

Case 11

	CT emissions			Duct Burner Discharge			Stack Exhaust					
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.48000	3.99360	14.11136	401750.46	12.48000	3.99360	14.11136	401750.46	12.48000	3.99360	14.11136	401750.46
carbon dioxide	3.75000	1.65000	5.83027	165987.65	3.75000	1.65000	5.83027	165987.65	3.75000	1.65000	5.83027	165987.65
water vapor	9.07000	1.63260	5.76878	164237.23	9.07000	1.63260	5.76878	164237.23	9.07000	1.63260	5.76878	164237.23
nitrogen	73.83000	20.67240	73.04580	2079613.96	73.83000	20.67240	73.04580	2079613.96	73.83000	20.67240	73.04580	2079613.96
argon	0.88000	0.35200	1.24379	35410.70	0.88000	0.35200	1.24379	35410.70	0.88000	0.35200	1.24379	35410.70
		28.30060	100.00000			28.30060	100.00000			28.30060	100.00000	
NOx	0.00099	0.00046	0.00162	46.00	0.00099	0.00046	0.00162	46.00	0.00039	0.00018	0.00063	17.86
carbon monoxide	0.00135	0.00038	0.00133	38.00	0.00135	0.00038	0.00133	38.00	0.00135	0.00038	0.00133	38.00
hydrocarbons CH4	0.00068	0.00011	0.00039	11.00	0.00068	0.00011	0.00039	11.00	0.00068	0.00011	0.00039	11.00
VOC	0.00014	0.00002	0.00008	2.20	0.00014	0.00002	0.00008	2.20	0.00014	0.00002	0.00008	2.20
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00009	0.00032	9.00		0.00009	0.00032	9.00		0.00009	0.00032	9.00
ammonia, NH3								29.26	0.00110	0.00019	0.00066	18.86
Total				2847000.00				2847000.00				2847000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.72484				13.72484				13.72484			
carbon dioxide	4.12405				4.12405				4.12405			
nitrogen	81.19433				81.19433				81.19433			
argon	0.96778				0.96778				0.96778			
NOx	0.00109	10.93203	9.01592		0.00109	10.93203	9.01592		0.00042	4.24384		3.5
CO	0.00148	14.83633	12.23589		0.00148	14.83633	12.23589		0.00148	14.83634		12.23589
VOC	0.00015	1.50315	1.23969		0.00015	1.50315	1.23969		0.00015	1.50316		1.23969
ammonia, NH3									0.00121	12.12526		10

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Revised 11/15/00

Case 12

Ambient temp (F) 70 Natural Gas
CT load (%) 50
Over pressure no
Power Augmentation no
Stack outlet (F) 160

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.86000	4.11520	14.52994	344069.09	12.86000	4.11520	14.52994	344069.09	12.86000	4.11520	14.52994	344069.09
carbon dioxide	3.57000	1.57080	5.54618	131333.53	3.57000	1.57080	5.54618	131333.53	3.57000	1.57080	5.54618	131333.53
water vapor	8.73000	1.57140	5.54830	131383.69	8.73000	1.57140	5.54830	131383.69	8.73000	1.57140	5.54830	131383.69
nitrogen	73.96000	20.70880	73.11861	1731448.77	73.96000	20.70880	73.11861	1731448.77	73.96000	20.70880	73.11861	1731448.77
argon	0.89000	0.35600	1.25696	29764.92	0.89000	0.35600	1.25696	29764.92	0.89000	0.35600	1.25696	29764.92
		28.32220	100.00000			28.32220	100.00000			28.32220	100.00000	
NOx	0.00094	0.00043	0.00152	36.00	0.00094	0.00043	0.00152	36.00	0.00037	0.00017	0.00060	14.15
carbon monoxide	0.00137	0.00038	0.00135	32.00	0.00137	0.00038	0.00135	32.00	0.00137	0.00038	0.00135	32.00
hydrocarbons CH4	0.00067	0.00011	0.00038	9.00	0.00067	0.00011	0.00038	9.00	0.00067	0.00011	0.00038	9.00
VOC	0.00013	0.00002	0.00008	1.80	0.00013	0.00002	0.00008	1.80	0.00013	0.00002	0.00008	1.80
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00011	0.00038	9.00		0.00011	0.00038	9.00		0.00011	0.00038	9.00
ammonia, NH3								23.02	0.00105	0.00018	0.00063	14.94
Total				2368000.00				2368000.00				2368000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	14.09006				14.09006				14.09006			
carbon dioxide	3.91147				3.91147				3.91147			
nitrogen	81.03429				81.03429				81.03429			
argon	0.97513				0.97513				0.97513			
NOx	0.00103	10.25562	8.90510		0.00103	10.25562	8.90510		0.00040	4.03080	3.5	
CO	0.00150	14.97646	13.00428		0.00150	14.97646	13.00428		0.00150	14.97646	13.00428	
VOC	0.00015	1.47425	1.28011		0.00015	1.47425	1.28011		0.00015	1.47425	1.28011	
ammonia, NH3									0.00115	11.51656	10	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Revised 11/15/00

Case 13

Ambient temp (F) 70 heat input lb/MMBtu (HHV) 439 Natural Gas
CT load (%) 100
Over pressure yes
Power Augmentation no
Stack outlet (F) 172

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.40000	3.96800	14.03231	494638.87	10.47473	3.35191	11.89790	421652.06	10.47473	3.35191	11.89790	421652.06
carbon dioxide	3.77000	1.65880	5.86613	206780.99	4.66373	2.05204	7.28390	258135.59	4.66373	2.05204	7.28390	258135.59
water vapor	9.26000	1.66680	5.89442	207778.24	10.96330	1.97339	7.00473	248242.03	10.96330	1.97339	7.00473	248242.03
nitrogen	73.70000	20.63600	72.97649	2572421.28	73.03610	20.45011	72.58940	2572510.26	73.03610	20.45011	72.58940	2572510.26
argon	0.87000	0.34800	1.23066	43380.63	0.86214	0.34485	1.22409	43380.77	0.86214	0.34485	1.22409	43380.77
		28.27760	100.00000			28.17231		100.00002		28.17231		100.00002
NOx	0.00099	0.00046	0.00162	57.00	0.00159	0.00073	0.00260	92.12	0.00048	0.00022	0.00078	27.76
carbon monoxide	0.00138	0.00039	0.00136	48.00	0.00248	0.00070	0.00247	87.51	0.00248	0.00070	0.00247	87.51
hydrocarbons CH4	0.00070	0.00011	0.00040	14.00	0.00253	0.00040	0.00144	50.88	0.00253	0.00040	0.00144	50.88
VOC	0.00014	0.00002	0.00008	2.80	0.00049	0.00008	0.00028	9.82	0.00049	0.00008	0.00028	9.82
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00026	9.00		0.000	0.000	11.20		0.00009	0.00032	11.20
ammonia, NH3								53.09	0.00137	0.00023	0.00083	29.31
Total				3525000.00				3543920.00				3543920.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.66542				11.76451				11.76451			
carbon dioxide	4.15473				5.23799				5.23799			
nitrogen	81.22107				82.02921				82.02921			
argon	0.95878				0.96829				0.96829			
NOx	0.00110	10.95473	8.96143		0.00179	17.87992	11.61600		0.00054	5.38737	3.50000	
CO	0.00152	15.15542	12.39777		0.00279	27.90418	18.12843		0.00279	27.90417	18.12843	
VOC	0.00015	1.54712	1.26561		0.00055	5.48199	3.56147		0.00055	5.48199	3.56147	
ammonia, NH3									0.00154	15.39249	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 14

Ambient temp (F) 95 Natural Gas
CT load (%) 100
Over pressure no
Power Augmentation no
Stack outlet (F) 176

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.27000	3.92640	13.92923	474847.55	12.27000	3.92640	13.92923	474847.55	12.27000	3.92640	13.92923	474847.55
carbon dioxide	3.75000	1.65000	5.85351	199546.26	3.75000	1.65000	5.85351	199546.26	3.75000	1.65000	5.85351	199546.26
water vapor	10.07000	1.81260	6.43035	219210.64	10.07000	1.81260	6.43035	219210.64	10.07000	1.81260	6.43035	219210.64
nitrogen	73.04000	20.45120	72.55234	2473309.43	73.04000	20.45120	72.55234	2473309.43	73.04000	20.45120	72.55234	2473309.43
argon	0.87000	0.34800	1.23456	42086.12	0.87000	0.34800	1.23456	42086.12	0.87000	0.34800	1.23456	42086.12
		28.18820	100.00000			28.18820	100.00000			28.18820	100.00000	
NOx	0.00099	0.00045	0.00161	55.00	0.00099	0.00045	0.00161	55.00	0.00039	0.00018	0.00063	21.47
carbon monoxide	0.00133	0.00037	0.00132	45.00	0.00133	0.00037	0.00132	45.00	0.00133	0.00037	0.00132	45.00
hydrocarbons CH4	0.00072	0.00012	0.00041	14.00	0.00072	0.00012	0.00041	14.00	0.00072	0.00012	0.00041	14.00
VOC	0.00014	0.00002	0.00008	2.80	0.00014	0.00002	0.00008	2.80	0.00014	0.00002	0.00008	2.80
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00026	9.00		0.000	0.000	9.00		0.00007	0.00026	9.00
ammonia, NH3									0.00110	0.00019	0.00066	22.67
Total				3409000.00				3409000.00				3409000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.64395				13.64395				13.64395			
carbon dioxide	4.16991				4.16991				4.16991			
nitrogen	81.21873				81.21873				81.21873			
argon	0.96742				0.96742				0.96742			
NOx	0.00110	10.99362	8.96699		0.00110	10.99362	8.96699		0.00043	4.29103	3.50000	
CO	0.00148	14.77713	12.05304		0.00148	14.77713	12.05304		0.00148	14.77714	12.05304	
VOC	0.00016	1.60907	1.31244		0.00016	1.60907	1.31244		0.00016	1.60906	1.31244	
ammonia, NH3									0.00123	12.26009	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 15

Ambient temp (F) **95** Natural Gas
CT load (%) **75**
Over pressure no
Power Augmentation no
Stack outlet (F) **166**

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.50000	4.00000	14.15629	395526.61	12.50000	4.00000	14.15629	395526.61	12.50000	4.00000	14.15629	395526.61
carbon dioxide	3.69000	1.62360	5.74604	160544.25	3.69000	1.62360	5.74604	160544.25	3.69000	1.62360	5.74604	160544.25
water vapor	9.44000	1.69920	6.01359	168019.71	9.44000	1.69920	6.01359	168019.71	9.44000	1.69920	6.01359	168019.71
nitrogen	73.49000	20.57720	72.82418	2034707.56	73.49000	20.57720	72.82418	2034707.56	73.49000	20.57720	72.82418	2034707.56
argon	0.89000	<u>0.35600</u>	1.25991	35201.87	0.89000	<u>0.35600</u>	1.25991	35201.87	0.89000	<u>0.35600</u>	1.25991	35201.87
		28.25600	100.00000			28.25600	100.00000			28.25600	100.00000	
NOx	0.00099	0.00046	0.00161	45.00	0.00099	0.00046	0.00161	45.00	0.00038	0.00017	0.00062	17.29
carbon monoxide	0.00137	0.00038	0.00136	38.00	0.00137	0.00038	0.00136	38.00	0.00137	0.00038	0.00136	38.00
hydrocarbons CH4	0.00070	0.00011	0.00039	11.00	0.00070	0.00011	0.00039	11.00	0.00070	0.00011	0.00039	11.00
VOC	0.00014	0.00002	0.00008	2.20	0.00014	0.00002	0.00008	2.20	0.00014	0.00002	0.00008	2.20
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00009	0.00032	9.00		0.00009	0.00032	9.00		0.00009	0.00032	9.00
ammonia, NH3									0.00109	0.00018	0.00065	18.26
Total				2794000.00				2794000.00				2794000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.80300				13.80300				13.80300			
carbon dioxide	4.07465				4.07465				4.07465			
nitrogen	81.15062				81.15062				81.15062			
argon	0.98277				0.98277				0.98277			
NOx	0.00109	10.92452	9.10757		0.00109	10.92452	9.10757		0.00042	4.19825	3.5	
CO	0.00152	15.15561	12.63495		0.00152	15.15561	12.63495		0.00152	15.15562	12.63495	
VOC	0.00015	1.53550	1.28012		0.00015	1.53550	1.28012		0.00015	1.53550	1.28012	
ammonia, NH3									0.00120	11.99499	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 16

Ambient temp (F) 95 Natural Gas
CT load (%) 50
Full pressure no
Power Augmentation no
Stack outlet (F) 160

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.96000	4.14720	14.66592	343475.89	12.96000	4.14720	14.66592	343475.89	12.96000	4.14720	14.66592	343475.89
carbon dioxide	3.48000	1.53120	5.41485	126815.75	3.48000	1.53120	5.41485	126815.75	3.48000	1.53120	5.41485	126815.75
water vapor	9.03000	1.62540	5.74797	134617.50	9.03000	1.62540	5.74797	134617.50	9.03000	1.62540	5.74797	134617.50
nitrogen	73.65000	20.62200	72.92647	1707937.82	73.65000	20.62200	72.92647	1707937.82	73.65000	20.62200	72.92647	1707937.82
argon	0.88000	0.35200	1.24479	29153.05	0.88000	0.35200	1.24479	29153.05	0.88000	0.35200	1.24479	29153.05
		28.27780	100.00000			28.27780	100.00000			28.27780	100.00000	
NOx	0.00092	0.00042	0.00149	35.00	0.00092	0.00042	0.00149	35.00	0.00036	0.00016	0.00058	13.65
carbon monoxide	0.00138	0.00039	0.00137	32.00	0.00138	0.00039	0.00137	32.00	0.00138	0.00039	0.00137	32.00
hydrocarbons CH4	0.00068	0.00011	0.00038	9.00	0.00068	0.00011	0.00038	9.00	0.00068	0.00011	0.00038	9.00
VOC	0.00014	0.00002	0.00008	1.80	0.00014	0.00002	0.00008	1.80	0.00014	0.00002	0.00008	1.80
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00011	0.00038	9.00		0.00011	0.00038	9.00		0.00011	0.00038	9.00
ammonia, NH3									0.00102	0.00017	0.00062	14.42
Total				2342000.00				2342000.00				2342000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	14.24645				14.24645				14.24645			
carbon dioxide	3.82544				3.82544				3.82544			
nitrogen	80.96076				80.96076				80.96076			
argon	0.96735				0.96735				0.96735			
NOx	0.00101	10.09882	8.97202		0.00101	10.09882	8.97202		0.00039	3.93957	3.5	
CO	0.00152	15.16884	13.47634		0.00152	15.16884	13.47634		0.00152	15.16885	13.47634	
VOC	0.00015	1.49318	1.32658		0.00015	1.49318	1.32658		0.00015	1.49319	1.32658	
ammonia, NH3									0.00113	11.25591	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 17

Ambient temp (F) 95 Natural Gas
CT load (%) 100
Full pressure yes Duct Burner Heat Input MMBtu/hr (HHV) 472.9
Power Augmentation yes
Stack outlet (F) 169

	CT Emissions			Duct Burner Discharge			Stack Exhaust					
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.23000	3.59360	12.99646	457995.36	9.21270	2.94806	10.70350	379372.713	9.21270	2.94806	10.70350	379372.713
carbon dioxide	3.75000	1.65000	5.96732	210288.38	4.69091	2.06400	7.49374	265606.622	4.69091	2.06400	7.49374	265606.622
water vapor	15.01000	2.70180	9.77122	344337.67	16.74735	3.01452	10.94480	387925.302	16.74735	3.01452	10.94480	387925.302
nitrogen	69.19000	19.37320	70.06430	2469066.02	68.52702	19.18757	69.66410	2469160.43	68.52702	19.18757	69.66410	2469160.43
argon	0.83000	0.33200	1.20070	42312.57	0.82202	0.32881	1.19380	42312.8084	0.82202	0.32881	1.19380	42312.8084
		27.65060	100.00000			27.54296	99.99994			27.54296	99.99994	
NOx	0.00126	0.00058	0.00210	74.00	0.00189	0.00087	0.00316	111.832	0.00048	0.00022	0.00081	28.56
carbon monoxide	0.00126	0.00035	0.00128	45.00	0.00361	0.00101	0.00367	130.122	0.00361	0.00101	0.00367	130.12
hydrocarbons CH4	0.00069	0.00011	0.00040	14.00	0.00261	0.00042	0.00152	53.7236	0.00261	0.00042	0.00152	53.7236
VOC	0.00014	0.00002	0.00008	2.80	0.00087	0.00014	0.00051	17.9328	0.00087	0.00014	0.00051	17.93
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00026	9.00		0.00009	0.00032	11.3645		0.00009	0.00032	11.3645
ammonia, NH3								60.93	0.00138	0.00023	0.00085	30.15
Total				3524000.00				3544380				3544380
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.21332				11.06595				11.06595			
carbon dioxide	4.41228				5.63454				5.63454			
nitrogen	81.40958				82.31213				82.31213			
argon	0.97659				0.98738				0.98738			
NOx	0.00149	14.85165	11.44389		0.00227	22.69241	13.70583		0.00058	5.79486	3.5	
CO	0.00148	14.83731	11.43284		0.00434	43.37755	26.19931		0.00434	43.37755	26.19931	
VOC	0.00016	1.61562	1.24491		0.00105	10.46166	6.31866		0.00105	10.46166	6.31866	
ammonia, NH3									0.00166	16.55675	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 18

Ambient temp (F) 95 DUCT BURNER DESIGN CASE Natural Gas
CT load (%) 100
Full pressure yes Duct Burner Heat Input MMBtu/hr (HHV) 541.7
Power Augmentation yes
Stack outlet (F) 168

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.23000	3.59360	12.99646	457995.36	8.92264	2.85525	10.37220	367937.199	8.92264	2.85525	10.37220	367937.199
carbon dioxide	3.75000	1.65000	5.96732	210288.38	4.82634	2.12359	7.71432	273653.159	4.82634	2.12359	7.71432	273653.159
water vapor	15.01000	2.70180	9.77122	344337.67	16.99754	3.05956	11.11440	394265.557	16.99754	3.05956	11.11440	394265.557
nitrogen	69.19000	19.37320	70.06430	2469066.02	68.43260	19.16113	69.60630	2469172.12	68.43260	19.16113	69.60630	2469172.12
argon	0.83000	0.33200	1.20070	42312.57	0.82088	0.32835	1.19280	42312.6715	0.82088	0.32835	1.19280	42312.6715
		27.65060	100.00000		100.00000	27.52787	100.00002			27.52787	100.00002	
NOx	0.00126	0.00058	0.00210	74.00	0.00198	0.00091	0.00331	117.336	0.00050	0.00023	0.00083	29.42
carbon monoxide	0.00126	0.00035	0.00128	45.00	0.00395	0.00111	0.00402	142.506	0.00395	0.00111	0.00402	142.51
hydrocarbons CH4	0.00069	0.00011	0.00040	14.00	0.00289	0.00046	0.00168	59.5028	0.00289	0.00046	0.00168	59.5028
VOC	0.00014	0.00002	0.00008	2.80	0.00098	0.00016	0.00057	20.1344	0.00098	0.00016	0.00057	20.13
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00026	9.00		0.00009	0.00033	11.7085		0.00009	0.00033	11.7085
ammonia, NH3								63.5545136	0.00142	0.00024	0.00088	31.06
Total				3524000.00				3547340				3547340
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.21332				10.74985				10.74985			
carbon dioxide	4.41228				5.81469				5.81469			
nitrogen	81.40958				82.44647				82.44647			
argon	0.97659				0.98898				0.98898			
NOx	0.00149	14.85165	11.44389		0.00238	23.84802	13.95961		0.00080	5.97925	3.5	
CO	0.00148	14.83731	11.43284		0.00476	47.58323	27.85320		0.00476	47.58324	27.8532	
VOC	0.00016	1.61562	1.24491		0.00118	11.76515	6.88682		0.00118	11.76515	6.88682	
ammonia, NH3									0.00171	17.08358	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 19

Ambient temp (F) 95 Natural Gas
CT load (%) 100
Full pressure yes Duct Burner Heat Input MMBtu/hr (HHV) 412.7
Power Augmentation no
Stack outlet (F) 170

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	12.27000	3.92640	13.92923	474847.55	10.40516	3.32965	11.85480	406237.915	10.40516	3.32965	11.85480	406237.915
carbon dioxide	3.75000	1.65000	5.85351	199546.26	4.61637	2.03120	7.23184	247819.247	4.61637	2.03120	7.23184	247819.247
water vapor	10.07000	1.81260	6.43035	219210.64	11.71370	2.10847	7.50693	257245.976	11.71370	2.10847	7.50693	257245.976
nitrogen	73.04000	20.45120	72.55234	2473309.43	72.40240	20.27267	72.17830	2473391.55	72.40240	20.27267	72.17830	2473391.55
argon	0.87000	0.34800	1.23456	42086.12	0.86237	0.34495	1.22815	42085.9986	0.86237	0.34495	1.22815	42085.9986
		28.18820	100.00000		100.00000	28.08694	100.00002			28.08694	100.00002	
NOx	0.00099	0.00045	0.00161	55.00	0.00157	0.00072	0.00257	88.016	0.00047	0.00022	0.00078	26.63
carbon monoxide	0.00133	0.00037	0.00132	45.00	0.00240	0.00067	0.00240	82.143	0.00240	0.00067	0.00240	82.14
hydrocarbons CH4	0.00072	0.00012	0.00041	14.00	0.00249	0.00040	0.00142	48.6668	0.00249	0.00040	0.00142	48.6668
VOC	0.00014	0.00002	0.00008	2.80	0.00048	0.00008	0.00027	9.4032	0.00048	0.00008	0.00027	9.40
SO2	0.00000	0.00000	0.00000	0.00	0.00000	0.00000	0.00000	0	0.00000	0.00000	0.00000	0.00
Particulate, PM-10		0.00007	0.00026	9.00		0.00009	0.00032	11.0635		0.00009	0.00032	11.0635
ammonia, NH3								50.8064908	0.00136	0.00023	0.00082	28.12
Total				3409000.00				3426780				3426780
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	13.64395				11.78570				11.78570			
carbon dioxide	4.16991				5.22886				5.22886			
nitrogen	81.21873				82.00865				82.00865			
argon	0.96742				0.97679				0.97679			
NOx	0.00110	10.99362	8.96699		0.00178	17.76351	11.56691		0.00054	5.37501	3.5	
CO	0.00148	14.77713	12.05304		0.00272	27.23563	17.73480		0.00272	27.23564	17.7348	
VOC	0.00016	1.60907	1.31244		0.00055	5.45608	3.55279		0.00055	5.45608	3.55279	
ammonia, NH3									0.00154	15.35717	10	

Case 20

<u>CT emissions</u>				<u>Duct Burner Discharge</u>				<u>Stack Exhaust</u>				
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.47000	3.67040	12.92158	517250.76	11.47000	3.67040	12.92158	517250.76	11.47000	3.67040	12.92158	517250.76
carbon dioxide	5.44000	2.39360	8.42663	337317.84	5.44000	2.39360	8.42663	337317.84	5.44000	2.39360	8.42663	337317.84
water vapor	10.26000	1.84680	6.50163	260260.11	10.26000	1.84680	6.50163	260260.11	10.26000	1.84680	6.50163	260260.11
nitrogen	71.98000	20.15440	70.95321	2840256.83	71.98000	20.15440	70.95321	2840256.83	71.98000	20.15440	70.95321	2840256.83
argon	0.85000	<u>0.34000</u>	1.19696	47914.47	0.85000	<u>0.34000</u>	1.19696	47914.47	0.85000	<u>0.34000</u>	1.19696	47914.47
		28.40520	100.00000			28.40520	100.00000			28.40520	100.00000	
NOx	0.00518	0.00238	0.00839	336.00	0.00518	0.00238	0.00839	336.00	0.00123	0.00057	0.00199	79.69
carbon monoxide	0.00180	0.00050	0.00177	71.00	0.00180	0.00050	0.00177	71.00	0.00180	0.00050	0.00177	71.00
hydrocarbons CH4	0.00071	0.00011	0.00040	16.00	0.00071	0.00011	0.00040	16.00	0.00071	0.00011	0.00040	16.00
VOC	0.00035	0.00006	0.00020	8.00	0.00035	0.00006	0.00020	8.00	0.00035	0.00006	0.00020	8.00
SO2	0.00000	0.00076	0.00267	107.00	0.00000	0.00076	0.00267	107.00	0.00000	0.00076	0.00267	107.00
Particulate, PM-10		0.00012	0.00042	17.00		0.000	0.000	17.00		0.00012	0.00042	17.00
ammonia, NH3									0.00123	0.00021	0.00074	29.45
Total				4003000.00				4003000.00				4003000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.78137				12.78137				12.78137			
carbon dioxide	6.06196				6.06196				6.06196			
nitrogen	80.20949				80.20949				80.20949			
argon	0.94718				0.94718				0.94718			
NOx	0.00578	57.75740	42.16571		0.00578	57.75740	42.16571		0.00137	13.69772	10.00000	
CO	0.00201	20.05056	14.63788		0.00201	20.05056	14.63788		0.00201	20.05056	14.63788	
VOC	0.00040	3.95363	2.88634		0.00040	3.95363	2.88634		0.00040	3.95363	2.88634	
ammonia, NH3									0.00137	13.69772	10.00000	

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 21

Ambient temp (F) 19 Distillate
CT load (%) 75
Over pressure no
Power Augmentation no
Stack outlet (F) 262

	CT emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.11000	3.55520	12.51091	382833.82	11.11000	3.55520	12.51091	382833.82	11.11000	3.55520	12.51091	382833.82
carbon dioxide	5.67000	2.49480	8.77931	268647.00	5.67000	2.49480	8.77931	268647.00	5.67000	2.49480	8.77931	268647.00
water vapor	10.42000	1.87560	6.60032	201969.82	10.42000	1.87560	6.60032	201969.82	10.42000	1.87560	6.60032	201969.82
nitrogen	71.94000	20.14320	70.88483	2169075.76	71.94000	20.14320	70.88483	2169075.76	71.94000	20.14320	70.88483	2169075.76
argon	0.87000	0.34800	1.22463	37473.61	0.87000	0.34800	1.22463	37473.61	0.87000	0.34800	1.22463	37473.61
		28.41680	100.00000			28.41680	100.00000			28.41680	100.00000	
NOx	0.00541	0.00249	0.00876	268.00	0.00541	0.00249	0.00876	268.00	0.00128	0.00059	0.00208	63.58
carbon monoxide	0.00196	0.00055	0.00193	59.00	0.00196	0.00055	0.00193	59.00	0.00196	0.00055	0.00193	59.00
hydrocarbons CH4	0.00070	0.00011	0.00039	12.00	0.00070	0.00011	0.00039	12.00	0.00070	0.00011	0.00039	12.00
VOC	0.00035	0.00006	0.00020	6.00	0.00035	0.00006	0.00020	6.00	0.00035	0.00006	0.00020	6.00
SO2	0.00000	0.00000	0.00281	86.00	0.00000	0.00000	0.00281	86.00	0.00000	0.00000	0.00281	86.00
Particulate, PM-10		0.00016	0.00056	17.00		0.00016	0.00056	17.00		0.00016	0.00056	17.00
ammonia, NH3									0.00128	0.00022	0.00077	23.50
Total				3060000.00				3060000.00				3060000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.40232				12.40232				12.40232			
carbon dioxide	6.32954				6.32954				6.32954			
nitrogen	80.30810				80.30810				80.30810			
argon	0.97120				0.97120				0.97120			
NOx	0.00604	60.39760	42.14924		0.00604	60.39760	42.14924		0.00143	14.32946	10	
CO	0.00218	21.84423	15.24427		0.00218	21.84423	15.24427		0.00218	21.84422	15.24427	
VOC	0.00039	3.88753	2.71296		0.00039	3.88753	2.71296		0.00039	3.88753	2.71296	
ammonia, NH3									0.00143	14.32946	10	

Orlando Combined Cycle Emissions Revised 12/6/00
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Case 22

Ambient temp (F) 19 Distillate
CT load (%) 50
Full pressure no
Power Augmentation
Stack outlet (F) 249

	CT Emissions				Duct Burner Discharge				Stack Exhaust			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.58000	3.70560	13.00731	321020.37	11.58000	3.70560	13.00731	321020.37	11.58000	3.70560	13.00731	321020.37
carbon dioxide	5.47000	2.40680	8.44829	208503.84	5.47000	2.40680	8.44829	208503.84	5.47000	2.40680	8.44829	208503.84
water vapor	9.53000	1.71540	6.02136	148607.06	9.53000	1.71540	6.02136	148607.06	9.53000	1.71540	6.02136	148607.06
nitrogen	72.56000	20.31680	71.31554	1760067.62	72.56000	20.31680	71.31554	1760067.62	72.56000	20.31680	71.31554	1760067.62
argon	0.86000	0.34400	1.20750	29801.11	0.86000	0.34400	1.20750	29801.11	0.86000	0.34400	1.20750	29801.11
		28.48860	100.00000			28.48860	100.00000			28.48860	100.00000	
NOx	0.00522	0.00240	0.00843	208.00	0.00522	0.00240	0.00843	208.00	0.00124	0.00057	0.00200	49.27
carbon monoxide	0.00272	0.00076	0.00267	66.00	0.00272	0.00076	0.00267	66.00	0.00272	0.00076	0.00267	66.00
hydrocarbons CH4	0.00072	0.00012	0.00041	10.00	0.00072	0.00012	0.00041	10.00	0.00072	0.00012	0.00041	10.00
VOC	0.00036	0.00006	0.00020	5.00	0.00036	0.00006	0.00020	5.00	0.00036	0.00006	0.00020	5.00
SO2	0.00000	0.00078	0.00276	68.00	0.00000	0.00078	0.00276	68.00	0.00000	0.00078	0.00276	68.00
Particulate, PM-10		0.00020	0.00069	17.00		0.00020	0.00069	17.00		0.00020	0.00069	17.00
ammonia, NH3									0.00124	0.00021	0.00074	18.21
Total				2468000.00				2468000.00				2468000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.79982				12.79982				12.79982			
carbon dioxide	6.04620				6.04620				6.04620			
nitrogen	80.20338				80.20338				80.20338			
argon	0.95059				0.95059				0.95059			
NOx	0.00577	57.69350	42.21384		0.00577	57.69350	42.21384		0.00137	13.66696	10	
CO	0.00301	30.07511	22.00571		0.00301	30.07511	22.00571		0.00301	30.07512	22.00571	
VOC	0.00040	3.98723	2.91742		0.00040	3.98723	2.91742		0.00040	3.98723	2.91742	
ammonia, NH3									0.00137	13.66696	10	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (natural gas), w/o CO catalyst

Revised 11/15/00

Case 23

Ambient temp (F) **45**
CT load (%) **100**
Over pressure no
Power Augmentation no
Stack outlet (F) **281**

Distillate

	<u>CT emissions</u>				<u>Duct Burner Discharge</u>				<u>Stack Exhaust</u>			
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.32000	3.62240	12.77472	488633.09	11.32000	3.62240	12.77472	488633.09	11.32000	3.62240	12.77472	488633.09
carbon dioxide	5.47000	2.40680	8.48780	324658.27	5.47000	2.40680	8.48780	324658.27	5.47000	2.40680	8.48780	324658.27
water vapor	10.78000	1.94040	6.84300	261744.60	10.78000	1.94040	6.84300	261744.60	10.78000	1.94040	6.84300	261744.60
nitrogen	71.58000	20.04240	70.68134	2703561.15	71.58000	20.04240	70.68134	2703561.15	71.58000	20.04240	70.68134	2703561.15
argon	0.86000	<u>0.34400</u>	1.21315	46402.88	0.86000	<u>0.34400</u>	1.21315	46402.88	0.86000	<u>0.34400</u>	1.21315	46402.88
		28.35600	100.00000			28.35600	100.00000			28.35600	100.00000	
NOx	0.00522	0.00240	0.00847	324.00	0.00522	0.00240	0.00847	324.00	0.00124	0.00057	0.00201	76.70
carbon monoxide	0.00177	0.00050	0.00175	67.00	0.00177	0.00050	0.00175	67.00	0.00177	0.00050	0.00175	67.00
hydrocarbons CH4	0.00070	0.00011	0.00039	15.00	0.00070	0.00011	0.00039	15.00	0.00070	0.00011	0.00039	15.00
VOC	0.00035	0.00006	0.00020	7.50	0.00035	0.00006	0.00020	7.50	0.00035	0.00006	0.00020	7.50
SO2	0.00159	0.00076	0.00269	103.00	0.00159	0.00076	0.00269	103.00	0.00159	0.00076	0.00269	103.00
Particulate, PM-10		0.00013	0.00044	17.00		0.000	0.000	17.00		0.00013	0.00044	17.00
ammonia, NH3								119.74	0.00124	0.00021	0.00074	28.34
Total				3825000.00				3825000.00				3825000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.68774				12.68774				12.68774			
carbon dioxide	6.13091				6.13091				6.13091			
nitrogen	80.22865				80.22865				80.22865			
argon	0.96391				0.96391				0.96391			
NOx	0.00585	58.52460	42.24453		0.00585	58.52460	42.24453		0.00139	13.85377	10.00000	
CO	0.00199	19.88237	14.35159		0.00199	19.88237	14.35159		0.00199	19.88154	14.35100	
VOC	0.00039	3.89487	2.81141		0.00039	3.89487	2.81141		0.00039	3.89486	2.81141	
ammonia, NH3									0.00139	13.85377	10.00000	

Orlando Combined Cycle Emissions
per CT/HRSG (numbers in bold are input)
3.5ppm NOx (with natural gas), w/o CO catalyst

Revised 11/15/00

Case 24

Ambient temp (F) 70 Distillate
CT load (%) 100
Over pressure no
Power Augmentation no
Stack outlet (F) 276

CT emissions				Duct Burner Discharge				Stack Exhaust				
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.09000	3.54880	12.56177	458002.07	11.09000	3.54880	12.56177	458002.07	11.09000	3.54880	12.56177	458002.07
carbon dioxide	5.49000	2.41560	8.55055	311753.21	5.49000	2.41560	8.55055	311753.21	5.49000	2.41560	8.55055	311753.21
water vapor	11.72000	2.10960	7.46740	272261.37	11.72000	2.10960	7.46740	272261.37	11.72000	2.10960	7.46740	272261.37
nitrogen	70.86000	19.84080	70.23093	2560619.76	70.86000	19.84080	70.23093	2560619.76	70.86000	19.84080	70.23093	2560619.76
argon	0.84000	0.33600	1.18935	43363.59	0.84000	0.33600	1.18935	43363.59	0.84000	0.33600	1.18935	43363.59
		28.25080	100.00000			28.25080	100.00000			28.25080	100.00000	
NOx	0.00524	0.00241	0.00853	311.00	0.00524	0.00241	0.00853	311.00	0.00124	0.00057	0.00202	73.70
carbon monoxide	0.00177	0.00050	0.00176	64.00	0.00177	0.00050	0.00176	64.00	0.00177	0.00050	0.00176	64.00
hydrocarbons CH4	0.00068	0.00011	0.00038	14.00	0.00068	0.00011	0.00038	14.00	0.00068	0.00011	0.00038	14.00
VOC	0.00034	0.00005	0.00019	7.00	0.00034	0.00005	0.00019	7.00	0.00034	0.00005	0.00019	7.00
SO2	0.00160	0.00077	0.00272	99.00	0.00160	0.00077	0.00272	99.00	0.00160	0.00077	0.00272	99.00
Particulate, PM-10		0.00013	0.00047	17.00		0.00013	0.00047	17.00		0.00013	0.00047	17.00
ammonia, NH3								114.93	0.00124	0.00021	0.00075	27.24
Total				3646000.00				3646000.00				3646000.00
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.56230				12.56230				12.56230			
carbon dioxide	6.21885				6.21885				6.21885			
nitrogen	80.26733				80.26733				80.26733			
argon	0.95152				0.95152				0.95152			
NOx	0.00593	59.34093	42.19700		0.00593	59.34093	42.19700		0.00141	14.06283	10.00000	
CO	0.00201	20.06198	14.26596		0.00201	20.06198	14.26596		0.00201	20.06198	14.26596	
VOC	0.00038	3.83999	2.73059		0.00038	3.83999	2.73059		0.00038	3.83998	2.73059	
ammonia, NH3									0.00141	14.06283	10	

Orlando Combined Cycle Emissions Revised 11/15/00
per CT/HRSG (numbers in bold are input)
3.5 ppm NOx (with natural gas) and w/o CO catalyst

Case 25

Ambient temp (F) 95 Distillate
CT load (%) 100
Over pressure no
Power Augmentation no
Stack outlet (F) 272

CT emissions				Duct Burner Discharge				Stack Exhaust				
	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)	(% vol)	(lb-mol)	(% wt)	(lb/hr)
oxygen	11.00000	3.52000	12.48714	439172.73	11.00000	3.52000	12.48714	439172.73	11.00000	3.52000	12.48714	439172.73
carbon dioxide	5.47000	2.40680	8.53808	300284.35	5.47000	2.40680	8.53808	300284.35	5.47000	2.40680	8.53808	300284.35
water vapor	12.27000	2.20860	7.83497	275555.93	12.27000	2.20860	7.83497	275555.93	12.27000	2.20860	7.83497	275555.93
nitrogen	70.42000	19.71760	69.94785	2460065.95	70.42000	19.71760	69.94785	2460065.95	70.42000	19.71760	69.94785	2460065.95
argon	0.84000	0.33600	1.19195	41921.03	0.84000	0.33600	1.19195	41921.03	0.84000	0.33600	1.19195	41921.03
		28.18900	100.00000			28.18900	100.00000			28.18900	100.00000	
NOx	0.00523	0.00240	0.00853	300.00	0.00523	0.00240	0.00853	300.00	0.00124	0.00057	0.00202	71.01
carbon monoxide	0.00175	0.00049	0.00173	61.00	0.00175	0.00049	0.00173	61.00	0.00175	0.00049	0.00173	61.00
hydrocarbons CH4	0.00070	0.00011	0.00040	14.00	0.00070	0.00011	0.00040	14.00	0.00070	0.00011	0.00040	14.00
VOC	0.00035	0.00006	0.00020	7.00	0.00035	0.00006	0.00020	7.00	0.00035	0.00006	0.00020	7.00
SO2	0.00160	0.00077	0.00273	96.00	0.00160	0.00077	0.00273	96.00	0.00160	0.00077	0.00273	96.00
Particulate, PM-10		0.00014	0.00048	17.00		0.00014	0.00048	17.00		0.00014	0.00048	17.00
ammonia, NH3									0.00124	0.00021	0.00075	26.24
Total			3517000.00				3517000.00				3517000.00	
	(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)		(%vol dry)	(ppmvd)	(ppmvd@15%O2)	
oxygen	12.53847				12.53847				12.53847			
carbon dioxide	6.23504				6.23504				6.23504			
nitrogen	80.26901				80.26901				80.26901			
argon	0.95748				0.95748				0.95748			
NOx	0.00596	59.58303	42.24983		0.00596	59.58303	42.24983		0.00141	14.10255	10.00000	
CO	0.00199	19.90357	14.11346		0.00199	19.90357	14.11346		0.00199	19.90358	14.11346	
VOC	0.00040	3.99703	2.83426		0.00040	3.99703	2.83426		0.00040	3.99703	2.83426	
ammonia, NH3									0.00141	14.10255	10	

Attachment 3
Potential-To-Emit (PTE), Enveloped Spreadsheet, and HAPs Analysis

Table 1
Hourly Emission Rates (Per CCCT/HRSG)

Case	Ambient Temperature (°F)	Load (%)	NOx (lb/hr)	CO (lb/hr)	PM/PM ₁₀ (lb/hr)	SO ₂ (lb/hr)	VOC (lb/hr)
Natural Gas							
1	19	100	24.13	31.00	9.00	2.77	3.00
2	19	75	19.23	25.00	9.00	2.23	2.40
3	19	50	15.18	20.00	9.00	1.78	2.00
4	19	100	30.38	75.90	11.49	3.50	10.98
5	45	100	23.21	50.00	9.00	2.67	3.00
6	45	75	18.54	40.00	9.00	2.15	2.40
7	45	50	14.70	33.00	9.00	1.73	2.00
8	45	100	29.76	97.13	11.62	3.43	11.38
9	60	100	29.04	129.50	11.26	3.35	17.49
10	70	100	22.26	48.00	9.00	2.56	2.80
11	70	75	17.86	38.00	9.00	2.07	2.20
12	70	50	14.15	32.00	9.00	1.66	1.80
13	70	100	27.76	87.51	11.20	3.20	9.82
14	95	100	21.47	45.00	9.00	2.47	2.80
15	95	75	17.29	38.00	9.00	2.01	2.20
16	95	50	13.65	32.00	9.00	1.60	1.80
17	95	100	28.56	130.12	11.36	3.29	17.93
18	95	100	29.42	142.51	11.71	3.39	20.13
19	95	100	26.63	82.14	11.06	3.07	9.40
Maximum Emission Rate			30.38	142.51	11.71	3.50	20.13
Distillate Fuel Oil							
20	19	100	79.69	71.00	17.00	107.00	8.00
21	19	75	63.58	59.00	17.00	86.00	6.00
22	19	50	49.27	66.00	17.00	68.00	5.00
23	45	100	76.70	67.00	17.00	103.00	7.50
24	70	100	73.70	64.00	17.00	99.00	7.00
25	95	100	71.01	61.00	17.00	96.00	7.00
Maximum Emission Rate			79.69	71.00	17.00	107.00	8.00

Table 2
Annual Emission Rates

Cases ^d	No. of CCCT/HRSGs	Annual Operation (hrs/yr)	Emission Rates									
			NO _x		CO		PM/PM ₁₀		SO ₂		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4, 8, 8, 4, 8	2	6,760 ^a	60.76	205.37	194.26	656.60	23.24	78.55	7.00	23.66	22.76	76.93
18, 18, 18, 18, 18	2	1,000 ^b	58.84	29.42	285.02	142.51	23.42	11.71	6.78	3.39	40.26	20.13
20, 20, 20, 20, 20	2	1,000 ^c	159.38	79.69	142.00	71.00	34.00	17.00	214.00	107.00	16.00	8.00
Totals	2	8,760	N/A	314.48	N/A	870.11	N/A	107.26	N/A	134.05	N/A	105.06

^aAssumes operation on natural gas (including duct burning) for 6,760 hour per year at 100% load.
^bAssumes operation on natural gas (including duct burning and power augmentation) for 1,000 hours per year at 100% load.
^cAssumes operation on distillate fuel oil for 1,000 hours per year at 100% load.
^dCases are listed respectively for the pollutants as they are listed across the top of the table.

Table 3
Fuel Flow Rates Per CTG/HRSG

Case	Ambient Temperature (°F)	Load (%)	Heat Input HHV (Btu/hr)	Fuel Rate Gas (ft ³ /hr) Oil (gal/hr)
Natural Gas ^a (ft ³ /hr)				
1	19	100	1.90E+09	1.94E+06
2	19	75	1.53E+09	1.56E+06
3	19	50	1.22E+09	1.25E+06
4	19	100	2.40E+09	2.45E+06
5	45	100	1.83E+09	1.87E+06
6	45	75	1.48E+09	1.51E+06
7	45	50	1.18E+09	1.21E+06
8	45	100	2.35E+09	2.40E+06
9	60	100	2.30E+09	2.34E+06
10	70	100	1.75E+09	1.79E+06
11	70	75	1.42E+09	1.45E+06
12	70	50	1.14E+09	1.16E+06
13	70	100	2.19E+09	2.24E+06
14	95	100	1.69E+09	1.73E+06
15	95	75	1.38E+09	1.41E+06
16	95	50	1.10E+09	1.12E+06
17	95	100	2.26E+09	2.30E+06
18	95	100	2.33E+09	2.37E+06
19	95	100	2.11E+09	2.15E+06
Distillate Fuel Oil ^b (gal/hr)				
20	19	100	2.07E+09	1.44E+04
21	19	75	1.66E+09	1.16E+04
22	19	50	1.30E+09	9.10E+03
23	45	100	1.99E+09	1.39E+04
24	70	100	1.91E+09	1.33E+04
25	95	100	1.84E+09	1.29E+04
^a Based on a natural gas heat content of 23,325 Btu/lb (HHV) and density of 23.8 ft ³ /lb.				
^b Based on a distillate oil heat content of 20,306 Btu/lb (HHV) and a density of 1 gal/7.05 lb.				

Enveloped Representative Pollutant Emission and Stack Parameters

Combined Cycle Operation - Natural Gas												Combined Cycle Operation - Fuel Oil											
NOTE Ref. 01/16/01 performance data.												NOTE Ref. 01/16/01 performance data.											
Load 100 percent GE7FA												Load 100 percent GE7FA											
Case Name Case 1 Case 4 Case 5 Case 8 Case 9 Case 10 Case 13 Case 14 Case 17 Case 18 Case 19												Case Name Case 20 Case 23 Case 24 Case 25											
Ambient Temp (F) 19 19 45 45 60 70 70 95 95 95 95												Ambient Temp (F) 19 45 70 95											
Evap Cooler												Evap Cooler											
Power Aug. (Steam Inj.)												Power Aug. (Steam Inj.)											
Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX (e) CO PM/PM10 SO2 (c) VOC												Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX (e) CO PM/PM10 SO2 (d) VOC											
185 62.29 24.13 31.00 9.00 2.77 3.00												287 75.25 79.69 71.00 17.00 107.00 8.00											
178 62.21 30.38 75.90 11.49 3.50 10.98												281 71.45 76.70 67.00 17.00 103.00 7.50											
181 59.49 23.21 50.00 9.00 2.67 3.00												276 67.9 73.70 64.00 17.00 99.00 7.00											
175 59.55 29.76 97.13 11.62 3.43 11.38												272 65.28 71.01 61.00 17.00 96.00 7.00											
178 61.00 29.04 129.50 11.26 3.35 17.49																							
178 56.85 22.26 48.00 9.00 2.56 2.80																							
172 56.84 27.76 87.51 11.20 3.20 9.82																							
176 54.98 21.47 45.00 9.00 2.47 2.80																							
169 57.87 28.56 130.12 11.36 3.29 17.93																							
168 57.85 29.42 142.51 11.71 3.39 20.13																							
170 54.94 26.63 82.14 11.06 3.07 9.40																							
Enveloped Load Representative Emissions and Stack Parameters												Enveloped Load Representative Emissions and Stack Parameters											
Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX CO PM/PM10 SO2 VOC												Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX CO PM/PM10 SO2 VOC											
168.00 54.94 30.38 142.51 11.71 3.50 20.13												348.71 16.75 3.83 17.96 1.48 0.44 2.54											
K m/s g/s g/s g/s g/s g/s												K m/s g/s g/s g/s g/s g/s											
Load 75 percent												Load 75 percent											
Case Name Case 2 Case 6 Case 11 Case 15												Case Name Case 21											
Ambient Temp (F) 19 45 70 95												Ambient Temp (F) 19											
Evap Cooler												Evap Cooler											
Power Aug. (Steam Inj.)												Power Aug. (Steam Inj.)											
Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX (e) CO PM/PM10 SO2 (c) VOC												Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX (e) CO PM/PM10 SO2 (d) VOC											
170 47.55 19.23 25.00 9.00 2.23 2.40												262 55.57 63.58 59.00 17.00 86.00 6.00											
170 46.38 18.54 40.00 9.00 2.15 2.40												281 71.45 76.70 67.00 17.00 103.00 7.50											
168 45.16 17.86 38.00 9.00 2.07 2.20												276 67.9 73.70 64.00 17.00 99.00 7.00											
166 44.25 17.29 38.00 9.00 2.01 2.20												272 65.28 71.01 61.00 17.00 96.00 7.00											
Enveloped Load Representative Emissions and Stack Parameters												Enveloped Load Representative Emissions and Stack Parameters											
Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX CO PM/PM10 SO2 VOC												Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX CO PM/PM10 SO2 VOC											
166.00 44.25 19.23 40.00 9.00 2.23 2.40												347.59 13.49 2.42 5.04 1.13 0.28 0.30											
K m/s g/s g/s g/s g/s g/s												K m/s g/s g/s g/s g/s g/s											
Load 50 percent												Load 50 percent											
Case Name Case 3 Case 7 Case 12 Case 16												Case Name Case 22											
Ambient Temp (F) 19 45 70 95												Ambient Temp (F) 19											
Evap Cooler												Evap Cooler											
Power Aug. (Steam Inj.)												Power Aug. (Steam Inj.)											
Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX (e) CO PM/PM10 SO2 (c) VOC												Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX (e) CO PM/PM10 SO2 (d) VOC											
157 38.14 15.18 20.00 9.00 1.78 2.00												249 43.90 49.27 66.00 17.00 68.00 5.00											
160 37.60 14.70 33.00 9.00 1.73 2.00												281 71.45 76.70 67.00 17.00 103.00 7.50											
160 37.06 14.15 32.00 9.00 1.66 1.80												276 67.9 73.70 64.00 17.00 99.00 7.00											
160 36.71 13.65 32.00 9.00 1.60 1.80												272 65.28 71.01 61.00 17.00 96.00 7.00											
Enveloped Load Representative Emissions and Stack Parameters												Enveloped Load Representative Emissions and Stack Parameters											
Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX CO PM/PM10 SO2 VOC												Exit Temp (F) Exit Velocity (ft/s) Emissions (lb/h) NOX CO PM/PM10 SO2 VOC											
157.00 36.71 15.18 33.00 9.00 1.78 2.00												342.59 11.19 1.91 4.16 1.13 0.22 0.25											
K m/s g/s g/s g/s g/s g/s												K m/s g/s g/s g/s g/s g/s											

Notes

a

Combined Total Reduced Sulfur Compounds (including H2S) and Total Reduced Sulfur (including H2S)

b

H2SO4 based on a 10% conversion of SO2 to SO3 and a molecular ratio of 1.22 from SO3 to H2SO4 (in the stack and SCR).

c

Sulfur content assumed for the Natural Gas =0.5grains of sulfur/100 SCF

d

Sulfur content assumed for the fuel oil = 0.05% sulfur.

e

Natural Gas NOx emissions at 3.5 ppmvd @ 15% O2. Fuel Oil NOx emissions at 10 ppmvd @ 15% O2.

f

Assumed 100% conversion of Sulfur to SO2 for natural gas.

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Hazardous Air Pollutants

Hazardous Air Pollutants ¹																			
Duct Burner					Combustion Turbine														
Natural Gas					Total from Duct Burners					Natural Gas					Oil				
Pollutant	Uncontrolled Emission Factor (lb/10 ⁶ scf) ²	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy) ³		Pollutant	Facility PTE (tpy) ³				Pollutant	Uncontrolled Emission Factor (lb/MMBtu) ^{2,4}	Normal CTG Maximum Heat Input (Mbtu/h) ⁵	CTG using Power Augmentation Maximum Heat Input (Mbtu/h) ⁵	Facility PTE (tpy) ³					
1,3-Butadiene					1,3-Butadiene	1.12E-04				1,3-Butadiene	4.30E-07	1903.1	1903.1	0.0072					
2-Methylnaphthalene	2.40E-05	541.7	1.12E-04		2-Methylnaphthalene	1.12E-04				2-Methylnaphthalene									
3-Methylnaphthalene	1.80E-06	541.7	8.37E-06		3-Methylnaphthalene	8.37E-06				3-Methylnaphthalene									
7,12-Dimethylbenz(a)anthracene	1.80E-05	541.7	7.44E-05		7,12-Dimethylbenz(a)anthracene	7.44E-05				7,12-Dimethylbenz(a)anthracene									
Acenaphthene	1.80E-06	541.7	8.37E-06		Acenaphthene	8.37E-06				Acenaphthene									
Acenaphthylene	1.80E-06	541.7	8.37E-06		Acenaphthylene	8.37E-06				Acenaphthylene									
Acetaldehyde					Acetaldehyde					Acetaldehyde	4.00E-05	1903.1	1903.1	0.6888					
Acrolein					Acrolein					Acrolein	6.40E-06	1903.1	1903.1	0.1067					
Anthracene	2.40E-06	541.7	1.12E-05		Anthracene	1.12E-05				Anthracene									
Benzo(a)anthracene	1.80E-06	541.7	8.37E-06		Benzo(a)anthracene	8.37E-06				Benzo(a)anthracene									
Benzene	2.10E-03	541.7	9.77E-03		Benzene	9.77E-03				Benzene	1.20E-05	1903.1	1903.1	0.2001					
Benzo(b)pyrene	1.20E-06	541.7	5.58E-06		Benzo(b)pyrene	5.58E-06				Benzo(b)pyrene									
Benzo(k)fluoranthene	1.80E-06	541.7	8.37E-06		Benzo(k)fluoranthene	8.37E-06				Benzo(k)fluoranthene									
Benzo(g,h,i)perylene	1.20E-06	541.7	5.58E-06		Benzo(g,h,i)perylene	5.58E-06				Benzo(g,h,i)perylene									
Benzo(k)fluoranthene	1.80E-06	541.7	8.37E-06		Benzo(k)fluoranthene	8.37E-06				Benzo(k)fluoranthene									
Chrysene	1.80E-06	541.7	8.37E-06		Chrysene	8.37E-06				Chrysene									
Dibenz(a,h)anthracene	1.20E-06	541.7	5.58E-06		Dibenz(a,h)anthracene	5.58E-06				Dibenz(a,h)anthracene									
Dichlorobenzene	1.20E-03	541.7	5.58E-03		Dichlorobenzene	5.58E-03				Dichlorobenzene									
Ethylbenzene					Ethylbenzene					Ethylbenzene	3.20E-05	1903.1	1903.1	0.5335					
Fluoranthene	3.00E-06	541.7	1.40E-05		Fluoranthene	1.40E-05				Fluoranthene									
Fluorene	2.80E-06	541.7	1.30E-05		Fluorene	1.30E-05				Fluorene									
Formaldehyde	7.50E-02	541.7	3.48E-01		Formaldehyde ⁶	3.48E-01				Formaldehyde ⁶	8.42E-05	1903.1	1903.1	1.4037					
Heptane	1.80E+00	541.7	8.37E+00		Heptane	8.37E+00				Heptane									
Indeno(1,2,3-cd)pyrene	1.80E-06	541.7	8.37E-06		Indeno(1,2,3-cd)pyrene	8.37E-06				Indeno(1,2,3-cd)pyrene	1.30E-06	1903.1	1903.1	0.0217					
Naphthalene	6.10E-04	541.7	2.84E-03		Naphthalene	2.84E-03				Naphthalene	2.20E-06	1903.1	1903.1	0.0367					
PAH					PAH					PAH									
Phenanthrene	1.70E-05	541.7	7.91E-05		Phenanthrene	7.91E-05				Phenanthrene	2.80E-05	1903.1	1903.1	0.4835					
Propylene Oxide					Propylene Oxide					Propylene Oxide									
Pyrene	5.00E-06	541.7	2.33E-05		Pyrene	2.33E-05				Pyrene	1.30E-04	1903.1	1903.1	2.1673					
Toluene	3.40E-03	541.7	1.58E-02		Toluene	1.58E-02				Toluene	6.40E-05	1903.1	1903.1	1.0670					
Xylenes					Xylenes					Xylenes									
TOTAL					8.76	TOTAL					6.69	TOTAL							
Metallic Hazardous Air Pollutants ¹					Combustion Turbine														
Duct Burner					Total from Duct Burners					Natural Gas					Oil				
Pollutant	Uncontrolled Emission Factor (lb/10 ⁶ scf) ²	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy) ³		Pollutant	Facility PTE (tpy) ³				No Natural Gas, Metallic HAPs listed in AP-42 for combustion turbines.									
Arsenic	2.00E-04	541.7	8.24E-04		Arsenic	8.24E-04													
Beryllium	1.20E-05	541.7	4.95E-05		Beryllium	4.95E-05													
Cadmium	1.10E-05	541.7	4.53E-05		Cadmium	4.53E-05													
Chromium	1.40E-05	541.7	5.77E-05		Chromium	5.77E-05													
Cobalt	8.40E-05	541.7	3.48E-04		Cobalt	3.48E-04													
Lead					Lead														
Manganese	3.80E-04	541.7	1.57E-03		Manganese	1.57E-03													
Mercury	2.80E-04	541.7	1.07E-03		Mercury	1.07E-03													
Nickel	2.10E-03	541.7	8.65E-03		Nickel	8.65E-03													
Selenium	2.40E-05	541.7	9.69E-05		Selenium	9.69E-05													
TOTAL					2.29E-02	TOTAL					8.78	TOTAL							
Duct Burner					Total from Combustion Turbines					Natural Gas					Oil				
Pollutant	Uncontrolled Emission Factor (lb/10 ⁶ scf) ²	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy) ³		Pollutant	Facility PTE (tpy) ³				Pollutant	Uncontrolled Emission Factor (lb/MMBtu) ^{2,4}	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy) ³						
Arsenic	2.00E-04	541.7	8.24E-04		Arsenic	0.0227				Arsenic	1.10E-05	2067.6	0.023						
Beryllium	1.20E-05	541.7	4.95E-05		Beryllium	0.0008				Beryllium	3.10E-07	2067.6	0.001						
Cadmium	1.10E-05	541.7	4.53E-05		Cadmium	0.0080				Cadmium	4.60E-06	2067.6	0.010						
Chromium	1.40E-05	541.7	5.77E-05		Chromium	0.0227				Chromium	1.10E-05	2067.6	0.023						
Cobalt	8.40E-05	541.7	3.48E-04		Cobalt	3.48E-04				Cobalt									
Lead					Lead	0.0289				Lead	1.40E-05	2067.6	0.028						
Manganese	3.80E-04	541.7	1.57E-03		Manganese	1.834				Manganese	7.90E-04	2067.6	1.834						
Mercury	2.80E-04	541.7	1.07E-03		Mercury	0.0025				Mercury	1.20E-05	2067.6	0.002						
Nickel	2.10E-03	541.7	8.65E-03		Nickel	0.0095				Nickel	4.60E-06	2067.6	0.010						
Selenium	2.40E-05	541.7	9.69E-05		Selenium	0.0517				Selenium	2.50E-05	2067.6	0.052						
TOTAL					2.29E-02	TOTAL					1.78	TOTAL							
TOTAL					8.78	TOTAL					9.17	TOTAL							
Notes																			
¹ Factors are derived for 2 units operating at high loads (~80 percent load) only.																			
² The AP-42 emission factors were based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60 degrees F.																			
³ The AP-42 emission factors were based on an average distillate oil heating value (HHV) of 139 MMBtu/10 ³ gallons.																			
⁴ Fuel oil operation per year based on 1000 hours. Natural gas operation based on 7760 hours of normal operation and 1000 hours of power augmentation.																			
⁵ From AP-42 (768) Table 1.4-3 and 1.4-4 and listed as a HAP as defined by Section 112(b) of the Clean Air Act.																			
⁶ From AP-42 (768) Table 3.1-3.																			
⁷ From AP-42 (768) Table 3.1-4.																			
⁸ From AP-42 (768) Table 3.1-5.																			
⁹ Formaldehyde emission factor from AP-42 Ch.3 Emission Factor Query for Natural Gas.																			
¹⁰ Formaldehyde emission factor from AP-42 Ch.3 Emission Factor Query for Fuel Oil.																			

Heat Input

Combined Cycle Operation - Natural Gas													Combined Cycle Operation - Fuel Oil					
NOTE Ref. 11/16/01 performance data.													NOTE Ref. 11/16/01 performance data.					
Load 100 percent													Load 100 percent					
GE7FA													GE7FA					
Case Name Case 1 Case 4 Case 5 Case 8 Case 9 Case 10 Case 13 Case 14 Case 17 Case 18 Case 19													Case Name Case 20 Case 23 Case 24 Case 25					
Ambient Temp (F) 19 19 45 45 60 70 70 95 95 95 95													Ambient Temp (F) 19 45 70 95					
Evap Cooler X X X X X X													Evap Cooler X X					
Power Augmentation (Steam Inj.) X X X													Power Augmentation (Steam Inj.)					
CTG Heat Input HHV (Btu/hr) 1.90E+09 1.90E+09 1.83E+09 1.83E+09 1.84E+09 1.75E+09 1.75E+09 1.69E+09 1.78E+09 1.78E+09 1.69E+09													CTG Heat Input HHV (Btu/hr) 2.07E+09 1.99E+09 1.91E+09 1.84E+09					
Duct Burner Heat Input HHV (Btu/hr) 0 4.99E+08 0 5.24E+08 4.53E+08 0 4.39E+08 0 4.73E+08 5.42E+08 4.13E+08													Duct Burner Heat Input HHV (Btu/hr) 0 0 0 0					
Total Heat Input HHV (Btu/hr) 1.90E+09 2.40E+09 1.83E+09 2.35E+09 2.30E+09 1.75E+09 2.19E+09 1.69E+09 2.26E+09 2.33E+09 2.11E+09													Total Heat Input HHV (Btu/hr) 2.07E+09 1.99E+09 1.91E+09 1.84E+09					
Fuel Rate (cu ft/hr) 1.94E+06 2.45E+06 1.87E+06 2.40E+06 2.34E+06 1.79E+06 2.24E+06 1.73E+06 2.30E+06 2.37E+06 2.15E+06													Fuel Rate (gal/hr) 1.44E+04 1.39E+04 1.33E+04 1.29E+04					
Load 75 percent																		
Case Name Case 2 Case 6 Case 11 Case 15													Case Name Case 21					
Ambient Temp (F) 19 45 70 95													Ambient Temp (F) 19					
Evap Cooler													Evap Cooler					
Power Augmentation (Steam Inj.)													Power Augmentation (Steam Inj.)					
CTG Heat Input HHV (Btu/hr) 1.53E+09 1.48E+09 1.42E+09 1.38E+09													CTG Heat Input HHV (Btu/hr) 1.66E+09					
Duct Burner Heat Input HHV (Btu/hr) 0 0 0 0													Duct Burner Heat Input HHV (Btu/hr) 0					
Total Heat Input HHV (Btu/hr) 1.53E+09 1.48E+09 1.42E+09 1.38E+09													Total Heat Input HHV (Btu/hr) 1.66E+09					
Fuel Rate (cu ft/hr) 1.56E+06 1.51E+06 1.45E+06 1.41E+06													Fuel Rate (gal/hr) 1.16E+04					
Load 50 percent																		
Case Name Case 3 Case 7 Case 12 Case 16													Case Name Case 22					
Ambient Temp (F) 19 45 70 95													Ambient Temp (F) 19					
Evap Cooler													Evap Cooler					
Power Augmentation (Steam Inj.)													Power Augmentation (Steam Inj.)					
CTG Heat Input HHV (Btu/hr) 1.22E+09 1.18E+09 1.14E+09 1.10E+09													CTG Heat Input HHV (Btu/hr) 1.30E+09					
Duct Burner Heat Input HHV (Btu/hr) 0 0 0 0													Duct Burner Heat Input HHV (Btu/hr) 0					
Total Heat Input HHV (Btu/hr) 1.22E+09 1.18E+09 1.14E+09 1.10E+09													Total Heat Input HHV (Btu/hr) 1.30E+09					
Fuel Rate (cu ft/hr) 1.25E+06 1.21E+06 1.16E+06 1.12E+06													Fuel Rate (gal/hr) 9.10E+03					

COOLING TOWER EMISSION RATE ESTIMATES

Particulate matter (PM/PM₁₀) emissions from the induced draft mechanical cooling tower were estimated using procedures found in AP42, Section 13.4, Wet Cooling Towers.

A. Cooling Tower Data

Total Liquid Drift = 0.002% of recirculation water flow rate

Total Liquid Drift = 0.002 gal/100 gal recirculation water flow rate

Recirculation Water Flow Rate = 125,000 gal/min

Recirculation Water Total Dissolved Solids (TDS) = 3,704

B. PM/PM₁₀ Emission Rate Calculations

$$\text{PM/PM}_{10} = (125,000 \text{ gal / min}) \times (0.002 \text{ gal / 100 gal H}_2\text{O}) \times (8.345 \text{ lb / gal H}_2\text{O}) \\ \times (3,704 \text{ lb PM/PM}_{10} / 10^6 \text{ lb water}) \times (60 \text{ min / hr})$$

$$\text{PM/PM}_{10} = 4.64 \text{ lb/hr}$$

$$\text{PM/PM}_{10} = 20.32 \text{ ton/yr (8,760 hours/year operation)}$$

Attachment 4
Best Available Control Technology

**Best Available Control Technology Analysis
for the
Curtis H. Stanton Energy Center Combined Cycle
Combustion Turbine Project**

Submitted by

**Orlando Utilities Commission
Kissimmee Utility Authority
Florida Municipal Power Authority
and
Southern Company-Florida, LLC**

**Prepared by
Black & Veatch**

**January 2001
Project No. 98362**

Table of Contents

Table of Contents	TOC-1
List of Tables	TOC-3
1.0 Executive Summary	1-1
2.0 Project Description	2-1
3.0 Basis of Combustion Turbine BACT Analysis	3-1
3.1 Regulatory and Methodology Basis	3-1
3.2 Operations/Emissions Basis	3-2
3.3 Economic Basis	3-4
4.0 Combustion Turbine NO _x and CO BACT Analysis	4-1
4.1 NO _x BACT/LAER Clearinghouse Reviews	4-1
4.2 CO BACT/LAER Clearinghouse Reviews	4-2
4.3 Alternative NO _x Emission Reduction Systems	4-3
4.3.1 Water or Steam Injection	4-4
4.3.2 Dry Low NO _x Burners	4-4
4.3.3 XONON	4-5
4.3.4 Selective Non-Catalytic Reduction	4-5
4.3.5 Selective Catalytic Reduction	4-6
4.3.6 SCONO _x	4-8
4.4 Alternative CO Emission Reduction Systems	4-11
4.5 Combined NO _x and CO Control Technology Summary	4-12
4.6 Evaluation of Feasible Technologies	4-16
4.6.1 SCONO _x Energy Impacts	4-16
4.6.2 SCONO _x Environmental Impacts	4-17
4.6.3 SCR Energy Impacts	4-17
4.6.4 SCR Environmental Impacts	4-18
4.6.5 Oxidation Catalyst Energy Impacts	4-19
4.6.6 Oxidation Catalyst Environmental Impacts	4-19
4.6.7 Economic Impacts for SCR/Oxidation Catalyst and SCONO _x	4-20
4.6.7.1 Capital Costs for SCR/Oxidation Catalyst and SCONO _x	4-20
4.6.7.2 Operating Costs for SCR/Oxidation Catalyst and SCONO _x	4-22
4.6.7.3 Total Annualized Costs for SCR/Oxidation Catalyst and SCONO _x	4-24
4.7 Economic Impacts for SCR	4-25
4.7.1 Capital Costs for SCR System	4-25

4.7.2 Operating Costs for SCR	4-27
4.7.3 Total Annualized Costs for SCR	4-27
4.8 Economic Impacts for Oxidation Catalyst	4-29
4.8.1 Capital Cost for Oxidation Catalyst	4-29
4.8.2 Operating Costs for Oxidation Catalyst	4-29
4.8.3 Total Annualized Costs for Oxidation Catalyst	4-30
4.9 Conclusions	4-33
5.0 Combustion Turbine PM/PM ₁₀ BACT Analysis	5-1
6.0 Combustion Turbine VOC BACT Analysis	6-1
6.1 BACT/LAER Clearinghouse Reviews	6-1
6.2 Alternative VOC Emission Reduction Systems	6-1
6.3 Evaluation of Feasible Technologies	6-2
6.3.1 Economic Impacts	6-2
6.3.1.1 Capital Costs	6-4
6.3.1.2 Operating Costs	6-4
6.3.1.3 Total Annualized Costs	6-5
6.3.2 Energy Impacts	6-5
6.3.3 Environmental Impacts	6-8
6.4 Conclusions	6-8
7.0 Combustion Turbine SO ₂ BACT Analysis	7-1
8.0 Cooling Tower BACT Analysis	8-1
9.0 Conclusions	9-1
APPENDIX A	A-1

List of Tables

3-1	Uncontrolled Emission Rates for Per GE 7FA CCCT Unit	3-3
3-2	Project Economic Evaluation Criteria	3-4
4-1	Estimated NO _x and CO Emissions from Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing During Natural Gas Firing	4-13
4-2	Estimated NO _x and CO Emissions from Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing and Power Augmentation During Natural Gas Firing	4-14
4-2	Estimated NO _x and CO Emissions from Alternate Combined Control Technologies Per GE 7FA CCCT During Fuel Oil Firing	4-15
4-3	Combined NO _x and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit	4-21
4-4	Combined NO _x and CO Control Alternative Annualized Cost Per GE 7FA CTG/HRSG Unit	4-23
4-5	NO _x Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit	4-26
4-6	NO _x Control Alternative Annualized Cost Per GE 7FA CTG/HRSG Unit	4-28
4-7	CO Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit	4-31
4-8	CO Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit	4-32
6-1	Estimated VOC Emissions from Alternative Control Technologies Per GE 7FA CTG/HRSG Unit During Natural Gas Firing	6-3
6-2	Estimated VOC Emissions from Alternative Control Technologies Per GE 7FA CTG/HRSG Unit During Fuel Oil Firing	6-4
6-3	VOC Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit	6-6
6-4	VOC Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit	6-7
A-1	NO _x BACT Clearinghouse Review List	A-1
A-2	CO BACT Clearinghouse Review List	A-2
A-3	VOC BACT Clearinghouse Review List	A-3

1.0 Executive Summary

The 1977 Clean Air Act Amendment (CAAA) established revised conditions for the approval of pre-construction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the act emitted in significant amounts from new major sources or modifications. The new major sources proposed for this project include two-combined cycle combustion turbines and one cooling tower that are subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this project.

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for Orlando Utilities Corporation (OUC). The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for the BACT analysis are based on each combustion turbine-generator/heat recovery steam generator (CTG/HRSG) unit operating at three different operating conditions. These three conditions are 1) natural gas operation at full load with duct burner firing for 6,760 hours per year, 2) natural gas firing with power augmentation for 1,000 hours per year at an ambient temperature of 70 F with the CT and duct burner firing at full load, and 3) fuel oil firing of the combustion turbine-generator (CTG) unit at full load operation without duct firing for 1,000 hours per year at an ambient temperature of 70 F.

GE PG7241(FA) CTG/HRSG Units:

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners with selective catalytic reduction (SCR) during natural gas firing and water injection with an SCR for fuel oil firing to achieve the following emission limits.

- Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O₂.
- Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O₂.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O₂ (without power

augmentation) and 26.3 ppmvd at 15 percent O₂ (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O₂ during fuel oil firing.

Particulate (PM/PM₁₀) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O₂ (without power augmentation) and 6.3 ppmvd at 15 percent O₂ (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O₂ during fuel oil firing.

Sulfur Dioxide (SO₂) Emissions -- BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

2.0 Project Description

The electric generating facility (hereinafter referred to as the "Project") to be installed for OUC will consist of two (2) General Electric (GE) PG7241(FA) combined cycle combustion turbines (CCCT) and one (1) cooling tower. The combined cycle operation consists of using two combustion turbines and two-heat recovery steam generators (HRSGs) with a steam turbine in a Rankine power cycle. The configuration is used to generate additional power. Although the CTG/HRSG power plant is well suited for continuous operation at full load, it is not well suited for large load changes or quick and frequent startups and shutdowns. Each CTG/HRSG configuration will also include a supplemental duct burner (DB) located in the outlet duct from the combustion turbine to provide additional heat for high power demand periods. The HRSG will be used to recover energy from the high temperature flue gas generated by each combustion turbine and duct burner. A steam turbine will be used to generate additional electricity from the steam produced in the HRSG. The steam from the HRSG may also be injected into the combustion turbine to increase power during peak electrical demands. The use of steam injection power augmentation can also improve the efficiency of the combustion turbine. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas.

The output ratings of each GE PG7241(FA) combine cycle combustion turbine will be nominally 170 MW. The proposed operating scenario for the combustion turbines consists of operating up to 7,760 hours per year while firing natural gas and operating up to 1,000 hours per year while firing fuel oil. As with most combustion turbine facilities that have been permitted in the United States, the use of fuel oil will be considered as a backup fuel to natural gas for this project and the balance of this facility's operation is expected to consist of firing natural gas. For the purposes of this analysis, worst case annual operation and emissions were evaluated. This is equivalent to natural gas operation at 6,670 hours per year at full load with duct firing, natural gas firing at full load for 1,000 hours per year at full load with duct firing and power augmentation, and fuel oil firing at full load for 1,000 hours per year.

3.0 Basis of Combustion Turbine BACT Analysis

This section describes the basis of the combustion turbine BACT analysis. Information is provided on such issues as the BACT methodology and approach used. The parameters and factors used in developing the analysis are identified.

3.1 Regulatory and Methodology Basis

The BACT analysis for the GE PG7241(FA) combustion turbine units with and without duct burner firing is based on certain regulatory requirements and project assumptions. The following is a summary of the requirements and assumptions on which this BACT analysis is based.

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal New Source Performance Standards (NSPS) for combustion turbines with heat input greater than 10 mmBtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for NO_x emissions. No NSPS criteria have been established for limiting CO, VOC and PM/PM₁₀ emissions. The following flue gas emission limit is established by NSPS for Subpart GG units:

NO_x: 75 ppmvd at 15 percent O₂, corrected for fuel nitrogen content and turbine heat rate.

- Federal NSPS for electric utility steam generating units for which construction is commenced after September 18, 1978 with a maximum design heat input (fuel burn rate) of more than 250 mmBtu/hr (40 CFR 60 Subpart Da) establish limiting criteria for NO_x, SO₂, and particulate emissions only. No NSPS criteria have been established for limiting CO and VOC emissions. The heat input for each duct burner at the average ambient condition of 70 F is approximately 439 mmBtu/hr for this Project.

As defined in the air permit application, operation of the Project will result in an increase in the potential to emit emissions of NO_x, CO, VOC, SO₂, and PM/PM₁₀ in excess of the major source PSD threshold levels set for these pollutants. BACT is defined as an emission limitation established 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 United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (March 15, 1990) on 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.

3.2 Operations/Emissions Basis

As mentioned previously, the proposed operating scenario for the CTG/HRSGs with duct firing is 7,760 hours per year while firing natural gas. Moreover, the proposed operating scenario for firing fuel oil for each CTG is 1,000 hours per year. Table 3-1 shows the uncontrolled emission rates for natural gas operation of a GE PG7241(FA) combined cycle combustion turbine unit at 100 percent base load with duct burner firing (with and without power augmentation) and fuel oil firing at 100 percent of base load without duct burner at an average annual site temperature of 70 F. The emissions shown in Table 3-1 are controlled with dry low NO_x burners during natural gas firing and water injection during fuel oil firing and lb/mmBtu values are based on the higher heating value (HHV).

Table 3-1
Uncontrolled Emission Rates Per GE PG7241(FA) CCCT Unit

Emission Parameter	GE PG7241(FA) with Duct Firing (Natural Gas) ^a	GE PG7241(FA) with Power Augmentation and Duct Firing (Natural Gas) ^b	GE PG7241(FA) without Duct Firing (Fuel Oil) ^c
NO _x , ppmvd at 15% O ₂	11.6	13.7	42.2
NO _x , lb/hr	92.1	114.4	311.0
NO _x , lb/mmBtu (HHV)	0.0420	0.0495	0.1628
CO, ppmvd at 15% O ₂	18.1	26.3	14.3
CO, lb/hr	87.5	133.2	64.0
CO, lb/mmBtu (HHV)	0.0399	0.0576	0.0335
VOC, ppmvd at 15% O ₂	3.6	6.3	2.7
VOC, lb/hr	9.8	18.2	7.0
VOC, lb/mmBtu (HHV)	0.0045	0.0079	0.0037
PM/PM ₁₀ (front half), lb/hr	11.2	11.4	17.0
PM/PM ₁₀ (front half), lb/mmBtu (HHV)	0.0051	0.0049	0.0089

Notes:

- ^a Total emissions are based on 7,760 hours per year firing natural gas at 100 percent of base load with duct firing at an ambient temperature of 70 F.
- ^b Total emissions are based on 1,000 hours per year firing natural gas at 100 percent of base load with power augmentation and duct firing at an ambient temperature of 70 F.
- ^c Total emissions are based on 1,000 hours per year firing fuel oil at 100 percent of base load without duct firing at an ambient temperature of 70 F.

3.3 Economic Basis

Economic analysis used to determine the capital and annualized costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), "Top Down" Best Available Control Technology Guidance Document (March 1990), The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (February 1996, Fifth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

Table 3-2 lists the economic criteria used in the analysis of BACT alternatives. The contingency, real interest rate, economic life, labor cost, and reagent cost (anhydrous ammonia) were estimated based on guidance documents described above, internal project developer cost factors, and vendor budgetary estimates. The capital recovery factor was calculated based on the real interest rate and economic life of the equipment or the guaranteed catalyst life.

Table 3-2 Project Economic Evaluation Criteria	
Economic Parameters	Value
Contingency, percent	20
Real Interest Rate, percent	7
Economic Life, years	15
Capital Recovery Factor, (15 years)	0.1098
Capital Recovery Factor, (3 years)	0.3811
Labor Cost, \$/man-hr	40
Natural Gas Cost, \$/mmBtu	3.07
Anhydrous Ammonia Cost, \$/ton	269.25
Energy Cost, \$/kWhr	0.0285
Catalyst Life Guarantee, years	3

4.0 Combustion Turbine NO_x and CO BACT Analysis

The objective of this analysis is to determine BACT for NO_x and CO emissions from the combined cycle combustion turbines. This includes the CTs and supplemental firing in the HRSG as a total unit during natural gas firing. The CTs without supplemental firing in the HRSG will only be considered when fuel oil firing. Unless otherwise noted the NO_x and CO emission rates described in this section are corrected to 15 percent oxygen.

4.1 NO_x BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Appendix A. A review of the BACT/LAER Clearinghouse documents (Florida DEP, 1997 - 2000, CAPCOA, 1985 - 2000; and USEPA, 1990 - 2000) indicates that the lowest emissions achieved for a natural gas fired combustion turbine is 2.0 ppmvd for the Federal Cold Storage Cogeneration facility located in California. The 2.0 ppmvd was achieved for six months (June 1997 to December 1997) with 15-minute continuous emission monitoring system (CEMS) averaging periods. Further, Region IX of the EPA has deemed the limit of 2.0 ppmvd at 15 percent oxygen was achieved in practice with three hour averaging. The emissions from that unit are controlled through the use of water injection and a SCONO_x system. It should be noted that the Federal Cold Storage Cogeneration facility is located in a non-attainment area for ozone, with NO_x regulated as a non-attainment pollutant. Thus, this emission level represents LAER for the CTG/HRSG. It should also be noted that this is a small, 222 mmBtu/hr GE model LM2500-M-2 combined cycle gas turbine that is only producing 32 MW (cogeneration). The current use of this specific control application on CTG/HRSG project applications (e.g., units under 30 MW) is not considered applicable to the Project as will be discussed.

In addition, the Sacramento Power Authority (Campbell Soup) located in the Sacramento Metropolitan AQMD in California has set a 3.0 ppmvd NO_x emission limit for a natural gas fired CTG/HRSG. The emissions from that unit are controlled through the use of standard combustors, water injection, and selective catalytic reduction (SCR). This unit consists of a 1,257 mmBtu/hr combined cycle natural gas fired Siemens V84.2 gas turbine generator with water injection for power augmentation and 200 mmBtu/hr of supplemental firing capacity producing 103 MW. This combustion turbine emission limit is noted in the Clearinghouse as being representative of LAER at the time of the permit (1994). Another

stringent NO_x emissions limit for a gas fired CT is 3.5 ppmvd 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. Furthermore, a recent project listed in the CAPCOA BACT/LAER Clearinghouse database is the Sutter Power Plant in the Feather River AQMD in California. This unit has been permitted at 2.5 ppmvd at 15 percent O₂ for a one hour average. The facility will consist of two-combined cycle 1,900 mmBtu/hr gas fired, 170 MW Siemens Westinghouse 501FD turbines with 170 mmBtu/hr HRSGs driving a common 160 MW steam turbine. The NO_x emissions are to be controlled by dry low NO_x combustors, selective catalytic reduction, and low NO_x duct burners. The facility is listed in the CAPCOA BACT/LAER Clearinghouse documents, but is still under construction and demonstration of this level of NO_x control has not been achieved in practice at this time.

A review of the BACT/LAER Clearinghouse documents (Florida DEP, 1997 - 2000, CAPCOA, 1985 - 2000; and USEPA, 1990 - 2000) indicates that the lowest emissions for a fuel oil fired combustion turbine are 6.0 ppmvd for the Mantua Creek Generating facility and the Cogeneration Technology Linden facility, both located in New Jersey. The Mantua Creek Generating facility is permitted for three ABB GT-24 CCCTs with a total plant output of 881 MW. The emissions from that unit are controlled through the use of dry low NO_x and SCR. The Cogeneration Technology Linden facility is permitted for one GE 7FA CCCT with a total plant output of 180 MW. The emissions from this unit are controlled through the use of dry low NO_x and SCR. It should be noted that both projects also have a proposed NO_x emission limit of 2.5 ppmvd that represents LAER for the non-attainment locations of both projects. Both facilities are listed in the Florida DEP database, but demonstration of this level of NO_x control has not been achieved in practice at this time.

The EPA BACT/LAER Clearinghouse database lists two cogeneration facilities that have 10 ppmvd limits for NO_x emissions during fuel oil firing. The facilities are the Brooklyn Navy Yard Cogeneration Partnership located in New York, New York and the Newark Bay Cogeneration Project located in Newark, New Jersey. The control device at both facilities is SCR for each CCCT unit.

4.2 CO BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Appendix A. A review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a combustion turbine is 1.8 ppmvd at 15 percent O₂ for the Newark Bay

Cogeneration L.P. project located in New Jersey. The 617-mmBtu/hr combustion turbine units fire natural gas. The low emissions are achieved by reducing CO emissions by 80 percent (from 9 ppmvd to 1.8) through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in non-attainment areas for CO and ozone.

A further review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a fuel oil fired combustion turbine is 2.6 ppmvd at 15 percent O₂ for the Newark Bay Cogeneration L.P. project located in New Jersey. The 640-mmBtu/hr combustion turbine units fire kerosene. The CO emissions are achieved through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in non-attainment areas for CO and ozone.

4.3 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. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxide 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. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

In Combustor Type:

- 1) Water/Steam Injection
- 2) Dry Low-NO_x (DLN) Burners
- 3) Xonon

Post Combustion Type:

- 1) Selective Non-Catalytic Reduction (SNCR)
- 2) Selective Catalytic Reduction (SCR)
- 3) SCONO_x

4.3.1 Water or Steam Injection

NO_x emissions from the combustion turbines can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. However, there is a point at which the amount of water injected into the combustion turbine seriously degrades its reliability and operational life. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions that are formed as a result of incomplete combustion.

The development of DLN burners has replaced the use of wet controls except for certain cases such as oil firing. Therefore, the use of water injection will be considered for operations during oil firing and will be eliminated from further evaluation for control during natural gas firing for reducing NO_x emissions in this BACT analysis.

4.3.2 Dry Low NO_x Burners

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of DLN burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called DLN burners, because when firing fuel, no water needs to be injected into the combustion chamber to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion systems as the state of the art for NO_x controls in combustion turbines.

DLN combustion turbine burner designs are available which use improved air/fuel mixing and reduced flame temperatures to limit thermal NO_x formation. DLN burner 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. 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.

The controlled emission level will vary from manufacturer to manufacturer of the combustion turbine. The F-Class combustion turbines proposed for the Project are manufactured by GE and have DLN burners that can achieve a NO_x emission level of approximately 9 ppmvd at 15 percent O₂. It should also be noted that as with the standard combustor with water injection, the DLN burners could be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures will result in higher CO and VOC emissions.

Due to the proven performance of the DLN burner technology, this method of NO_x emissions control will be considered in this BACT analysis.

4.3.3 XONON

Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700 F at full power generation, which significantly reduces NO_x emissions without raising and possibly even lowering emissions of carbon monoxide and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers. To date, commercialization of this technology on large utility size combustion turbines such as proposed for the Project has not been developed.

Due to the technical and commercial limitations of this technology, this method of post-combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.3.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of

ammonia or urea is 1,500 to 1,900 F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions (slip). Operation above the temperature window results in increased NO_x emissions. The exhaust temperature at the exit of a combustion turbine, which is approximately 1,100 F for these units, is too low for any consideration of this technology.

Due to the technical and operational limitations on temperature and available reaction time, this method of post-combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.3.5 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CTG/HRSG projects for the past five years. 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 combustion turbine 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, ultimately requiring 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. Vanadium/titanium catalysts have been used on the vast majority of SCR system installations (greater than 95 percent). The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600 to 750 F. At temperatures above 800 F permanent damage to the vanadium/titanium catalyst occurs. For the combined cycle turbines proposed for the Project, this temperature window does exist. The flue gas temperature is reduced in the HRSG of the CTG/HRSG proposed for this Project and would typically range from 200 to 700 F. Accordingly, a vanadium/titanium catalyst can be installed at this Project. Therefore, the vanadium/titanium-based catalyst will be evaluated further for these units.

The operation of an SCR could present a negative impact on the environmental performance of the combustion turbine units. The environmental impact is due to the reaction of the excess ammonia that passes through the SCR with the sulfur trioxide (SO₃) in the flue gas to form ammonia-sulfur salts, such as ammonium bisulfate. These

compounds form when the flue gas cools upon leaving the stack. This particulate adds to the emissions of PM₁₀ from the unit.

Limitations to accurate measurements of emissions consistently below the 3 to 3.5 ppmvd are also a concern. Limitations in measuring any lower level of emission 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 ppmvd to have calibrations that deviate by up to 10 ppmvd and still be considered "in control." The difference of 1 ppmvd in the low values being measured will be in the "noise" range of the emission monitoring system. Lowering the limit to a level below 3.5 ppmvd will only magnify this lack of accuracy, thereby increasing the potential for emission exceedances without providing any further real reduction in emissions. A report by the American Society of Mechanical Engineers (ASME) on reviewing current measuring and monitoring practices indicated that relative accuracy results varied from 1.3 to 34 percent when testing at low NO_x emitters.

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 are 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. Reduction of the NO_x emission concentrations to levels below 3.5 ppmvd also raises concerns with the additional ammonia that may be emitted to obtain further reduced levels. Although SCR catalyst vendors have indicated that ammonia emissions will not be increased, these vendors are not solely responsible for guaranteeing ammonia slip. The distribution of the ammonia in the duct is the key parameter since localized maldistribution of the ammonia will cause the ammonia to pass through the catalyst without reacting with the NO_x. The proper distribution of the gas and ammonia is difficult to obtain when both reactants, NO_x and NH₃, are at such low concentrations. This distribution would be even more difficult, if not impossible, to maintain during transient operations, such as load changes, when flow patterns are changing. Changes in operation from one stable load to another stable load may present problems since the flow patterns and the loads may be different. Since the catalyst vendors are not responsible for the ammonia distribution, they typically limit their guarantees to some distribution level. Such conditions that increase ammonia

emissions will be counter productive to the reduction of overall emissions since ammonia presents an emission problem itself and is a precursor to PM₁₀.

This method of post-combustion control will be considered in this BACT analysis to control NO_x emissions.

4.3.6 SCONO_x

A third, relatively new post-combustion technology from Goal Line Environmental Technologies in conjunction with Alstom Power, is SCONO_x, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. As previously noted, the South Coast Management District has declared LAER as 2.0 ppm of NO_x, based on this technology. Although this system has been proven on a small size unit, scale up concerns still exist with regard to the use of this technology on large units. To date, SCONO_x has not been demonstrated in practice for a GE PG7241(FA) (i.e., Frame 7 or F-Class) combustion turbine.

The SCONO_x system utilizes hydrogen (H₂) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K₂CO₃) to oxidize both NO_x and CO and thereby reducing plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO₂). The catalyst is installed in the flue gas at a point where the temperature is between 300 to 700 F. Alstom/Goal Line guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst. This recycled material can account for as much as one-third the cost of the replacement catalyst.

The SCONO_x catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption SCOSO_x catalyst. The SCOSO_x catalyst is located upstream of the SCONO_x catalyst. The SO₂ is oxidized to sulfur trioxide (SO₃) by the SCOSO_x catalyst. The SO₃ is then deposited on the catalyst and removed from the catalyst when it is regenerated. The SCOSO_x catalyst is regenerated along with the SCONO_x catalyst.

The SCONO_x catalyst will require that it be re-coated or "washed" every six months to one year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the SCOSO_x catalyst. The "washing" consists of removing the catalyst modules from the unit and placing each module with a potassium carbonate reagent, which is the active ingredient of the catalyst. The SCOSO_x catalyst will also require washing, but

due to limited operating experience with the SCOSO_x catalyst, it is uncertain how often it will be required. However, it is expected that the SCOSO_x catalyst will require annual washing.

The current SCONO_x catalyst technology is in its second generation. The first generation operated for approximately ten months on a small LM-2500 combined cycle CT unit before it was taken out of service because of poor regeneration gas distribution.

A letter dated November 19, 1999 from EPA Region I had concerns regarding if SCONO_x could handle the increased gas flow, mechanical durability and scale-up of the damper/louver system, reliability of the regenerative gas distribution system, the performance of the sulfur removal method, and catalyst performance guarantees. The EPA had concerns with the technical uncertainties and was apprehensive about applying SCONO_x technology to large combined cycle turbines that burn primarily natural gas. In addition there are issues with applying SCONO_x to distillate fuel oil applications, given the higher sulfur content in the fuel. According to the EPA letter, Alstom Power has executed a re-design and testing program to develop the SCONO_x system for large turbine applications, but to date this new re-designed system has not been demonstrated in practice.

The November 19, 1999 EPA letter addresses that Alstom Power had redesigned and fabricated a full-scale louver prototype system for larger turbine applications. In addition Alstom Power had cycled the prototype louver system 102,000 times (approximately 5 years of operation) at operating temperatures of 620 F and enclosed the system in a hot casing shell design to avoid thermal stresses from the heat recovery steam generator. Alstom Power has increased the catalyst module and regenerative gas distribution system that supplies gas to each individual module but, Alstom Power has only performed computational fluid dynamics (CFD) modeling to try and verify the gas regeneration system. Alstom Power has addressed degradation of the SCONO_x catalyst from sulfur compounds found in natural gas, causing frequent system shutdowns, by verifying that a SCOSO_x catalyst can be used upstream of the SCONO_x catalyst. Furthermore, they claim the two catalysts are compatible and that the combined system will maintain sulfur and NO_x removal performance levels under different gas stream conditions. Alstom Power will provide performance guarantees to all owners and operators of natural gas fired combined cycle combustion turbines, regardless of size or O&M, and also will consider catalyst leasing arrangements where the responsibility and risk for catalyst maintenance will remain with Alstom. The EPA had them confirm the accuracy and correctness of their technical information in a response dated November 29, 1999. Alstom

Power has re-designed their SCONO_x system for large turbine applications, but to date this new re-designed system has not been demonstrated in practice.

Another concern is the removal and replacement of the catalyst for re-coating without adversely impacting unit availability. The larger volume of catalyst used in an F class combustion turbine will require a significant period of washing or will necessitate the purchase of several spare catalyst modules.

The SCONO_x system would also impact the power generation of the proposed facility. The flue gas pressure drop due to the catalyst is larger for the SCONO_x process (approximately 4 to 5 in. w.g.) than an SCR process (approximately 2 to 3 in. w.g.). This increase in backpressure would result in an increase in lost power generation.

SCONO_x is a technology that has effectively reduced emissions at the Federal Cold Storage facility thus far, and may have future promise. While mechanically very complicated, SCONO_x technology allows for transient operation (load changes) and no ammonia issues are present, such as transportation, storage, or slip emissions. In addition, the wide operating temperature range has the potential for flexibility for future projects. The SCONO_x catalyst can be placed in the most cost-effective location in an HRSG. The SCONO_x catalyst can also significantly reduce CO emissions, thus reducing the need for an oxidation catalyst. However, there are a number of serious concerns regarding SCONO_x that still need to be addressed prior to application to a Frame 7 or Class F machine. They include:

- Scale-up design issues for increasing the size of the application by 6 times from a LM-2500 to a Frame F combustion turbine. Scale-up design issues include damper size and proper distribution of regeneration gas.
- Mechanical system reliability: Damper and damper bearings are moving parts in the flue gas system that may present maintenance problems.
- On-line removal of catalyst for washing, including mechanics of how it is to be accomplished, time period, labor (cost), and safety issues.
- SCOSO_x reliability: The SO₂ guard catalyst bed (SCOSO_x) can cause contaminated regeneration gas (containing sulfur and sulfur acids) to be handled, thereby questioning the effectiveness and reliability of the catalyst.
- Increased pressure drop.
- Proprietary Issue: SCONO_x catalyst is a proprietary catalyst leading to concerns regarding long-term pricing.

- **Warranty Issues:** Since Goal Line is a relatively small company, there has been concern in the past regarding their ability to follow through with respect to potential warranty claims, not only for any single installation, but also in the event that multiple claims were to be made. Alstom Power has signed a licensing agreement which will provide the financial backing and credibility required for warranties and guarantees. Alstom Power has guaranteed the performance of their system, but operational risks associated with the use of SCONO_x still need to be resolved.
- **Financial Concerns:** Lenders will have to assume performance and operational risks associated with the use of SCONO_x. The full-scope price without installation for a SCONO_x system is estimated to be 4 times larger than installing an SCR system on a large scale combined cycle facility.

As discussed above, the SCONO_x technology may have future promise. The application of this technology has been demonstrated on combined cycle CT units under 32 MW. Although, there are technical concerns with using this new technology related to the operating plant size proposed for the Project, this system will be evaluated in this BACT analysis.

4.4 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increase the emissions of CO. CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. The development of good combustion practice improvements with state of the art DLN burners has reduced CO emissions as compared to those previously obtained by the use of water injection as the main NO_x control method. These improved combustion characteristics have allowed minimization of CO emissions without sacrificing NO_x control performance. For this reason, the use of low NO_x burners that use good combustion practices is the standard method of also controlling CO emissions.

A current CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO₂. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic.

No reagent injection is necessary and oxidizing catalysts, dependent on the uncontrolled emission level, are capable of reducing CO emissions from 80 to 90 percent.

Another CO control technology that was screened was the previously discussed SCONO_x process. The SCONO_x system reduces CO emissions by oxidizing the CO to CO₂. As noted for the NO_x control evaluation, the SCONO_x technology may have future promise. The application for this technology is currently limited to combined cycle CT units under 32 MW. The large size of the units proposed for this Project (170 MW) as compared to the size of the SCONO_x operating plant makes the potential scale-up challenging and unpractical. Although, there are technical concerns with using this new technology related to the operating plant size proposed for the Project, this system will be evaluated in this BACT analysis.

This technology evaluation indicates that an oxidation catalyst and a SCONO_x system are the control technologies suitable for further evaluation beyond the use of good combustion practices, as provided by a DLN burner.

4.5 Combined NO_x and CO Control Technology Summary

In-combustor NO_x and CO control by advanced combustion controls using dry low NO_x burners is the least stringent control technology considered for this Project. However, the use of an SCR system and oxidation catalyst or the SCONO_x system to reduce emissions after combustion are technologies capable of achieving significantly lower emissions. Because the SCONO_x system is capable of reducing NO_x and CO emissions, the NO_x and CO BACT analysis have been combined to avoid double counting the SCONO_x technology, thus inflating its economic impacts. The following control technologies will be evaluated in this NO_x and CO BACT analysis and are ranked in order of relative control effectiveness:

- In-combustor NO_x and CO control consisting of DLN combustors to limit outlet emissions during natural gas and fuel oil firing for all operating loads for the CTG/HRSGs.
- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x to 3.5 ppmvd at 15 percent O₂ and CO to 3.6 ppmvd at 15 percent O₂ emissions from each combustion turbine with duct burner firing natural gas. The addition of an SCR system and oxidation catalyst to reduce outlet NO_x to 10 ppmvd at 15 percent O₂ and CO to 2.9 ppmvd at 15 percent O₂ emissions from each combustion turbine while firing fuel oil.

- The addition of a SCONO_x system to reduce outlet NO_x emissions from each combustion turbine with duct burner firing natural gas and each combustion turbine firing fuel oil to 2.0 ppmvd at 15 percent O₂.

The SCR system with a 3.5-ppmvd NO_x emission limit and an oxidation catalyst will be compared to the SCONO_x system with a 2.0 ppmvd NO_x emission limit.

The NO_x and CO emissions per CTG/HRSG unit with application of the above possible controls are summarized in Tables 4-1, 4-2, and 4-3 for natural gas (with and without power augmentation) and fuel oil firing, respectively.

Table 4-1 Estimated NO_x and CO Emissions From Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing During Natural Gas Firing.			
	Control Technology Alternatives		
	Dry Low NO _x Combustors	SCR/Oxidation Catalyst	SCONO _x
NO_x Emissions			
ppmvd (at 15 percent O ₂)	11.6	3.5	2.0
tons per year	311.4	94.0	53.7
percent reduction	N/A	70%	83%
NO _x BACT Analysis (Annual) ^a	311.4	94.0	53.7
tons per year			
CO Emissions			
ppmvd (at 15 percent O ₂)	18.1	3.6	3.6
tons per year	295.8	59.2	59.2
percent reduction	N/A	80%	80%
CO BACT Analysis (Annual) ^a	295.8	59.2	59.2
tons per year			
Notes: ^a Total emissions are based on 6,760 hours per year firing natural gas at 100 percent of base load with duct firing at an ambient temperature of 70 F.			

Table 4-2 Estimated NO_x and CO Emissions From Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing and Power Augmentation During Natural Gas Firing.			
	Control Technology Alternatives		
	Dry Low NO _x Combustors	SCR/Oxidation Catalyst	SCONO _x
NO_x Emissions			
ppmvd (at 15 percent O ₂)	13.7	3.5	2.0
tons per year	57.2	14.6	8.4
percent reduction	N/A	74%	85%
NO _x BACT Analysis (Annual) ^a	57.2	14.6	8.4
tons per year			
CO Emissions			
ppmvd (at 15 percent O ₂)	26.3	3.6	3.6
tons per year	66.6	9.2	9.2
percent reduction	N/A	86%	86%
CO BACT Analysis (Annual) ^a	66.6	9.2	9.2
tons per year			
Notes: ^a Total emissions are based on 1,000 hours per year firing natural gas at 100 percent of base load with duct firing and power augmentation at an ambient temperature of 70 F.			

Table 4-3 Estimated NO_x and CO Emissions From Alternate Combined Control Technologies Per GE 7FA CCCT During Fuel Oil Firing.			
	Control Technology Alternatives		
	Dry Low NO _x Combustors	SCR/Oxidation Catalyst	SCONO _x
NO_x Emissions			
ppmvd (at 15 percent O ₂)	42.2	10	2.0
tons per year	155.5	36.9	7.4
percent reduction	N/A	76%	95%
NO _x BACT Analysis (Annual) ^a	155.5	36.9	7.4
tons per year			
CO Emissions			
ppmvd (at 15 percent O ₂)	14.3	2.9	2.9
tons per year	32.0	6.4	6.4
percent reduction	N/A	80%	80%
CO BACT Analysis (Annual) ^a	32.0	6.4	6.4
tons per year			
Notes: ^a Total emissions are based on 1,000 hours per year firing fuel oil at 100 percent of base load without duct firing at an ambient temperature of 70 F.			

4.6 Evaluation of Feasible Technologies

The following evaluation considers energy, environmental and economic impacts for the potential NO_x and CO BACT scenarios evaluated.

4.6.1 SCONO_x Energy Impacts

The use of a SCONO_x system will increase the energy requirements on the system. The SCONO_x system will increase the backpressure on each combustion turbine by about 4

inches water gauge (in. w.g.). This will reduce the output of each CTG/HRSG by approximately 0.3 percent and increase the lost power generation. In addition, the period required for catalyst washing will result in increasing the lost power generation. It is estimated the unit will be offline for a period of 4 days per year to accommodate the washing process. Furthermore, there will be an energy loss due to steam consumption from the regeneration system. The steam serving as a carrier gas for the natural gas will be required regardless of the SCONO_x location in the HRSG. Alstom Power estimated that between 15,000 to 20,000 lb/hr of steam would be used in the regeneration production. These three effects will be added together to determine the total lost power generation and are included in the annualized cost estimate. The SCONO_x system will have minimal effect on power consumption that will be necessary to operate the damper actuators and regeneration system. Alstom Power estimated that approximately 10 to 20 kW would be consumed during operation of the SCONO_x system. This increase in power consumption will be included in the annualized cost estimate. The natural gas required for the production of the regeneration gas will increase the annualized cost associated with using the SCONO_x system. Alstom Power estimated that 2 percent of the carrier gas will consist of the regeneration gas. Therefore, approximately 7,000 ft³/hr (300 lb/hr) will be consumed in the regeneration process of the SCONO_x/SCOSO_x catalyst. The annualized cost of natural gas consumption is included in the annualized cost analysis.

4.6.2 SCONO_x Environmental Impacts

The SCONO_x catalyst is composed of precious metals coated with potassium carbonate. When the potassium carbonate coating can no longer be regenerated, the precious metal content of the remaining catalyst can be recycled. The oxidation of CO also directly results in increased production of CO₂, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO₂ because of its contribution to global climate change. Installation of a SCONO_x system would directly counter this initiative.

4.6.3 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst will increase the backpressure on each combustion turbine. The SCR system will add about 1.6 inches water gauge (in. w.g.) backpressure to each unit. This will reduce the output of the each unit by approximately 0.1

percent. Increased power consumption and lost power generation are included in the annualized cost estimate.

4.6.4 SCR Environmental Impacts

The vanadium content of the 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 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). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes. 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. Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates associated catalyst replacement. With fresh catalyst ammonia slip emissions will be very low, but as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and may be classified as hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO₂ in the flue gas to SO₃. Once the flue gas cools below approximately 600 F the ammonia present in the flue gas may react with SO₃ to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO₃ will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas.

4.6.5 Oxidation Catalyst Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine. The additional backpressure of about 1.2 inches, water gauge, will reduce the combustion turbine output by approximately 0.1 percent. The cost of lost power revenue due to the backpressure is included in the economic analysis.

4.6.6 Oxidation Catalyst Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions is that a percentage of the SO₂ in the flue gas will oxidize to SO₃. The higher the operating temperature the higher the SO₂ to SO₃ oxidation potential. It is estimated that approximately 30 percent of the SO₂ in the flue gas will oxidize to SO₃ as a result of the CO oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The SO₃ will react with the moisture in the flue gas to form sulfuric acid (H₂SO₄) mist in the atmosphere. The increase in H₂SO₄ emissions would increase PM₁₀ (matter less than 10 microns in diameter) emissions.

Spent oxidation 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 CO oxidation catalyst can also be recycled to recover the precious metals.

As mentioned previously, the installation of an oxidation catalyst will also increase the backpressure on the turbine, thereby decreasing efficiency. This decrease in efficiency will lead to increased emissions of all pollutants on a unit power output basis. The oxidation of CO also directly results in increased production of CO₂, a greenhouse gas.

There is currently a worldwide effort to reduce industrial emissions of CO₂ because of its contribution to global climate change. Installation of an oxidation catalyst would directly counter this initiative.

4.6.7 Economic Impacts for SCR/Oxidation Catalyst and SCONO_x

The use of an SCR and oxidation catalyst has significant economic impacts to the Project. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year and at 100 percent of base load with power augmentation and duct firing for 1,000 hours per year on natural gas. The BACT costs presented in this analysis also include operating the combustion turbine for 1,000 hours per year on fuel oil. The capital and annualized cost for the SCONO_x system also includes the SCOSO_x system.

4.6.7.1 Capital Costs for SCR/Oxidation Catalyst and SCONO_x

Table 4-4 presents the capital costs for installing an SCR/Oxidation Catalyst and SCONO_x system on each CTG/HRSG unit during natural gas and fuel oil firing. The cost of the SCR/Oxidation Catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation, and freight. The cost of the SCONO_x system includes the catalyst, regenerative gas distribution system, catalytic reactor housing, controls and instrumentation, and freight. The balance of plant equipment cost for SCONO_x was estimated to be the same percentage as an SCR/Oxidation Catalyst system. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the SCR and oxidation catalyst material were based on vanadium/titanium and precious metal type catalysts, respectively. The direct installation costs included the balance of plant items listed in Table 4-4 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs for the SCR/Oxidation Catalyst system are percentages of the purchased equipment costs (PEC) and are site specific. The indirect costs for the SCONO_x system are percentages of the SCONO_x system capital cost and are site specific. It should be noted that the OAQPS Control Cost Manual recommends the indirect costs are to be calculated by multiplying by the PEC, however, for

the SCONO_x system this is judged to be inaccurate. The PEC for using SCONO_x would overestimate the indirect costs associated for the project; therefore, the indirect costs were estimated by multiplying the percentages by only the SCONO_x system cost. In addition, the 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

Total capital costs for the SCR and oxidation catalyst control system is calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per combustion turbine unit for a 3.5 ppmvd NO_x and 3.6 ppmvd CO outlet emission during natural gas firing and a 10 ppmvd NO_x and 2.9 ppmvd CO outlet emission during fuel oil firing SCR/Oxidation Catalyst system is estimated to be \$3,286,000.

The total capital costs for the SCONO_x control system is also calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per combustion turbine unit for a 2.0 ppmvd NO_x and 3.6 ppmvd CO outlet emission during natural gas firing and a 2.0 ppmvd NO_x and 2.9 ppmvd CO outlet emission during fuel oil firing using a SCONO_x system is estimated to be \$14,131,000.

Table 4-4 Combined NO _x and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit				
	SCONO _x System	SCR/Oxidation Catalyst	Low NO _x Burners	Remarks
Direct Capital Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3
SCR and Oxidation Catalysts System	Included	1,907,000	N/A	Estimated from Engelhard Corporation
SCONO _x Catalyst	7,800,000	N/A	N/A	Estimated from ABB Alstom Power
SCONO _x System	5,200,000	N/A	N/A	Estimated from ABB Alstom Power
Catalyst Reactor Housing	Included	268,000	N/A	Estimated from ABB Alstom and scaled from an estimate from Engelhard Corporation
Control/Instrumentation	Included	180,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Equipment/Storage)	N/A	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	13,000,000	2,555,000	N/A	
Freight	650,000	128,000	N/A	5% of Purchased Equipment Costs
Total Purchased Equipment Costs	13,650,000	2,683,000	N/A	
Direct Installation Costs				
Balance of Plant	4,095,000	805,000	N/A	For SCR & SCONO _x : 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	9,945,000	1,998,000	Base	Catalyst cost is excluded as annual O&M cost
Indirect Capital Costs				
Contingency	2,730,000	537,000	N/A	20% of Total Purchased Equipment Costs (TPEC)
Engineering and Supervision	520,000	268,000	N/A	For SCONO _x : 10% of SCONO _x System Cost; For SCR: 10% of TPEC
Construction & Field Expense	260,000	134,000	N/A	For SCONO _x : 5% of SCONO _x System Cost; For SCR: 5% of TPEC
Construction Fee	520,000	268,000	N/A	For SCONO _x : 10% of SCONO _x System Cost; For SCR: 10% of TPEC
Start-up Assistance	104,000	54,000	N/A	For SCONO _x : 2% of SCONO _x System Cost; For SCR: 2% of TPEC
Performance Test	52,000	27,000	N/A	For SCONO _x : 1% of SCONO _x System Cost; For SCR: 1% of TPEC
Total Indirect Capital Costs	4,186,000	1,288,000	Base	
Total Installed Cost	14,131,000	3,286,000	Base	

4.6.7.2 Operating Costs for SCR/Oxidation Catalyst and SCONO_x

Table 4-5 presents the annualized operating costs and emission rates using a SCR/Oxidation catalyst and SCONO_x system during natural gas and fuel oil firing. Annualized operating costs for the SCR/Oxidation Catalyst include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. Throughout the life of the plant, catalyst elements for both the SCR and the oxidation catalyst will require periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions will increase and the catalyst will eventually have to be replaced. The oxidation catalyst is installed upstream of the ammonia injection grid and SCR catalyst, therefore there are no problems associated with ammonia slip, but the CO catalyst will degrade such that CO emissions increase. Currently, catalyst manufacturers are willing to guarantee an SCR and oxidation catalyst life of three years of equivalent operating hours. The catalyst replacement cost was calculated by multiplying the cost of the catalyst replacement modules by 15 percent for installation cost, 5 percent that includes freight, and a capital recovery factor based on the real interest rate over the 3 year guaranteed life of the catalyst.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.4 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with NO₂. The heat rate penalty cost item reflects the cost due to the SCR and oxidation catalyst backpressure losses. The additional backpressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annualized cost estimate.

The annualized operating costs for the SCONO_x system include catalyst replacement, energy impacts, operating personnel, maintenance, natural gas consumption, catalyst washing, and heat rate penalty due to backpressure losses and steam usage. The SCONO_x catalyst will require periodic washing and replacement throughout the life of the facility. The emissions will increase as the catalyst becomes deactivated, resulting in more frequent washing cycles. Replacement of the catalyst will result in lost power generation during the outage period. Alstom Power estimates the anticipated life of the first 10 percent of the catalyst to be 10 years and the remaining catalyst to be 30 years. However, Alstom Power is only willing to guarantee a SCONO_x catalyst life for 3 years. Therefore, the guaranteed life will be used to determine the catalyst replacement cost.

Table 4-5
Combined NO_x and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit

	SCONO _x System	SCR/Oxidation Catalyst	Low NO _x Burners	Remarks
Direct Annual Cost				Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	3,589,000	686,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	197,000	40,000	N/A	See text for background information on this item
Reagent Feed	N/A	87,000	N/A	Assumes 1.4 stoichiometric ratio
Natural Gas Consumption	191,000	N/A	N/A	Based on 7,000 ft ³ /hr required
Power Consumption	4,000	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR and damper actuation for SCONO _x
Lost Power Generation				
SCONO _x Washing	694,000	N/A	N/A	Down time due to SCONO _x washing period
Steam Consumption	655,000	N/A	N/A	Loss based on 15,000 lb/hr of steam required
Backpressure	132,000	95,000	N/A	Includes backpressure on CT
Annual Distribution Check	<u>N/A</u>	<u>8,000</u>	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	5,462,000	923,000	N/A	
Indirect Annual Costs				
Overhead	56,000	20,000	N/A	60% of O&M Labor
Administrative Charges	283,000	66,000	N/A	2% of Total Installed Cost
Property Taxes	389,000	90,000	N/A	2.75% of Total Installed Cost
Insurance	141,000	33,000	N/A	1% of Total Installed Cost
Capital Recovery	<u>1,552,000</u>	<u>151,000</u>	N/A	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	2,421,000	360,000	N/A	
Total Annualized Cost	7,883,000	1,283,000	N/A	
Annual Emissions, tpy	144.1	220.1	918.5	Total emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	774.3	698.3	N/A	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, \$/ton	10,200	1,800	N/A	Total Annualized Cost/Emissions Reduction
Incremental Annualized Cost	6,600,000	N/A	N/A	See text for background information on this item
Incremental Reduction	87,000	N/A	N/A	See text for background information on this item.

The use of either an SCR/Oxidation Catalyst system or a SCONO_x system increases the energy requirements of the project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the project. SCONO_x consumes a relatively small amount of power to open and close the catalyst dampers and to produce the regenerating gas. Maintenance costs will consist of routine system maintenance for each system. However, there is an additional maintenance cost associated with catalyst washing for the SCONO_x system. The replacement materials are assumed to be two percent of the original cost for equipment and labor is assumed to be equal to materials. The SCONO_x system will include the additional O&M cost for catalyst washing.

4.6.7.3 Total Annualized Costs for SCR/Oxidation Catalyst and SCONO_x

Total annualized costs for the SCR and oxidation catalyst control systems are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. Table 4-5 shows the total annualized cost per unit for a SCR/Oxidation Catalyst system per combustion turbine is estimated to be \$1,283,000. This annualized cost for the CTG/HRSG unit results in a cost effectiveness of approximately \$1,800 per ton of NO_x and CO removed.

The total annualized costs for the SCONO_x control system are calculated as the sum of the operating costs plus capital recovery factor times the total installed costs. The total annualized cost per unit for a SCONO_x system per combustion turbine is estimated to be \$7,883,000. This annualized cost for the CTG/HRSG unit results in a cost effectiveness of approximately \$10,200 per ton of NO_x and CO removed.

The incremental annualized cost system is calculated as the difference in annualized cost between the SCONO_x and SCR/Oxidation catalyst. In addition, the incremental NO_x and CO reduction in tons per year is calculated as the difference in combined tons per year of NO_x and CO removed (alternative controlled baseline) between the two control technologies. Furthermore, the incremental removal cost is determined by dividing the incremental annualized cost by the controlled baseline reduction. It should be noted that this incremental cost effectiveness is considered relative to the next most stringent control alternative baseline (i.e., SCONO_x compared to SCR/Oxidation Catalyst rather than just DLN). These cost increments will allow a comparison between the two removal

technologies. The incremental annualized cost between SCONO_x and the SCR/Oxidation Catalyst system is estimated to be \$6,600,000. This results in an incremental cost effectiveness of approximately \$87,000. This cost is considered high and for this application it is not cost effective to use SCONO_x over a SCR/Oxidation catalyst system per CTG/HRSG unit.

4.7 Economic Impacts for SCR

The control of NO_x emissions separate from CO emission control is possible through the application of an SCR to the CTG/HRSG units without additional CO emission controls. To determine the BACT levels for NO_x controls without the influence of the CO emissions a separate economic analysis is required. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year while firing natural gas and operating at 100 percent of base load for 1,000 hours per year with power augmentation and duct firing on natural gas. The BACT costs presented in this analysis also include operating each combustion turbine at 100 percent of base load for 1,000 hours per year on fuel oil.

4.7.1 Capital Costs for SCR System

Table 4-6 presents the capital costs for installing an SCR system on the CTG/HRSG units during natural gas and fuel oil firing to achieve a NO_x outlet emission level of 3.5 and 10.0 ppmvd. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation and freight. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the SCR catalyst material were based on vanadium/titanium type catalysts. The direct installation costs included the balance of plant items listed in Table 4-6 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the PEC and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

Total capital costs for the SCR system to reduce NO_x is calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. the

total capital cost per unit for an SCR catalyst system per combustion turbine is estimated to be \$2,480,000.

Table 4-6 NO _x Control Capital Cost Per GE 7FA CTG/HRSG Unit			
Cost Item	SCR	Low NO _x Burners	Remarks
Direct Capital Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
SCR Catalysts System	1,161,000	N/A	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	N/A	Scaled from an estimate from Engelhard Corporation
Control/Instrumentation	140,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia Injection/Dilution Equipment	Included	N/A	Estimated from Engelhard Corporation
Ammonia Storage	<u>200,000</u>	N/A	Estimated from previous projects
Purchased Equipment Costs	1,769,000	N/A	
Freight	<u>88,000</u>	N/A	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,857,000	N/A	
Direct Installation Costs			
Balance of Plant	<u>557,000</u>	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	1,588,000	Base	Catalyst Cost is excluded as annual O&M Cost
Indirect Capital Costs			
Contingency	371,000	N/A	20% of Total Purchased Equipment Cost
Engineering and Supervision	186,000	N/A	10% of Total Purchased Equipment Cost
Construction & Field Expense	93,000	N/A	5% of Total Purchased Equipment Cost
Construction Fee	186,000	N/A	10% of Total Purchased Equipment Cost
Start-up Assistance	37,000	N/A	2% of Total Purchased Equipment Cost
Performance Test	<u>19,000</u>	N/A	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	892,000	Base	
Total Installed Cost	2,480,000	Base	

4.7.2 Operating Costs for SCR

Table 4-7 presents the annualized operating costs and emission rates using an SCR during natural gas and fuel oil firing. Annualized operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. The description of the operating costs and effects of ammonia consumption, backpressure, and catalyst life have already been described in Section 4.6.

4.7.3 Total Annualized Costs for SCR

The total annualized costs for the SCR system are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. The total annualized cost per unit for an SCR system per combustion turbine is estimated to be \$1,003,000. This annualized cost for each CTG/HRSG unit results in an incremental cost effectiveness of approximately \$2,600 per ton of NO_x removed.

Table 4-7 NO _x Control Annualized Cost Per GE 7FA CTG/HRSG Unit			
	SCR	Low NO _x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	380,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	36,000	N/A	See text for background information on this item
Reagent Feed	87,000	N/A	Assumes 1.4 stoichiometric ratio
Power Consumption	7,000	N/A	Includes injection blower and vaporization of ammonia for SCR
Lost Power Generation	53,000		Back Pressure on CT
Annual Distribution Check	<u>8,000</u>	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	571,000	N/A	
Indirect Annual Costs			
Overhead	17,000	N/A	60% of O&M Labor
Administrative Charges	50,000	N/A	2% of Total Installed Cost
Property Taxes	68,000	N/A	2.75% of Total Installed Cost
Insurance	25,000	N/A	1% of Total Installed Cost
Capital Recovery	<u>272,000</u>	N/A	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	432,000	N/A	
Total Annualized Cost	1,003,000	N/A	
Annual Emissions, tpy	145.4	524.1	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	378.7	N/A	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, \$/ton	2,600	N/A	Total Annualized Cost/Emissions Reduction

4.8 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts to the Project. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year without power augmentation and 1,000 hours per year with power augmentation on natural gas. The BACT costs presented in this analysis also include operating each combustion turbine for 1,000 hours per year on fuel oil.

4.8.1 Capital Cost for Oxidation Catalyst

Table 4-8 presents the capital costs for installing an oxidation catalyst on the CTG/HRSG units during natural gas and fuel oil firing to achieve a CO outlet emission level of 3.6 and 2.9 ppmvd, respectively. The capital costs for the systems includes the oxidation catalyst reactor, controls and instrumentation and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the balance of plant items listed in Table 4-8 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the PEC and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

Total capital costs for the oxidation catalyst control system to reduce CO is calculated as the sum of the direct and indirect installed costs. The total capital cost per unit for an oxidation catalyst system is estimated to be \$1,306,000.

4.8.2 Operating Costs for Oxidation Catalyst

Table 4-9 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve an 80 and 86 percent reduction in CO emissions while firing natural gas for the CTG/HRSG units with and without power augmentation, respectively. CO outlet emissions would be reduced to a maximum of 3.6 and 2.9 ppmvd during natural gas and fuel oil firing respectively, for the CTG/HRSG units. Annualized operating costs for the system includes catalyst replacement, operating personnel, maintenance costs, and lost power generation. Throughout the life of the plant, catalyst elements will require

periodic replacement. Currently, catalyst manufacturers are willing to guarantee an oxidation catalyst life of three years of equivalent operating hours for an oxidation catalyst.

4.8.3 Total Annualized Costs for Oxidation Catalyst

Total annualized costs for using the oxidation catalyst are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. The total annualized cost per combustion turbine unit is estimated to be \$570,000. This annualized cost per CTG/HRSG unit results in a cost effectiveness of approximately \$1,800 per ton of CO removed.

Table 4-8 CO Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst	746,000	NA	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	NA	Scaled from an estimate from Engelhard Corporation based on catalyst size
Control/Instrumentation	<u>40,000</u>	NA	Estimated
Purchased Equipment Costs	1,054,000		
Freight	<u>53,000</u>		5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000		
Direct Installation Costs			
Balance of Plant	<u>332,000</u>	NA	8% For Foundations & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting.
Total Direct Capital Cost Less Catalyst	775,000	Base	
Indirect Capital Costs			
Contingency	221,000	NA	20% of Total Purchased Equipment Cost
Engineering and Supervision	111,000	NA	10% of Total Purchased Equipment Cost
Construction & Field Expense	55,000	NA	5% of Total Purchased Equipment Cost
Construction Fee	111,000	NA	10% of Total Purchased Equipment Cost
Start-up Assistance	22,000	NA	2% of Total Purchased Equipment Cost
Performance Test	<u>11,000</u>	NA	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	531,000	Base	
Total Installed Cost	1,306,000	Base	

Table 4-9 CO Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1, 4-2, and 4-3
Catalyst Replacement	306,000	NA	Catalyst life of 3 yr. Of equivalent operating hours
Operation and Maintenance	4,000	NA	See text for background information on this item
Lost Power Generation	<u>40,000</u>	NA	Back Pressure on Combustion Turbine
Total Direct Annual Cost	350,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	26,000	NA	2% of Total Installed Cost
Property Taxes	36,000	NA	2.75% of Total Installed Cost
Insurance	13,000	NA	1% of Total Installed Cost
Capital Recovery	<u>143,000</u>	NA	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	220,000	NA	
Total Annualized Cost	570,000	NA	
Annual Emissions, tpy	74.7	394.4	Emissions taken from Tables 4-1, 4-2, and 4-3
Emissions Reduction, tpy	319.7	NA	Emissions calculated from Tables 4-1, 4-2, and 4-3
Total Cost Effectiveness, \$/ton	1,800	NA	Total Annualized Cost/Emissions Reduction

4.9 Conclusions

To summarize the information discussed in this section of the NO_x and CO BACT, there are several significant technological concerns with utilizing the SCONO_x system. First, SCONO_x is still in the development and demonstration stage. Even though Alstom Power has re-designed their SCONO_x system for large turbine applications, to date this new re-designed system has not been demonstrated in practice. The LAER level of 2 ppmvd NO_x emissions based on using a combination of water injection and a SCONO_x catalyst is considered unproven and technically unacceptable for this project. Although, that system was proven successful for operation at 32 MW, the plant size proposed for the Project raises technical concerns with using this new technology. Second, the higher capital and annualized O&M cost of the SCONO_x system will negatively impact the Project's economics. The capital cost for a SCONO_x system would be approximately \$14,131,000 per CTG/HRSG unit. Furthermore, installation of a SCONO_x system designed to reduce NO_x and CO emissions would add approximately \$7,883,000 to the annualized operating cost per CTG/HRSG unit. The resultant cost effectiveness is approximately \$10,200 per ton of NO_x and CO removed for each CTG/HRSG unit. These costs are considered high for reducing NO_x and CO emissions for this Project compared to an equivalent SCR and oxidation catalyst system.

The annualized and capital costs for the SCONO_x system are approximately 4 and 5 times the cost for an equivalent SCR and oxidation catalyst system. The capital cost for an SCR/Oxidation catalyst system would be about \$3,286,000 per CTG/HRSG unit. Installation of a SCR/Oxidation catalyst system would add approximately \$1,283,000 to the annualized operating cost of each CTG/HRSG unit. The resultant cost effectiveness is approximately \$1,800 per ton of NO_x and CO removed per CTG/HRSG unit. Furthermore, the incremental annualized cost of the SCONO_x system compared to the SCR/Oxidation catalyst system is about \$6,600,000 for each CTG/HRSG unit, which is considered high in light of the existing feasible technologies that can attain the same reductions at a lower overall cost. The SCONO_x system at its current capital and annualized cost can not compete economically to a SCR/Oxidation catalyst system for this combustion turbine application. Therefore, based on economics and the lack of a demonstrated emission limit on larger CTG/HRSG units, this new system was not considered BACT for the Project.

SCR catalysts have proven emissions reduction capabilities and low maintenance requirements at a variety of different facilities throughout the United States, Europe, and Asia. SCR systems are representative of the BACT/LAER level of NO_x emissions reduction. SCR systems have been successfully used on combined cycle combustion turbine applications. The capital and annualized operating cost for an SCR system per CTG/HRSG unit is \$2,480,000 and \$1,003,000, respectively. The incremental cost effectiveness for the CTG/HRSG unit is estimated to be \$2,600 per additional ton of NO_x removed. The operation of an SCR at lower emission rates will likely result in increased PM₁₀ emissions caused by the additional SO₂ to SO₃ oxidation, as well as associated ammonium bisulfate/sulfate and H₂SO₄ emissions. Therefore, based on energy, environmental and economic impacts, the use of DLN combustors with an SCR to meet an emissions level of 3.5 ppmvd for each natural gas fired CTG/HRSG with duct burners (with and without power augmentation) and 10 ppmvd for each combustion turbine during fuel oil firing are proposed as BACT for NO_x.

Installation of an oxidation catalyst would have negative energy, environmental and economic impacts. In summary, the oxidation catalyst would increase the backpressure on the turbine; thereby increasing emissions per unit of electric generation due to decreased turbine efficiency and increased fuel consumption. The oxidation catalyst would increase particulate emissions as a result of increased SO₃ production. In addition, the oxidation catalyst results in an increase in CO₂ emissions, which may contribute to global warming. The negative economic impacts include increased production costs due to decreased efficiency, increased capital cost for the installation of the oxidation catalyst, and increased operating cost due to periodic replacement of the oxidation catalyst.

The capital cost to install an oxidation catalyst system for a CTG/HRSG unit designed to reduce CO emissions by 80 and 86 percent would be \$1,306,000 and the annualized operating cost would be increased by \$570,000 per year. The resultant cost effectiveness on a per ton of CO removed basis is approximately \$1,800. Therefore, based on economic, environmental, and energy impacts, the proposed CO BACT for the control of CO emissions from each combustion turbine during natural gas firing is good combustion practices to achieve a CO emission limit of 18.1 ppmvd at 15 percent O₂ (without power augmentation) and 26.3 ppmvd at 15 percent O₂ (with power augmentation). The proposed CO BACT for the control of CO emissions from each combustion turbine is good

combustion practices to achieve a CO emission limit of 14.3 ppmvd at 15 percent O₂ during fuel oil firing.

5.0 Combustion Turbine PM/PM₁₀ BACT Analysis

The objective of this analysis is to determine BACT for PM/PM₁₀ emissions from the combined cycle combustion turbines. This includes the combustion turbines and supplemental firing in the HRSG as a total unit.

The emissions of particulate matter from the Project 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 a particulate emission limit. Natural gas contains only trace 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 as referenced by the State of Florida, such as the FPL Fort Myers, Santa Rosa and Tallahassee projects, the use of combustion controls is considered BACT for particulate matter and is proposed for this project. BACT was determined to be good combustion controls during natural gas and fuel oil firing.

6.0 Combustion Turbine VOC BACT Analysis

The objective of this analysis is to determine BACT for VOC emissions from the combustion turbines while firing natural gas and fuel oil. This includes duct burner firing with natural gas and only CT firing with fuel oil. Unless otherwise noted the VOC emission rates described in this section are corrected to 15 percent oxygen.

6.1 BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Appendix A. A review of the EPA BACT/LAER Clearinghouse Bulletin Board and the California Air Resource Board (BACT/LAER) indicates that the most stringent VOC emissions limit for a gas fired CT (454 mmBtu/hr, 48 MW) is 0.6 ppmvd at 15 percent O₂ for Bear Mountain Limited located in California. The CAPCOA and EPA BACT/LAER Clearinghouse databases also list a VOC limit of 1.0 ppmvd at 15 percent O₂ for the Casco Ray Energy Company in Maine, Florida Power and Light facility in Florida, and the Sutter Power Plant located California. The emission levels at the Florida Power and Light facility and the Sutter Power Plant are achieved through the application of good combustion practices and an oxidation catalyst. The Casco Ray Energy Company controls VOC emissions with DLN burners.

6.2 Alternative VOC Emission Reduction Systems

Volatile organic compounds are formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. VOC are typically defined as non-methane, non-ethane hydrocarbons that are emitted from the combustion turbine and duct burner. VOC formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize VOC emissions. Therefore, 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 VOC emissions.

An alternative control method is catalytic oxidation, which is a post-combustion method for reduction of VOC emissions. This process is identical to that used for CO reduction where the same oxidation catalyst is used to promote the oxidation of VOC to

CO₂ and H₂O. The oxidation catalyst is typically a precious metal catalyst. No reagent injection is necessary.

Two factors affect the ability of the catalyst to promote oxidation of VOC. Those factors are the temperature of the flue gas as it passes through the catalyst and the species of VOC present in the flue gas. Higher temperatures promote better oxidation of VOC. Long chain hydrocarbons are also easier to oxidize than short chain hydrocarbons. Therefore, the ability of the catalyst to oxidize VOC depends directly on the specific hydrocarbons that are in the flue gas.

Since the exact nature of the VOC's to be emitted from a combustion source are difficult to determine, the exact reduction that may be achieved can not be easily quantified. This uncertainty and the limited amount of removal that may be expected are reflected in the permitting of past projects with oxidation catalyst. As previously noted, most of the oxidation catalyst applications identified in the BACT/LAER databases indicate only an assumed destruction rate varying from 5 to 10 percent. This assumed rate is most likely a reflection that the catalyst was justified as a CO control technology for the given application. Any reduction of VOC was assumed since the catalyst was not installed based on VOC reduction. The estimated VOC emissions for the units with the applicable control technology are listed in Tables 6-1 and 6-2 per CTG/HRSG unit.

6.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenarios evaluated. Although several facilities in the CAPCOA BACT/LAER database have listed 5 to 10 percent reductions in VOCs using an oxidation catalyst, this VOC BACT conservatively assumed a 10 percent (without power augmentation) and 50 percent (with power augmentation) reduction during natural gas firing. A 30 percent reduction in VOC emissions was estimated during fuel oil firing.

6.3.1 Economic Impacts

The use of an oxidation catalyst has a significant negative economic impact to the project. Analysis of the economic impacts is provided in the following section. The VOC BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 6,760 hours per year on natural gas without power augmentation and 1,000 hours per year with power augmentation on natural gas. The VOC BACT costs presented in this analysis also are based on operating each combustion turbine

for 1,000 hours per year on fuel oil.

Table 6-1 Estimated VOC Emissions From Alternate Control Technologies Per GE 7FA CTG/HRSG Unit During Natural Gas Firing				
	Dry Low NO _x Combustors (without Power Augmentation)	Oxidation Catalyst	Dry Low NO _x Combustors (with Power Augmentation)	Oxidation Catalyst
VOC Emissions				
ppmvd at 15 percent O ₂	3.6	3.2	6.3	3.2
tons per year	33.2 ^a	29.9 ^a	9.1 ^b	4.6 ^b
percent removal	N/A	10	N/A	50
Notes: ^a Annual emission based on 7,760 hours of natural gas operation per year at 100 percent of base load with duct firing at an ambient temperature of 70 F. ^b Annual emission based on 1,000 hours of natural gas operation per year at 100 percent of base load with power augmentation and duct firing at an ambient temperature of 70 F.				

Table 6-2 Estimated VOC Emissions From Alternate Control Technologies Per GE 7FA CTG/HRSG Unit During Fuel Oil Firing		
	Dry Low NO _x Combustors	Oxidation Catalyst
VOC Emissions		
ppmvd at 15 percent O ₂	2.7	1.9
tons per year	3.5 ^b	2.5 ^b
Percent removal	N/A	30
Notes: ^a Annual emission based on 1,000 hours of fuel oil operation per year at 100 percent of base load without duct firing at an ambient temperature of 70 F.		

6.3.1.1 Capital Costs

Table 6-3 presents the capital costs for installing an oxidation catalyst system on the combined cycle combustion turbines proposed for the Project. The capital costs for the systems includes the oxidation catalytic reactor, controls and instrumentation and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the balance of plant items listed in Table 6-3 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the PEC and are site specific. The 3 percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating.

6.3.1.2 Operating Costs

Table 6-4 presents the annualized operating costs and emission rates using an oxidation catalyst for the reduction of VOCs per CTG/HRSG unit during natural gas and

fuel oil firing. VOC outlet emissions would be reduced to a maximum of approximately 3.2 and 1.9 ppmvd during natural gas and fuel oil firing, respectively, for each CTG/HRSG unit. Annualized operating costs for the system includes catalyst replacement, operating personnel, maintenance costs, and lost power generation. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours for an oxidation catalyst.

6.3.1.3 Total Annualized Costs

Total annualized cost for the oxidation catalyst system is calculated as the sum of the annualized operating costs plus capital recovery. The total annualized operating cost for an oxidation catalyst is estimated to be \$570,000 per CTG/HRSG unit, which results in an incremental VOC removal cost of approximately \$64,000 per ton.

6.3.2 Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine. The additional backpressure of 1.2 inches, water gauge, will reduce the combustion turbine output by approximately 0.1 percent. The cost of the lost power revenue due to the backpressure is included in the economic analysis.

Table 6-3
VOC Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst	746,000	NA	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	NA	Scaled from an estimate from Engelhard Corporation based on catalyst size
Control/Instrumentation	<u>40,000</u>	NA	Estimated; includes controls and monitoring equipment
Purchased Equipment Costs	1,054,000	NA	
Freight	<u>53,000</u>	NA	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,107,000	NA	
Direct Installation Costs			
Balance of Plant	<u>332,000</u>	NA	8% For Foundations & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting.
Total Direct Capital Cost Less Catalyst	775,000	Base	
Indirect Capital Costs			
Contingency	221,000	NA	20% of Total Purchased Equipment Cost
Engineering and Supervision	111,000	NA	10% of Total Purchased Equipment Cost
Construction & Field Expense	55,000	NA	5% of Total Purchased Equipment Cost
Construction Fee	111,000	NA	10% of Total Purchased Equipment Cost
Start-up Assistance	22,000	NA	2% of Total Purchased Equipment Cost
Performance Test	<u>11,000</u>	NA	1% of Total Purchased Equipment Cost
Total Indirect Capital Costs	531,000	Base	
Total Installed Cost	1,306,000	Base	

Table 6-4
VOC Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Tables 6-1 and 6-2
Catalyst Replacement	306,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	4,000	NA	See text for background information on this item
Lost Power Generation	<u>40,000</u>	NA	Back pressure on combustion turbine
Total Direct Annual Cost	350,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	26,000	NA	2% of Total Installed Cost
Property Taxes	36,000	NA	2.75% of Total Installed Cost
Insurance	13,000	NA	1% of Total Installed Cost
Capital Recovery	<u>143,000</u>	NA	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	220,000	NA	
Total Annualized Cost	570,000	NA	
Annual Emissions, tpy	36.9	45.8	Emissions taken from Tables 6-1 and 6-2 (Combined Natural Gas and Fuel Oil)
Emissions Reduction, tpy	8.9	NA	Emissions calculated from Tables 6-1 and 6-2
Total Cost Effectiveness, \$/ton	64,000	NA	Total Annualized Cost/Emissions Reduction

6.3.3 Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce VOC emissions is that a percentage of the SO_2 in the flue gas will oxidize to SO_3 . The higher the operating temperature the higher the SO_2 to SO_3 oxidation potential. It is estimated that approximately 30 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the VOC oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. The increase in H_2SO_4 emissions would increase PM_{10} (particulate matter less than 10 microns in diameter) emissions.

6.4 Conclusions

Installation of an oxidation catalyst system designed to reduce VOC emissions would add approximately \$570,000 to the annualized cost and the capital cost is approximately \$1,306,000 per CTG/HRSG unit. This corresponds to a cost effectiveness on a per ton of VOC removed basis of approximately \$64,000 for each CTG/HRSG unit. This is considered a high cost and VOC catalysts have not typically been applied to similar CTG/HRSG applications under BACT consideration. Therefore, based on economic, environmental, and energy impacts, the proposed BACT for the control of VOC emissions from each combustion turbine during natural gas firing is good combustion practices using advanced combustion controls design to achieve an emission level of 3.6 ppmvd at 15 percent O_2 (without power augmentation) and 6.3 ppmvd at 15 percent O_2 (with power augmentation). The proposed BACT for the control of VOC emissions from each combustion turbine during fuel oil firing is good combustion practices using advanced combustion controls design to achieve an emission level of 2.7 ppmvd at 15 percent O_2 .

7.0 Combustion Turbine SO₂ BACT Analysis

The objective of this analysis is to determine BACT for sulfur dioxide (SO₂) emissions from the combustion turbine. This includes the combustion turbine and supplemental firing in the HRSG as a total unit. The SO₂ emissions are based on operating each combustion turbine with duct firing at 100 percent of base load for a total of 7,760 hours per year on natural gas and operating each combustion turbine for a total of 1,000 hours per year on fuel oil.

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. Fuel oil will be limited to less than 0.05 percent sulfur. The selection of these fuels provides inherently low SO₂ emissions. No supplemental SO₂ emission controls have been imposed on natural gas fired combustion turbines by regulatory agencies.

Emissions of SO₂ can be controlled by limiting sulfur content in the fuel, limiting high sulfur fuel usage, or by a post-combustion flue gas desulfurization (FGD) system. The fuel for this project is natural gas with a sulfur content of 0.5 grains per 100 standard cubic feet. Therefore, it is considered to have the BACT for this project to be using natural gas and low sulfur fuel oil.

8.0 Cooling Tower BACT Analysis

Uncontrolled cooling towers can be high emitters of PM/PM₁₀ under certain conditions. PM/PM₁₀ from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as drift. A portion of the water droplets emitted from the tower exhausts will evaporate leaving the suspended or dissolved solids in the atmosphere and thus subject to dispersion. Typically, drift eliminators are used to minimize drift (droplet) losses. The drift eliminator control efficiency for the proposed cooling tower is 0.002 percent. The use of drift eliminators are proposed as BACT for PM/PM₁₀ for the cooling tower.

9.0 Conclusions

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for OUC. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. The proposed operating scenario for the combustion turbines consists of operating up to 7,760 hours per year while firing natural gas and operating up to 1,000 hours per year while firing fuel oil. Although, as with most combustion turbine facilities that have been permitted in the United States, the use of fuel oil will be considered as a backup fuel to natural gas for this project and the balance of the facility's operation is expected to consist of firing natural gas. For the purposes of this analysis, worst case annual operation and emissions were evaluated. This is equivalent to natural gas operation at 6,670 hours per year at full load with duct firing, natural gas firing at full load for 1,000 hours per year at full load with duct firing and power augmentation, and fuel oil firing at full load for 1,000 hours per year.

GE PG7241(FA) CTG/HRSG Units:

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners with selective catalytic reduction (SCR) during natural gas firing and water injection with an SCR for fuel oil firing to achieve the following emission limits.

- Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O₂.
- Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O₂.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O₂ (without power augmentation) and 26.3 ppmvd at 15 percent O₂ (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O₂ during fuel oil firing.

Particulate (PM/PM₁₀) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O₂ (without power augmentation) and 6.3 ppmvd at 15 percent O₂ (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O₂ during fuel oil firing.

Sulfur Dioxide (SO₂) emissions -- BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

APPENDIX A

Table A-1 NO_x BACT Clearinghouse Review List						
Facility	State	Permit Date	Process	Output	Emission limit, ppmvd	Control Technology
Federal Cold Storage Cogeneration	CA	Dec-96	GE LM2500-M-2	222 mmBtu/hr	2.0	Water Injection, SCONOx
Sutter Power Plant	CA	APR-99	SW 501F	170 MW	2.5	Dry low NOx, SCR
La Paloma Generating Co.LLC	CA	MAY-99	ABB Model GT-24	262 MW	2.5	Dry-low NOx, SCR
Turlock Irrigation District	CA	AUG-94	GE LM5000	417 mmBtu/hr	3.0	SCR, Steam Injection
Sacramento Power Authority (Campbell Soup)	CA	AUG-94	Siemens V84.2	1257 mmBtu/hr	3.0	Water injection, SCR
Brooklyn Navy Yard Cogeneration Partners L.P.	NY	JUN-95	Turbine, Natural Gas Fired	240 MW	3.5	SCR
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas	170 MW	3.5	SCR
Granite Road Limited	CA	MAY-91	Turbine, Gas	460.9 mmBtu/hr	3.5	SCR, Steam Injection

Table A-2 CO BACT Clearinghouse Review List						
Facility	State	Permit Date	Process	Output, MW	Emission limit ppmvd	Control Technology
Newark Bay Cogeneration Partnership, L.P.	NJ	JUN-93	Turbines, Combustion Natural Gas Fired	617	1.8 ppmvd	Oxidation Catalyst
Saranac Energy Company	NY	JUL-92	Turbines, Combustion Natural Gas Fired	1123	3 ppmvd	Oxidation Catalyst
Alabama Power, Plant Barry	AL	AUG-98	GE 7FA	170	0.057 lb/mmBtu	Good Combustion Control
Alabama Power, Plant Barry	AL	AUG-99	GE 7FA	170	0.06 lb/mmBtu	Good Combustion Control
Mobile Energy, LLC - Hog Bayou	AL	JAN-99	GE 7FA	170	0.04 lb/mmBtu	Good Combustion Control
Sutter Power Plant	CA	APR-99	Turbine, SW 501F	170	4 ppmvd	Oxidation Catalyst
Alabama Power Theodore Cogeneration Facility	AL	MAR-99	GE 7FA	170	0.086 lb/mmBtu	No Control
Blue Mountain Power, L.P	PA	JUL-96	Combustion Turbine with Heat Recovery Boiler	153	3.1 ppmvd	Oxidation Catalyst
Brooklyn Navy Yard Cogeneration Partners, L.P	NY	JUN-95	Turbine, Natural Gas Fired	240	4 ppmvd	No Control
Crockett Cogeneration (C&H Sugar)	CA	OCT-93	GE PG7221 (FA)	240	5.9 ppmvd	Good Combustion Control

**Table A-3
VOC BACT Clearinghouse Review List**

Facility	State	Permit Date	Process	Output, MW	Emission limit	Control Technology
Bear Mountain Limited	CA	AUG-94	Turbine, GE, Cogeneration, 48 MW	48	0.6 ppmvd	Oxidation Catalyst
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas, two	170	1.0 ppmvd	Low NOx Burner
Florida Power and Light	FL	MAR-91	Turbine, Gas, 4 Each	240	1.0 ppmvd	Combustion Control
Sutter Power Plant	CA	APR-99	SW 501F, Combined Cycle	170	1.0 ppmvd	Oxidation Catalyst
Florida Power and Light	FL	JUN-91	Turbine, Gas, 4 Each	400	1.6 ppmvd	Combustion Control
Sacramento Cogeneration Authority	CA	AUG-94	GE LM6000	42	1.1 lb/hr	Oxidation Catalyst
Carson Energy Group and Central Valley Financing	CA	JUL-93	GE LM6000	42	2.46 lb/hr	Oxidation Catalyst

Attachment 5
Air Modeling Protocols

Air Modeling Protocol
Class II



BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114 USA

Tel: (913) 458-2000

Black & Veatch Corporation

OUC/KUA/FMPA
Stanton 3/ Cane Island 4
Pre-Application Meeting

B&V Project 098362.0040
B&V File 14.0400
June 7, 2000

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32339

Subject: PSD Air Quality Impact Analyses

Attention: Cleve Holladay

As discussed at the meeting at FDEP's offices on May 31, 2000, OUC, KUA, FMPA propose to construct and operate either a 3X1 at Stanton EC, 2X1 at Stanton EC, and/or a 2X1 at Cane Island. The combustion turbines will all be "F" class machines operating in combined cycle (CC) mode, with all projects reserving the ability to operate in simple cycle (SC) mode. Fuels will consist of natural gas with No. 2 distillate fuel oil as backup. Each proposed project will constitute a major modification to an existing major source, with expected significant emissions of NO_x, CO, SO₂, and PM₁₀. As such, a BACT analysis, air quality impact analyses, and additional impact analyses will be required for those pollutants as part of the PSD review process. The information contained in the Attachment of this letter, as discussed in the meeting on May 31, 2000, will serve as the modeling protocol for the three proposed projects and thus a formal protocol document will not be required for the PSD air quality impact analysis. Please review the information and provide comments by Monday, June 19, 2000. Additionally, a list of items which FDEP agreed to review and provide additional information has also been included.

If you have questions, please feel free to contact me at 913-458-9062 or Mr. Brian O'Neal at 913-458-8199.

Very truly yours,

BLACK & VEATCH

Kyle J. Lucas
Air Quality Scientist

bdo

cc: File
M. Soltys
M. Rollins
B. O'Neal
K. Butler

Attachment

PSD Air Quality Impact Analysis

- Latest version of ISCST3 will be used with regulatory defaults.
- Simple terrain with the FLAT option.
- Five years of meteorological data (1987 – 1991 Orlando surface with Tampa upper air).
- Due to the large number of operating scenarios, an enveloping approach to obtain the worst-case operating scenario for use in the air dispersion modeling can be used.
- Downwash Analysis
The Building Profile Input Program (BPIP) will be used to assess downwash for all stacks. Furthermore, it was suggested that for the Stanton facility, the future coal units be considered in the downwash analysis of the proposed project to prevent potential downwash issues in the future for this turbine addition if the coal units are built. However, inclusion of the future coal addition is not required.
- The same type of receptor grid used for KUA3 can be used for the proposed projects. Specifically, a 10 km nested rectangular grid consisting of 100 m spacing out to 1 km, 500 m spacing from 1 to 5 km, 1 km spacing from 5 to 10 km, and 100 m spacing along the fenceline.
- Rural dispersion coefficient.
- FDEP did not require state specific modeling be performed.
- If the proposed projects impacts are less than the PSD SILs, then demonstration is complete. A NAAQS and Increment analysis will be performed only if the project(s) impacts are above the PSD SILs. If such analyses are necessary, FDEP will provide the source inventories.
- A request for a waiver from pre-application monitoring, if required, can be requested in the application. A separate letter is not necessary.
- All PM is considered to be PM₁₀ and is for front-half catch only (filterable).

Class I Area Analyses

- The Chassahowitzka Wilderness Area is a PSD Class I area located approximately 100 km from the proposed projects and must be modeled using the Calpuff air dispersion model to assess criteria pollutant impacts, regional haze, and pollutant deposition analyses.
- FDEP uses 4 percent of the Class I Increment to represent the Class I SILs for criteria pollutant impacts modeling.
- Calpuff Lite modeling is acceptable for the regional haze analysis as long as the project is under the 5 percent threshold. If the Calpuff Lite analysis yields results greater than 5 percent level, a Calpuff refined analysis must be performed.

OUC/KUA/FMPA
Stanton 3/Cane Island 4
Pre-Application Meeting

B&V Project 98362
B&V File 14.0400
June 7, 2000
Page 3

- Use Calpuff default ozone and ammonia levels. A protocol for the refined analysis, if applicable, should be prepared and submitted to Cleve Holladay. FDEP will organize all Class I analyses and activities with the Fish and Wildlife Service.
- A deposition analysis is required.

112(g)- case-by-case MACT

- The analysis will consist of the MACT determination for HAPS. If the Potential to Emit case for the facility is below the 25 tpy limit and the 10 tpy limit for each individual pollutant, then no further analysis is required.
- AP-42 is an acceptable reference.

Additional Information from FDEP

- Cleve Holladay will assess whether the electronic files (specifically the Calmet file(s)) from the submitted Calpine Osprey Project can be used for the proposed projects.
- Cleve Holladay will verify if the deposition analysis for the Chassahowitzka Class I area is to be a total nitrogen analysis or a nitrates analysis.
- Jeff Koerner will verify which combustion sources are applicable to the MACT determination.

Air Modeling Protocol
Class I



BLACK & VEATCH

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Black & Veatch Corporation

OUC/KUA/FMPA
Stanton 3

B&V Project 098362.0040
B&V File 14.0400
August 30, 2000

Florida Department of Air Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399

Subject: Class I Analyses Protocol Document

Attention: Cleve Holladay

As discussed at the meeting at FDEP's offices on May 31, 2000, OUC, KUA, and FMPA propose to construct and operate a 2-on-1 combined cycle electric generating plant at the Stanton Energy Center. As such, FDEP requested additional impact analyses be performed, in addition to the PSD air quality impact analysis, for the Chassahowitzka Wilderness Area which is a designated Class I area and under the jurisdiction of the US Fish and Wildlife Service (FWS) as the Federal Land Manager (FLM). Enclosed, please find the class I analyses modeling protocol document for your review as discussed in the meeting on May 31, 2000. Please review the document and provide you comments by Friday, September 8, 2000.

If you have any questions, please feel free to contact me at 913-458-9062 or Mr. Brian O'Neal at 913-458-8199.

Very truly yours,

BLACK & VEATCH


Kyle J. Lucas
Air Quality Specialist

kjl
Enclosure

cc: File
M. Soltys
M. Rollins
B. O'Neal

**STANTON ENERGY CENTER
CALPUFF MODELING PROTOCOL**

**PREPARED BY
BLACK & VEATCH**

AUGUST 2000

TABLE OF CONTENTS

1.0	Introduction.....	1-1
2.0	Model Selection and Inputs	2-1
2.1	Model Selection	2-1
2.2	CALPUFF Model Settings.....	2-1
2.3	Building Wake Effects.....	2-1
2.4	Receptor Locations	2-3
2.5	Meteorological Data Processing	2-3
2.5.1	CALMET Settings	2-3
2.5.2	Modeling Domain	2-3
2.5.3	Mesoscale Model Data.....	2-3
2.5.4	Surface Data Stations and Processing.....	2-4
2.5.5	Upper Air Data Stations and Processing.....	2-4
2.5.6	Precipitation Data Stations and Processing.....	2-4
2.5.7	Geophysical Data Processing.....	2-5
2.6	Facility Emissions.....	2-5
3.0	CALPUFF Analyses	3-1
3.1	Regional Haze Analysis.....	3-1
3.1.1	Visibility	3-1
3.1.2	Background Visual Ranges and Relative Humidity Factors.....	3-2
3.1.3	Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines	3-2
3.2	Deposition Analyses	3-5
3.3	Class I Impact Analysis	3-5

LIST OF TABLES

Table 2-1	CALPUFF Model Settings.....	2-2
Table 3-1	Outline of IWAQM Refined Modeling Analyses Recommendations*	3-3

LIST OF FIGURES

Figure 1-1	Proposed Project Location	1-2
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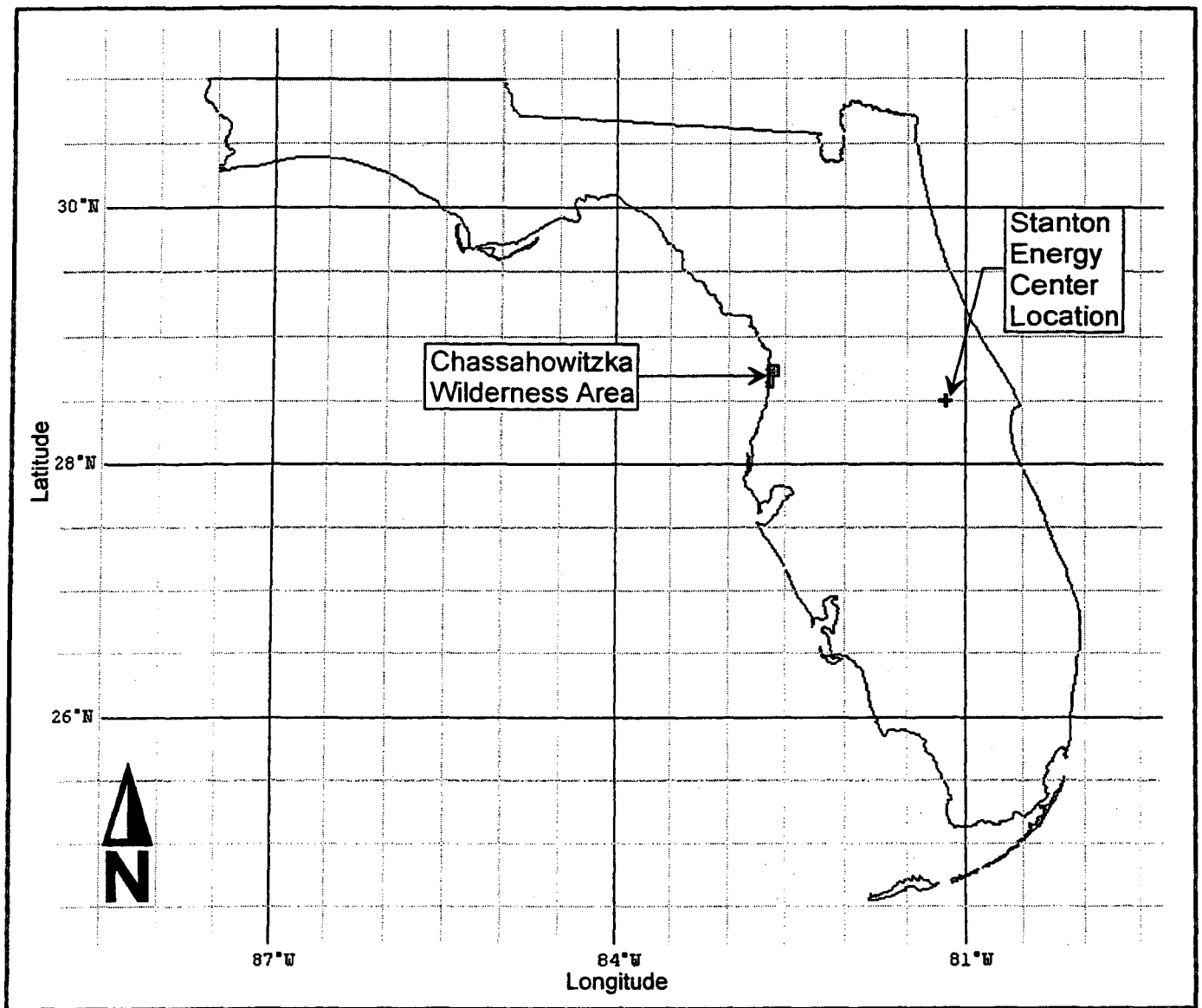
ATTACHMENT

Chassahowitzka Receptor Locations

1.0 Introduction

Orlando Utilities Commission (OUC), in conjunction with Kissimmee Utility Authority (KUA) and Florida Municipal Power Authority (FMPA), are proposing to construct two 170-MW combined-cycle combustion turbines serving one steam turbine (2x1), for a total nominal output of approximately 620 MW, at the existing Stanton Energy Center, which is located near the city of Orlando, Florida. As part of the air impact evaluation for the proposed facility, the Florida Department of Environmental Protection (FDEP) has requested that analyses of the proposed facility's affect on the Chassahowitzka Wilderness Area (CWA) be performed. The CWA is a Prevention of Significant Deterioration (PSD) Class I area located in west-central Florida approximately 100 km northwest of the proposed facility site. Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze, deposition, and Class I Significant Impact Levels (SILs). Figure 1-1 presents the locations of the proposed project site with respect to the CWA.

The CALPUFF analysis will closely follow those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Draft Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) dated October 1999, as well as coordination with the FDEP who will in turn communicate as necessary with the U.S. Fish and Wildlife Service (FWS) which is the Federal Land Manager (FLM) for the CWA. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach.



Location of Stanton Energy Center
And
Chassahowitzka Wilderness Area

Figure 1-1

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, version 5.4) air modeling system will be used to model the proposed facility and assess the AQRVs at CWA. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts. Both CALMET and CALPUFF will be used in a manner that is recommended by the IWAQM Phase 2 Report and Draft Phase I FLAG Report.

2.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 2-1 will be used for the modeling analyses.

2.3 Building Wake Effects

The CALPUFF analysis will include the proposed facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures will be processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

Table 2-1 CALPUFF Model Settings	
Parameter	Setting
Pollutant Species	SO ₂ , SO ₄ , NO _x , HNO ₃ , and NO ₃ , and PM10
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	<u>Regional Haze:</u> Highest predicted 24-hour SO ₄ , NO ₃ and PM10 concentrations for the year. <u>Deposition:</u> Highest predicted annual SO ₂ , SO ₄ , NO _x , HNO ₃ , and NO ₃ values in deposition units. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Ozone: 80 ppb; Ammonia: 10 ppb

2.4 Receptor Locations

The CALPUFF analysis will use an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the CWA. Specifically, the array will consist of receptors obtained from FDEP via a July 20, 2000 email, which covers the extent of the CWA. A graphical depiction of the receptor locations can be found in the Attachment. Because the terrain throughout the CWA is flat, an elevation of zero will be used for all receptors.

2.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.2) will be used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data to be used and processed in the CALMET model.

2.5.1 CALMET Settings

The CALMET settings, including horizontal and vertical grid coverage, number of weather stations (surface, upper air, and precipitation), and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed facility to the receptors at the CWA with at least a 50-km buffer zone in each direction. The air modeling analysis will be performed in the UTM coordinate system.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets, prognostic wind fields or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant

levels) are extensive and only allow for a one-year data base set; specifically, 1990. The analysis will use the MM4 mesoscale meteorological data set to initialize the CALMET wind field. The data will be extracted from a 12-volume CD-ROM set put out by the National Climatic Data Center (NCDC). The MM4 data have a horizontal spacing or resolution of 80 km and are used to simulate atmospheric variables within the modeling domain.

The mesoscale meteorological data set (MM4) to be used in CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables will be processed into the appropriate format and introduced into the CALMET model through the utilization of additional data files obtained from numerous sources. These ancillary data files are described in more detail in the following sections.

2.5.4 Surface Data Stations and Processing

The surface station data for the CALPUFF analyses will consist of data from several National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The station data may be obtained directly from NCDC or extracted from a CD-ROM set put out by NCDC. The data will be processed with the CALMET preprocessor utility program, SMERGE, to create one surface file.

2.5.5 Upper Air Data Stations and Processing

The analysis will include several upper air NWS stations located within the CALMET domain. Data for these stations will be obtained from the NCDC Radiosonde Data CD and processed into the NCDC Tape Deck (TD) 6201 format by the READ62 utility program for input to CALMET.

2.5.6 Precipitation Data Stations and Processing

Precipitation data will be processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations within the CALMET domain. The precipitation files are contained in a 2-volume CD-ROM set from NCDC. The utility programs PXTRACT and PMERGE will be used to process the data into the format for the Precip.dat file that is used by CALMET.

2.5.7 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain will be obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data will be extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, will also be obtained from the USGS. Land-use values for the domain grid will be extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters will be combined with the terrain information in a processor called MAKEGEO. This processor will produce one GEO.DAT file for input to CALMET.

2.6 Facility Emissions

Performance data for the combustion turbines will be based on vendor data at certain design ambient temperatures at base load operation, considering both natural gas and distillate fuel oil firing. The maximum pound per hour emission rates considering representative ambient temperatures at base load operation for natural gas and distillate fuel oil firing will be used for the pollutants modeled with CALPUFF.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the CWA, including regional haze, deposition (both sulfur and nitrogen), and Class I SILs.

3.1 Regional Haze Analysis

Regional haze analyses will be performed for the CWA for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4 , NO_3 , and PM_{10} concentrations.

3.1.1 Visibility

Visibility is an AQRV for the CWA. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the CWA lies beyond 50 km from the proposed facility, the change in visibility is analyzed as regional haze at those locations of the CWA. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{\text{ext}}(\text{Mm}^{-1}) = 3912 / \text{vr}(\text{Mm}^{-1})$$

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, 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.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
 b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} 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_{extb} , or; percent change in extinction. Based on National Park Service (NPS) guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extsb}) \times 100$$

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual range for the CWA will be obtained from the Draft Phase I FLAG document. The average relative humidity factor for each species' worst day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity will be obtained by using Table 2.A-1 of Appendix 2.A of the Draft Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). Again, all of this can be accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis will follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98). Table 3-1 summarizes the IWAQM Phase II

Table 3-1 Outline of IWAQM Refined Modeling Analyses Recommendations*	
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage. A figure depicting the location of the receptors can be found in the Attachment.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO ₄ , PM ₁₀ and NO ₃ values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction. This can all now be accomplished with the use of the CALPOST post-processor.
*IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 12/98).	

recommendations. The methodology below will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of six modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. A typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain maximum 24-hour SO_4 and NO_3 impacts, in units of micrograms per cubic meter ($\mu\text{g}/\text{m}^3$).
2. Convert the SO_4 impact to $(\text{NH}_4)_2\text{SO}_4$ by the following formula:

$$(\text{NH}_4)_2\text{SO}_4 (\mu\text{g}/\text{m}^3) = \text{SO}_4 (\mu\text{g}/\text{m}^3) \times \text{molecular weight } (\text{NH}_4)_2\text{SO}_4 / \text{molecular weight } \text{SO}_4$$

$$(\text{NH}_4)_2\text{SO}_4 (\mu\text{g}/\text{m}^3) = \text{SO}_4 (\mu\text{g}/\text{m}^3) \times 132/96 = \text{SO}_4 (\mu\text{g}/\text{m}^3) \times 1.375$$
 Convert the NO_3 impact to NH_4NO_3 by the following formula:

$$\text{NH}_4\text{NO}_3 (\mu\text{g}/\text{m}^3) = \text{NO}_3 (\mu\text{g}/\text{m}^3) \times \text{molecular weight } \text{NH}_4\text{NO}_3 / \text{molecular weight } \text{NO}_3$$

$$\text{NH}_4\text{NO}_3 (\mu\text{g}/\text{m}^3) = \text{NO}_3 (\mu\text{g}/\text{m}^3) \times 80/62 = \text{NO}_3 (\mu\text{g}/\text{m}^3) \times 1.29$$
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

$$b_{\text{exts}} = 3 \times \text{NH}_4\text{NO}_3 \times f(\text{RH}) + 3 \times (\text{NH}_4)_2\text{SO}_4 \times f(\text{RH}) + 1 \times \text{PM}_{10}$$
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FALG document with the following formula:

$$b_{\text{extb}} = 3.912 / \text{Visual range (km)}$$
5. Compute the change in extinction coefficients:
 in terms of deciviews:

$$dv = 10 \ln (1 + b_{\text{exts}} / b_{\text{extb}})$$
 in terms of percent change of visibility:

$$\Delta\% = (b_{\text{exts}} / b_{\text{extb}}) \times 100$$

Based on the predicted SO_4 , NO_3 , and PM_{10} concentrations, the proposed facility's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2 Deposition Analyses

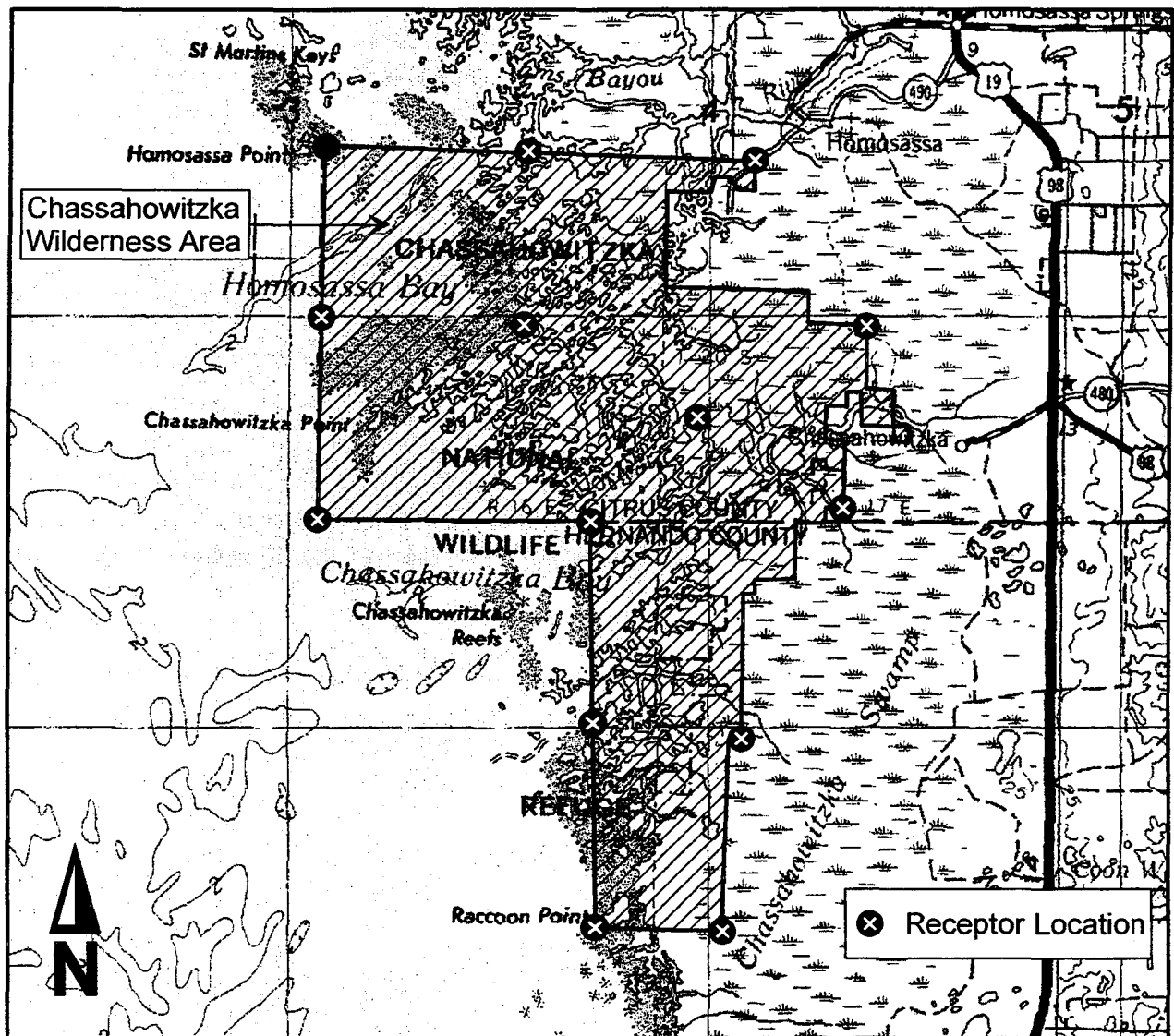
Deposition analyses will be performed for the CWA for both sulfur and nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 3.1 (including output of both dry and wet deposition).
2. Perform individual CALPOST post-processor runs to output the maximum annual average wet and dry deposition impacts of SO_2 , SO_4 , NO_x , HNO_3 , and NO_3 in $\text{g/m}^2/\text{s}$ units.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the above CALPOST runs to account for normalization based on the ratio of molecular weights, as well as the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results will be in kg/ha/yr .
4. For total sulfur deposition, sum the results of both the wet deposition and dry deposition values for both SO_2 and SO_4 .
5. For total nitrogen deposition, sum the results of both the wet deposition and dry deposition values for NO_x , HNO_3 , and NO_3 .

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu\text{g/m}^3$) onto to the CWA will be calculated for the criteria pollutants that exceed PSD Significant Emission Levels (SELs) for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values

ATTACHMENT



Chassahowitzka Wilderness Area Receptors

Attachment 1

Attachment 6
Air Dispersion Modeling Files

Appendix 10.7

Air Construction Application Forms for the Curtis H. Stanton Energy Center Combined Cycle Combustion Turbine Project

Submitted by

**Orlando Utilities Commission
Kissimmee Utility Authority
Florida Municipal Power Authority
and
Southern Company-Florida, LLC**

**Prepared by
Black & Veatch**

**January 2001
Project No. 98362**

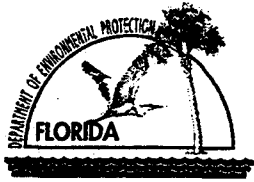
Contents

I. Application Information	1
II. Facility Information.....	7
A. General Facility Information.....	7
B. Facility Regulations.....	8
C. Facility Pollutants.....	9
D. Facility Supplemental Information	10
III. Emissions Unit Information	12
1. Emissions Unit Information (004)-Combined Cycle Combustion Turbine.....	12
A. General Emissions Unit Information	12
B. Emissions Unit Capacity Information	15
C. Emissions Unit Regulations	16
D. Emission Point (Stack/Vent) Information	17
E. Segment (Process/Fuel) Information.....	18
F. Emissions Unit Pollutants.....	19
G. Emissions Unit Pollutant Detail Information.....	20
H. Visible Emissions Information.....	31
I. Continuous Monitor Information.....	32
J. Emissions Unit Supplemental Information	35
2. Emissions Unit Information (005)-Combined Cycle Combustion Turbine.....	37
A. General Emissions Unit Information	37
B. Emissions Unit Capacity Information	40
C. Emissions Unit Regulations	41
D. Emission Point (Stack/Vent) Information	42
E. Segment (Process/Fuel) Information.....	43
F. Emissions Unit Pollutants.....	44
G. Emissions Unit Pollutant Detail Information.....	45
H. Visible Emissions Information.....	56
I. Continuous Monitor Information.....	57
J. Emissions Unit Supplemental Information	60
3. Emissions Unit Information (006)-Cooling Tower.....	62
A. General Emissions Unit Information	62
B. Emissions Unit Capacity Information	64
C. Emissions Unit Regulations	65
D. Emission Point (Stack/Vent) Information	66

E. Segment (Process/Fuel) Information.....	67
F. Emissions Unit Pollutants.....	68
G. Emissions Unit Pollutant Detail Information.....	69
H. Visible Emissions Information.....	70
I. Continuous Monitor Information.....	71
J. Emissions Unit Supplemental Information	72
4. Emissions Unit Information (007)-Fuel Oil Storage Tank	74
A. General Emissions Unit Information	74
B. Emissions Unit Capacity Information	76
C. Emissions Unit Regulations	77
D. Emission Point (Stack/Vent) Information	78
E. Segment (Process/Fuel) Information.....	79
F. Emissions Unit Pollutants.....	80
G. Emissions Unit Pollutant Detail Information.....	81
H. Visible Emissions Information.....	83
I. Continuous Monitor Information.....	84
J. Emissions Unit Supplemental Information	85

Attachments

- Attachment A Applicable Regulations
- Attachment B Area Map Showing Facility Location
- Attachment C Facility Plot Plan
- Attachment D Process Flow Diagrams
- Attachment E Fuel Analyses
- Attachment F Stack Sampling Facility
- Attachment G Operating Matrix
- Attachment H Acid Rain Permit Application
- Attachment I TANKS Calculation



Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Authority, and Southern Company – Florida, LLC.	
2. Site Name: Curtis H. Stanton Energy Center	
3. Facility Identification Number: 564 [] Unknown	
4. Facility Location: Orlando Utilities Commission (OUC) Curtis H. Stanton Energy Center Street Address or Other Locator: 5100 South Alafaya Trail City: Orlando County: Orange Zip Code: 32831	
5. Relocatable Facility? [] Yes [X] No	6. Existing Permitted Facility? [X] Yes [] No

Application Contact

1. Name and Title of Application Contact: James O. Vick; Manager, Environmental Affairs	
2. Application Contact Mailing Address: Organization/Firm: Southern Company – Florida, LLC Street Address: One Energy Place City: Pensacola State: Florida Zip Code: 32520-0328	
3. Application Contact Telephone Numbers: Telephone: (850)444-6311 Fax: (850)444-6217	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

- ☐ Initial Title V air operation permit for an existing facility which is classified as a Title V source.
- ☐ Initial Title V air operation permit 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: _____

- ☐ Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: _____

Operation permit number to be revised: _____

- ☐ Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: _____

- ☐ Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: _____

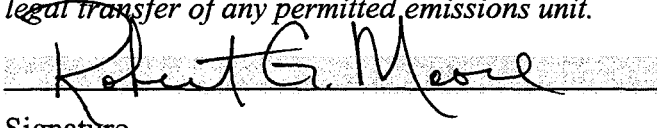
Reason for revision: _____

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

- ☒ Air construction permit to construct or modify one or more emissions units.
- ☐ Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.
- ☐ Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Robert G. Moore, Vice-President of Power Generation and Transmission	
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Street Address: One Energy Place City: Pensacola State: FL Zip Code: 32520-0328	
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (850) 444 - 6383 Fax: (850) 444 - 6744	
4. Owner/Authorized Representative or Responsible Official Statement: <i>I, the undersigned, am the owner or authorized representative*(check here [], if so) or the responsible official (check here [x], if so) 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 unit.</i>  _____ Signature 1/14/2001 Date	

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Greg N. Terry Registration Number: 52786-	
2. Professional Engineer Mailing Address: Organization/Firm: Street Address: One Energy Place City: Pensacola State: FL Zip Code: 32520-0340	
3. Professional Engineer Telephone Numbers: Telephone: (850) 429 - 2381 Fax: (850) 429 - 2246	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Robert G. Moore; Vice-President of Power Generation and Transmission
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Southern Company – Florida, LLC Street Address: One Energy Place City: Pensacola State: Florida Zip Code: 32520-0328
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (850)444-6383 Fax: (850)444-6744
4. Owner/Authorized Representative or Responsible Official Statement: <i>I, the undersigned, am the owner or authorized representative*(check here [], if so) or the responsible official (check here [], if so) 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 unit.</i> _____ Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Rodney I. Unruh Registration Number: Florida No. 28564
2. Professional Engineer Mailing Address: Organization/Firm: Black & Veatch Street Address: 11401 Lamar City: Overland Park State: Kansas Zip Code: 66211
3. Professional Engineer Telephone Numbers: Telephone: (913)458-7309 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 pollution 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.

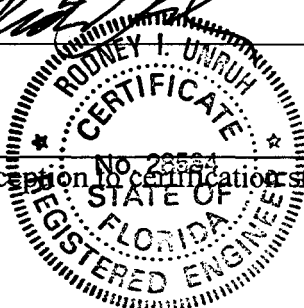
If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit 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.

Signature

Date

(seal)

* Attach any exception to certification statement.



Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
004	Nominal 317 MW Combined Cycle Combustion Turbine	AC1A	N/A
005	Nominal 317 MW Combined Cycle Combustion Turbine	AC1A	N/A
006	Cooling Tower	AC1A	N/A
007	Distillate Fuel Oil Storage Tank (1,680,000 gal)		N/A

Application Processing Fee

Check one: ☐ Attached - Amount: \$ _____ ☒ Not Applicable (Part of the site Certification Fee).

Construction/Modification Information**1. Description of Proposed Project or Alterations:**

The electric generating facility to be installed for at the existing Curtis H. Stanton Energy Center will include the construction of two combined cycle combustion turbine (CCCT) units rated at approximately a nominal 317 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a backup fuel, and one 10-cell mechanical draft cooling tower. Each CCCT will be equipped with a heat recovery steam generator (HRSG) containing natural gas-fired duct burners. The two CCCT/HRSGs will feed a single, common steam turbine generator; this configuration is regularly referred to as a 2x1 configuration. The CCCTs will include provisions for the optional use of evaporative coolers and steam power augmentation. The new CCCT/HRSGs will be capable of operating at base load for up to 8,760 hours per year with a potential of 1,000 hours of operation using steam injection for power augmentation and 1,000 hours of operation on distillate fuel oil.

2. Projected or Actual Date of Commencement of Construction:	10/01/2001
3. Projected Date of Completion of Construction:	9/01/2003

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone:17 East (km):483.61 North (km):3151.1			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 28/29/17 Longitude (DD/MM/SS): 81/10/03			
3. Governmental Facility Code: 4	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters): Construction of two new combustion turbines, one cooling tower and one distillate oil fuel storage tank at an existing facility.			

Facility Contact

1. Name and Title of Facility Contact: James O. Vick; Manager, Environmental Affairs			
2. Facility Contact Mailing Address: Organization/Firm: Southern Company – Florida, LLC Street Address: One Energy Place City: Pensacola State: Florida Zip Code: 32520-0328			
3. Facility Contact Telephone Numbers: Telephone: (850) 444-6311 Fax: (850) 444-6217			

B. FACILITY REGULATIONS

Facility Regulatory Classifications

Check all that apply:

1. ☐ Small Business Stationary Source?	☐ Unknown
2. ☒ Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. ☐ Synthetic Minor Source of Pollutants Other than HAPs?	
4. ☐ Major Source of Hazardous Air Pollutants (HAPs)?	
5. ☐ Synthetic Minor Source of HAPs?	
6. ☒ One or More Emissions Units Subject to NSPS?	
7. ☐ One or More Emission Units Subject to NESHAP?	
8. ☒ Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): 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.	

List of Applicable Regulations

See Attachment A

C. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. <u>Requested Emissions Cap</u>		4. Basis for Emissions Cap	5. Pollutant Comment
		lb/hour	tons/year		
NO _x	A	N/A	N/A		
CO	A	N/A	N/A		
PM/PM ₁₀	A	N/A	N/A		
SO ₂	A	N/A	N/A		
VOC	A	N/A	N/A		
HAPS	B	N/A	N/A		

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: <u>Attachment B</u> [] Not Applicable [] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: <u>Attachment C</u> [] Not Applicable [] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: <u>Attachement D</u> [] Not Applicable [] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: <u>SCA Section 4.5</u> [] Not Applicable [] Waiver Requested
5. Fugitive Emissions Identification: [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: <u>SCA Appendix 10.7</u> [] Not Applicable
7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: ☐ Attached, Document ID: _____ ☒ Not Applicable
9. List of Equipment/Activities Regulated under Title VI: ☐ Attached, Document ID: _____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable
10. Alternative Methods of Operation: ☐ Attached, Document ID: _____ ☒ Not Applicable
11. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☒ Not Applicable
12. Identification of Additional Applicable Requirements: ☐ Attached, Document ID: _____ ☒ Not Applicable
13. Risk Management Plan Verification: ☐ Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID: _____) or previously submitted to DEP (Date and DEP Office: _____) ☐ Plan to be submitted to CEPPO (Date required: _____) ☒ Not Applicable
14. Compliance Report and Plan: ☐ Attached, Document ID: _____ ☒ Not Applicable
15. Compliance Certification (Hard-copy Required): ☐ Attached, Document ID: _____ ☒ Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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.			
2. 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.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator operating in combined cycle (CCCT) mode with one heat recovery steam generator (HRSG) having a nominal rating of 317 MW. The CCCT/HRSG will be capable of firing both natural gas and distillate fuel oil.			
4. Emissions Unit Identification Number: ☐ [] No ID ID: 004 ☐ [] ID Unknown			
5. Emissions Unit Status Code: C	6. Initial Startup Date: 10/01/2003	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters)

The nominal 317 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 is the primary fuel; low sulfur distillate fuel oil is the back up fuel.

Applicant requested emission limitation:

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and duration of excess emission shall be minimized.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Dry Low No_x (DLN) Combustor during Natural Gas firing - Burner technology to control NO_x emissions. This technology uses a two-staged 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.

Water injection during Fuel Oil firing- For Oil firing cases only, this type of control injects water into the primary combustion zone with the fuel. The water serves to reduce NO_x formation by reducing the peak flame temperature.

Selective Catalytic Reduction (SCR)- For both Natural Gas and Oil firing, the SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water.

2. Control Device or Method Code(s): 024, 025, 028, 065

Emissions Unit Details

1. Package Unit: Combined Cycle Combustion Turbine Generator
 Manufacturer: General Electric
 Model Number: PG 7241 FA

2. Generator Nameplate Rating: 317 MW

3. Incinerator Information: N/A

Dwell Temperature:	°F
Dwell Time:	seconds
Incinerator Afterburner Temperature:	°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	(Natural Gas firing)	2402.0 (HHV)	mmBtu/hr
	(Fuel Oil firing)	2067.6 (HHV)	mmBtu/hr
2. Maximum Incineration Rate:	N/A		
3. Maximum Process or Throughput Rate:	N/A		
4. Maximum Production Rate:	N/A		
5. Requested Maximum Operating Schedule:			
For natural gas:	24 hours/day	7 days/week	
	52 weeks/year	8760 hours/year	
For fuel oil:	24 hours/day	7 days/week	
	52 weeks/year	1000 hours/year	
6. Operating Capacity/Schedule Comment (limit to 200 characters):			
Maximum Heat Input Rate in Field 1 based on: Gas: 19 F, base load, with duct burner on. Performance Data Case 4. Oil: 19 F, base load. Performance Data Case 20. All cases of Natural Gas and Oil firing were considered in these maximums. Maximum hours of operation on Natural Gas is 8760 hrs/yr and 1000 hrs/yr for Fuel Oil.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 004		2. Emission Point Type Code: 2	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): 160-ft vertical cylindrical exhaust stack associated with the combustion turbine and heat recovery steam generator.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 19 feet	
8. Exit Temperature: 287 °F	9. Actual Volumetric Flow Rate: 1280130 acfm	10. Water Vapor: N/A	
11. Maximum Dry Standard Flow Rate: N/A		12. Nonstack Emission Point Height: N/A	
13. Emission Point UTM Coordinates: Zone:17 East (km):483.61 North (km):3151.12			
14. Emission Point Comment (limit to 200 characters): Field 8 based on: Distillate Oil 100% load, 19 F case. Field 9 based on: Distillate Oil 100% load, 19 F case. Stack temperature and flow rate will vary with fuel, load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined cycle mode on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e. 8760 hours).		
1. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 2.35	5. Maximum Annual Rate: 20628.94	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = $\frac{2402.0 \text{ mmBtu/hr (HHV)}}{1020 \text{ mmBtu/mmBtu/hr (HHV)}} = 2.35 \text{ mmscf/hr}$ Maximum Annual Rate = $\frac{8760 \text{ hrs/yr} \times 2402.0 \text{ mmBtu/hr}}{1020 \text{ mmBtu/mmBtu/hr}} = 20628.94 \text{ mmscf/yr}$		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined mode on No.2 distillate fuel oil. This unit is allowed to operate on No.2 distillate fuel oil for 1000 hours/yr		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand gallons burned (all liquid fuel)	
4. Maximum Hourly Rate: 14.87	5. Maximum Annual Rate: 14874.82	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = $\frac{2067.6 \text{ mmBtu/hr}}{139 \text{ mmBtu/ thousand gallons}} = 14.87 \text{ thousand gallons/hr}$ Maximum Annual Rate = $\frac{1000 \text{ hrs/yr} \times 2067.6 \text{ mmBtu/hr}}{139 \text{ mmBtu/ thousand gallons}} = 14874.82 \text{ thousand gallons/yr}$		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO _x	024	025, 028, 065	EL
CO			EL
PM/PM ₁₀			EL
SO ₂			EL
VOC			EL
HAPS			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO _x		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual Operation		157.24 tons/year	
Natural Gas Firing		132.58 tons/year	
Fuel Oil Firing		39.85 tons/year	
5. Range of Estimated Fugitive Emissions:			
[] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor:		7. Emissions Method Code:	
Reference: Manufacturer		0	
8. Calculation of Emissions (limit to 600 characters):			
Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(30.38 \text{ lb/hr} * 7760 \text{ hr/yr}) + (29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 132.58 \text{ tons per year}$ Fuel Oil Firing: $\frac{79.69 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 39.85 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(30.38 \text{ lb/hr} * 6760 \text{ hr/yr}) + (79.69 \text{ lb/hr} * 1000 \text{ hr/yr}) + (29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 157.24 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):			
Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
2. Requested Allowable Emissions and Units: 3.5 ppmvd (at 15% O ₂ for Natural Gas)	4. Equivalent Allowable Emissions: 30.38 lb/hour 133.06 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppmvd (at 15% O ₂ for Fuel Oil)	4. Equivalent Allowable Emissions: 79.69 lb/hour 39.85 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hrs/year of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual Operation	435.05 tons/year		
Natural Gas Firing	448.12 tons/year		
Fuel Oil Firing	35.50 tons/year		
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(97.13 \text{ lb/hr} * 7760 \text{ hr/yr}) + (142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 448.12 \text{ tons per year}$ Fuel Oil Firing: $\frac{71.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 35.50 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(97.13 \text{ lb/hr} * 6760 \text{ hr/yr}) + (71.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 435.05 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 97.13 lb/hr for Natural Gas with duct burning 142.51 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 448.12 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 71.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 71.00 lb/hour 35.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM ₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Annual 53.63 tons/year Natural Gas Firing 50.94 tons/year Fuel Oil Firing 8.50 tons/year		4. Synthetically Limited? ☐	
5. Range of Estimated Fugitive Emissions: ☐ 1 ☐ 2 ☐ 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(11.62 \text{ lb/hr} * 7760 \text{ hr/yr}) + (11.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 50.94 \text{ tons per year}$ Fuel Oil Firing: $\frac{17.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 8.5 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(11.62 \text{ lb/hr} * 6760 \text{ hr/yr}) + (17.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (11.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 53.63 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.62 lb/hr for Natural Gas with duct burning 11.71 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 50.94 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 17.00 lb/hour 8.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Emissions based on 1000 hours/yr of Fuel Oil firing. The applicant will assume 20% opacity limit for Fuel Oil firing in lieu of the 17.00 lb/hr PM/PM ₁₀ limit during Fuel Oil-firing.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO ₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual	67.03 tons/year		
Natural Gas Firing	15.28 tons/year		
Fuel Oil Firing	53.50 tons/year		
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(3.50 \text{ lb/hr} * 7760 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 15.28 \text{ tons per year}$ Fuel Oil Firing: $\frac{107.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 53.50 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(3.50 \text{ lb/hr} * 6760 \text{ hr/yr}) + (107.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 67.03 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.50 lb/hour Natural Gas	4. Equivalent Allowable Emissions: 3.50 lb/hour 15.33 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 107.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 107.00 lb/hour 53.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual	52.53 tons/year		
Natural Gas Firing	54.22 tons/year		
Fuel Oil Firing	4.00 tons/year		
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(11.38 \text{ lb/hr} * 7760 \text{ hr/yr}) + (20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 54.22 \text{ tons per year}$ Fuel Oil Firing: $\frac{8.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 4.00 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(11.38 \text{ lb/hr} * 6760 \text{ hr/yr}) + (8.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 52.53 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.38 lb/hr for Natural Gas with duct burning 20.13 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 54.22 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hours/yr of Natural Gas-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 8.00 lb/hour 4.00 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: HAPs		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Natural Gas Firing 15.47 tons/year Fuel Oil Firing 2.47 tons/year			4. Synthetically Limited? []
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer/AP-42 Emission Factors			7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Refer to Attachment 2 of SCA PSD Application Appendix 10.7 for full calculations.			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's heat input data and AP-42 emission factors for individual HAPs.			

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:VE20	2. Basis for Allowable Opacity: [X] Rule [] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: 20% Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - Stack testing (USEPA Method 9 Visual Determination of Opacity) - VE limit proposed in lieu of PM/PM ₁₀ pound per hour limit.	
5. Visible Emissions Comment (limit to 200 characters): Florida Air Regulation Rule 62.296	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 6

1. Parameter Code:EM	2. Pollutant(s): NO _x
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
1. Continuous Monitor Comment (limit to 200 characters): Continuous compliance with any emission limitations will be demonstrated through compliance with Rule 62.4.070 and 62-204.800(7), F.A.C. to avoid PSD review. Rule: 40 CFR Part 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code:WTF	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): 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 3 of 6

Continuous Monitoring System: Continuous Monitor 4 of 6

33

Emissions Unit Information Section 1 of 4

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: O ₂	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): 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	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM for opacity will be installed before operation of the emission source. This CEM will be installed on the HRSG stack. Required by 40 CFR Part 75	

**J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)**

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: <u>Attachment D</u> [] Not Applicable [] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: <u>Attachment E</u> [] Not Applicable [] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: <u>SCA BACT Analysis Appendix 10.7, Section 3.0</u>
4. Description of Stack Sampling Facilities [X] Attached, Document ID: <u>Attachment F</u> [] Not Applicable [] Waiver Requested
5. Compliance Test Report [] Attached, Document ID: _____ [] Previously submitted, Date: _____ [X] Not Applicable
6. Procedures for Startup and Shutdown [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
7. Operation and Maintenance Plan [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: <u>SCA PSD Application Appendix 10.7</u>
9. Other Information Required by Rule or Statute [] Attached, Document ID: _____ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [X] Attached, Document ID: <u>Attachment G</u> [] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [] Attached, Document ID: _____ [X] Not Applicable
13. Identification of Additional Applicable Requirements [] Attached, Document ID: _____ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [] Attached, Document ID: _____ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: <u>Attachment H</u> [] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ [] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ [] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ [] Phase II Nox Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ [] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ [] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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.			
2. 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.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator operating in combined cycle (CCCT) mode with one heat recovery steam generator (HRSG) having a nominal rating of 317 MW. The CCCT/HRSG will be capable of firing both natural gas and distillate fuel oil.			
4. Emissions Unit Identification Number: ☐ [] No ID ID: 005 ☐ [] ID Unknown			
5. Emissions Unit Status Code: C	6. Initial Startup Date: 10/01/2003	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters)

The nominal 317 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 is the primary fuel; low sulfur distillate fuel oil is the back up fuel.

Applicant requested emission limitation:

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and duration of excess emission shall be minimized.

Emissions Unit Control Equipment**1. Control Equipment/Method Description (Limit to 200 characters per device or method):**

Dry Low NO_x (DLN) Combustor during Natural Gas firing - Burner technology to control NO_x emissions. This technology uses a two-staged 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.

Water injection during Fuel Oil firing- For Oil firing cases only, this type of control injects water into the primary combustion zone with the fuel. The water serves to reduce NO_x formation by reducing the peak flame temperature.

Selective Catalytic Reduction (SCR)- For both Natural Gas and Oil firing, the SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water.

2. Control Device or Method Code(s): 024, 025, 028, 065**Emissions Unit Details**

1. Package Unit: Combined Cycle Combustion Turbine Generator
 Manufacturer: General Electric
 Model Number: PG 7241 FA

2. Generator Nameplate Rating: 317 MW

3. Incinerator Information: N/A
 Dwell Temperature: °F
 Dwell Time: seconds
 Incinerator Afterburner Temperature: °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	(Natural Gas firing)	2402.0 (HHV)	mmBtu/hr
	(Fuel Oil firing)	2067.6 (HHV)	mmBtu/hr
2. Maximum Incineration Rate:	N/A		
3. Maximum Process or Throughput Rate:	N/A		
4. Maximum Production Rate:	N/A		
5. Requested Maximum Operating Schedule:			
For natural gas:	24 hours/day	7 days/week	
	52 weeks/year	8760 hours/year	
For fuel oil:	24 hours/day	7 days/week	
	52 weeks/year	1000 hours/year	
6. Operating Capacity/Schedule Comment (limit to 200 characters):			
Maximum Heat Input Rate in Field 1 based on: Gas: 19 F, base load, with duct burner on. Performance Data Case 4. Oil: 19 F, base load. Performance Data Case 20. All cases of Natural Gas and Oil firing were considered in these maximums. Maximum hours of operation on Natural Gas is 8760 hrs/yr and 1000 hrs/yr for Fuel Oil.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 005		2. Emission Point Type Code: 2	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): 160-ft vertical cylindrical exhaust stack associated with the combustion turbine and heat recovery steam generator.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 19 feet	
8. Exit Temperature: 287 °F	9. Actual Volumetric Flow Rate: 1280130 acfm	10. Water Vapor: N/A	
11. Maximum Dry Standard Flow Rate: N/A		12. Nonstack Emission Point Height: N/A	
13. Emission Point UTM Coordinates: Zone:17 East (km):483.61 North (km):3151.08			
14. Emission Point Comment (limit to 200 characters): Field 8 based on: Distillate Oil 100% load, 19 F case. Field 9 based on: Distillate Oil 100% load, 19 F case. Stack temperature and flow rate will vary with fuel, load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined cycle mode on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e. 8760 hours).		
1. Source Classification Code (SCC): 2-01-002-01		3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)
4. Maximum Hourly Rate: 2.35	5. Maximum Annual Rate: 20628.94	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = $\frac{2402.0 \text{ mmBtu/hr (HHV)}}{1020 \text{ mmBtu/mmBtu/hr (HHV)}} = 2.35 \text{ mmscf/hr}$ Maximum Annual Rate = $\frac{8760 \text{ hrs/yr} \times 2402.0 \text{ mmBtu/hr}}{1020 \text{ mmBtu/mmBtu/hr}} = 20628.94 \text{ mmscf/yr}$		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined mode on No.2 distillate fuel oil. This unit is allowed to operate on No.2 distillate fuel oil for 1000 hours/yr		
2. Source Classification Code (SCC): 2-01-001-01		3. SCC Units: Thousand gallons burned (all liquid fuel)
4. Maximum Hourly Rate: 14.87	5. Maximum Annual Rate: 14874.82	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
9. Segment Comment (limit to 200 characters): Maximum Hourly Rate = $\frac{2067.6 \text{ mmBtu/hr}}{139 \text{ mmBtu/ thousand gallons}} = 14.87 \text{ thousand gallons/hr}$ Maximum Annual Rate = $\frac{1000 \text{ hrs/yr} \times 2067.6 \text{ mmBtu/hr}}{139 \text{ mmBtu/ thousand gallons}} = 14874.82 \text{ thousand gallons/yr}$		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO _x	024	025, 028, 065	EL
CO			EL
PM/PM ₁₀			EL
SO ₂			EL
VOC			EL
HAPS			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO _x		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual Operation 157.24 tons/year			
Natural Gas Firing 132.58 tons/year			
Fuel Oil Firing 39.85 tons/year			
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(30.38 \text{ lb/hr} * 7760 \text{ hr/yr}) + (29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 132.58 \text{ tons per year}$ Fuel Oil Firing: $\frac{79.69 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 39.85 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(30.38 \text{ lb/hr} * 6760 \text{ hr/yr}) + (79.69 \text{ lb/hr} * 1000 \text{ hr/yr}) + (29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 157.24 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
2. Requested Allowable Emissions and Units: 3.5 ppmvd (at 15% O ₂ for Natural Gas)	4. Equivalent Allowable Emissions: 30.38 lb/hour 133.06 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppmvd (at 15% O ₂ for Fuel Oil)	4. Equivalent Allowable Emissions: 79.69 lb/hour 39.85 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hrs/year of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual Operation	435.05 tons/year		
Natural Gas Firing	448.12 tons/year		
Fuel Oil Firing	35.50 tons/year		
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(97.13 \text{ lb/hr} * 7760 \text{ hr/yr}) + (142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 448.12 \text{ tons per year}$ Fuel Oil Firing: $\frac{71.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 35.50 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(97.13 \text{ lb/hr} * 6760 \text{ hr/yr}) + (71.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 435.05 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 97.13 lb/hr for Natural Gas with duct burning 142.51 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 448.12 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 71.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 71.00 lb/hour 35.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM ₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual	53.63 tons/year		
Natural Gas Firing	50.94 tons/year		
Fuel Oil Firing	8.50 tons/year		
5. Range of Estimated Fugitive Emissions:			
[] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor:		7. Emissions Method Code:	
Reference: Manufacturer		0	
8. Calculation of Emissions (limit to 600 characters):			
Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(11.62 \text{ lb/hr} * 7760 \text{ hr/yr}) + (11.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 50.94 \text{ tons per year}$ Fuel Oil Firing: $\frac{17.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 8.5 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(11.62 \text{ lb/hr} * 6760 \text{ hr/yr}) + (17.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (11.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 53.63 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):			
Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.62 lb/hr for Natural Gas with duct burning 11.71 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 50.94 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 7760 hours/yr of Natural Gas-firing with duct burning and 1000 hours with power augmentation.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 17.00 lb/hour 8.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Emissions based on 1000 hours/yr of Fuel Oil firing. The applicant will assume 20% opacity limit for Fuel Oil firing in lieu of the 17.00 lb/hr PM/PM ₁₀ limit during Fuel Oil-firing.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO ₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual	67.03 tons/year		
Natural Gas Firing	15.28 tons/year		
Fuel Oil Firing	53.50 tons/year		
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(3.50 \text{ lb/hr} * 7760 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 15.28 \text{ tons per year}$ Fuel Oil Firing: $\frac{107.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 53.50 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(3.50 \text{ lb/hr} * 6760 \text{ hr/yr}) + (107.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 67.03 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.50 lb/hour Natural Gas	4. Equivalent Allowable Emissions: 3.50 lb/hour 15.33 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hrs/yr of Natural Gas-firing. Duct burning case is higher than power augmentation case, therefore emissions assumed 8760 hours of CCCT operation with duct burning. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 107.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 107.00 lb/hour 53.50 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions:		4. Synthetically Limited? []	
Annual	52.53 tons/year		
Natural Gas Firing	54.22 tons/year		
Fuel Oil Firing	4.00 tons/year		
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions (using highest hourly emissions based on worst case ambient conditions): CCCT Natural Gas and duct firing (with power augmentation): $\frac{(11.38 \text{ lb/hr} * 7760 \text{ hr/yr}) + (20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 54.22 \text{ tons per year}$ Fuel Oil Firing: $\frac{8.00 \text{ lb/hr} * 1000 \text{ hr/yr}}{2000 \text{ lb/ton}} = 4.00 \text{ tons per year}$ Annual Operation on Natural Gas and Duct Firing Plus Oil Firing (with power augmentation): $\frac{(11.38 \text{ lb/hr} * 6760 \text{ hr/yr}) + (8.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 52.53 \text{ tons per year}$			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.			

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 11.38 lb/hr for Natural Gas with duct burning 20.13 lb/hour for Natural Gas with duct burning and power augmentation	4. Equivalent Allowable Emissions: 54.22 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8760 hours/yr of Natural Gas-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.00 lb/hour for Fuel Oil	4. Equivalent Allowable Emissions: 8.00 lb/hour 4.00 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 1000 hours/yr of Fuel Oil-firing. Expected lb/hr operating limit in forth coming air construction permit. Maximum lb/hr emission rate considering all temperatures and loads.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units –
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: HAPs		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Natural Gas Firing 15.47 tons/year Fuel Oil Firing 2.47 tons/year		4. Synthetically Limited? []	
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year			
6. Emission Factor: Reference: Manufacturer/AP-42 Emission Factors		7. Emissions Method Code: 0	
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Refer to Attachment 2 of SCA PSD Application Appendix 10.7 for full calculations.			
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's heat input data and AP-42 emission factors for individual HAPs.			

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:VE20	2. Basis for Allowable Opacity: [X] Rule [] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: 20% Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - Stack testing (USEPA Method 9 Visual Determination of Opacity) - VE limit proposed in lieu of PM/PM ₁₀ pound per hour limit.	
5. Visible Emissions Comment (limit to 200 characters):	
Florida Air Regulation Rule 62.296	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 6

1. Parameter Code:EM	2. Pollutant(s): NO _x
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
6. Continuous Monitor Comment (limit to 200 characters): Continuous compliance with any emission limitations will be demonstrated through compliance with Rule 62.4.070 and 62-204.800(7), F.A.C. to avoid PSD review. Rule: 40 CFR Part 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code:WTF	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Rule: New Source Performance Standards 40 CFR 60, Subpart GG	

Emissions Unit Information Section 2 of 4

Continuous Monitoring System: Continuous Monitor 3 of 6

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Fuel oil flow monitoring will be operated pursuant of CFR 40 Part 75	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later Serial Number:	
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CEM will be installed before operation of the emission source Natural gas flow monitor will be installed pursuant to CFR 40 Part 75	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: <u>Attachment D</u> [] Not Applicable [] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: <u>Attachment E</u> [] Not Applicable [] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: <u>SCA BACT Analysis Appendix 10.7, Section 3.0</u>
4. Description of Stack Sampling Facilities [X] Attached, Document ID: <u>Attachment F</u> [] Not Applicable [] Waiver Requested
5. Compliance Test Report [] Attached, Document ID: _____ [] Previously submitted, Date: _____ [X] Not Applicable
6. Procedures for Startup and Shutdown [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
7. Operation and Maintenance Plan [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: <u>SCA PSD Application Appendix 10.7</u>
9. Other Information Required by Rule or Statute [] Attached, Document ID: _____ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation ☒ Attached, Document ID: <u>Attachment G</u> ☐ Not Applicable
12. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable
13. Identification of Additional Applicable Requirements ☐ Attached, Document ID: _____ ☒ Not Applicable
14. Compliance Assurance Monitoring Plan ☐ Attached, Document ID: _____ ☒ Not Applicable
15. Acid Rain Part Application (Hard-copy Required) ☒ Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: <u>Attachment H</u> ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ ☐ Phase II Nox Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ ☐ Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ ☐ Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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.			
2. Regulated or Unregulated Emissions Unit? (Check one) ☐ [] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit. ☒ [X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): 10-cell linear mechanical draft cooling tower equipped with drift eliminators for control of PM/PM ₁₀ emissions.			
4. Emissions Unit Identification Number: ☐ [] No ID ID: 006 ☐ [] ID Unknown			
5. Emissions Unit Status Code: C	6. Initial Startup Date: 10/01/2003	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? []
9. Emissions Unit Comment: (Limit to 500 Characters)			

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Drift eliminators

2. Control Device or Method Code(s): 015

Emissions Unit Details

1. Package Unit:		
Manufacturer:		Model Number:
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: N/A		
	Dwell Temperature:	°F
	Dwell Time:	seconds
	Incinerator Afterburner Temperature:	°F

**B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Heat Input Rate:	mmBtu/hr
2. Maximum Incineration Rate:	N/A
3. Maximum Process or Throughput Rate:	125,000 gal/min
4. Maximum Production Rate:	N/A
5. Requested Maximum Operating Schedule:	
	24 hours/day 7 days/week
	52 weeks/year 8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):	
	Maximum process rate (Field 3) is cooling tower water recirculation rate.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 006		2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Cooling tower consists of 10 cells.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 44.7 feet	7. Exit Diameter: 34 feet	
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: N/A	
11. Maximum Dry Standard Flow Rate: N/A		12. Nonstack Emission Point Height: N/A	
13. Emission Point UTM Coordinates: Zone: 17 East (km): 483.50 North (km): 3,151.02			
14. Emission Point Comment (limit to 200 characters): Cooling tower consists of 10 cells with 10 individual exhaust fans. Stack height and diameter provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Cooling tower water recirculation flow rate.		
1. Source Classification Code (SCC): 2-01-002-01		3. SCC Units: Thousand gallons transferred
4. Maximum Hourly Rate: 7500	5. Maximum Annual Rate: 65700000	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM/PM ₁₀	015		NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM ₁₀	2. Total Percent Efficiency of Control:
3. Potential Emissions: 4.6 lb/hr 20.3 tons/year	4. Synthetically Limited? []
5. Range of Estimated Fugitive Emissions: [] 1 [] 2 [] 3 _____ to _____ tons/year	
6. Emission Factor: 4.6 Reference: AP-42, Section 13.4	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): $(125,000 \text{ gal/min}) * (0.002 \text{ gal/100 gal}) * (3704 \text{ lb PM}/10^6 \text{ lb water}) * (8.345 \text{ lb/gal water}) * (60 \text{ min/hr}) = 4.6 \text{ lb/hr}$ $(4.6 \text{ lb/hr}) * (8760 \text{ hr/yr}) * (1 \text{ ton}/2000 \text{ lb}) = 20.3 \text{ tons/yr PM/PM}_{10}$	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emission calculations based on manufacturer's guarantee.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [] Rule [] Other
3. Requested Allowable Opacity: Normal Conditions: Exceptional Conditions: % Maximum Period of Excess Opacity Allowed:	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information: Manufacturer: Model Number:	
5. Installation Date:	Serial Number: 6. Performance Specification Test Date:
6. Continuous Monitor Comment (limit to 200 characters): 	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: <u>Attachment D</u> [] Not Applicable [] Waiver Requested
2. Fuel Analysis or Specification [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: <u>SCA BACT Analysis Appendix 10.7, Section 3.0</u>
4. Description of Stack Sampling Facilities [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
5. Compliance Test Report [] Attached, Document ID: _____ [] Previously submitted, Date: _____ [X] Not Applicable
6. Procedures for Startup and Shutdown [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
7. Operation and Maintenance Plan [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: <u>SCA PSD Application Appendix 10.7</u>
9. Other Information Required by Rule or Statute [] Attached, Document ID: _____ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [☐] Attached, Document ID: _____ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [☐] Attached, Document ID: _____ [X] Not Applicable
13. Identification of Additional Applicable Requirements [☐] Attached, Document ID: _____ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [☐] Attached, Document ID: _____ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [☐] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: _____ [☐] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ [☐] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ [☐] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ [☐] Phase II Nox Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ [☐] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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).			
☒ 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.			
2. Regulated or Unregulated Emissions Unit? (Check one)			
☒ 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.			
3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):			
No. 2 Distillate Fuel Oil Storage Tank (1,680,000 gal).			
4. Emissions Unit Identification Number:			
☐ No ID ID: 007 ☐ ID Unknown			
5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	10/01/2003	49	☐
9. Emissions Unit Comment: (Limit to 500 Characters)			
This distillate fuel oil storage tank (1,680,000 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 vertical fixed roof design.			

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)**Emissions Unit Operating Capacity and Schedule**

1. Maximum Heat Input Rate:	mmBtu/hr	
2. Maximum Incineration Rate:	N/A	
3. Maximum Process or Throughput Rate:	28800	thousand gal/yr
4. Maximum Production Rate:	N/A	
5. Requested Maximum Operating Schedule:		
6. Operating Capacity/Schedule Comment (limit to 200 characters): The maximum throughput rate corresponds to the use of No. 2 distillate fuel oil for 1,000 hours per year.		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? 007		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 feet	
8. Exit Temperature: 70 °F	9. Actual Volumetric Flow Rate: 0 acfm	10. Water Vapor: N/A	
11. Maximum Dry Standard Flow Rate: N/A		12. Nonstack Emission Point Height: 40 feet	
13. Emission Point UTM Coordinates: Zone: 17 East (km): 483.25 North (km): 3,150.93			
14. Emission Point Comment (limit to 200 characters): 			

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): 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).		
1. 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: 1680
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): (1680000 gal stored)/(1000 gal) = 1680 capacity factor		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): 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.		
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: 28800
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
9. Segment Comment (limit to 200 characters): (28800000 gal of fuel oil consumed by the turbines per year)/(1000 gal) = 28800 gal/yr		

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions:	4. Synthetically Limited? ☐ ☐
5. Range of Estimated Fugitive Emissions: ☐ ☐ 1 ☐ ☐ 2 ☐ ☐ 3 _____ to _____ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5 (EPA TANKS Program)
8. Calculation of Emissions (limit to 600 characters): 	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): 	

Emissions Unit Information Section 4 of 4

Pollutant Detail Information Page 1 of 1

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: N/A
2. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): As specified in 40 CFR 60.116(a) and (b), Subpart Kb	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Rule: 40 CFR 60.Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [] Rule [] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information: Manufacturer: Model Number:	
5. Installation Date:	Serial Number:
6. Continuous Monitor Comment (limit to 200 characters):	6. Performance Specification Test Date:

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: <u>Attachment D</u> [] Not Applicable [] Waiver Requested
2. Fuel Analysis or Specification [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
3. Detailed Description of Control Equipment [] Attached, Document ID: _____
4. Description of Stack Sampling Facilities [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
5. Compliance Test Report [] Attached, Document ID: _____ [] Previously submitted, Date: _____ [X] Not Applicable
6. Procedures for Startup and Shutdown [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
7. Operation and Maintenance Plan [] Attached, Document ID: _____ [X] Not Applicable [] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: <u>Attachment I</u>
9. Other Information Required by Rule or Statute [] Attached, Document ID: _____ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☒ Not Applicable
12. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable
13. Identification of Additional Applicable Requirements ☐ Attached, Document ID: _____ ☒ Not Applicable
14. Compliance Assurance Monitoring Plan ☐ Attached, Document ID: _____ ☒ Not Applicable
15. Acid Rain Part Application (Hard-copy Required) ☐ Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: _____ ☐ Phase II Nox Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID: _____ ☐ Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID: _____ ☒ Not Applicable

Attachment A
Applicable 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 GG – Standards of Performance for Stationary Gas Turbines

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

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

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 Designed Representative

Section 72.23 – Changing the Seignated 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

Section 72.33 – Identification if 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 Board

Section 72.64 – Statement of Basis

Section 72.65 – Public Notice of Opportunities for Public Comment

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 72.71 – Approval of State Programs – General

Section 72.72 – State Permit Program Approval Criteria

Section 72.73 – State Issue 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

Section 72.83 – Administrative Permit Amendment

Section 72.84 – Automatic Permit Amendment

Section 72.85 – Permit Reopening

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 – Sulfur 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

Section 73.11 – Revision of Allocations

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

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 – Segregation 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

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 Capacity

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

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 – Timeliness 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

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 – Capacity 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

Section 76.5 – NO_x Emission Limitations for Group 1 Boilers

Section 76.6 – NO_x Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 – Revised NO_x 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 NO_x 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

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

62-214.330 – Acid Rain Compliance Plan and Compliance Options

62-214.350 – Certification

62-214.370 – Revisions Administration 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

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

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

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

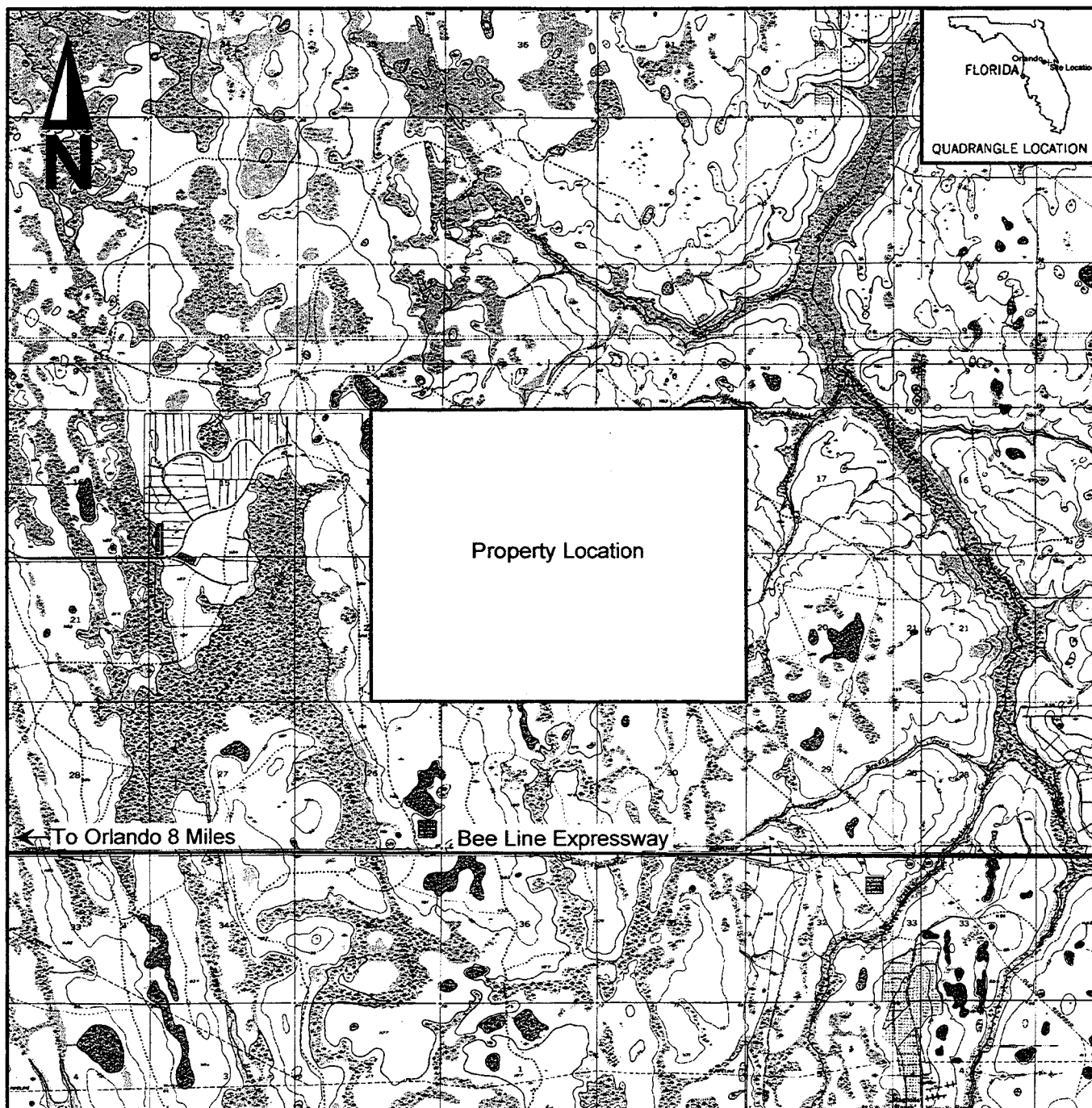
Subpart E – Alternative Monitoring Systems

Subpart 75.40 – General Demonstration Requirements

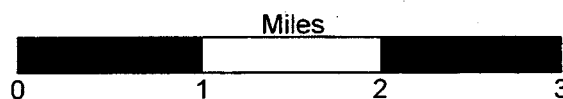
**1,680,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements**

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, 1994.
40 CFR 60.116b, Monitoring of Operations	The owner or 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 B
Area Map Showing Facility Location



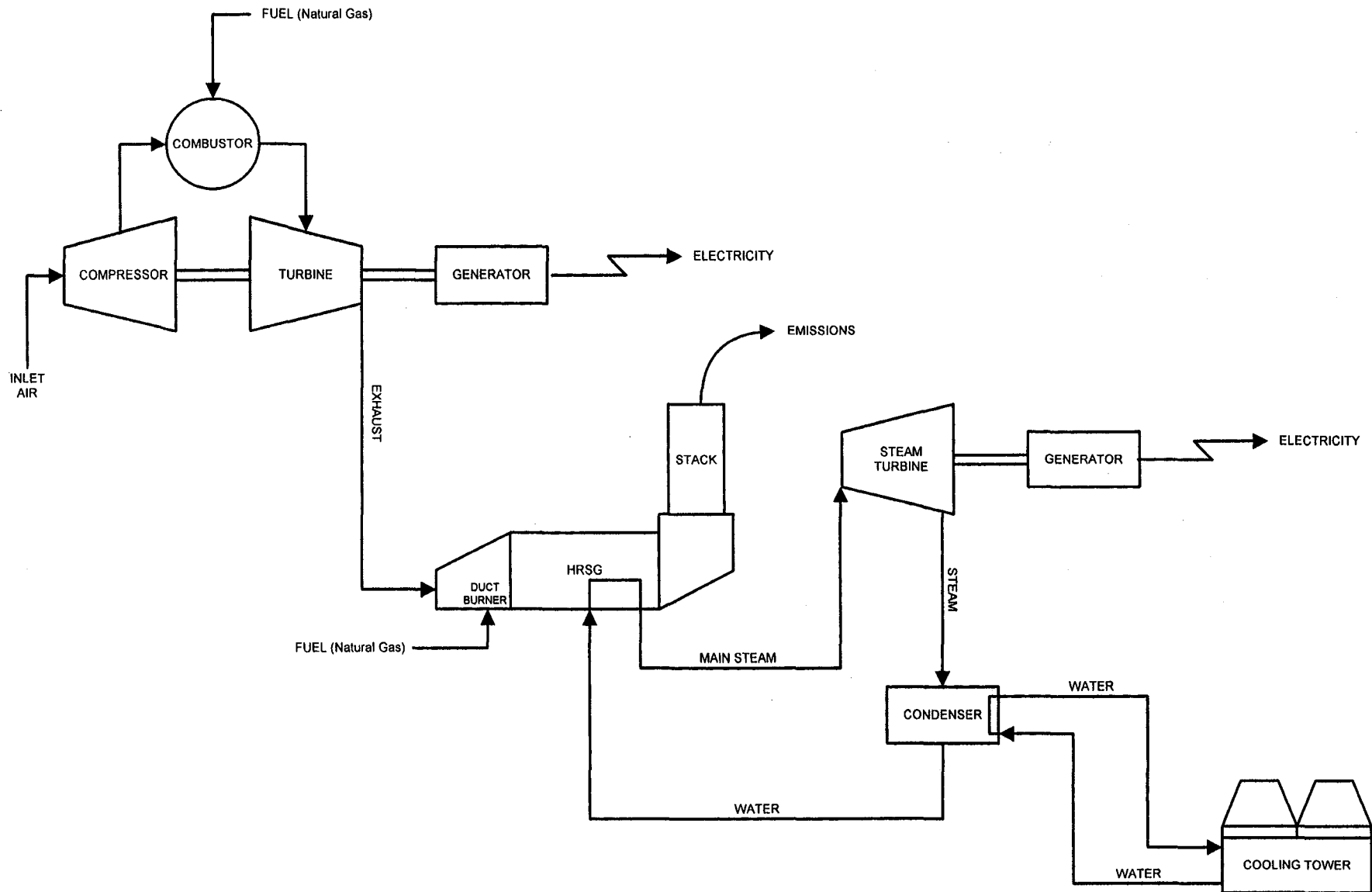
Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)



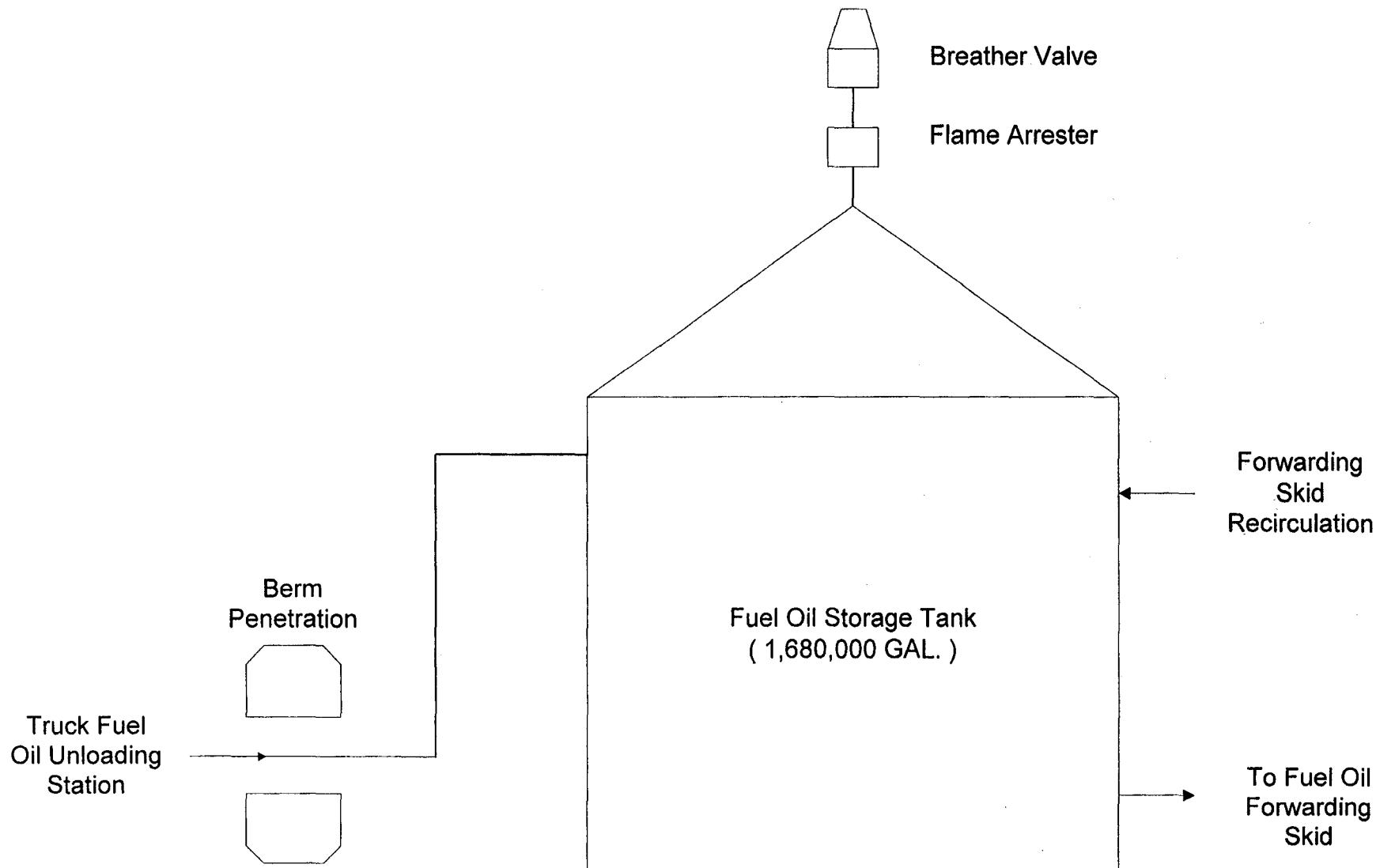
Stanton Energy Center Property Location

Attachment C
Facility Plot Plan

Attachment D
Process Flow Diagram



Combined Cycle Combustion Turbine
Process Flow Diagram



Attachment E
Fuel Analysis

The primary fuel for the Project is natural gas and the backup fuel is low sulfur (0.05 percent) No. 2 fuel oil. Operation on oil is proposed to be limited to 1,000 hours per year, per unit. Tables E-1 and E-2 present typical property values for the primary and backup fuels, respectively.

Table E-1
Natural Gas Properties

Parameter	Mole, percent	Gal/Mcf**	Btu*	Rel Den*
C6+	0.075	0.029	60.0	0.00015
Propane	0.665	0.182	342.0	0.00077
I-Butane	0.152	0.049	101.0	0.00023
N-Butane	0.130	0.041	87.0	0.00020
I-Pentane	0.040	0.015	33.0	0.00008
N-Pentane	0.020	0.007	16.0	0.00004
Nitrogen	0.309	0.000	0.0	0.00023
Methane	95.067	0.000	1,9209.0	0.04006
CO ₂	0.881	0.000	0.0	0.00102
Ethane	2.661	0.708	957.0	0.00210
Totals	100.0	1.031	2,0798.0	0.04488
*The component C6+ is assumed to be C6H6 only.				
**The density for each component is evaluated under a pressure of 14.64 psia.				

Table E-2
Typical No. 2 Fuel Oil Properties

Parameter	Value
Ash Content, percent wt	0.001
Sulfur Content by XRF, percent wt	<0.05
Water Content KF, percent wt	<0.50 percent
Density, kg/l at 15 C	0.8422
Gross Heat Value, Btu/gal	138,000
Net Heat Value, Btu/gal	129,575
Gross Heat Value, Btu/lb	19,756
Net Heat Value, Btu/lb	18,550
Arsenic, ppm	<0.05
Beryllium, ppm	<0.05
Mercury, ppm	<0.05
Lead, ppm	0.07

Attachment F
Stack Sampling Facilities

The stack sampling facilities will be installed in accordance with Rule 62-297 310 (6).

Attachment G
Operating Matrix

Table 1
Combustion Turbine Operating Scenarios

Natural Gas							
Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Power Augmentation	Duct Burner
1	19	100	X	X			
2	19	75	X	X			
3	19	50	X	X			
4	19	100	X	X			X
5	45	100	X	X			
6	45	75	X	X			
7	45	50	X	X			
8	45	100	X	X			X
9	60	100	X	X	X	X	X
10	70	100	X	X	X		
11	70	75	X	X			
12	70	50	X	X			
13	70	100	X	X	X		X
14	95	100	X	X	X		
15	95	75	X	X			
16	95	50	X	X			
17	95	100	X	X	X	X	X
18	95	100	X	X	X	X	X
19	95	100	X	X	X		X
Distillate Fuel Oil							
20	19	100	X	X			
21	19	75	X	X			
22	19	50	X	X			
23	45	100	X	X			
24	70	100	X	X	X		
25	95	100	X	X	X		

Attachment H
Acid Rain Permit Application

Will be submitted by a Orlando Utility Commission, Kissimmee Utility Authority,
Florida Municipal Power Authority, and Southern Company – Florida, LLC designated
representative.

Attachment I
TANKS Calculation

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	007
City:	Pensacola
State:	Florida
Company:	OUC
Type of Tank:	Vertical Fixed Roof Tank
Description:	Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft):	40.00
Diameter (ft):	82.23
Liquid Height (ft):	38.50
Avg. Liquid Height (ft):	19.25
Volume (gallons):	1,680,000.00
Turnovers:	17.14
Net Throughput (gal/yr):	28,800,000.00
Is Tank Heated (y/n):	N

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):	43.12

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Orlando, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

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	74.32	68.84	79.80	72.34	0.0103	0.0086	0.0122	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0

Emissions Report - Detail Format

Detail Calculations (AP-42)

Annual Emission Calculations	
Standing Losses (lb):	633.8478
Vapor Space Volume (cu ft):	204,547.5111
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9795
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	204,547.5111
Tank Diameter (ft):	82.2300
Vapor Space Outage (ft):	38.5162
Tank Shell Height (ft):	40.0000
Average Liquid Height (ft):	19.2500
Roof Outage (ft):	17.7662
Roof Outage (Dome Roof)	
Roof Outage (ft):	17.7662
Dome Radius (ft):	43.1150
Shell Radius (ft):	41.1150
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Daily Avg. Liquid Surface Temp. (deg. R):	533.9945
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cu ft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0067
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sq ft day):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.9205
Daily Vapor Pressure Range (psia):	0.0035
Breather Vent Press. Setting Range (psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg R):	533.9945
Daily Min. Liquid Surface Temp. (deg R):	528.5143
Daily Max. Liquid Surface Temp. (deg R):	539.4746
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9795
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Space Outage (ft):	38.5162
Working Losses (lb):	915.1126

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	0.0103
Annual Net Throughput (gal/yr.):	28,800,000.00
	00
Annual Turnovers:	17.1400
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,680,000.000
	0
Maximum Liquid Height (ft):	38.5000
Tank Diameter (ft):	82.2300
Working Loss Product Factor:	1.0000
 Total Losses (lb):	 1,548.9604

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)		Total Emissions
	Working Loss	Breathing Loss	
Distillate fuel oil no. 2	915.11	633.85	1,548.96