HARDEE
POWER
STATION

SITE CERTIFICATION APPLICATION/ ENVIRONMENTAL ASSESSMENT

CHAPTER 3

THE PLANT AND DIRECTLY ASSOCIATED FACILITIES

CHAPTER 3

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3.0 THE PLANT AND DIRECTLY ASSOCIATED FACILITIES

3.1 BACKGROUND

The Hardee Power Station is proposed to consist of a combined cycle power plant and directly associated facilities. The combined cycle facility will be constructed in modular units that will consist of combustion turbines and associated electric generator, and heat recovery steam generators (HRSG). The HRSG will utilize the waste heat from the combustion turbines to generate steam for producing additional electricity in a steam turbine. Each unit (Figure 3.1-1) will have a nominal generating capacity of 220 MW (net) and would consist of two combustion turbines and associated electric generators, two HRSGs and one steam electric generator.

By utilizing the otherwise wasted heat from the combustion turbines, the combined cycle plant will be more efficient than either simple cycle combustion turbines or steam cycle power plants. The use of modular unit configuration provides flexibility in adding plant capacity. Directly associated facilities would include: switchyard, water treatment building, administrative building, fuel oil unloading and storage facilities, warehouse and cooling reservoir.

Site certification is being sought for an ultimate capacity of 660 MW (nominal net); however, the facility will be constructed in phases (Figure 3.1-1). Phase 1-A will consist of a 295 MW capacity facility, which will be placed in operation in January 1993. The Phase 1-A facility will consist of a nominal 220 MW combined cycle unit and a stand-alone combustion turbine. Phase 1-B will add 145 MW of generating capacity through the addition of a combustion turbine, two HRSGs and one steam electric generator. The expected service date for Phase 1-B is 2003. Phases 1-A and 1-B will result in two 220 MW combined cycle units. Phase 2 will consist of a third 220 MW unit to be added at an unspecified future date.

The combustion turbines would be capable of both combined cycle and simple cycle operation; the latter is possible by using by-pass stacks. It is anticipated that the combustion turbines will use natural gas as the primary fuel and distillate oil as the backup fuel. Gas will be transported to the

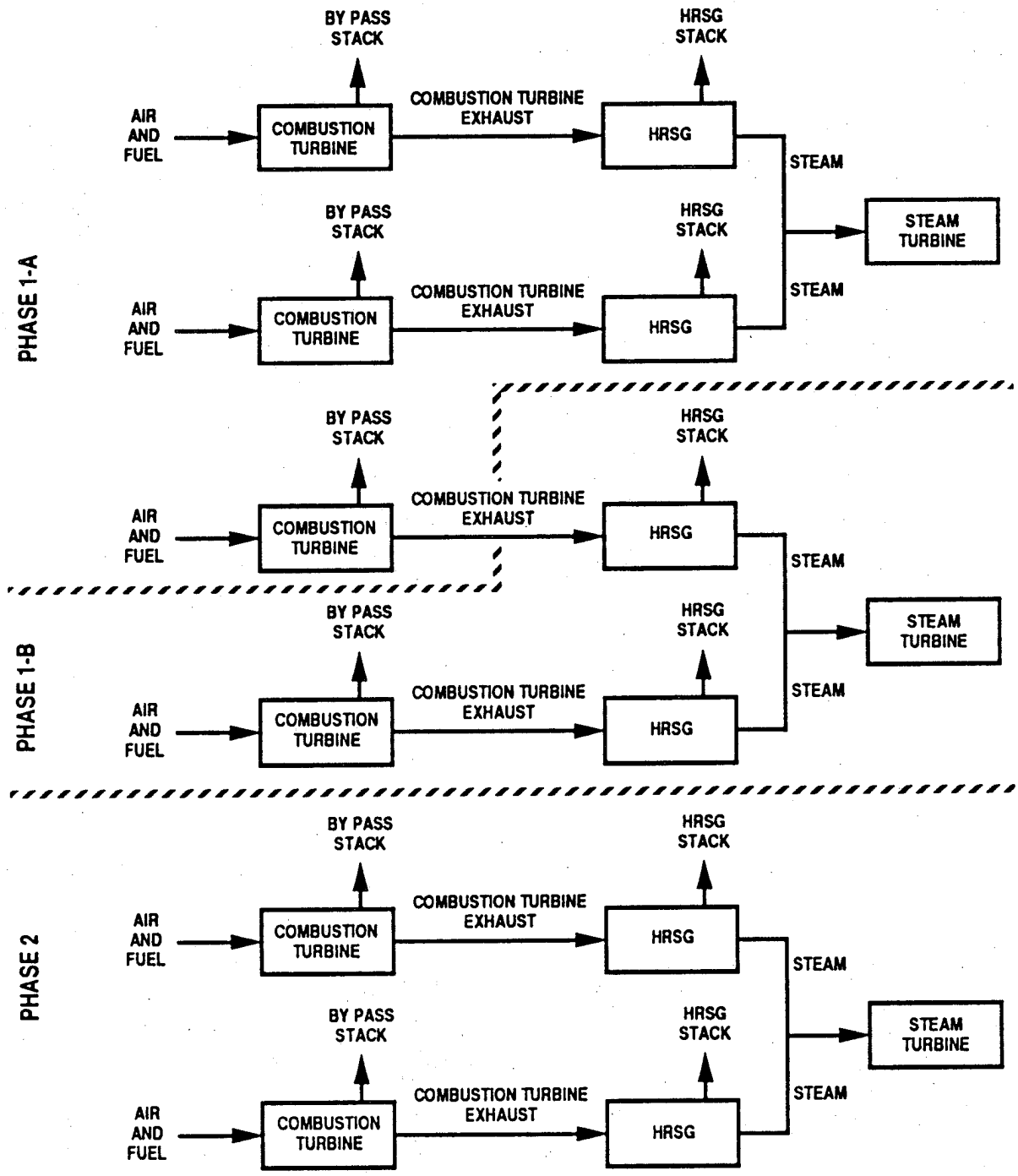

Figure 3.1-1 SIMPLIFIED FLOW DIAGRAM OF HARDEE POWER STATION

Hardee Power Station

site via pipeline while oil will be trucked and/or piped to the site. The natural gas pipeline [48 centimeters (18 inches)] will connect the plant to Florida Gas Transmission (FGT) system at a location north of Polk City. An 8-inch liquid fuels pipeline, which will originate from Port Manatee, will supply distillate oil when completed.

Primary water uses will be for makeup to the 231 ha (570 acres) cooling reservoir, air pollution control and steam cycle makeup. The cooling reservoir will be constructed from reclaimed phosphate lands that are adjacent to the power plant facilities. This cooling option provides an alternative use of previously impacted lands and provides for the reclamation of existing mining operations (refer to Section 8.2.1 for further details on alternative designs). Circulating water lines will be connected to the cooling reservoir by intake and discharge structures. Wells in the Floridan Aquifer will supply plant makeup water.

Air pollution emission control will consist of water injection in the combustion turbines for nitrogen oxides (NO_x) control. This design alternative minimizes air pollutant emissions and minimizes economic, environmental and energy impacts [refer to Section 3.4 for the analysis of Best Available Control Technology (BACT)].

The facility has been designed to eliminate direct discharge to surface waters. Stormwater runoff from non-equipment areas will be collected and routed to a stormwater detention pond which has been designed to meet Southwest Florida Water Management District (SWFWMD) requirements. All wastewaters such as plant water pretreatment backwash water, sanitary treatment system wastewater, plant and equipment drains and neutralization basin effluent, will be treated, as appropriate, and routed to the cooling reservoir. The cooling reservoir will be constructed with a spillway to route excess water resulting from extremely significant rainfall events to Payne Creek. Such events are expected to occur less than one time in ten years.

Associated linear facilities include the natural gas pipeline, a liquid fuels pipeline from Port Manatee and approximately 64 km (40 miles) of 230 kV transmission line that will connect the plant to existing distribution systems (refer to Chapter 6, which presents design, location and environmental impact information on the transmission line, the gas pipeline and the liquid fuels pipeline).

3.2 SITE LAYOUT

The proposed layout for Phase 1-A (i.e., 295 MW) of the Hardee Power Station site is presented in Figure 3.2-1. The power plant and associated facilities will be located on 510 ha (1,259 acres). Power plant facilities, not including the cooling reservoir, occupy approximately 40 ha (100 acres) of the site. The facilities and their approximate areas, at the ultimate site capacity (i.e., 660 MW), are:

Power Block	3 ha - (7 acres)
Switchyard	2 ha - (6 acres)
Water Treatment Building	0.2 ha - (0.5 acres)
Administration Building	0.1 ha - (0.3 acres)
Fuel Oil Storage Tank & Containment	0.8 ha - (2 acres)
Warehouse	1 ha - (3 acres)
Site Runoff Detention Pond	2 ha - (6 acres)
Cooling Reservoir	230 ha - (570 acres)
Construction Offices	0.8 ha - (2 acres)
Construction Lay Down	3 ha - (8 acres)

A profile of the new facilities is shown in Figure 3.2-2, with elevations and dimensions presented in Table 3.2-1. The elevations and dimensions are preliminary and may change as detailed engineering design proceeds.

The location of discharge to surface waters, i.e., Payne Creek, are at the cooling reservoir and site runoff detention pond (see Figure 3.2-1). As previously stated, discharges will be infrequent.

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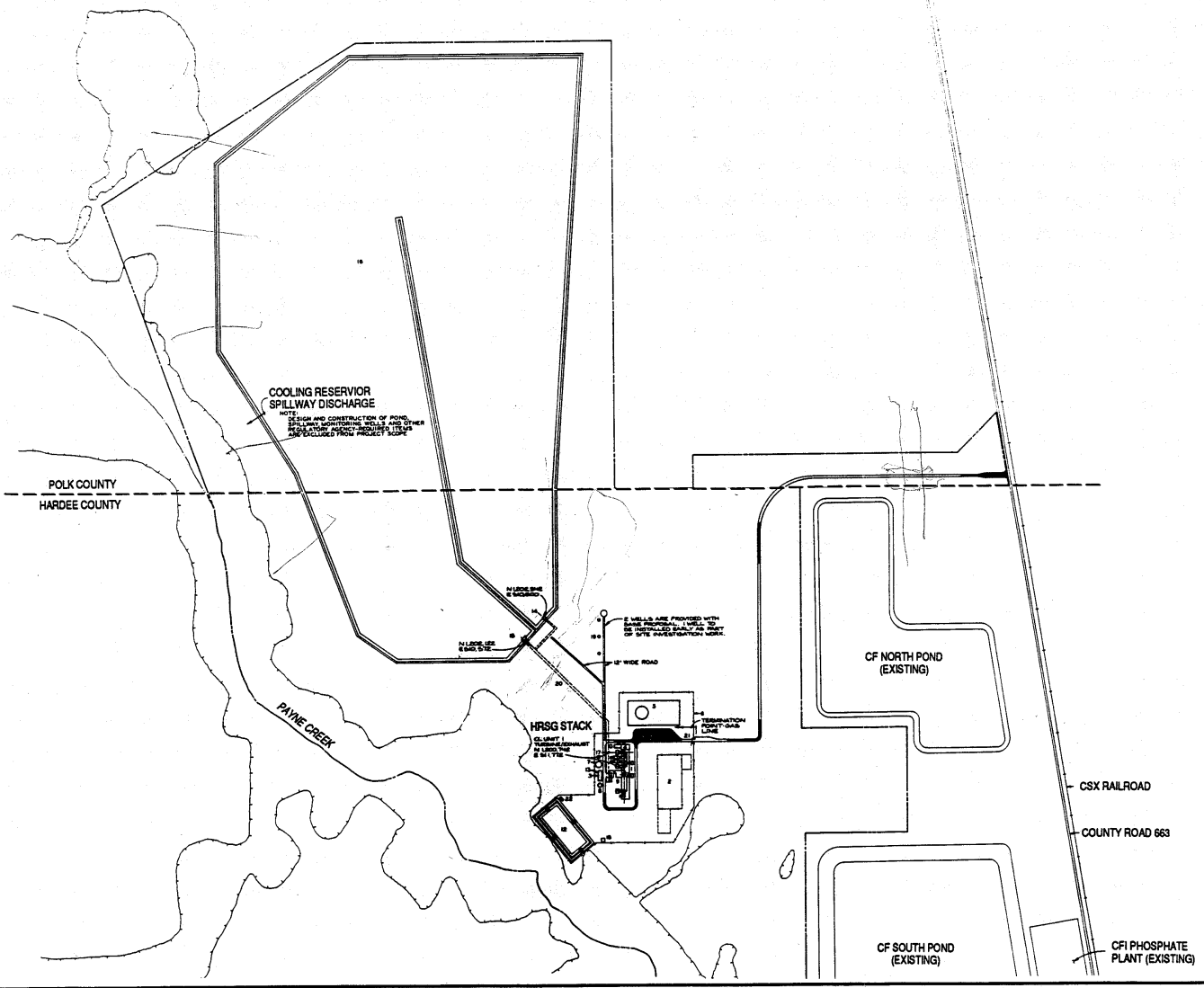


BUILDING AND FACILITIES LEGEND	
NO.	NOMENCLATURE
1	POWER BLOCK
2	SWITCHYARD
3	WATER TREATMENT BUILDING
4	SERVICE BUILDING
5	FUEL OIL STORAGE TANK W/CONTAINMENT WALL
6	SECURITY FENCE
7	DEMINERALIZED WATER STORAGE TANK
8	RAW WATER STORAGE TANK
9	CONTROL BUILDING
10	WAREHOUSE
11	FUEL OIL UNLOADING STATION
12	SITE RUNOFF DETENTION POND
13	NEUTRALIZATION BASIN
14	DISCHARGE STRUCTURE
15	INTAKE STRUCTURE
16	COOLING RESERVOIR
17	PLANT WASTEWATER SUMP/OIL SEPARATOR
18	SEWAGE TREATMENT PLANT
19	WATER SUPPLY WELL
20	PIPING CORRIDOR
21	MOTORIZED GATE
22	STORMWATER PUMP PIT

PROPERTY LINE
FUTURE

North 0 400 800 1200 Feet

Figure 3.2-1 PROPOSED HARDEE POWER STATION SITE LAYOUT FOR PHASE 1-A (i.e., 295 MW)

Hardee Power Station

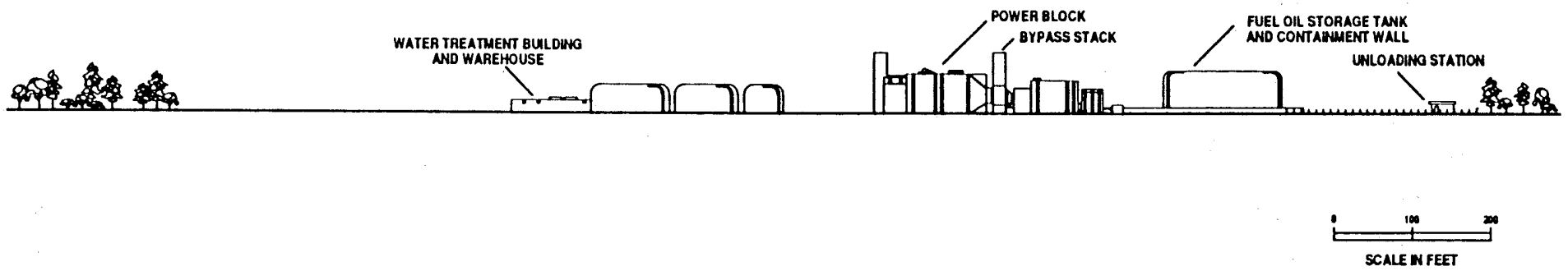


Figure 3.2-2 CONCEPTUAL PROFILE OF HARDEE POWER STATION

Hardee Power Station

Table 3.2-1. Approximate Elevations and Dimensions of Major Plant Facilities for the Hardee Power Station*

Facility+	Elevation** (feet)	Length (feet)	Width (feet)
Combustion Turbine Enclosure (6)	30	110	30
By-Pass Stack (6)	75	15	15
Inlet Air Filter (6)	40	45	30
HRSG (6)	55	50	25
HRSG Stack (6)	90	--	14.5++
Steam Turbine (6)	45	80	40
Raw Water Tank (2)	43	--	48++
Demineralizer Tank (2)	48	--	64++
Condensate Tank	43	--	22++
Fuel Oil Storage Tank (3) (4.4 million gallons)	40	--	140++

Note: Air quality impact analyses were performed using worst cast facility dimensions and HRSG stack height; refer to Table 5.6.1-5 and the PSD application (Appendix 11.1.4) for further information.

* For 660 MW facility.
\+ Number in parenthesis shows the maximum number of each facility.
** Above ground surface.
++ Diameter.

Air pollutants will be emitted from a stack associated with each HRSG exhaust and each combustion turbine bypass stack. The latter would only be operated when the HRSG and associated steam cycle are not in operation, or when simple cycle operation is desired.

3.3 FUEL

The primary fuel used by the combustion turbines will be natural gas, piped to the plant. Typical properties of pipeline grade natural gas are shown in Table 3.3-1. The heat content is typically 20,870 Btu/lb (LHV) with a maximum sulfur content of 20 grains per 100 standard cubic foot (SCF) of gas. The secondary fuel will be distillate fuel oil, furnished to the plant by truck deliveries and/or through a liquid fuels pipeline. Typical properties of the fuel oil are shown in Table 3.3-2. The fuel oil will have a heat content of 17,870 Btu/LB (LHV) with a maximum sulfur content of 0.5%.

No storage will be provided for natural gas. Fuel oil will be stored onsite in one 4.4 million gallon steel storage tank. As part of the oil storage and delivery system, berms and special drainage will be provided. Oily wastewater will be routed to oil separation equipment included with the site drainage system.

The combustion turbines will also be capable of burning synthetic gas derived from coal gasification. The plant site could accommodate the possible future addition of coal gasification facilities, which would include a gasifier, gas cleanup equipment, and coal handling and storage systems. Although a coal gasification facility is not being proposed, a discussion of coal gasification alternatives and the site capability to accommodate such facilities is presented in Section 8.3.

The generating capacity of a combined cycle plant is affected by ambient temperature, with increased temperature resulting in less electric output. Greater fuel consumption will occur at lower ambient temperatures. For the purpose of calculating maximum fuel use quantities, the following operating conditions for the combustion turbine were used:

Table 3.3-1. Typical Natural Gas Specification*

Constituents, Percent by Volume	
Hydrogen (H_2)	--
Methane (CH_4)	83.40
Ethylene (C_2H_4)	--
Ethane (C_2H_6)	15.80
Carbon Monoxide (CO)	--
Carbon Dioxide (CO_2), max.	2.0
Nitrogen (N_2)	0.80
Oxygen (O_2), max.	0.40
Hydrogen Sulfide (H_2S), MAX.	1 grain/100 SCF
Water (H_2O) Vapor, max.	4 lb/10^6 SCF
Synthetic Lubricants (Phosphate-Ester Based)	Trace
Specific Gravity (relative to air)	0.636
Ultimate, Percent by Weight	
Sulfur (S), max.	20 grains/100 SCF
Hydrogen (H_2)	23.53
Carbon (C)	75.25
Nitrogen (N_2)	1.22
Oxygen (O_2)	--
Btu/ft^3 @ 60 F and 30 inches HgA (HHV)	950 (min) - 1129
Btu/lb of Fuel (HHV)	23,170
(LHV)	20,870

* Pipeline grade.

Table 3.3-2. Typical Distillate Fuel Oil Specification*

Specific gravity, 60°F	0.82 - 0.86
Viscosity, cSt, 100°F, min.	0.5
Pour point, max, °F	0
Gross heating value, kcal/kg	10,500 - 10,950
Gross heating value, Btu/lb	19,000 - 19,600
Filterable dirt, mg/100 ml	4
Carbon residue (10% Bottoms), %, max.	0.25
Carbon residue (100% Sample), %, max.	1.0
Sulfur, %, maximum	0.5
Nitrogen, %	0.005 - 0.015
Hydrogen, %	12.2 - 13.2
Ash (fuel as delivered), ppm, max.	50
Trace metal contaminants (untreated)	
Sodium plus potassium, ppm, max.	1
Vanadium, ppm, max.	0.5
Lead, ppm, max.	1
Calcium, ppm, max.	2

* Specification is typical of American Society of Testing and Materials (ASTM) Grade of No. 2 (ASTM D-398).

- o 32°F dry bulb ambient temperature
- o 80% relative humidity
- o 125 ft mean sea level (MSL) elevation
- o 4 inches H_2O inlet pressure drop
- o 42 ppmvd (at 15% O_2) NO_x emission level when firing natural gas
- o 65 ppmvd (at 15% O_2) NO_x emission level when firing distillate fuel oil
- o 20,870 Btu/lb heating value (LHV) of natural gas
- o 17,870 Btu/lb heating value (LHV) of distillate fuel oil.

At these conditions the maximum heat input, for the nominal 660 MW facility, is 6,342 and 6,562 million Btu/hr when firing natural gas and distillate fuel oil, respectively.

The corresponding maximum fuel use is 303,900 lb/hr of natural gas and 367,180 lb/hr of distillate fuel oil.

3.4 AIR EMISSIONS AND CONTROLS

3.4.1 Air Emissions Types and Sources

Air pollutant emissions will be emitted from the combustion turbines when firing either natural gas or fuel oil. Emissions will emanate from either the by-pass or HRSG stack.

The types of emissions result from either the combustion process itself or impurities in the fuel. Table 3.4.1-1 presents the maximum estimated emission rates of regulated pollutants. The maximum estimated emission rates were determined using manufacturers' information for the equipment being considered for the project. Those design parameters which produced the maximum emission for each combustion turbine were used to produce a conservative design envelope for the plant. The Prevention of Significant Deterioration (PSD) application (see Appendix 11.1.4) presents the basis for the emission rates and maximum annual emissions of regulated and non-regulated pollutants.

Table 3.4.1-1. Maximum Estimated Air Pollutant Emissions from the Hardee Power Station

Pollutant	Fuel	Maximum Emission Rate* (lb/hr)
Particulate/PM 10	Gas	6.3
	Oil	57.1
Sulfur Dioxide	Gas	35.8
	Oil	734.4
Nitrogen Oxides	Gas	215.9
	Oil	383.8
Carbon Monoxide	Gas	128.3
	Oil	46.7
Volatile Organic Compounds	Gas	17.9
	Oil	20.5
Lead	Gas	negligible
	Oil	0.0117
Fluorides	Gas	negligible
	Oil	0.0427
Sulfuric Acid Mist	Gas	1.6
	Oil	33.7
Mercury	Gas	0.0144
	Oil	0.0039
Beryllium	Gas	negligible
	Oil	0.0033
Inorganic Arsenic	Gas	negligible
	Oil	0.0055

Notes: Refer to prevention of significant deterioration (PSD) application contained in Appendix 11.1.4 for bases for emission rates.

* Based on 32°F operating conditions for one combustion turbine.

The largest quantities of potential emissions when firing natural gas are NO_x and carbon monoxide (CO). When firing fuel oil the largest quantities emitted are NO_x and sulfur dioxide (SO_2).

During combustion, two types of NO_x are formed: fuel NO_x and thermal NO_x. Fuel NO_x emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_x emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. Nitrogen oxides formation can be limited by lowering combustion temperatures (through water or steam injection) and/or staging combustion (a reducing atmosphere followed by an oxidizing atmosphere).

Carbon monoxide is formed by incomplete combustion of the fuel. High combustion temperatures, adequate excess air and good fuel/air mixing during combustion will minimize CO emissions. Carbon monoxide formation is limited by ensuring complete efficient combustion of the fuel in the turbines. Therefore, staging combustion and lowering combustion temperatures for NO_x emissions control can be counterproductive with regard to CO emissions.

Emissions of NO_x are proposed at concentrations of 42 ppm and 65 ppm corrected to 15% oxygen (O_2), dry conditions, for natural gas and fuel oil firing, respectively. Maximum estimated NO_x emissions for fuel oil firing are based on a maximum fuel bound nitrogen concentration of 0.015%; higher fuel bound nitrogen concentrations would concomitantly increase NO_x emissions. At a fuel bound nitrogen concentration of 0.05%, NOx would increase to about 77 ppm (corrected conditions).

Emission rates of CO were established by the level of NO_x control, since wet injection, the proposed control technique, affects the combustion process. Maximum emission rates for the project would be 41 ppm and 13 ppm (corrected to 15% O_2, dry conditions), respectively for natural gas and fuel oil firing.

Maximum SO_2 emission rates are dictated by the amount of sulfur in the fuels.

3.4.2 Air Emission Controls

The use of clean fuels, i.e. natural gas and No. 2 fuel oil, and combustion controls will be used to minimize air emissions and comply with applicable emission limiting standards. Using clean fuels will minimize emissions of SO_2, particulate matter/PM10 and other fuel bound contaminants. Combustion controls will minimize the formation of NO_x, by water injection, and the formation of CO and volatile organic compounds (VOC) by combustor design. These techniques are proposed as Best Available Control Technology (BACT) for this project based on an evaluation of economic, energy and environmental impacts. The following subsection presents a summary of the BACT analysis.

3.4.3 Best Available Control Technology (BACT)

Emissions of NO_x, CO, VOC, SO_2, particulate matter/PM10, beryllium, mercury, inorganic arsenic (As) and sulfuric acid mist are subject to BACT review. The pollutant specific applicability is discussed in detail in Chapter 3 of the PSD application which is contained in Appendix 11.1.4. Under the federal Clean Air Act (CAA), BACT represents the maximum degree of pollutant reduction determined on a case-by-case basis after consideration of energy, environmental, and economic factors. However, BACT cannot be less stringent than the emission limits established by any applicable new source performance standard (NSPS).

3.4.3.1 Nitrogen Oxides

The alternative for obtaining the maximum amount of control for NO_x emissions from combustion turbines is wet injection in combustor combined with selective catalytic reduction (SCR) in the HRSG. Wet injection alone provides the next greatest level of control. These control techniques were evaluated in the BACT analysis.

SCR is a post combustion method for control of NO_x emissions. In the SCR process, vaporized ammonia is reacted with NO_x in the presence of a catalyst

to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The reaction takes place between 600 and 700°F and to achieve these conditions the catalyst must be placed in the HRSG.

The economic, environmental and energy impacts of installing SCR with wet injection were determined for the BACT analysis based on an exhaust concentration of 9 ppm when firing natural gas and 14 ppm when firing fuel oil (concentrations corrected to 15% O_2 dry conditions). These exhaust concentrations represent 80% NO_x removal and are the lowest concentrations being established as BACT for large combustion turbines.

SCR with wet injection was rejected as BACT based on technical considerations as well as significant economic and environmental impacts. SCR has not been technically demonstrated on simple cycle operation, cycling combustion turbines or combined cycle plants firing fuel oil. Proven and dependable equipment and technology are requirements of the Hardee Power Station and are necessary to provide reliable, on-demand, electric power.

Exhaust temperatures from combustion turbines (about 1000°F) are much higher than that required for reacting NH_3 and NO_x. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. When operating in simple cycle mode, i.e., using the by-pass stack, SCR operation is therefore not feasible.

SCR has only been installed on base loaded, natural gas fired, combined cycle co-generation facilities; experience with facilities that perform cycling duty, which is projected for the Hardee Power Station, is limited. Cycling the combustion turbines will cause variable exhaust conditions, i.e., temperature and flow, which can damage the catalyst. Operation under such variable conditions will require frequent catalyst replacement and significantly increase the cost of SCR.

When firing fuel oil, the sulfur and other trace constituents in the gas stream will poison the catalyst during prolonged operation. Experience with

fuel oil firing has found significant catalyst damage occurring after only about 500 hours of operation. To resolve these problems, operational limits on oil firing have been recommended by catalyst manufacturers and have been allowed by permit conditions.

Economic impacts of installing SCR would be significant as demonstrated by the capital and annual costs for an SCR system installed for a 660 MW plant. An SCR system would add approximately $57.0 million (1993 dollars) to the capital cost and $22 million to the annual cost of the 660 MW plant. Capital costs for the selective catalytic reduction system include catalytic reactors, ammonia additive injection system, balance of plant costs, and incremental turbine costs. Annual costs include fixed charges on capital investment, operating personnel, maintenance, ammonia additive, spent catalyst replacement, and steam and electric energy.

The levelized annual cost difference for an SCR System as compared to the next level of control, i.e., an improved combustor design, is about $16.8 million and results in an incremental removal cost of between $4,600 and $8,250 per additional ton of NO_x reduction. The energy requirements of the SCR system would reduce the output of the combustion turbines by approximately 1%.

The use of an SCR system would result in a negative environmental impact by releasing significant quantities of unreacted ammonia to the atmosphere. This is due to reaction rate inefficiencies resulting in NH_3 exhaust concentrations of up to 50 ppm which have been reported from SCR systems. In addition, catalytic elements are toxic. Because they have to be replaced periodically, hazardous waste disposal procedures must be followed. Environmental benefits from installing SCR are small since the predicted impacts are much less than the PSD increment and AAQS.

SCR is the only effective post combustion NO_x reduction alternative control technology available. The temperatures at the outlet of a combustion turbine are too low (1,000°F) for selective non-catalytic reduction systems (Thermal $DeNO_x$). A Thermal $DeNO_x$ system requires gas temperatures of at

least 1,500°F for NO_x reduction. Since this would require supplemental heating of the flue gas, thereby increasing total emissions from the plant due to increased fuel usage, this alternative was judged unacceptable for application on a combined cycle facility.

WET INJECTION

Use of water or steam injection in the combustion zones of a combustion turbine can limit the amount of NO_x formed. Thermal NO_x formation is minimized by lowering combustion temperatures through the water or steam injection. Water injection into the combustor will be used for this project. The degree of reduction in NO_x formation is somewhat proportional to the amount of water injected into the turbine.

Since the combustion turbine NSPS was last revised in 1982, combustion turbines have improved their tolerance to the water or steam necessary to control NO_x emissions below the NSPS requirement. Some manufacturers have begun to market an improved low NO_x burner design with steam injection only. These burners provide improved air/fuel mixing and reduced flame temperatures in conjunction with steam injection, resulting in lower concentrations of NO_x as compared to a standard combustion chamber design (with water or steam injection). Design improvements have reported an emission rate of 25 ppmvd as compared to 42 ppmvd with a standard combustor design when firing natural gas. The principal disadvantage of these low NO_x combustion chamber designs compared to the manufacturer's standard design is the lack of operating experience and the increased capital cost of the turbines. Approximately 25 gpm of additional demineralized water per turbine would be required for injection into the combustion chamber. Because of the increase in steam, CO concentrations increase substantially over the standard combustor design. However, low NO_x burner designs are not available for several of the manufacturers. In addition, current designs require steam injection. Water injection is a requirement of the project since the facility will be cycled and rapid start-ups will be necessary. An independent source of steam for steam injection would be required and would increase the air emissions of other pollutants.

The estimated annualized cost for the improved combustor is $5.2 million compared to the standard combustor of $2.5 million; a difference of $2.7 million. The incremental cost effectiveness for the improved combustor ranges from $915 to $1,626 per ton of pollutant removed, which is over three times that of a standard combustor. In addition, installation of the improved combustor will increase CO emissions. To bring CO emissions for the improved combustor to a comparable level as a standard combustor design, the total annualized cost would exceed $10 million with a total cost effectiveness ranging from $2,800 to $5,000 per ton of NO_x removed. This cost effectiveness is about ten times that of the standard combustor, which ranges from $176 to $504 per ton of pollutant removed. Because of the economic impacts and technical constraints, i.e., availability and lack of operating experience on water injection, low NO_x burner designs are considered infeasible for the project.

With standard combustion chamber design, there is a point where the amount of water or steam injected into the turbine seriously degrades its reliability and operational life. This generally occurs at NO_x emission levels of about 65 ppmvd (with no heat rate adjustment) on oil and 42 ppmvd on natural gas. These NO_x emission levels can be achieved at moderate additional cost (i.e., annualized cost of $2.5 million) and with limited impact on reliability or power output.

The consideration of environmental factors also supports the selection of water injection combustion controls as BACT for NO_x. Areas surrounding the proposed location of the combustion turbines are all classified as attainment for ambient NO_2 levels. In addition, modeling analysis at the proposed NO_x emission rates resulted in a maximum predicted impact well below the NO_x standard. Therefore, lower NO_x emissions from using SCR or advanced combustors will not result in any significant environmental benefits for the project.

3.4.3.2 Carbon Monoxide and Volatile Organic Compounds

CO and VOC emissions from the project will be minimized through combustion control. The installation of an oxidation catalyst, the technology with the

greatest level of control, was rejected based on economic and technical grounds. Installing an oxidation catalyst would have an annualized cost of about $5.7 million with a cost effectiveness of greater than $2,600 per ton of pollutant removed. Oxidation catalysts have not been demonstrated on fuel oil firing facilities. Poisoning of the catalyst could potentially result and the formation of SO_3 would cause corrosive damage to the back end of the HRSG and stack. In addition, plant cycling would potentially damage the catalyst.

3.4.3.3 Sulfur Dioxide and Sulfuric Acid Mist

The proposed BACT for controlling SO_2 emissions is the use of low sulfur fuel, i.e., natural gas and No. 2 fuel oil. SO_2 emissions can be reduced by specifying a lower sulfur content fuel of fuel oil or mixing No. 2 fuel oil with a higher grade of distillate oil, e.g., No. 1 fuel oil or kerosene. The estimated annualized cost to lower the maximum sulfur content from 0.5% to 0.2% would be about $21 million. The cost effectiveness of this alternative would exceed $2,000 per ton of potential pollutant removed and more likely exceed $6,500 per ton of actual pollutant removed.

Therefore, a lower sulfur fuel is not considered economically feasible and limiting the fuel sulfur content to 0.50% by weight is proposed as BACT for SO_2 and sulfuric acid mist.

3.4.3.4 Particulate Emissions and other Regulated Pollutants

The emission of particulates/PM10, beryllium, mercury, fluorides and inorganic arsenic from the facility will be controlled by using clean fuels; and for particulates by ensuring as complete combustion of the fuel as possible. Post combustion particulate control technologies have not been installed on gas/oil fueled combustion turbines for these pollutants. The natural gas and distillate oil fuels to be used in the proposed combustion turbines will only contain trace quantities of these constituents.

3.4.4 Design Data for Control Equipment

Combustor design, water injection and the use of clean fuels will be used to control air emissions. Combustor design is manufacturer-specific. The

maximum amount of water injected into the combustion turbine based on maximum fuel use rates (i.e., at 32°F conditions) would be approximately 76,000 lb/hour for natural gas firing and, approximately 97,000 lb/hour for fuel oil firing.

3.4.5 Design Philosophy

Air quality control system will be designed to provide a continuous level of emission reduction that maintain a level of performance equal or better than the proposed emission rates. Adequate spare parts will be available to ensure the operating reliability of the plant.

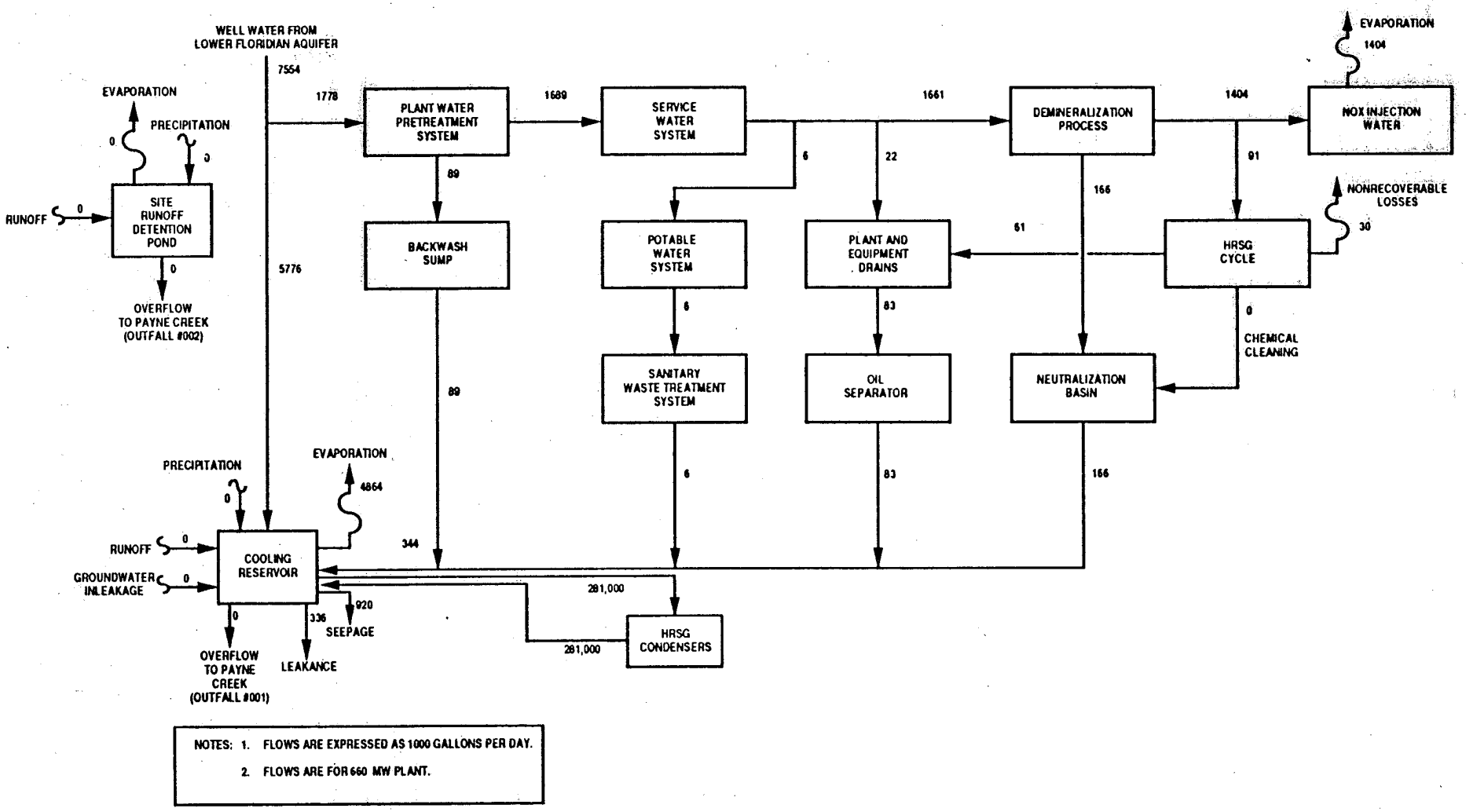
Control of NO_x emissions from the combustion turbines will be accomplished by regulating the amount of water and fuel injected into the combustion turbines. Based on the amount of fuel being burned in the combustion turbines, the required water injection rates will be established based on correlation factors which relate water flow requirements to NO_x emissions. These correlation factors, calibrated and validated by the results from performance tests, will ensure compliance with NO_x emission requirements.

3.5 PLANT WATER USE

The primary water demands and uses at the proposed Hardee Power Station Project include condenser cooling water, potable water, general plant service water, emergency (fire control) water, NOx injection water, and steam cycle makeup water.

Condenser cooling water demands will be satisfied through the use of a surface cooling reservoir constructed on reclaimed phosphate mines. Other water demands will be satisfied through direct withdrawal and use of Lower Floridan Aquifer water.

Overall plant water balances for the maximum daily makeup, maximum daily discharge, and average annual makeup conditions are presented in Figures 3.5-1, 3.5-2, and 3.5-3, respectively. Maximum daily makeup is based on a plant load of 100% and worst case monthly climatological data for April (i.e., the driest month) over the past 51 years, which results in the



NOTES: 1. FLOWS ARE EXPRESSED AS 1000 GALLONS PER DAY.

2. FLOWS ARE FOR 660 MW PLANT.

Figure 3.5-1 WATER MASS BALANCE: MAXIMUM DAILY MAKEUP

Hardee Power Station

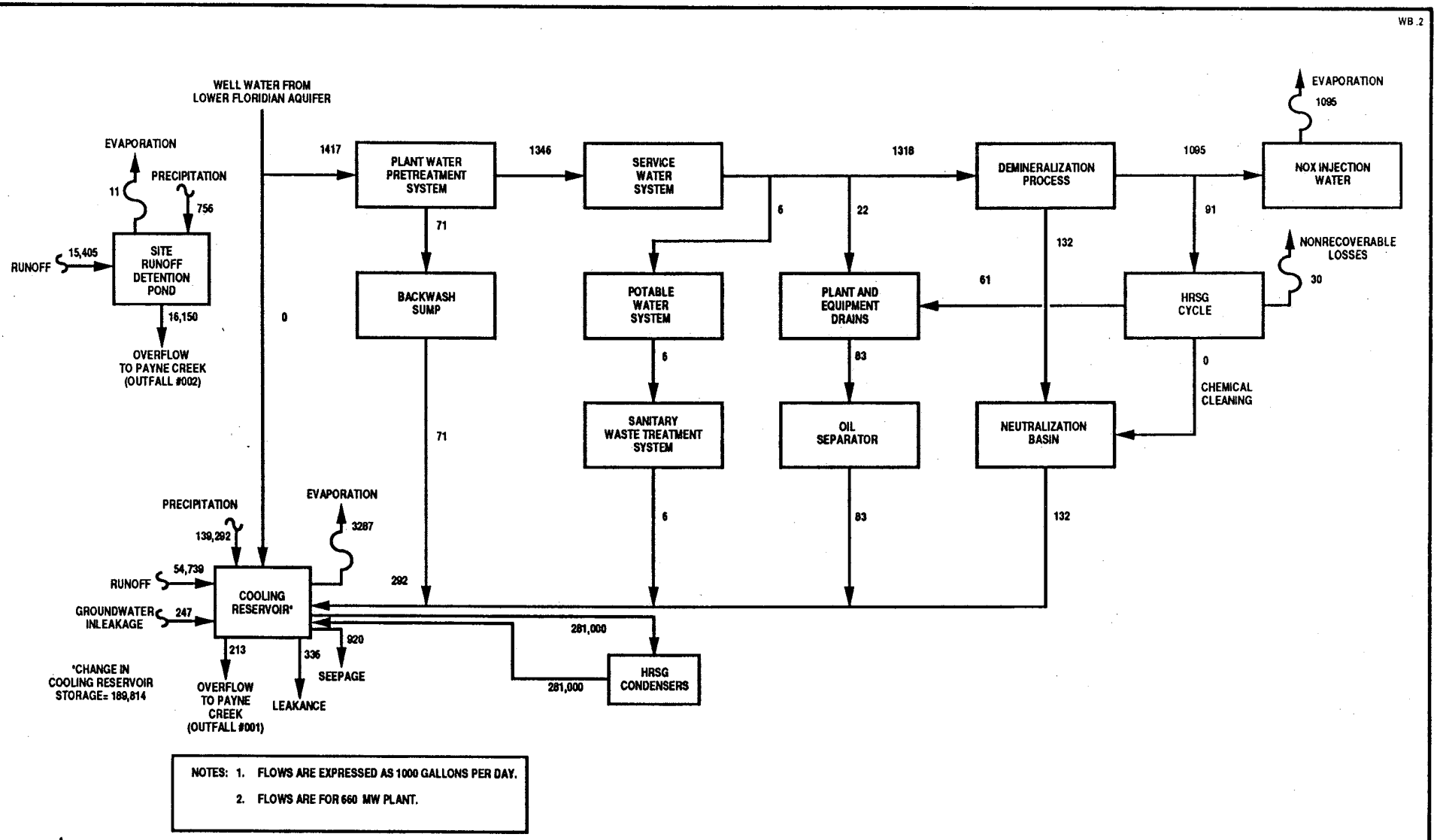


Figure 3.5-2 WATER MASS BALANCE: MAXIMUM DAILY DISCHARGE (25 YEAR - 24 HOUR STORM)

Hardee Power Station

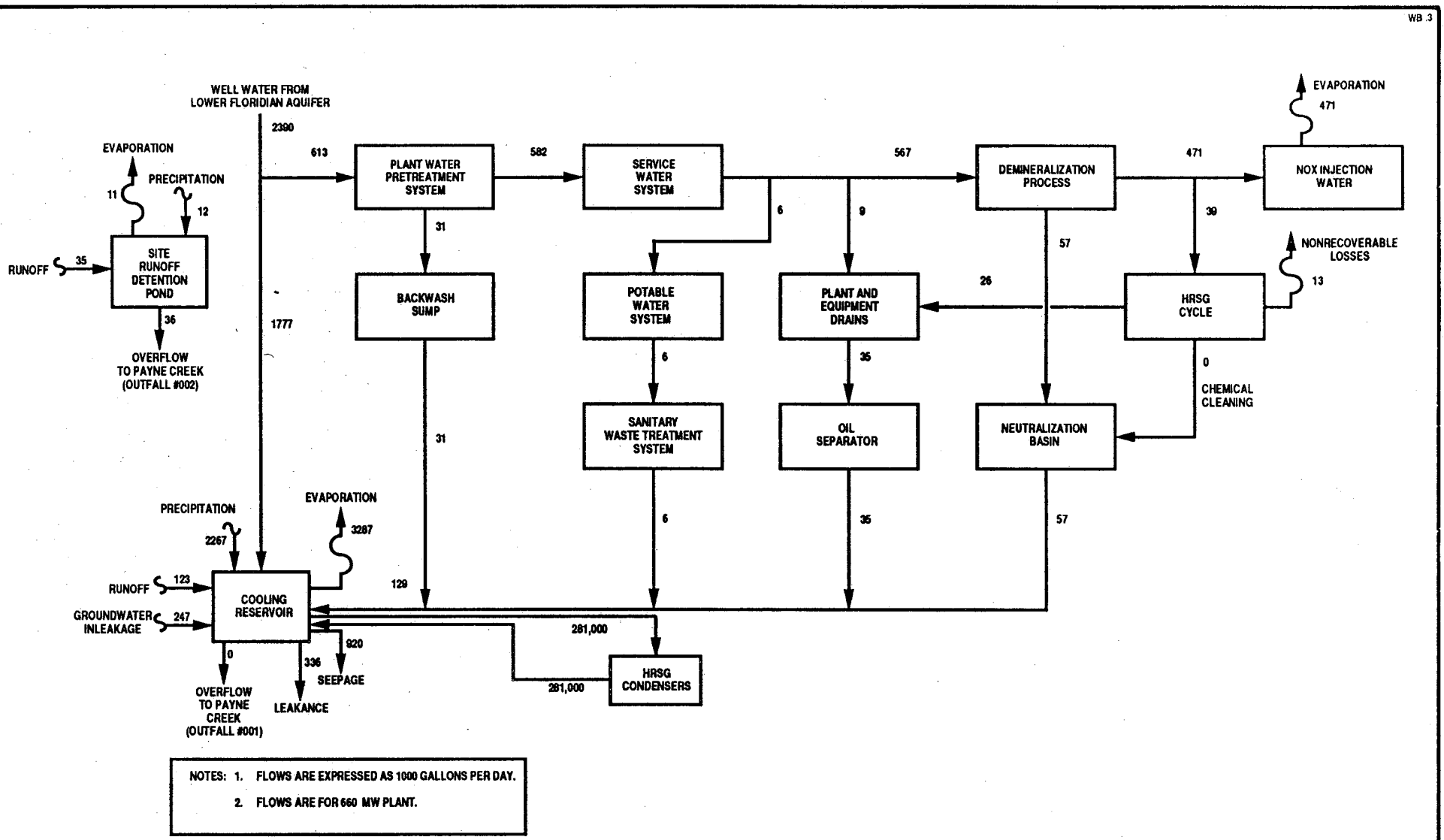


Figure 3.5-3 WATER MASS BALANCE: ANNUAL AVERAGE MAKEUP

Hardee Power Station

conditions. Average annual makeup is based on annual average climatological data and the average annual plant load. Each component of these water balances are discussed in detail below. (Refer to Section 3.5.5 for a discussion of plant size on water use; e.g., a 295 MW configuration.)

Design water quality characteristics for surface runoff, surficial aquifer seepage and Lower Floridan aquifer makeup of the Hardee Power Station are presented in Table 3.5-1. Lower Floridan aquifer will be a source of plant service water and cooling reservoir makeup; surficial aquifer water and surface runoff will be contributing flows to cooling reservoir water balance. Three 2,000 (gpm) wells will be installed to supply Lower Floridan aquifer water.

3.5.1 Cooling Reservoir and Heat Dissipation Systems

3.5.1.1 System Design

For the proposed power plant, the largest single water use is for condenser cooling/heat rejection for the steam portion of the proposed combined cycle station. Based on the current plant design, the following cooling system engineering design criteria were used:

1. The cooling system shall be capable of rejecting 1.95×10^9 BTH/hour continuously.
2. The cooling system shall be optimize for the expected ambient conditions and performance characteristics and requirements of the various heat rejection systems.
3. The cooling system shall be capable of supplying a daily average water temperature of 95°F or cooler to the condenser at all times under design ambient conditions and 100% load. Additionally, the condenser back pressure shall not exceed 4.5 inches Hg.
4. Cooling system water quality shall be maintained at satisfactory quality to allow continuous condenser cooling operation.

Based on current designs, a 570 acre recirculating cooling reservoir will be constructed to satisfy these engineering design and operational criteria (e.g., sufficient water supply and heat rejection capabilities). A viable

Table 3.5-1. Design Water Quality Characteristics for the Hardee Power Station (Page 1 of 2)

Parameter	Surface Runoff	Surficial Aquifer Seepage	Lower Floridan Aquifer Makeup
Calcium, mg/L as $CaCO_3$	63	83	113
Magnesium, mg/L as $CaCO_3$	39	30	49
Sodium, mg/L as $CaCO_3$	17	30	37
Potassium, mg/L as $CaCO_3$	0	1	8
Total Hardness, mg/L as $CaCO_3$	102	113	162
Alkalinity, mg/L as $CaCO_3$	61	83	160
Sulfate, mg/L as $CaCO_3$	37	30	26
Chloride, mg/L as $CaCO_3$	21	34	21
Silca, mg/L	5.4	17	27
Fluoride, mg/L	1.0	0.57	2.0
Cyanide, mg/L	<0.004	<0.004	<0.005
MBAS, mg/L	0.040	0.040	<0.180
Oil and Grease, mg/L	<5	<5	<5
Turbidity, NTU	1.7	51	14
pH, units	7	7.5	7.5
Total Dissolved Solids, mg/L	190	158	342
Specific Conductivity, umhos/cm	173	225	320
Total Kjeldahl Nitrogen, mg/L	0.74	0.14	0.39
Ammonia Nitrogen, mg/L	0.11	0.07	0.20
Organic Nitrogen, mg/L	0.65	0.07	0.19
Nitrate+Nitrite-Nitrogen, mg/L	0.50	0.085	0.031
Total Nitrogen, mg/L	1.24	0.24	0.421
Orthophosphorus, mg/L	0.41	0.47	0.20
Total Phosphorus, mg/L	0.44	2.08	0.20
Arsenic, ug/L	<5	<9	<10
Barium, ug/L	<10	<10	75
Beryllium, ug/L	<3	10	<0.9
Cadmium, ug/L	<0.4	6	<0.7
Chromium, ug/L	<10	<10	13
Copper, ug/L	7	65	7
Iron, ug/L	293	1700	420
Lead, ug/L	6.1	<67	14

Table 3.5-1. Design Water Quality Characteristics for the Hardee Power Station (Page 2 of 2)

Parameter	Surface Runoff	Surficial Aquifer	Lower Floridan Aquifer
Manganese, ug/L	7.9	28	28
Mercury, ug/L	0.24	0.24	<0.2
Nickel, ug/L	16	16	23
Selenium, ug/L	<5	<5	16
Silver, ug/L	<0.08	<0.08	<0.4
Strontium, ug/L	100	100	300
Zinc, ug/L	7.4	<50	143
Alpha, Gross (pC/L)	1.7	30	8.4
Radium 226 (pC/L)	0.7	2.0	3.0

and feasible alternative to this cooling reservoir is the construction and operation of mechanical draft cooling tower with blowdown discharge to the Peace River. This alternative is discussed in detailed in Chapter 8 and the SECI Combine Cycle Environmental Licensing Plan of Study.

This cooling reservoir will be constructed on reclaimed phosphate mines and will be constructed as part of reclamation efforts by Agrico for their approved and on going mining operations (Figures 3.5.1-1, 3.5.1-2 and 3.5.1-3). The inside slope of the reservoir edge will be 4:1 (horizontal:vertical). The northeastern portion of the reservoir will be below grade (i.e., the reservoir water surface will be below the adjacent reclaimed ground surface). The south and western edges of the reservoir will be above grade (i.e., the reservoir water surface will be above the adjacent reclaimed and/or undisturbed ground surface). In these areas, the reservoir will be created and maintained by the construction of a wide berm. The outside slope will be 20:1 and the inside slope will be 4:1. This very flat, outside slope was selected to create a very stable structure with low maintenance and seepage control requirements. Based on Agrico's previous reclamation and reservoir construction experience in the area, this very flat slope provides ideal, stable and low maintenance conditions for the creation of ponds and reservoirs. The average cooling reservoir water depth will be greater than 10 ft.

In addition to the condenser cooling water supply, the cooling reservoir will function as the fundamental component of the heat dissipation/rejection system. In the recirculating cooling reservoir system, cooling water from the cooling reservoir is pumped through the condenser to condense the turbine exhaust steam. This heated water is discharged back to the reservoir, where it is cooled through evaporative, radiant and other cooling mechanisms as it flows through the reservoir. After cooling, the water is then reused for additional condenser cooling.

The cooling reservoir provides two critical functions: (1) to collect, store and supply water for use in condenser cooling; and (2) to reject heat through evaporative, radiant and other cooling mechanisms.

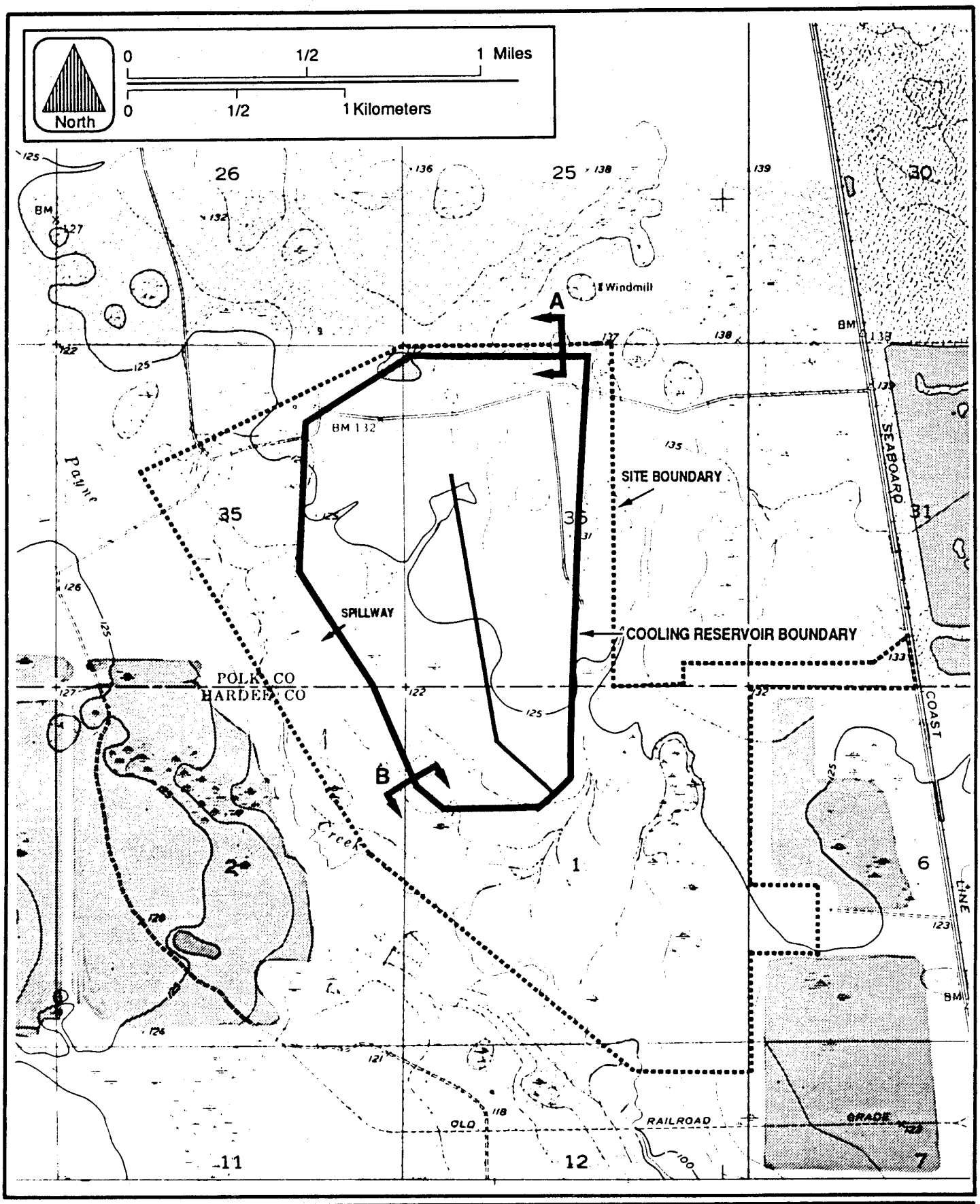


Figure 3.5.1-1 PLAN LOCATION OF COOLING RESERVOIR EDGE CROSS-SECTIONS

Hardee Power Station

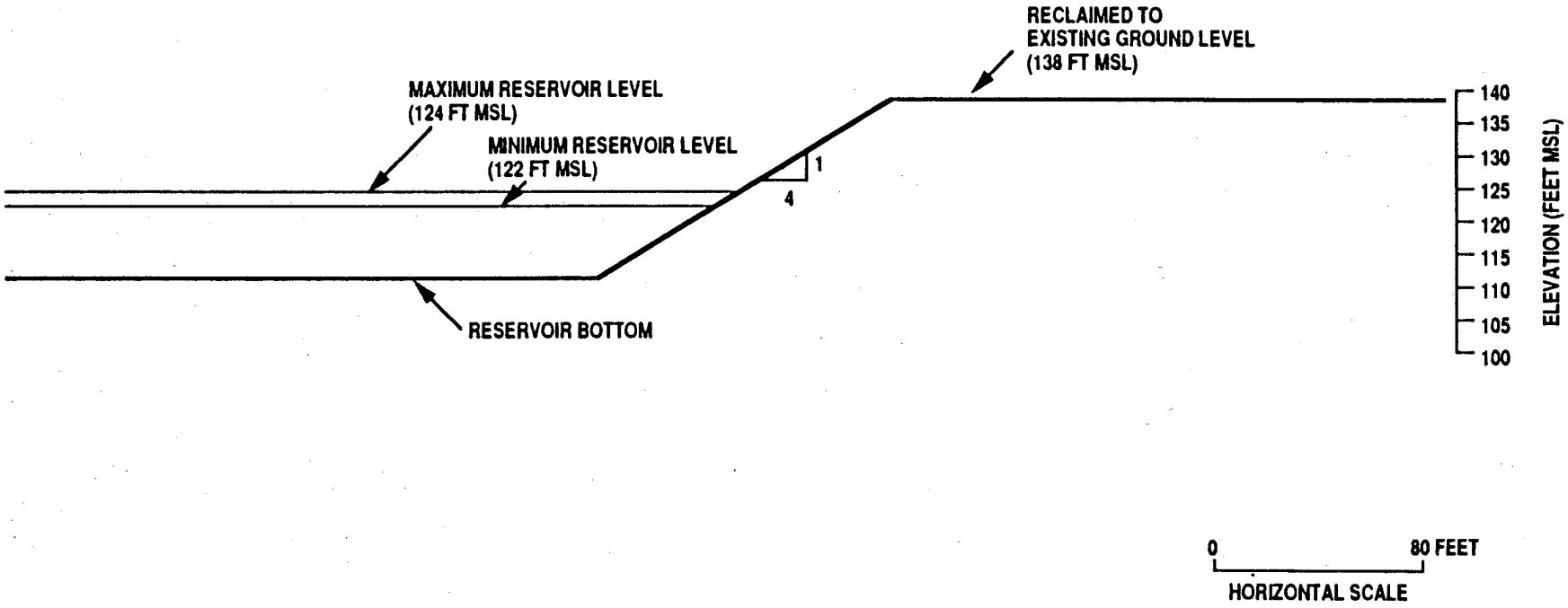


Figure 3.5.1-2 CROSS -SECTION A -
TYPICAL BELOW GRADE EDGE OF RESERVOIR

Hardee Power Station

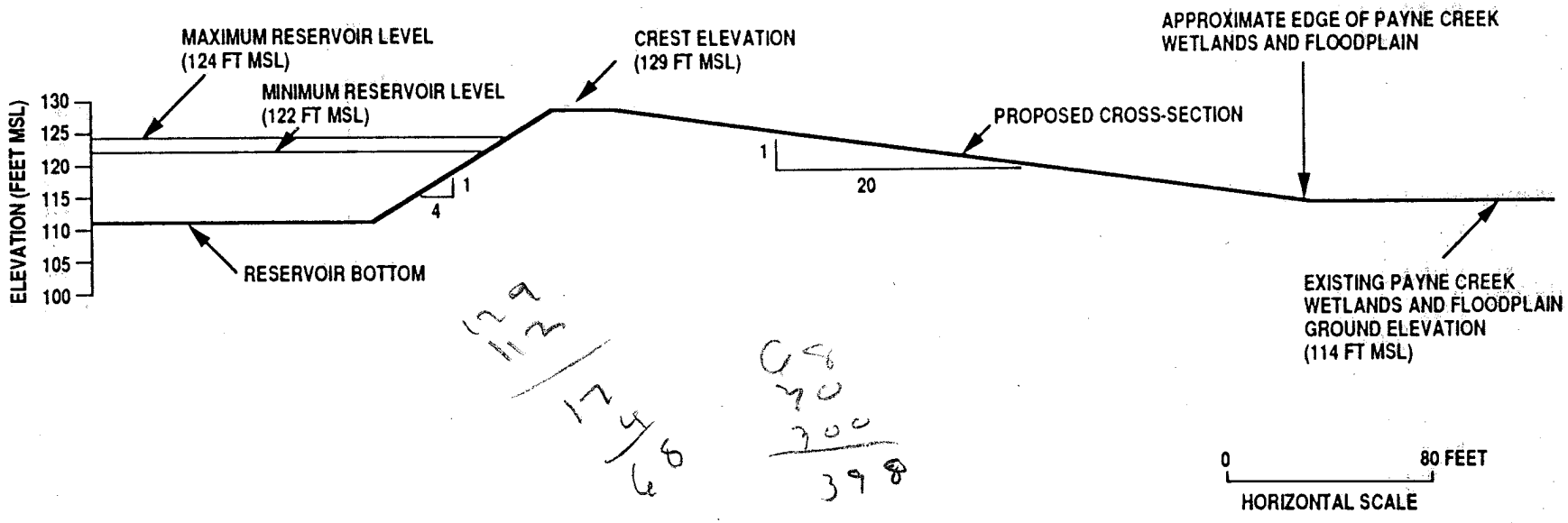


Figure 3.5.1-3 CROSS-SECTION B -
TYPICAL ABOVE GRADE EDGE OF RESERVOIR
(ADJACENT TO PAYNE CREEK)

Hardee Power Station

Within the 660 MW facility, the circulating water system consists of three heat recovery cycle condensers (one for each 220 MW module), circulating water pumps, and supply and return circulating water piping to withdraw and return cooling water to the cooling reservoir (described above). The condensers will be single pressure, surface condensers. In addition to the surface condensers, an auxiliary cooling water system for equipment cooling will be installed. This system consists of water-to-water heat exchangers and receives cooling water from the circulating water system.

3.5.1.2 Sources of Cooling Reservoir Water Makeup

Water makeup of the reservoir will include direct rainfall, runoff and seepage from the upland watershed, plant discharges to the reservoir and, as necessary to maintain the reservoir water balance, pumped Lower Floridan Aquifer well water. Plant discharges to the reservoir include sanitary wastewater, plant and equipment drains, boiler blowdown, and demineralizer regeneration wastes; these will be treated as shown in the water mass balance (see Figures 3.5-1 through 3.5-3). Lower Floridan Aquifer well water will not be treated before use as makeup to the cooling reservoir. The three Lower Floridan Aquifer wells will be approximately 1,300 feet deep, and will be located on the plant site (see Figure 3.2-1).

The expected maximum daily well water makeup to the cooling reservoir for the 660 MW facility will be approximately 5.8 mgd (see Figure 3.5-1). The expected average annual water well makeup to the cooling reservoir for a 660 MW plant is estimated to be about 1.7 mgd (see Figure 3.5-3). Estimated long term circulating water quality, based on annual average climatological data and average annual load conditions, are shown in Table 3.5.1-1. The expected maximum annual well water makeup rate for the cooling reservoir based on worst case meteorological conditions is estimated to average 3.8 mgd for a 660 MW plant. The maximum daily and average well water makeup volumes are being proposed as operating limits for the project.

3.5.1.3 Cooling Reservoir Water Discharges

Water losses from the reservoir include seepage through the berm, leakance into lower aquifers, evaporation and infrequent discharges to Payne Creek

Table 3.5.1-1. Estimated Cooling Reservoir Water Quality for the Hardee Power Station (Page 1 of 2)

Parameter	Cooling Reservoir Quality[1] (660 MW)
Calcium, mg/L as $CaCO_3$	240
Magnesium, mg/L as $CaCO_3$	100
Sodium, mg/L as $CaCO_3$	200
Potassium, mg/L as $CaCO_3$	16
Total Hardness, mg/L as $CaCO_3$	340
Alkalinity, mg/L as $CaCO_3$	260
Sulfate, mg/L as $CaCO_3$	250
Chloride, mg/L as $CaCO_3$	50
Silca, mg/L	60
Fluoride, mg/L	4.1
Cyanide, mg/L	0.01
MBAS, mg/L	0.36
Oil and Grease, mg/L	<5
Turbidity, NTU	31
pH, units	7.5
Total Dissolved Solids, mg/L	860
Specific Conductivity, umhos/cm	1080
Total Kjeldahl Nitrogen, mg/L	0.9
Ammonia Nitrogen, mg/L	0.4
Unionized Ammonia, mg/L (2)	0.014
Organic Nitrogen, mg/L	0.4
Nitrate+Nitrite-Nitrogen, mg/L	0.1
Total Nitrogen, mg/L	1.0
Orthophosphorus, mg/L	0.5
Total Phosphorus, mg/L	0.8
Arsenic, ug/L	20
Barium, ug/L	150
Beryllium, ug/L	4.0
Cadmium, ug/L	2.6
Chromium, ug/L	28
Copper, ug/L	27
Iron, ug/L	980
Lead, ug/L	29

Table 3.5.1-1. Estimated Cooling Reservoir Water Quality for the Hardee Power Station (Page 2 of 2)

Parameter	Cooling Reservoir Quality[1] (660 MW)
Manganese, ug/L	47
Mercury, ug/L	0.5
Nickel, ug/L	49
Selenium, ug/L	32
Silver, ug/L	0.8
Strontium, ug/L	610
Zinc, ug/L	280
Alpha, Gross (pC/L)	22.2
Radium 226 (pC/L)	6.2

Note: 1. Reservior effluent estimates are based on mass balances and do not take into account any chemical reaction, precipitation, sedimentation, deposition or biological activity which may occur in the reservoir and act to remove material from the water column and thus reduce reservoir concentrations.

2. Unionized ammonia concentrations are based on a worst case reservoir water temperature of 95°F (35°C).

(i.e., discharges resulting from rainfalls greater than the 10-year, 24-hour storm). Seepage from the cooling reservoir will serve as a continuous blowdown from the recirculating water system and will function to preclude the accumulation of adverse levels of dissolved solids within the reservoir. To accommodate the infrequent discharges which may occur during extreme (wet) meteorological conditions, a reservoir overflow to Payne Creek is proposed. The cooling reservoir overflow/discharge will be directed from the reservoir surface to edge of the Payne Creek floodplain/wetlands by a large wide swale. As necessary, this swale will be protected with rip-rap. At the upland edge of the Payne Creek floodplain/wetlands, the swale will be widened and/or a spreader swale used to allow the cooling reservoir overflow/discharge by sheet flow into Payne Creek.

3.5.2 Domestic/Sanitary Wastewater

Domestic/sanitary wastewater generated within the proposed plant will be treated in a package sewage treatment plant. Effluent from the sewage treatment plant will be routed to the cooling reservoir. The expected average sanitary wastewater flow is approximately 6,000 gallons/day for a 660 MW facility.

3.5.3 Potable Water

Potable water uses at the plant will include water for drinking, washing, and toilets. Potable water for the plant will be from the service water system, which will be supplied by deep well water which has been treated in the service water pretreatment system and chlorinated prior to use. The average expected potable water usage is approximately 6,000 gallons/day for a 660 MW facility.

3.5.4 Process Water

3.5.4.1 Demineralized Water

The second largest water use in the new facility will be for demineralized water. Demineralized water is required for: (1) injection into the combustion turbines to reduce NO_x emissions; (2) makeup to replace blowdown from the HRSG (necessary to maintain a low dissolved solids content in the

HRSG); and (3) makeup to replace miscellaneous steam losses in the heat recovery cycles.

Service water (i.e., pretreated Lower Floridan Aquifer well water) will be demineralized in ion exchange demineralizer trains. Each train will consist of a cation and anion exchanger. A forced draft type degasifier will be located between the primary cation and anion exchange vessels in each train for reduction of carbon dioxide (CO_2). The demineralizer ion exchange vessels will be regenerated with dilute solutions of sulfuric acid and sodium hydroxide (NaOH). The resulting regenerant waste streams will be treated as described in Section 3.6. The treated regenerant wastewater will be discharged to a neutralization basin and recycled to the cooling reservoir for use as cooling reservoir makeup.

3.5.4.2 General Service Water

General usage water, including seal water, cleaning and flushing water, and emergency (fire control) water, will be provided by the service water system. Water requirements are expected to average 15 gpm for a 660 MW facility and will be supplied from the service water pretreatment system.

3.5.4.3 Plant Drains

Separate collection systems will be used to collect miscellaneous plant drains. Miscellaneous drains will be directed to an oil separator and then routed to the cooling reservoir for reuse as cooling water.

3.5.5 Water Use Variations

Maximum daily water requirements discussed in the preceding sections are based on a 660 MW facility operating at 100% load and when ambient meteorological conditions would necessitate the greatest overall consumption of water. For the major plant water uses (i.e., cooling water and demineralized water for NOx injection water and steam cycle makeup), water use is proportional to plant size and operating load. Thus, reduction in plant size or load would result in a proportional reduction in water demand. The balance of plant water uses (potable and general service uses) is less dependent of plant size and operating load.

Variations in ambient meteorological conditions will also result in variations in water demand for evaporative cooling and cooling reservoir makeup. Given that a large portion of the total cooling reservoir makeup comes from precipitation, an increase in precipitation will cause an equivalent decrease in cooling reservoir makeup from Lower Floridan wells. Similarly, periods of low temperature and/or high humidity will cause the evaporation in the cooling reservoir to decrease, and the cooling reservoir makeup from Lower Floridan wells to decrease proportionally.

Given its size and volume, the proposed cooling reservoir will substantially dampen short-term variations in cooling water makeup. Whereas actual evaporative losses may vary significantly based on plant load or daily meteorological conditions, the relative fluctuation in reservoir level or reservoir volume will be small. Cooling reservoir makeup can be maintained at a relative constant rate, independent of the short-term variations in plant and meteorological conditions. The proposed cooling reservoir will function as a surface water reservoir designed to manage all water inflows and outflows, thereby maximizing water reuse, minimizing water withdrawals and minimizing water demand and use variations.

The well water will be obtained from three onsite wells (2,000 gpm capacity each for full 660 MW buildout). Makeup to the cooling reservoir will be untreated. Water for all other plant uses will be treated in the service water pretreatment system.

3.6 CHEMICAL AND BIOCIDE WASTE

Overall water/wastewater flow scheme has been previously presented in Figures 3.5-1 through 3.5-3. All wastewaters generated within the proposed plant will be discharged to the cooling reservoir, after appropriate treatment, for reuse as cooling reservoir makeup and condenser cooling water. The principal water/wastewater discharges to the cooling reservoir include: circulating cooling water return flow; plant water pretreatment system backwash water; sanitary treatment system wastewater; plant and equipment drains; and neutralization basin effluent.

The principal uses of chemicals and biocides at the proposed project will be for cooling reservoir circulating water quality control, steam cycle water quality control, sanitary wastewater treatment, makeup water demineralization, chemical cleaning of the boiler and preboiler cycle piping systems, and miscellaneous chemical drains. These chemical wastes and related water/wastewater flows will be treated and routed as described in the following sections.

3.6.1 Cooling Reservoir Circulating Water Treatment

Intermittent shock chlorination will be used to prevent biofouling of the circulating water system. Chlorine will be fed within the intake structure at the circulating water pumps intake. The feed rate will be adjusted as necessary.

Additional biocides, both oxidizing and nonoxidizing, may be used for control of aquatic vegetation in the cooling reservoir or other biological growth in the system depending on the conditions present in the reservoir and circulating water system.

3.6.2 Steam Cycle Water Treatment

The steam cycle water will be treated to prevent HRSG corrosion or scaling. The steam cycle water will be treated with an oxygen scavenger, such as hydrazine, for dissolved oxygen control, and with ammonia or an amine for pH control. Sodium phosphate may also be fed to the cycle; residual phosphate will react with calcium hardness in the HRSG to form a nonadherent precipitate.

3.6.3 Sanitary Wastewater Treatment

During plant operation, the sanitary wastewater produced by the plant will be routed to an extended aeration sewage treatment plant. The average expected flow of sanitary wastewater is 6,000 gallons per day (gpd). The average expected biological loading is 7 pounds of BOD_5 per day based on 0.075 pound of BOD_5 per employee per day. Effluent from the sanitary wastewater treatment system will be routed to the cooling reservoir.

During construction, and prior to completion of the sewage treatment plant, construction related sanitary wastes will be managed by the installation, use and maintenance of portable chemical toilets. As necessary, sanitary wastes will be pumped from these individual toilets and disposed off-site in an approved facility by a licensed contractor.

3.6.4 Makeup Water Demineralization

As discussed in Section 3.5.4, the makeup water to the steam cycle will be demineralized using ion exchanger type demineralizer trains. The demineralization system will use sulfuric acid for cation resin regeneration and sodium hydroxide for anion resin regeneration. The sulfuric acid and sodium hydroxide will be stored in tanks located in or adjacent to the Water Treatment Building. The use of these chemicals will be on an intermittent and as needed basis, dependent on duration of demineralizer operation.

The wastewater from cation resin regeneration will include regenerant water containing unreacted sulfuric acid and dissolved sulfate salts of the cations removed from the resins during regeneration. The wastewater from anion resin regeneration will include regenerant water containing unreacted sodium hydroxide and dissolved sodium salts of the anions removed from the resins during regeneration.

The estimated regenerant waste flow will average approximately 166,000 gpd based on maximum makeup requirements conditions. These two waste streams will be routed to the neutralization basin for pH adjustment prior to discharge to the cooling reservoir; this neutralization basin is described in Section 3.6.7.

3.6.5 Chemical Cleaning

The heat recovery steam generator (HRSG) and feedwater piping will be chemically cleaned initially during commissioning and also periodically during the life of the plant. The chemicals used will not be permanently stored onsite, but will be delivered to the site at the time of the schedule periodic cleanings. The chemical cleaning solutions to be used for acid and

alkaline cleaning of the HRSG will be somewhat dependent on the HRSG manufacturer selected. The actual cleaning solutions used must be consistent with the HRSG manufacturer's recommendations. Chemicals typically used in HRSG and feedwater pipe cleaning include the following:

- o Inhibited hydrochloric acid
- o Ammonium bifluoride
- o Hydroxyacetic acid
- o Formic acid
- o Disodium phosphate
- o Trisodium phosphate
- o Soda ash
- o Nonfoaming wetting agents
- o Foam inhibitors

These wastewaters will consist of the cleaning solutions and material removed during the cleaning process. The chemical cleaning contractor will either dispose of the chemical cleaning wastes offsite or treat the wastes in a portable treatment system prior to routing the treated wastewater to the cooling reservoir.

Since chemical cleaning is an infrequent maintenance operation, it does not contribute to the liquid wastes produced by the normal operation of the plant.

3.6.6 Miscellaneous Chemical Drains

Chemical wastewater can result from draining a chemical storage tank, or from cleaning and maintenance operations such as hosing down chemical storage areas. A floor drain collection system will be provided to route miscellaneous chemical wastes to the neutralization basin. Flows from the miscellaneous chemical drains will be intermittent and will not normally contribute to the wastewater flows.

3.6.7 Neutralization Basin

A neutralization basin will be provided for pH adjustment of chemical wastes. The basin will be sufficient to accommodate the wastewaters

produced during regeneration of the makeup demineralizers. The neutralization basin will be a reinforced concrete basin lined with chemical resistant membrane, brick, and mortar. A chemical waste mixer will be provided to hasten pH adjustment of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the demineralizer regeneration equipment. The pH adjusted chemical wastewaters will be routed to the cooling reservoir. Table 3.6.7-1 presents the estimated water quality of the neutralization basin effluent.

3.6.8 Miscellaneous Plant Drains

Separate collection systems will be used to collect chemical drain wastewater and miscellaneous plant drain wastewater. Chemical drain wastewaters have been discussed previously in Section 3.6.6. Miscellaneous plant drain wastewater can result from general cleaning and maintenance, such as hosing general plant (i.e., non-chemical) areas. Miscellaneous floor drains will be directed to an oil separator and then routed to the cooling reservoir for reuse as cooling water.

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 Solid Waste

Only small quantities of solid wastes will be generated by the Hardee Power Station facilities since there will be no ash or FGD waste generated or requiring disposal. Solid wastes will be limited to general trash, sanitary waste treatment sludge and infrequent replacement of demineralizer resins. The sanitary waste sludge will be disposed of by a contractor who will remove sludge in the sludge holding compartment once or twice per year. Sanitary waste sludge will be hauled off site for disposal by the contractor. Other solid wastes will be disposed off-site in a sanitary landfill.

3.7.2 Hazardous Waste

The demineralized waste streams can contain up to 10% sulfuric acid or up to 5% sodium hydroxide along with the minerals removed from the ion exchange resins. The wastes will be combined in an elementary neutralization basin

Table 3.6.7-1. Estimated Characteristics of the Neutralization Basin Effluent for the Hardee Power Station (Page 1 of 2)

Parameter	Treated Neutralization Basin Effluent
Calcium, mg/L as $CaCO_3$	1130
Magnesium, mg/L as $CaCO_3$	490
Sodium, mg/L as $CaCO_3$	3050
Potassium, mg/L as $CaCO_3$	80
Total Hardness, mg/L as $CaCO_3$	1620
Alkalinity, mg/L as $CaCO_3$	0
Sulfate, mg/L as $CaCO_3$	4540
Chloride, mg/L as $CaCO_3$	210
Silca, mg/L	270
Fluoride, mg/L	20
Cyanide, mg/L	0.05
MBAS, mg/L	1.8
Oil and Grease, mg/L	0
Turbidity, NTU	10
pH, units	6-9
Total Dissolved Solids, mg/L	6860
Specific Conductivity, umhos/cm	12100
Total Kjeldahl Nitrogen, mg/L	3.9
Ammonia Nitrogen, mg/L	2.0
Organic Nitrogen, mg/L	1.9
Nitrate+Nitrite-Nitrogen, mg/L	0.3
Total Nitrogen, mg/L	4.2
Orthophosphorus, mg/L	2.0
Total Phosphorus, mg/L	2.0
Arsenic, ug/L	0.1
Barium, ug/L	750
Beryllium, ug/L	9
Cadmium, ug/L	7
Chromium, ug/L	130
Copper, ug/L	70
Iron, ug/L	0
Lead, ug/L	140

Table 3.6.7-1. Estimated Characteristics of the Neutralization Basin Effluent for the Hardee Power Station (Page 2 of 2)

Parameter	Treated Neutralization Basin Effluent
Manganese, ug/L	0
Mercury, ug/L	2
Nickel, ug/L	230
Selenium, ug/L	160
Silver, ug/L	4
Strontium, ug/L	3000
Zinc, ug/L	1400
Alpha, Gross (pC/L)	84
Radium 226 (pC/L)	30

to take advantage of their mutual neutralizing tendencies and monitored for pH. In the event the wastewaters are not neutralized, additional acid or caustic will be added to the basin from the demineralizer regeneration system as needed to adjust the pH. This activity is exempt from hazardous waste permitting pursuant to 40 CFR 264.1(g)(6) and 40 CFR 265.1(c)(10). The neutralized wastewater will not be accumulated and will discharge from this basin to the cooling reservoir as a non-hazardous waste. Acid cleaning wastes are addressed in Section 3.6.5.

3.8 ONSITE DRAINAGE SYSTEM

Site drainage facilities will be designed in accordance with the criteria of the SWFWMD for water quality and water quantity control. The site drainage facility is designed to provide detention for runoff from the first one inch of rainfall (i.e., water quality control) and to limit the post development peak discharge to the pre-development peak rate for the 25-year, 24-hour rainfall event (i.e., water quantity control). This will be accomplished by the construction of a plant site drainage system of pipes, channels and culverts which flow to a stormwater detention pond. This stormwater detention pond will discharge to Payne Creek.

3.8.1 Stormwater Detention Pond

Surface runoff from the area disturbed for new facility construction and plant operation will be collected and directed to the stormwater detention pond. This pond will be located in the southwestern portion of the site property and will receive surface drainage from the entire plant site.

The stormwater detention pond has been sized to address both the water quality and water quantity control criteria of the SWFWMD. For water quality control, the stormwater detention pond has been designed to provide "on-line" detention for runoff from the first one inch of rainfall. Treated stormwater from the pond will be directed to Payne Creek.

For water quantity control, the stormwater detention pond has been designed to provide sufficient volume for peak attenuation so that the peak pond discharge rate will be equal to or less than the pre-development site peak

discharge rate during a 25-year, 24-hour rainfall event. The overflow weir/outfall structure is designed to pass any flows which exceed that resulting from the 25-year, 24-hour rainfall event. Design calculations are presented in the Appendix 11.5.

3.8.2 Stormwater Runoff Control During Construction

The stormwater detention pond will be built during initial construction to serve as a construction stormwater detention pond. A system of temporary construction ditches and piping will direct the stormwater runoff or dewatering water flow to the pond. The construction drainage system will follow the layout of the permanent ditch system where possible.

Runoff from areas of the site not disturbed by construction activities or plant operations will be directed to the natural drainage systems within the area. Runoff from areas of the site disturbed by construction activities will be collected in the storm drainage system (i.e., open channel and/or storm sewer system) and directed to the stormwater detention pond, described above.

As necessary, sediment collected during the construction phase will be removed to assure adequate pond volume and filtration system operation.

3.8.3 Site Drainage

Generally, the drainage in the area of the new facility will be directed away from the structures and routed to the stormwater detention pond. The main plant complex area will be graded with moderate slopes (1% minimum) for effective drainage.

Site runoff will be conveyed to the stormwater detention pond through a drainage system of pipes, channels and culverts.

The drainage along the entrance road for the new facilities will consist of shallow swales which will provide wet detention for maintenance of water quality. As necessary, small ditch checks or "dikes" will be used to control discharge to satisfy water quantity criteria. After treatment in

these swales, this stormwater will be discharged to wetlands which drain to Payne Creek.

3.8.4 Flood Elevations

The site facilities will be designed so that no structures subject to damage by flooding will be placed at an elevation below that of the 100-year flood elevation. The grade in the area of the new facilities will be approximately at elevation 117 feet above mean sea level (MSL) with the main power block foundation at about 118 feet above MSL. These elevations will be verified during detailed plant design.

3.9 MATERIALS HANDLING

3.9.1 Construction Materials and Equipment

Construction materials and equipment will be delivered to the site by existing roads and railroads. As shown in Figure 3.2-1, an access road will be constructed on the site to provide access to the plant facilities from CR 663. Figure 3.2-1 also shows the existing CSX rail line located east of the project site. Rail deliveries of equipment will be made at an existing siding near the site and transported to the site by truck.

Construction laydown areas for materials will be located as described in Section 4.1.1. Materials will be unloaded and moved around the site using portable cranes and trucks. Some of the heaviest items such as the combustion turbines, generators, HRSGs and transformers will require rail delivery as discussed in Section 3.9.3. Pollution control measures for the laydown areas will include runoff collection as described in Section 3.8. Main roads in the laydown areas will be gravel surfaced and treated with dust palliative to reduce dust. Water sprays will also be used, as required, to control dust due to traffic.

3.9.2 Roads

Heavily loaded construction trucks will travel to the site via CR 663 and the site access road shown on Figure 3.2-1.

3.9.3 Railroad

A CSX Railroad branch-line currently runs north-south approximately 1/2 mile east of the proposed power block locations on the site. All rail deliveries of construction materials and equipment for the facility will be off-loaded at a rail siding near the CFI plant and transported by truck to the site. The branch-line is primarily used for phosphate rock shipments from local mines. This line can accommodate the shipments required for the project.

REFERENCES - Chapter 3

USEPA Memorandum from J.C. Potter (Assistant Administrator for Air and Radiation) to Regional Administrators. December 1, 1987.