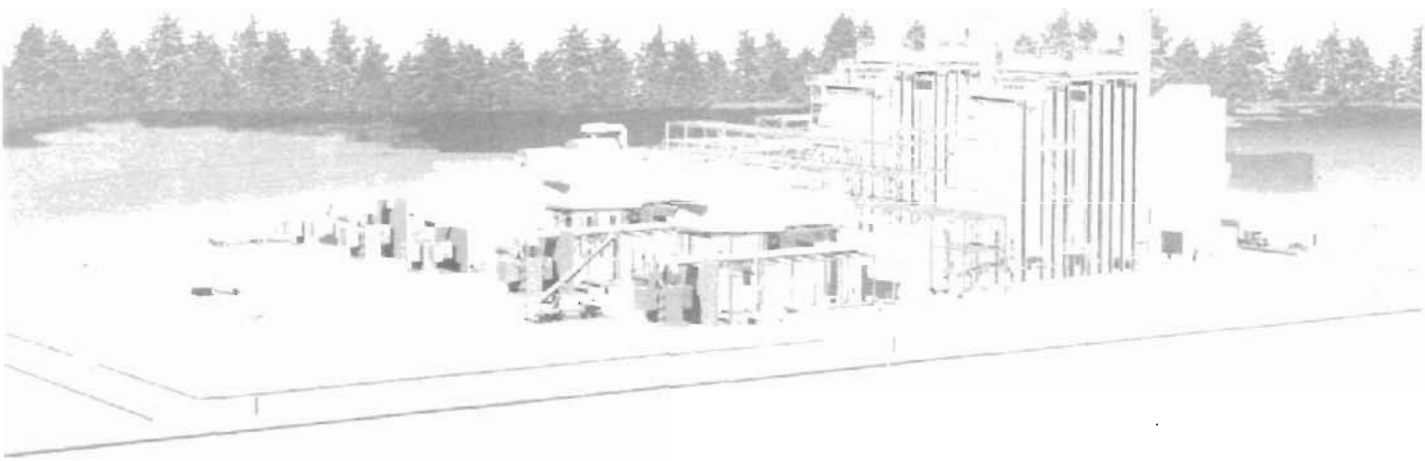
GULF POWER
SMITH UNIT 3
Site Certification Application



Volume 2 **June 1999**

GULF POWER
A SOUTHERN COMPANY

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Environmental Consulting & Technology, Inc.

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS

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LIST OF ABBREVIATIONS, ACRONYMS, AND UNITS OF MEASURE

AAQS	ambient air quality standards
ADT	average daily traffic
ANSI	American National Standards Institute
APCo	Alabama Power Company
ASTM	American Society for Testing and Materials
ATS	advanced technology systems
BACT	best available control technology
BMP	best management practices
bpf	blows per foot
Btu/ft^3	British thermal unit per cubic foot
Btu/kwh	British thermal unit per kilowatt-hour
°C	degrees Celsius
CAA	Clean Air Act
CAES	compressed air energy storage
CC	combined cycle
CEC	cation exchange capacity
CFR	Code of Federal Regulations
cfs	cubic feet per second
cm/sec	centimeter per second
CO	carbon monoxide
CO_2	carbon dioxide
CR	County Road
CTG	combustion turbine generator
dBA	A-weighted decibel
DOT	Department of Transportation
DSM	demand-side measures
EAR	Evaluation and Appraisal Review
EFOR	equivalent forced outage rate
EMF	electric-magnetic field
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement and construction
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FDACS	Florida Department of Agriculture and Consumer Services
FDCA	Department of Community Affairs
FDEP	Florida Department of Environmental Protection
FDOT	Florida Department of Transportation
FEMA	Federal Emergency Management Agency
FEPPSA	Florida Electrical Power Plant Siting Act
FGD	flue gas desulfurization
FGFWFC	Florida Game and Fresh Water Fish Commission
FGS	Florida Geological Survey

LIST OF ABBREVIATIONS, ACRONYMS,
AND UNITS OF MEASURE
(Continued, Page 2 of 4)

FGT	Florida Gas Transmission
FLUCFCS	Florida Land Use, Cover, and Forms Classification System
FLUM	Future Land Use Map
FNAI	Florida Natural Areas Inventory
FPC	Florida Power Corporation
FPSC	Florida Public Service Commission
ft	feet
ft/day	feet per day
ft bls	feet below land surface
ft-msl	feet above mean sea level
ft/sec	foot per second
FTU	nephelometric turbidity unit
g/s	gram per second
GE	General Electric
gpd	gallons per day
gpm	gallon per minute
gr S/100 scf	grains of sulfur per 100 standard cubic feet
gr/100 scf	grains per 100 standard cubic foot
gr/100 dscf	grains per 100 dry standard cubic feet
Gulf	Gulf Power Company
ha	hectares
HRSG	heat recovery steam generator
hr/yr	hour per year
H_2SO_4	sulfuric acid
IGCC	integrated gasification combined cycle
IRP	integrated resource planning
ISCST3	Industrial Source Complex Short-Term
ISO	International Standards Organization
K	Kelvin
$kg/km^2/month$	kilograms per square kilometer per month
$kg/km^2/yr$	kilograms per square kilometer per year
km	kilometer
km^2	square kilometer
kV	kilovolt
kw-yr	kilowatt-year
lb/hr	pound per hour
LHV	lower heating value
LOS	level of service
m	meter
meq/100g	milli-equivalents per 100 grams
MGD	million gallons per day
mg/kg	milligram per kilogram
mg/L	milligram per liter

LIST OF ABBREVIATIONS, ACRONYMS,
AND UNITS OF MEASURE
(Continued, Page 3 of 4)

MMBtu/day	million British thermal units per day
MMBtu/hr	million British thermal units per hour
mmhos/cm	millimhos per centimeter
MPCo	Mississippi Power Company
mph	miles per hour
msl	mean sea level
MW	megawatt
mwh	megawatt-hour
NCDC	National Climatic Data Center
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NSR	new source review
NWFWMD	Northwest Florida Water Management District
NWS	National Weather Service
NPV	net present value
OAQPS	Office of Air Quality Planning and Standards
O&M	operation and maintenance
O_2	oxygen
OSHA	Occupational Safety and Health Administration
PCFB	pressurized circulating fluidized bed
PM	particulate matter
PM_{10}	particulate matter less than or equal to 10 micrometers aerodynamic diameter
POD	point of discharge
ppm	part per million
ppmvd	part per million by dry volume
PSD	prevention of significant deterioration
psf	pound per square foot
PSH	pumped storage hydro
psia	pound per square inch absolute
psig	pound per square inch gauge
PWRR	present worth of revenue requirements
RARE	roadless area review and evaluation
RCRA	Resource Conservation and Recovery Act
RFP	request for proposal
RQD	rock quality designation
SACTI	Seasonal/Annual Cooling Tower Impact
SCA	site certification application
SCS	Southern Company Services
SES	Southern Electric System
SO_2	sulfur dioxide

LIST OF ABBREVIATIONS, ACRONYMS,
AND UNITS OF MEASURE
(Continued, Page 4 of 4)

SR	State Road
SRPP	Strategic Regional Policy Plan
SSC	species of special concern
SWMP	storm water management plan
tpy	tons per year
TYSP	ten-year site plan
µg/L	microgram per liter
$\mu g/m^3$	microgram per cubic meter
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VMT	vehicle miles traveled
VOC	volatile organic compound
WFRPC	West Florida Regional Planning Council
WWTP	wastewater treatment plant

3.0 THE PLANT AND DIRECTLY ASSOCIATED FACILITIES

This chapter provides descriptions of the proposed power plant facilities, the key components and systems of the plant and their operations, and the directly associated facilities which will comprise the Smith Unit 3 Power Project. The descriptions include, to the extent possible, estimates of the expected character, quality, and quantity of discharges and emissions from the plant facilities and operations. Also, proposed measures and systems to control and, as necessary, treat the expected emissions and discharges are described in order to provide reasonable assurance that the plant operations comply with applicable regulatory requirements and standards. The specific sections in this chapter are:

- 3.1—Background.
- 3.2—Site Layout.
- 3.3—Fuel.
- 3.4—Air Emissions and Controls.
- 3.5—Plant Water Use.
- 3.6—Chemical and Biocide Waste.
- 3.7—Solid and Hazardous Waste.
- 3.8—Onsite Drainage System.
- 3.9—Materials Handling.

The descriptions presented in this chapter are based on Project plans and available engineering and design information for the proposed Smith Unit 3 facility.

3.1 BACKGROUND

3.1.1 OVERVIEW

The Smith Unit 3 Project will add a new 500-MW class CC power plant to Gulf's existing Lansing Smith Plant. The Project will be constructed on a 50-acre site adjacent to the existing facility, which is located in Bay County, just north of Panama City, Florida. The new plant will produce electrical power by burning natural gas in two gas turbines and two HRSGs which will have supplemental burners.

Typical plant operation is expected to produce 519 MW when operating with the gas turbines at full load with no supplemental firing of the HRSGs at ambient conditions of 65°F and 60 percent relative humidity. Net plant output can achieve 574 MW during peak firing operation with the gas turbines utilizing power augmentation and the HRSGs supplementally fired to their maximum capability with natural gas.

The Project is currently scheduled to begin commercial operation on June 1, 2002, pending approval by the appropriate regulatory and environmental agencies. The onsite construction schedule is anticipated to last 21 months with onsite activities beginning as early as September 2000. The major construction activities include the following:

- Site clearing and grubbing.
- Site excavation, filling, and grading.
- General site improvements (lighting, fences, etc.).
- Excavation and installation of piles.
- Installation of underground piping and utilities.
- Concrete foundation completion.
- Erection of support building and structures.
- Erection of HRSGs, gas turbines, and steam turbines.
- Installation of auxiliary support equipment.
- Installation of interconnecting piping and wiring.
- Equipment testing and startup.
- Interconnection to electrical power grid.

- Plant acceptance testing.
- Final site landscaping and cleanup.

All construction activities will be performed in a manner that will minimize overall environmental impacts to the site and the general locale as much as possible. Existing roads to the Lansing Smith Plant will be used for overall site access. Site clearing and grubbing will consist of the removal of trees, vegetation, and underlayment from the site; excavation and grading will involve the removal of some quantity of additional underlayment and replacement with suitable soil and other appropriate fill for proper preparation of the site.

Gulf is proposing to use fly ash, an industrial coal combustion by-product generated from the burning of bituminous coal, as an alternative replacement fill material in lieu of natural backfill materials to be supplied from a local borrow pit. Fly ash is readily available at the Smith site where the ash handling process involves an ash sluice system wherein ash is hydraulically transferred from plant boilers to a permitted, onsite ash pond. The material can be excavated, de-watered, and beneficially re-used as a suitable alternative fill material for the Smith Unit 3 construction.

The use of piles for proper foundation support are anticipated with required pile driving being performed following completion of the site excavation, filling, and grading. The site development process will be properly managed to minimize the impacts of site runoff and soil erosion on the surrounding estuaries and wetlands.

Major equipment is currently anticipated to be delivered to the site by barge utilizing the existing site intake canal. The temporary barge unloading facility will be integrated into the existing barge unloading structures utilized at the Lansing Smith Plant. Other equipment will be received by truck at the site using existing roads to the Lansing Smith Plant. Due to the use of the existing Lansing Smith Plant site, the overall impact of additional noise levels, increased dust levels, and increased overall activity at the site is expected to have a minimal impact on the surrounding community.

3.1.2 MAJOR POWER PLANT COMPONENTS AND SYSTEMS AND THEIR OPERATION

The Smith Unit 3 Project will consist of the following major equipment pieces:

- Two 170-MW natural gas-fueled gas turbines with dry low-NO_x combustors.
- Two triple-pressure reheat HRSGs, each equipped with a supplemental duct burner for the production of additional steam.
- One 200-MW reheat steam turbine exhausting to a single steam condenser.
- A once-through cooling water system, including a mechanical draft cooling tower for circulating cooling water to the steam condenser and the service water cooling system.
- Auxiliary support systems including pumps, transformers, heat exchangers, building/control room, etc.

The integrated plant will represent a state-of-the-art CC facility which has been designed for highly efficient, continuous operation while minimizing the overall level of air emissions and overall environmental impact. The gas turbines will be GE model PG 7241(FA) units, which have a proven operating record in the United States and around the world. The GE 7FA gas turbines will utilize the latest developments in dry low-NO_x combustor technology to achieve the low emission limits at all anticipated load points. Each GE 7FA gas turbine is rated at 170 MW at standard International Standards Organization (ISO) conditions of 59°F ambient temperature and sea level elevation.

Each gas turbine exhausts into a HRSG designed and manufactured by Vogt-NEM. The HRSGs will be of the triple-pressure design and will include integral deaerators with the low-pressure section for improved efficiency. Each HRSG will be equipped with a supplemental burner that will be used for the production of additional steam. Each supplemental burner will be designed for firing natural gas only and will use the best available low-NO_x burner technology for minimizing overall air emissions.

The steam produced by the HRSGs will be utilized in a condensing reheat steam turbine with a single, low-pressure admission port. The steam turbine will typically operate with steam conditions of 1,800 psig, 1,050°F. The steam turbine will be designed and manufactured by GE.

Figure 3.1.2-1 presents a process flow diagram showing a representative CTG/HRSG system and other principal plant systems. The CTGs will fire only natural gas; no other fuels are planned.

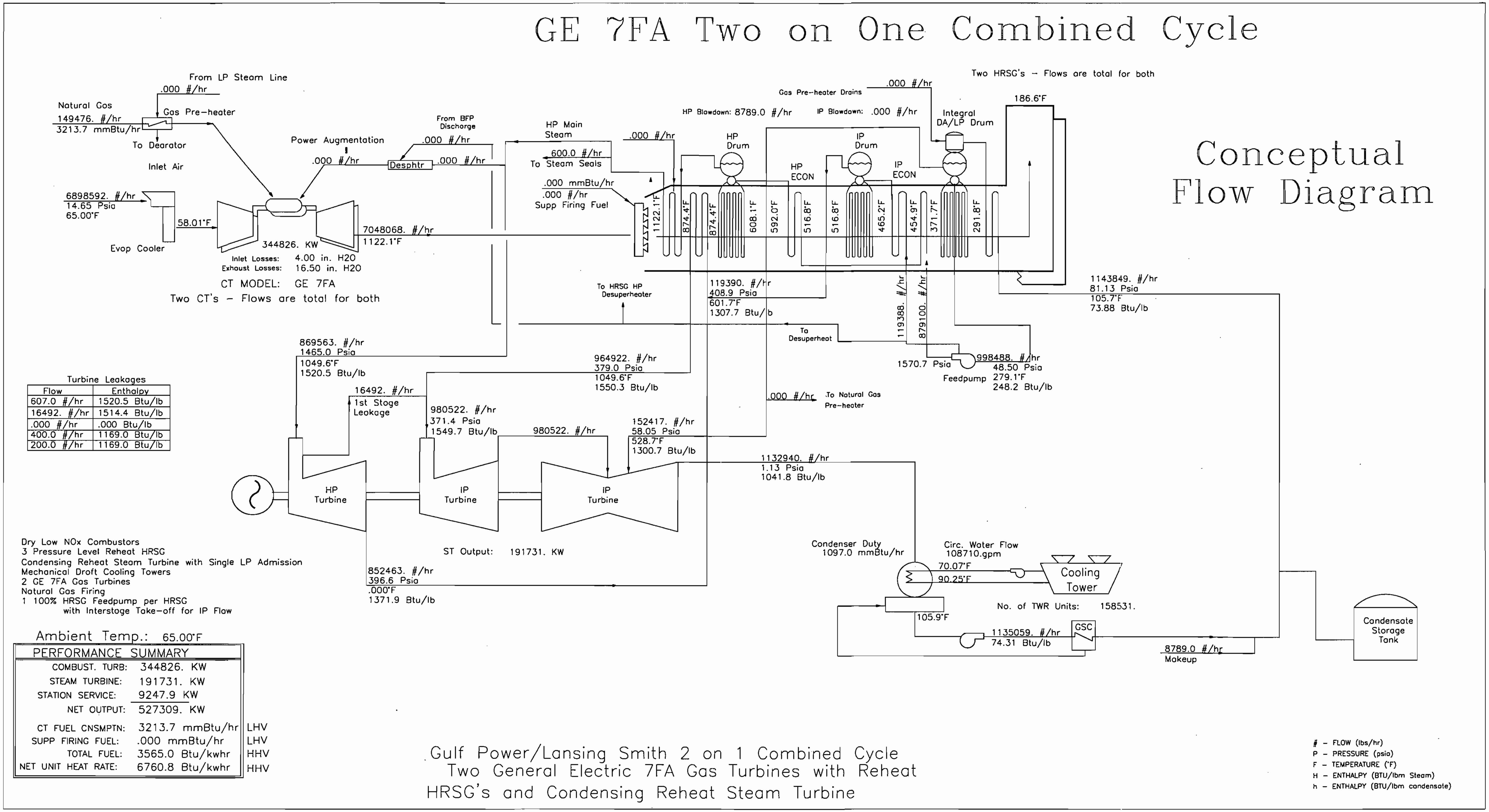

FIGURE 3.1.2-1.

CONCEPTUAL FLOW DIAGRAM

(FOR ACTUAL FLOWS SEE FIGURES 3.5.0-1 AND 3.5.0-2)

Source: SCS, 1999.

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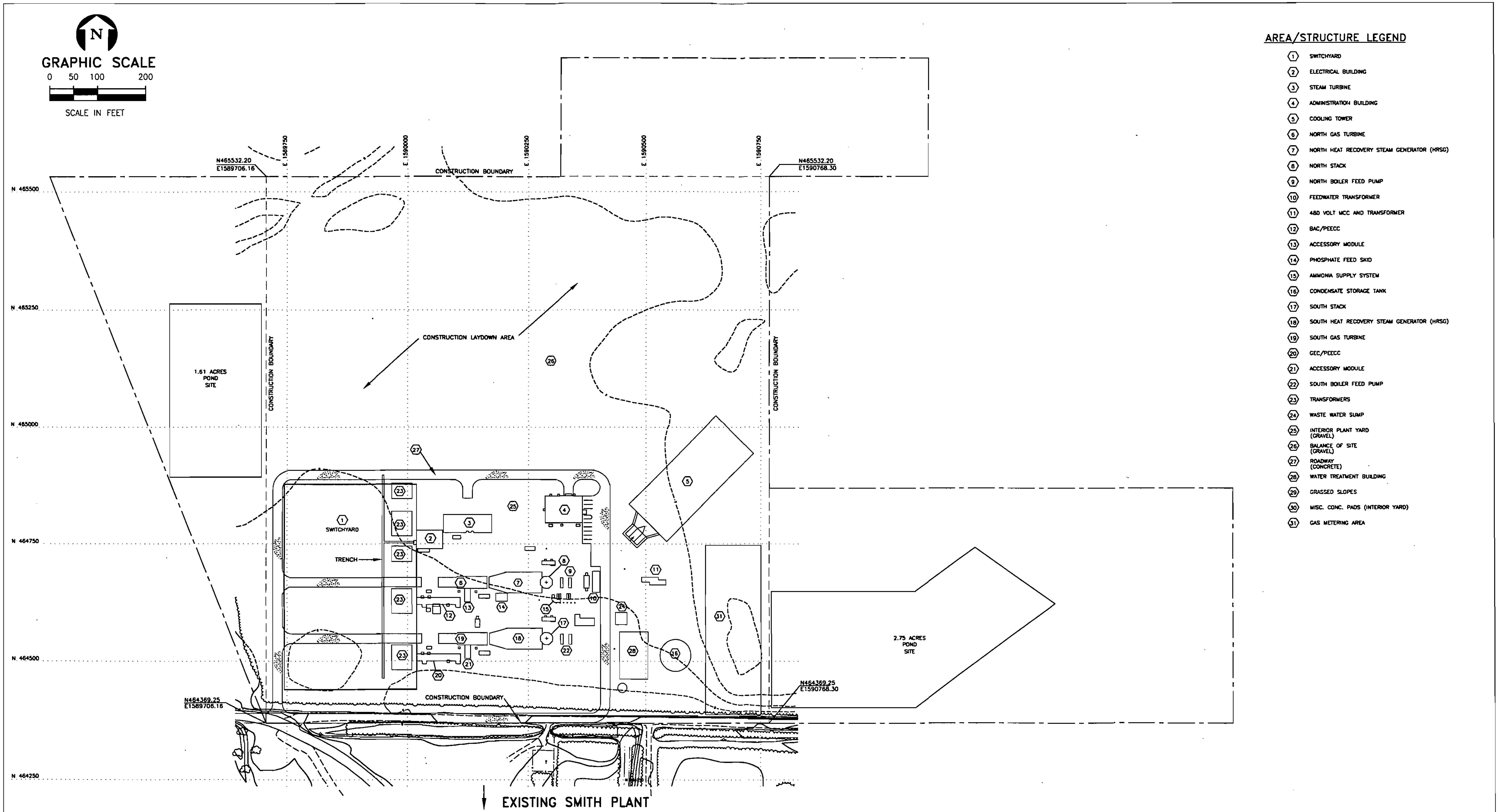

FIGURE 3.2.0-1.

PROPOSED SITE LAYOUT

Sources: Gulf Power, 1999; ECT, 1999.

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3.2 SITE LAYOUT

The general plant layout showing all major equipment is shown in Figure 3.2.0-1. Access to the site will be via a paved road (as described in Section 3.9.1).

The existing onsite 115-kV Lansing Smith substation will be expanded within the existing developed area to provide a breaker-and-a-half configuration, into which Smith Unit 3 will be connected. A breaker-and-a-half scheme has three breakers in series between the main buses. Two circuits are connected between the three breakers. This pattern is repeated along the main buses so that one-and-a-half breakers are used for each circuit. Under normal operating conditions, all breakers are closed and both buses energized. A circuit is tripped by opening the two associated breakers. The breaker-and-a-half scheme is superior in flexibility, reliability, and safety. Eight new breakers will be added to the existing substations to accommodate this reconfiguration. Within the substation, repositioning of three existing 115-kV transmission lines will be necessary.

Figure 3.2.0-2 provides an artist's rendering of the plant, consistent with the general plant layout, shown previously. The figure is essentially an oblique view. The water balance diagrams (Figure 3.5.0-1 and 3.5.0-2) show a schematic of the various interties/connections that will be made between Smith Unit 3 and the existing Smith facilities.

Smith Unit 3 will be constructed with its own substation consisting of the individual generator step-up transformers and station service transformers. This unit substation will connect to the existing Lansing Smith 230-kV substation by means of approximately 1,000 ft of wire bus. The wire bus section connecting Smith Unit 3 to the existing Lansing Smith substation will be constructed on already developed plant site property and, therefore, will not result in any additional environmental impacts. The existing Lansing Smith 230-kV substation will require a bus rearrangement and extension in order to accommodate the new unit's connection. This bus arrangement will also be performed on already developed plant property. In addition, six of the Lansing Smith 230-kV circuit breakers, one Highland City 115-kV breaker, and one Laguna 115-kV breaker will require replacement, in-place, and will not cause any environmental impact to the area.

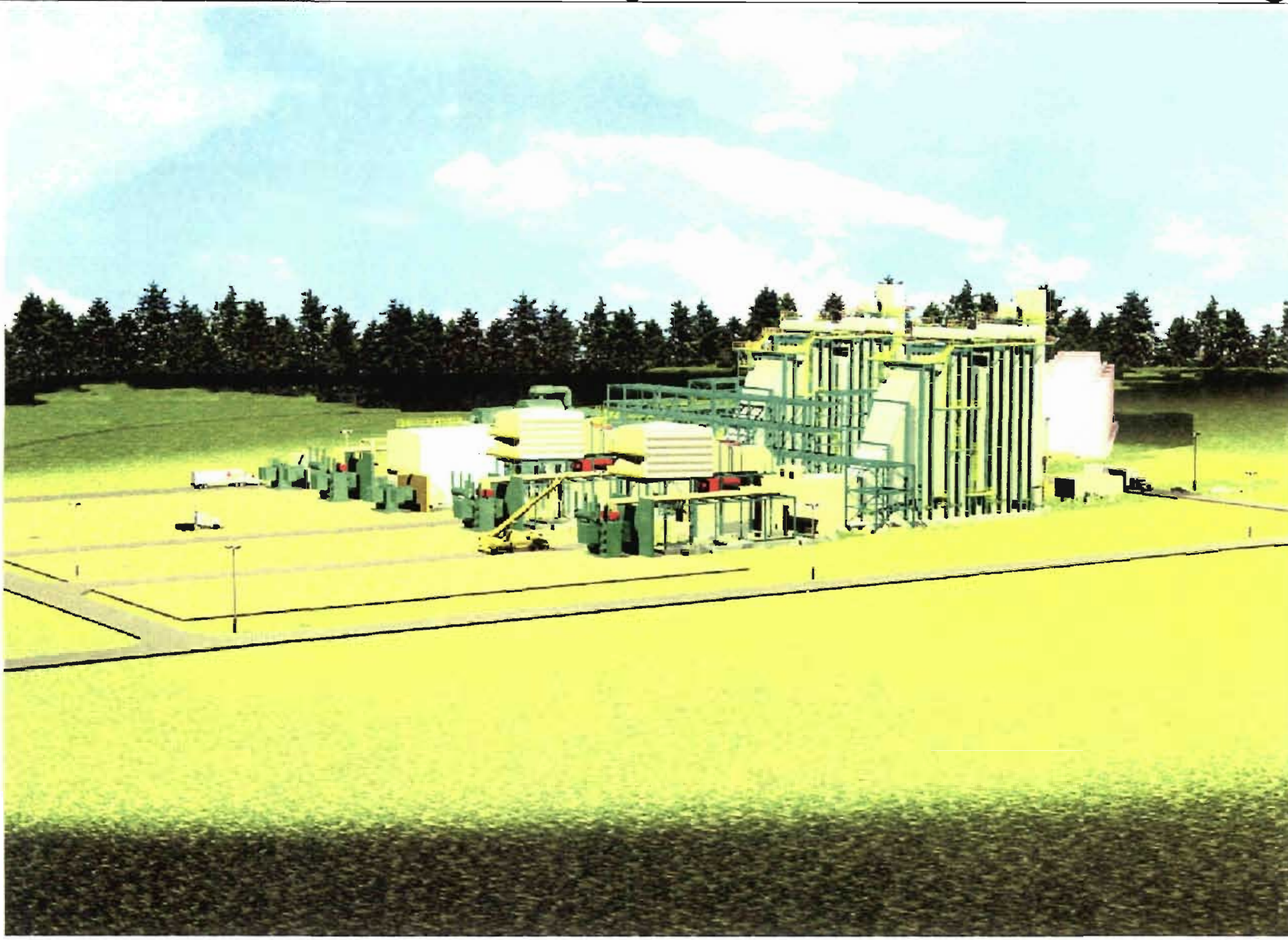

FIGURE 3.2.0-2.

RENDERING OF PROPOSED SMITH UNIT 3 (OBLIQUE VIEW)

Source: SCS, 1999.

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As a result of the addition of the new generation at Smith Plant, there are portions of three existing Gulf Power transmission lines that will require a change of the existing conductor to a conductor with higher ampacity in order to relieve contingency overloads. The existing offsite line sections requiring the replacement of conductor are (1) Smith—Greenwood 115-kV line (7.5 miles), (2) Smith—Highland City 115-kV line (7.6 miles), and (3) Highland City—Callaway 115-kV line (4.1 miles) (see Figure 3.2.0-3). This replacement of conductor will be performed on existing rights-of-way and will not necessitate the replacement or addition of transmission line structures or new access roads. Therefore, no additional impact will be caused as a result of this associated transmission upgrade resulting from the addition of Smith Unit 3 (see Section 6.1).

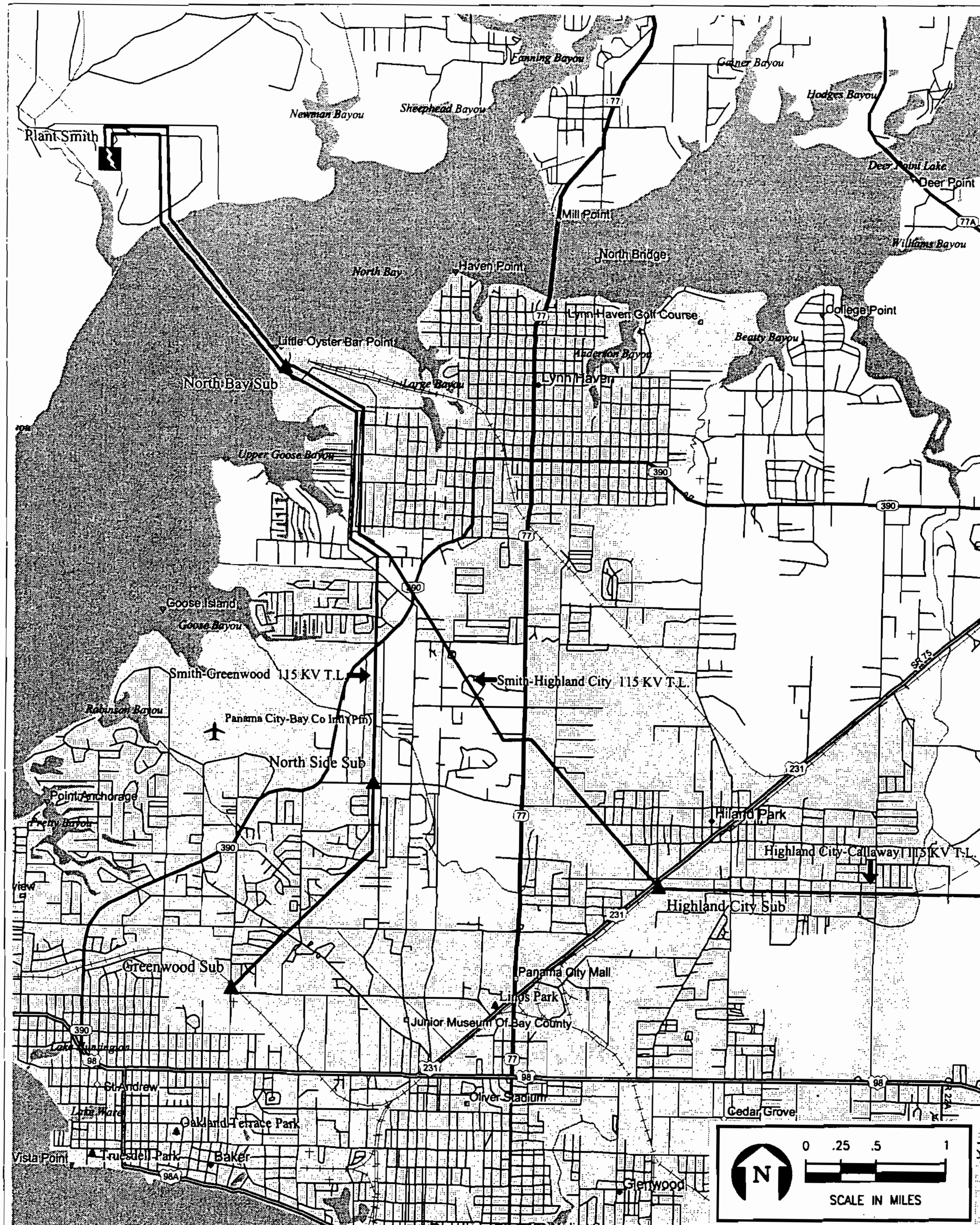

FIGURE 3.2.0-3.
TRANSMISSION UPGRADES

Sources: DeLorme, 1996; SCS, 1999.

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3.3 FUEL

The CTGs to be built at Smith Unit 3 fire on natural gas only. No alternate fuel will be available. Natural gas will be delivered to the site through a new pipeline lateral. The pipeline lateral will be connected to Florida Gas Transmission's (FGT's) pipeline system in Washington County, Florida. The interconnect will occur south of the town of Wausau and near where FGT's pipeline system crosses SR 77. The length of the pipeline lateral from FGT to Plant Smith is approximately 29 miles. A meter station and associated equipment will be constructed at Plant Smith. The plant will consume approximately 87,000 million British thermal units per day (MMBtu/day) on peak summer days and 100,000 MMBtu/day on cold days.

Table 3.3.0-1 presents a typical composition for the natural gas fuel.

Natural gas will be delivered to Smith Unit 3 by a new pipeline to be constructed by the pipeline vendor. The new pipeline's point of interconnection with existing facilities will occur South of Wausau, Florida, in Washington County, adjacent to SR 77. The pipeline lateral route will follow SR 77 south from FGT to a point where SR 77 intersects Gulf's transmission line in Bay County. Then it will parallel the transmission line into the plant.

The pipeline lateral will be licensed and permitted in separate applications by the pipeline vendor. The applications and detailed information about the pipeline will be evaluated by the appropriate regulatory agencies in separate, future proceedings. Chapter 6.0 of this SCA presents a preliminary overview of the proposed pipeline route and potential impacts.

Table 3.3.0-1. Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Pentane+	0.2
Propane	0.7
I-butane	0.2
N-butane	0.1
Nitrogen	0.4
Methane	94.5
CO_2	0.8
Ethane	3.2
Other Characteristics	
Heat content (LHV)	944 Btu/ft^3 at 14.73 psia, dry
Sulfur content (maximum)	2.0 gr/100 scf

Note: Btu/ft^3 = British thermal unit per cubic foot.
gr/100 scf = grain per 100 standard cubic foot.
LHV = lower heating value.
psia = pound per square inch absolute.

Source: Gulf Power Company, 1999.

3.4 AIR EMISSIONS AND CONTROLS

3.4.1 AIR EMISSION TYPES AND SOURCES

The principal sources of air emissions from Smith Unit 3 will be the two natural gas-fired CTGs. The pollutants emitted in the largest quantities will be NO_x and CO; lesser amounts of particulate matter (PM/PM_{10}), SO_2, volatile organic compounds (VOCs), and sulfuric acid (H_2SO_4) mist will also be emitted from the CTGs. Another source of PM/PM_{10} emissions will be the cooling tower, whose drift will contain dissolved, condensable solids.

As indicated previously, GE has been selected as the CTG vendor. Table 3.4.1-1 provides maximum hourly criteria pollutant emission rates (exclusive of startup and shutdown) for each GE 7241FA CTG/HRSG unit. Maximum hourly noncriteria pollutant (i.e., H_2SO_4 mist) emission rates are summarized in Table 3.4.1-2. The highest hourly emission rates for each pollutant are provided, taking into account load and ambient temperature, to develop maximum hourly emission estimates for each CTG/HRSG unit. Maximum hourly emission rates for PM/PM_{10}, NO_x, CO, and VOCs, in units of pounds per hour (lb/hr), are projected to occur for operations at 100-percent load, steam power augmentation and duct burner firing, and 95°F ambient temperature. For PM/PM_{10}, hourly emission rates are projected to be independent of CTG load and ambient temperature based on GE emissions data. Maximum hourly rates for SO_2 and H_2SO_4 mist are projected to occur for operations at 100-percent load, duct burner firing, and 0°F ambient temperature.

Table 3.4.1-3 presents projected maximum annualized criteria and noncriteria emissions for the facility. The maximum annualized rates were conservatively estimated assuming base load operation for 7,760 hr/yr with duct burner firing and evaporative cooling at an average annual ambient temperature of 59°F (i.e., Case 6 operating conditions) and base load operation for 1,000 hr/yr with steam power augmentation, evaporative cooling, and duct burner firing at an average annual ambient temperature of 95°F (i.e., Case 11 operating conditions). Cooling tower PM/PM_{10} emissions and total facility annual emissions are also shown in Table 3.4.1-3.

Table 3.4.1-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Pb	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	0†	20.8	2.62	12.7	1.60	78.7	9.91	78.7	9.91	10.2	1.29	Neg.	Neg.
	65‡	20.9	2.63	11.9	1.50	82.9	10.45	75.4	9.49	9.8	1.23	Neg.	Neg.
	95**	21.5	2.65	12.4	1.57	113.3	14.28	116.6	14.69	16.8	2.12	Neg.	Neg.
75	0	19.8	2.50	9.3	1.18	56.1	7.07	46.2	5.82	5.2	0.66	Neg.	Neg.
	65	19.8	2.50	8.6	1.09	51.7	6.51	42.9	5.41	5.2	0.65	Neg.	Neg.
	95	19.8	2.50	8.2	1.04	49.5	6.24	40.7	5.13	4.2	0.53	Neg.	Neg.
50	0	19.8	2.50	7.4	0.94	44.0	5.54	37.4	4.71	4.4	0.55	Neg.	Neg.
	65	19.8	2.50	6.9	0.87	41.8	5.27	35.2	4.44	4.4	0.55	Neg.	Neg.
	95	19.8	2.50	6.6	0.83	39.6	4.99	34.1	4.30	5.0	0.63	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible.

* Excludes H_2SO_4 mist.
† Emission rates include supplemental duct burner firing.
‡ Emission rates include use of evaporative cooler and supplemental duct burner firing.
** Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table 3.4.1-2. Maximum Noncriteria Pollutant Emission Rates for Three Loads and Three Ambient Temperatures (per CTG/HRSG Unit)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4 mist	
		lb/hr	g/s
100	0*	1.46	0.184
	65†	1.36	0.172
	95‡	1.43	0.180
75	0	1.07	0.135
	65	0.99	0.125
	95	0.94	0.119
50	15	0.85	0.108
	65	0.80	0.100
	95	0.76	0.095

Note: g/s = gram per second.

*Emission rates include supplemental duct burner firing.
†Emission rates include use of evaporative cooler and supplemental duct burner firing.
‡Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table 3.4.1-3. Maximum Annualized Emission Rates for Smith Unit 3

Pollutant	CTG/HRSG Units	Cooling Tower	Facility Totals
NO_x	756.9	N/A	756.9
CO	701.3	N/A	701.3
PM/PM_{10}*	183.6	68.9	252.5
SO_2	104.5	N/A	104.5
VOC	92.8	N/A	92.8
H_2SO_4 mist	12.0	N/A	12.0

Note: N/A = not applicable.

*Excludes H_2SO_4 mist.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Details of the annualized emission calculations are also included in the supporting documentation for the prevention of significant deterioration (PSD) permit application (see Appendix 10.2.7). Stack parameters for the natural gas-fired CTG/HRSG units are provided in Table 3.4.1-4.

3.4.2 AIR EMISSION CONTROLS

The conceptual design of the Smith Unit 3 incorporates state-of-the-art technology at every step, starting with the selection of advanced firing temperature F-class CTGs. The high efficiency of the Project will reduce emissions per unit of output by producing each MW-hour of electricity with less combustion of fuel. The use of natural gas as the only fuel for the CTGs also has the benefit of reducing emissions. The supplemental duct burners will employ low-NO_x burners to reduce NO_x emissions.

Table 3.4.2-1 presents a summary of air emission controls. The use of low-sulfur natural gas, along with highly efficient combustion, will limit PM/PM_{10} emissions from the CTGs and supplemental duct burners. CO and VOC emissions from the CTGs and supplemental duct burners will be controlled by the use of advanced combustion equipment and operational practices to obtain efficient combustion. Highly efficient combustion will, in turn, result in low CO and VOC emission rates. The CTGs and supplemental duct burners will be equipped with dry low-NO_x combustors and low-NO_x burners, respectively, to abate NO_x emissions. SO_2 and H_2SO_4 mist emissions will be controlled by the use of low-sulfur natural gas. Natural gas sulfur content will be no more than 2 grains per 100 dry standard cubic feet (gr/100 dscf). Finally, the use of drift eliminators to limit drift to no more than 0.001 percent of circulating water will control PM/PM_{10} emissions from the cooling tower.

3.4.3 BEST AVAILABLE CONTROL TECHNOLOGY

The PSD air permitting regulations require detailed consideration of alternative means of emission control on a pollutant-by-pollutant basis. The purpose of this control technology review process is to determine the best available control technology (BACT). As defined by Rule 62-210.200, Florida Administrative Code (F.A.C.), BACT represents an emission limitation that reflects the maximum degree of pollutant reduction achievable, determined

Table 3.4.1-4. Stack Parameters for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height m	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter m
100	0*	121	36.7	190	361	81.5	24.8	16.8	5.11
	65†	121	36.7	186	359	74.2	22.6	16.8	5.11
	95‡	121	36.7	170	350	73.3	22.3	16.8	5.11
75	0	121	36.7	170	350	62.6	19.1	16.8	5.11
	65	121	36.7	166	348	58.7	17.9	16.8	5.11
	95	121	36.7	180	355	58.1	17.7	16.8	5.11
50	0	121	36.7	159	344	50.2	15.3	16.8	5.11
	65	121	36.7	155	341	47.6	14.5	16.8	5.11
	95	121	36.7	173	351	47.9	14.6	16.8	5.11

Note: m = meter.
K = Kelvin.
m/sec = meter per second.

*Stack parameters reflect supplemental duct burner firing.
†Stack parameters reflect use of evaporative cooler and supplemental duct burner firing.
‡Stack parameters reflect use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table 3.4.2-1. Summary of Air Emission Controls

Pollutant	Means of Control
CTGs and Duct Burners	
PM/PM_{10}	• Exclusive use of low-sulfur natural gas.
	• Efficient and complete combustion.
CO and VOC	• Efficient and complete combustion.
NO_x	• Use of advanced dry low-NO_x combustor technology.
SO_2/H_2SO_4 mist	• Exclusive use of low-sulfur natural gas.
Cooling Tower	
PM/PM_{10}	• Efficient drift elimination.

Source: ECT, 1999.

on a case-by-case basis, with consideration given to energy, environmental, and economic impacts. BACT emission limitations must be no less stringent than any applicable new source performance standards (NSPS) (40 Code of Federal Regulations [CFR] 60), National Emission Standards for Hazardous Air Pollutants (NESHAPs) (40 CFR 61), and state emission standards (Chapter 62-296, F.A.C., Stationary Sources—Emission Standards).

A complete BACT evaluation for Smith Unit 3 is contained in the PSD permit application in Appendix 10.2.7. Proposed BACT emission limitations for the CTGs are summarized in Table 3.4.3-1. An abbreviated discussion of the BACT review is provided in the following sections. Note that NO_x emissions from Smith Unit 3 are not subject to PSD review because there will be a net reduction in NO_x emissions from the Lansing Smith Plant due to the installation of low-NO_x burner technology and an improved burner management system for Smith Unit 1.

3.4.3.1 Methodology

The BACT analysis was performed in accordance with the EPA *top-down* method. The first step in the top-down BACT procedure was the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Following the identification of available control technologies, the next step in the analysis was to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the *EPA New Source Review (NSR) Workshop Manual* (EPA, 1990). The third step in the top-down BACT process was the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness. Assessment of energy, environmental, and economic impacts was then performed. The economic analyses of the technologies used the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). The fifth and final step was the selection of a BACT emission limitation corresponding to the most stringent technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds. Control technology analyses using the five step *top-*

Table 3.4.3-1. Summary of Proposed BACT Emission Limitations

Pollutant	Proposed BACT Emission Limits (ppmvd @ 15% O_2)	(lb/hr)
GE PG7241 (FA) CTG/HRSG (per CTG/HRSG Unit)		
A. All Operating Scenarios		
PM/PM_{10}	10% opacity	
SO_2	Fuel ≤2.0 gr S/100 scf	
H_2SO_4	Fuel ≤2.0 gr S/100 scf	
B. With or Without Steam Power Augmentation, Without Duct Burner Firing		
CO	13.0	58.3
VOC	2.7	6.6
C. With Duct Burner Firing, Without Steam Power Augmentation		
CO	15.8	78.7
VOC	3.6	10.2
D. With Duct Burner Firing and Steam Power Augmentation		
CO	22.9	116.6
VOC	5.8	16.8
Cooling Tower		
PM/PM_{10}	0.001 percent drift loss rate	

Note: O_2 = oxygen.
ppmvd = part per million by dry volume.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

down BACT method were prepared for combustion products, products of incomplete combustion, and acid gases, respectively. The following is a summary of the BACT analyses that are contained in the PSD permit application.

3.4.3.2 Summary of BACT Determinations

PM/PM_{10}

Available technologies considered for controlling PM/PM_{10} from CTG/HRSG units include the following postprocess controls:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Post-process stack controls for PM/PM_{10} are not appropriate for CTG/HRSG units because of the very low concentrations of PM/PM_{10} emissions in the exhaust. The use of good combustion practices and clean fuels is considered to be BACT. The CTGs and supplemental duct burners will use the latest burner technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel that is completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTGs and supplemental duct burners will be fired exclusively with natural gas.

For the cooling tower, the only practical means of limiting PM/PM_{10} emissions in drift are to limit cooling water cycles of concentration (i.e., to keep dissolved solids at lower concentrations) and/or apply drift eliminators. Because of Gulf Power's desire to limit water use, cooling water will be recycled to the maximum practical degree. Drift eliminators will then be used to limit drift to no more than 0.001 percent of circulating water flow.

<u>CO</u>

There are two available technologies for controlling CO from CTG/HRSG units:

- Combustion process design.
- Oxidation catalysts.

Combustion process controls involve CTG combustion chamber and duct burner designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTGs, approximately 99 percent, CO emissions from CTGs are inherently low. CO emissions from the CTG/HRSG units at base load with or without steam power augmentation, and without duct burner firing, will be less than or equal to 13 ppmvd at 15 percent O_2. With duct burner firing and no steam power augmentation, CO emissions from the CTG/HRSG units at base load will be less than or equal to 16 ppmvd at 15 percent O_2. With duct burner firing and steam power augmentation, CO emissions from the CTG/HRSG units at base load will be less than or equal to 23 ppmvd at 15 percent O_2; this operating condition, however, will occur for no more than 1,000 hr/yr. These CO emissions are consistent with recent FDEP CO BACT determinations for CTG/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5.

Oxidation catalyst was determined not to be cost effective for the Smith Unit. 3. An economic evaluation of an oxidation catalyst system having an 80-percent CO removal efficiency was performed for the CTG/HRSG units using OAQPS and project-specific economic cost factors. Base case CO emissions are estimated to be 80 lb/hr per CTG/HRSG unit resulting in a controlled CO emission rate of 16 lb/hr. Base case CO emissions were conservatively estimated assuming 7,760 hr/yr operation at base load, evaporative cooling, duct burner firing, 59°F ambient temperature and 1,000 hr/yr, base load, steam power augmentation, evaporative cooling, and duct burner firing, 95°F ambient temperature per CTG/HRSG unit. Cost effectiveness of oxidation catalyst for CO emissions was determined to be $1,567 per ton of CO removed for each CC unit. Based on the high control costs, use of oxidation catalyst technology to control CO and VOC emissions was not considered to be economically feasible.

In addition, a CO oxidation catalyst control system does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to carbon dioxide (CO_2). From an air quality perspective, the only potential benefit of a CO oxidation catalyst control system is to prevent the possible formation of a localized area with elevated concentrations of CO. Accordingly, the use of oxidation catalyst to control CO from CTG/HRSG units is typically required only for facilities located in CO nonattainment areas. The Lansing Smith Plant is located in Bay County, Florida, which is designated as having air quality that meets or is better than the national and Florida AAQS for all criteria pollutants, including CO. Dispersion modeling of CO emissions from Smith Unit 3 indicate that maximum CO impacts, without oxidation catalyst, will be insignificant.

Use of combustion controls and good operating practices to minimize incomplete combustion are proposed as BACT for the CTG/HRSG units. These control methods are consistent with prior FDEP BACT determinations for CO emissions from CTG/HRSG units.

SO_2 and H_2SO_4 mist

Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and postcombustion add-on controls (i.e., flue gas desulfurization [FGD]) systems. These controls are applied to facilities burning high-sulfur fuels (e.g., coal). There have been no applications of FGD technology to CTG/HRSG units because low-sulfur fuels are typically utilized. The proposed CTG/HRSG units will be fired exclusively with natural gas. The sulfur content of natural gas is more than 100 times lower than the fuels (e.g., coal) employed in conventional coal-fired boilers utilizing FGD systems. In addition, CTG/HRSG units operate with a significant amount of excess air which generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of a FGD system to a CTG/HRSG exhaust stream would result in very low SO_2 removal efficiencies. Since the CTG/HRSG will produce a low SO_2 exhaust stream concentration, the SO_2 removal efficiencies would be unreasonably low, thus making FGD technology technically infeasible for CTG/HRSG units.

Because post-combustion SO_2 and H_2SO_4 mist controls are not appropriate, use of low-sulfur fuel is considered to represent BACT for the CTG/HRSG units. Natural gas will contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 scf).

3.4.4 DESIGN DATA FOR CONTROL EQUIPMENT

Control of air emissions for the Smith Unit 3 will be accomplished by the use of highly efficient process technologies and clean fuels. These process technologies and fuels will achieve low emission rates without the application of post-combustion control equipment. Process descriptions, emission rates and exhaust gas characteristics, and fuel specifications are provided in Section 3.3 of this SCA.

3.4.5 DESIGN PHILOSOPHY

Air emission controls planned for the Smith Unit 3 have been designed to fully comply with all applicable state and federal regulations. Specific design concepts are summarized as follows:

- Application of BACT for all affected pollutants and emission sources.
- Use of low-sulfur fuel.
- Use of efficient combustion to minimize emissions of pollutants associated with incomplete combustion.

The Project will use the most efficient technology available to convert natural gas to electrical power. On a total power production basis, CTG/HRSG air emissions are minimized by using technology that produces the most power for each unit of fuel consumed at near complete combustion. CTG/HRSG emissions, on a pound-per-megawatt basis, are well below the rates generated by conventional natural gas-, oil-, and coal-fired power plants.

Air emission control technologies planned for the Project reflect the application of BACT for each affected pollutant and emission source. The proposed BACT limitations are well below applicable state and federal emission standards (e.g., NSPS).

3.5 PLANT WATER USE

The Smith Unit 3 Project will be designed to minimize the overall impact of both water intake and water discharge on the local environment. The primary use of water will be for the cooling water system and for steam cycle makeup. The following list presents the expected major water usages during continuous plant operation.

- Cooling tower blowdown.
- Cooling tower evaporation.
- Gas turbine evaporative cooler evaporation.
- Gas turbine evaporative cooler blowdown.
- HRSG blowdown.
- Gas turbine on-line compressor water wash.
- Gas turbine steam injection losses (during power augmentation operation only).

Other water flows that must be considered include:

- Equipment cooling system losses (leaks, evaporation, etc.).
- Plant washdown.
- HRSG chemical cleaning (typically occurs once every 3 to 5 years).
- Potable water consumption by on-site personnel.
- Site runoff and wastewater.

The cooling water system has by far the greatest water need of all of the systems. Figures 3.5.0-1 and 3.5.0-2 present the proposed water budget flow diagram for the Project for normal operation and for power augmentation, respectively. Tables 3.5.0-1 and 3.5.0-2 present the breakdown of the water balance numbers under normal operating scenario and under power augmentation scenario, respectively.

3.5.1 HEAT DISSIPATION SYSTEM

3.5.1.1 System Design

The heat dissipation system is designed to meet all of the equipment cooling requirements of the plant, including the cooling requirements of the steam condenser. The major components of the system include:

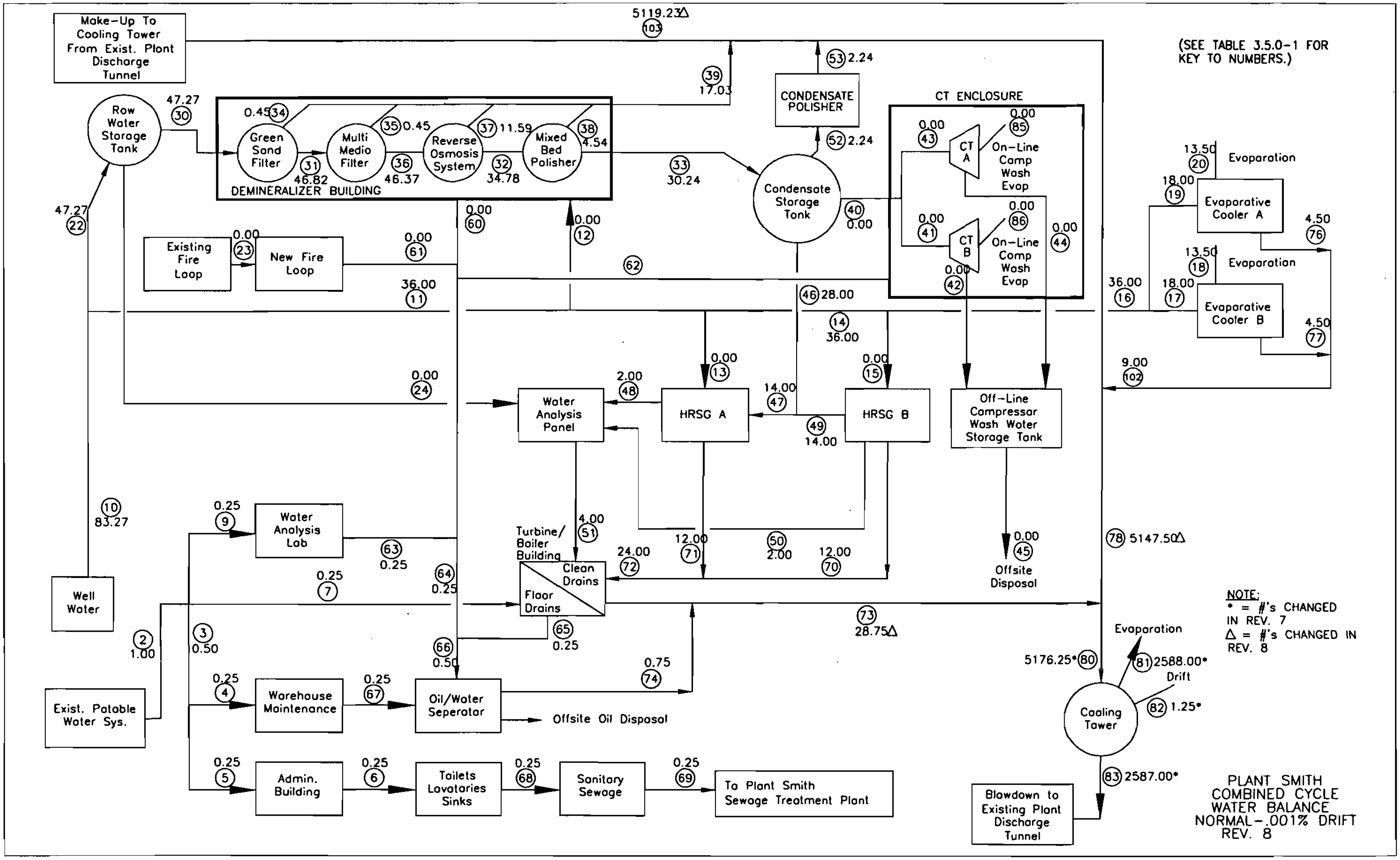

FIGURE 3.5.0-1.

WATER BUDGET FLOW DIAGRAM - NORMAL OPERATING SCENARIO

Source: SCS, 1999 (Rev. 8).

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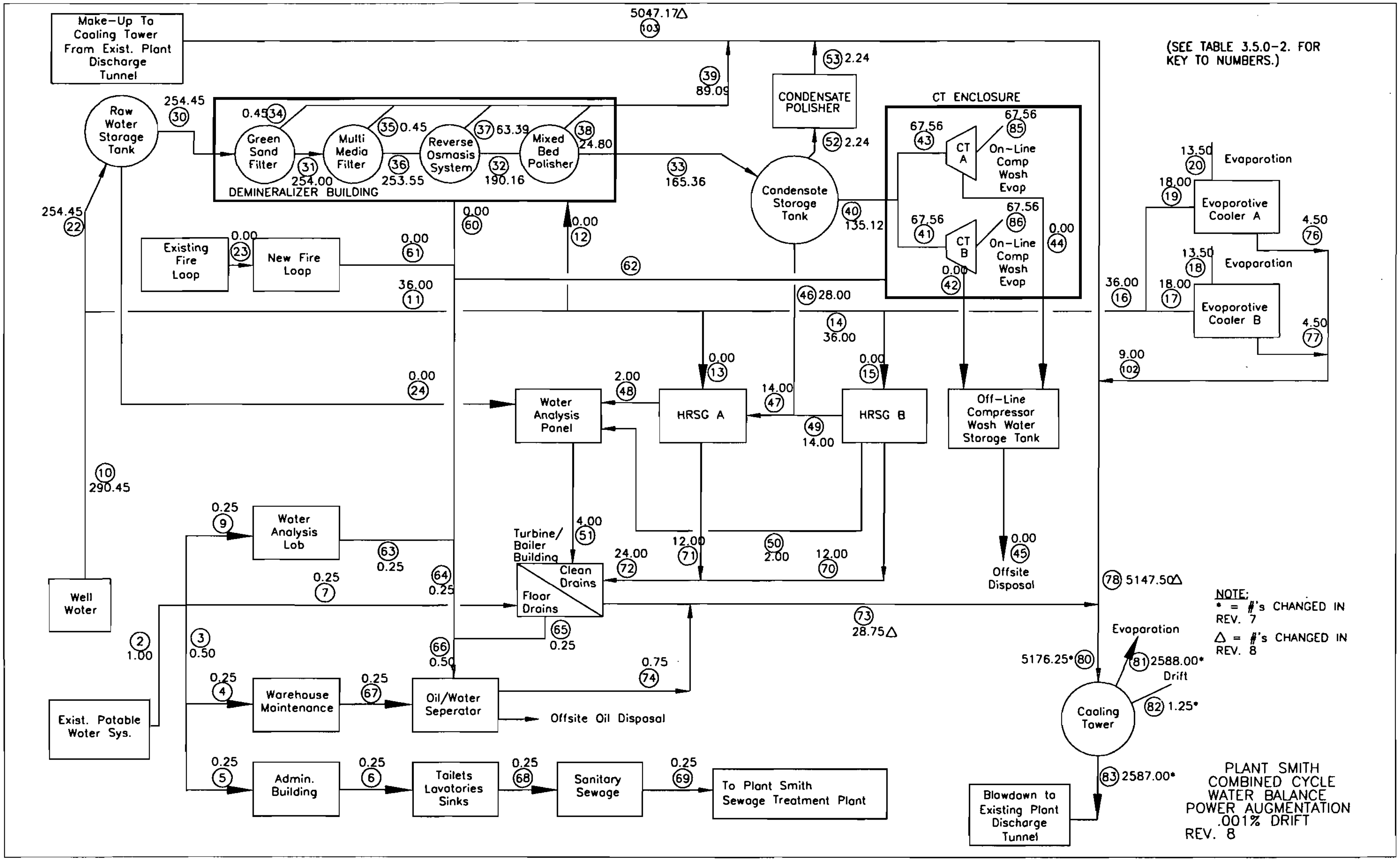

FIGURE 3.5.0-2.

WATER BUDGET FLOW DIAGRAM - POWER AUGMENTATION SCENARIO

Source: SCS, 1999 (Rev. 8).

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Table 3.5.0-1. Water Balance Under Normal Operating Conditions

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)

		Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
1																
2	Potable Water	1.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
3	Potable Water to Warehouse and Admin Building	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
4	Potable Water to Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
5	Potable Water to Admin. Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
6	Potable Water to Toilets, Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
7	Potable Water to Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
8																
9	Potable Water to Water Analysis Lab.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
10	Well Water to Evap. Coolers and Demineralizer	83.27	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
11	Well Water to Evap Coolers, and Demineralizer	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
12	Well Water to Demin Building	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
13	Well Water to HRSG A	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
14	Well Water to HRSG B and Evap. Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
15	Well Water to HRSG B	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
16	Well Water to Evaporative Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
17	Well Water to Evaporative Cooler B	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
18	Evaporative Cooler B - Evaporation	13.50				0.00					0.00					
19	Well Water to Evaporative Cooler A	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
20	Evaporative Cooler A - Evaporation	13.50				0.00					0.00					
21																
22	Well Water to Raw Water Storage Tank	47.27	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
23	Well Water to Fire Protection Pumps	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
24	Well Water to Water Analysis Panel Coolers	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
25																
26																
27																
28																
29																
30	Makeup Water to the Demineralizer	47.27	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
31	Green Sand Filter Effluent	46.82	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
32	Reverse Osmosis Permeate to Mixed Bed Polisher	34.78	1.25	0.16	4.38	5.80	3.74	0.02	2.44	0.00	6.20	6.17	0.26	0.00	60.00	0.00
33	Mixed Bed Effluent to Condensate Storage Tank	30.24	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
34	Green Sand Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00
35	Multi Media Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00
36	Filtered Water to Reverse Osmosis System	46.37	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
37	Reverse Osmosis Concentrate	11.59	965.33	123.00	571.73	1660.05	806.52	53.69	674.86	0.00	1535.07	7.40	59.23	0.00	60.00	0.00
38	Mixed Bed Regenerant Waste	4.54	0.00	0.00	460.00	460.00	1.97	459.00	0.00	0.00	460.97	7.00	0.00	0.00	60.00	0.00
39	Total Demineralizer Waste	17.03	669.92	85.35	519.47	1274.73	558.45	159.55	471.53	0.00	1189.53	7.26	41.13	42.28	60.00	0.00
40	Condensate to CT's	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
41	Condensate Makeup to CT B	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
42	CT B Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
43	Condensate Makeup to CT A	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
44	CT A Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
45	Off-Line Wash Water to Off-Site Disposal	0.00														
46	Condensate Makeup to HRSG's	28.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
47	Condensate Makeup to HRSG A	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
48	HRSG A Boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
49	Condensate Makeup to HRSG B	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
50	HRSG B boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
51	Boiler Water sample drains	4.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	9.6	0.01	0.00	77.00	0.00
52	Demin H2O to Cond. Polisher for Regen	2.24	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00

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Table 3.5.0-1. Water Balance Under Normal Operating Conditions (Continued, Page 2 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)

	Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
53 Condensate Polisher Regenerant Waste	2.24	27.25	44.28	904.70	976.23	106.60	520.00	132.54	0.22	759.36	8.29	30.54	800.00	120.00	0.00
54															
55															
56	(All elements are listed as Calcium Carbonate Equivalent, CaCO3)														
57					Total					Total					
58	Flow (gpm)	Calcium	Magnesium	Sodium	Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Anions	pH	Silica	TSS	Temp	Oil&Grease
59	*24 hr avg.*														
60 Clean Drains from Demineralizer	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
61 Drains from Fire Protection Pump Room	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
62 Drains from CT Enclosure	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
63 Drains from Water Analysis Laboratory	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
64 Drain Header from Wtr Lab, CT's, and Fire Prot.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
65 Floor Drains from Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
66 Drain Header from Turb/Blr ,CT's ,Fire Prot ,Wtr La	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
67 Drains from Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
68 Drains from Toilets, Lavatories, and Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
69 Sanitary Sewage Drain to Treatment System	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	3.00	413.93	7.50	15.30	0.00	60.00	0.00
70 HRSG B Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
71 HRSG A Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
72 Total Blowdown from HRSG's	24.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	0.50	2.00	212.00	0.00
73 Clean Drains from Turbine/Boiler Building	28.75	0.00	0.00	0.27	0.27	0.00	0.13	0.18	8.35	8.66	9.61	0.42	1.67	187.69	0.00
74 Effluent from Oil Water Seperator	0.75	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	10.00
75															
76 Blowdown from Evaporitive Cooler A	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
77 Blowdown from Evaporitive Cooler B	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
78 River Water and Evap. Cooler Blowdown	5147.50	430.71	2377.58	11998.32	14806.62	55.49	2896.81	12248.33	0.00	15200.63	7.97	0.20	6.95	85.88	0.00
79															
80 Cooling Tower Makeup	5176.25	428.32	2364.38	11931.68	14724.38	55.18	2880.72	12180.30	0.05	15116.25	7.97	0.20	6.92	86.45	0.00
81 Cooling Tower Evaporation	2588.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.00	0.00	0.00	0.00
82 Cooling Tower Drift	1.25														
83 Cooling Tower Blowdown (2 COC)	2587.00	856.64	4728.75	23863.37	29448.76	110.36	5761.44	24360.60	0.09	30232.50	7.97	0.41	13.85	86.00	0.00
84															
85 CT - A Power Augmentation Steam to Atms.	0.00														
86 CT - B Power Augmentation Steam to Atms.	0.00														
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101															
102 Blowdown from Evaporative Coolers	9.00	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
103 Raw Water to the Cooling Tower	5119.23	430.00	2390.30	12061.94	14882.24	53.30	2912.00	12313.53	0.00	15278.83	7.98	0.00	6.50	86.00	0.00
104															

Table 3.5.0-1. Water Balance Under Normal Operating Conditions (Continued, Page 3 of 4)

(All elements are listed as Calcium Carbonate Equivalent, $CaCO_3$)

	Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
105															

Water analysis	North Bay mg/l	North Bay as CaCO3	Well Water mg/l	Well Water as CaCO3	RO Concentrate mg/l	RO Concentrate as CaCO3	RO Permeate	RO Permeate as CaCO3	Mixed Bed	Mixed Bed as CaCO3
Calcium	172.00	430.00	96.60	241.50	386.13	965.33	0.50	1.25	0.000	0.000
Magnesium	583.00	2390.30	7.44	30.50	30.00	123.00	0.04	0.16	0.000	0.000
Sodium	5533.00	12061.94	67.00	146.06	262.26	571.73	2.01	4.38	0.003	0.007
Total Cations		14882.24		418.06		1660.05		5.80		0.007
Bicarbonate	65.00	53.30	204.88	168.00	806.52	661.35	4.56	3.74	0.000	0.000
Sulfate	2800.00	2912.00	13.26	13.79	53.69	55.84	0.02	0.02	0.003	0.003
Chloride	8733.00	12313.53	162.51	229.14	674.86	951.55	1.73	2.44	0.003	0.004
Phosphate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000
Total Anions		15278.83		410.93		1668.74		6.20		0.007
pH	7.98		7.5		7.4		6.17		5.64	
Silica	0.792	0.66	15.3	12.70	59.23	49.16	0.26	0.22	0.01	0.01
TSS	6.5		0		0		0		0	
Temperature	86 F		60 F		60 F		60 F		60 F	
Oil and Grease	0		0		0		0		0	
							Note:CO2 Stripper on RO Effluent			
Boiler pH	9.6									
Cooling tower basin temperature	86 F									

Water analysis (Calculated in Spreadsheet)	Cooling Tower Blowdown mg/l	Cooling Tower Blowdown as CaCO3	Oil Water Seperator Effluent mg/l	Oil Water Seperator Effluent as CaCO3
Calcium	342.66	856.64	96.60	241.50
Magnesium	1153.35	4728.75	7.44	30.50
Sodium	9545.35	23863.37	58.42	146.06
Total Cations		29448.76		418.06
Bicarbonate	134.59	110.36	204.88	168.00
Sulfate	13849.62	5761.44	33.15	13.79
Chloride	17277.02	24360.60	162.51	229.14
Phosphate	0.06	0.09	0.00	0.00
Total Anions		30232.50		410.93
pH	7.97		7.50	
Silica	0.49	0.41	18.43	15.30
TSS	13.85		0.00	
Temperature	86 F		60.00 F	
Oil and Grease	0		10.00	

Table 3.5.0-1. Water Balance Under Normal Operating Conditions (Continued, Page 4 of 4)

(All elements are listed as Calcium Carbonate Equivalent, $CaCO_3$)

Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease

Assumptions

1 1% Blowdown from the HRSG = 12 gpm/HRSG

2 Water Analysis panel coolers will utilize closed loop cooling system.

3 Water Analysis samples will flow continuously at an average of 750 ml/min. Newing will have 2 sample panels each consisting of 10 samples. Total flow .75 l/min x 10 x 2 = 15 l/min or 4 gpm

4 Line 33 & 34 - Backwash will be approximately 2X service flow.
Assume one backwash per week.
304 gpm for 15 min = 4560 gallons to the tank.
Drain tank at .45 gpm (24 hour flow).
Assume one pound of solids for each square foot of filter surface area.
152gpm/5 gpm/sqft = 30.4 sqft > 30.4 pounds of solids
(Line 33 & 34) ppm = pounds of solids / pounds of water = parts/1,000,000 = 800 ppm

5 Line 70,71 - Assumed 2 ppm TSS blown. Value obtained from Chevron Generation Facility.

6 Line 76, 77 - Evaporative coolers operate at 2 cycles of concentration.

7 All flows in spreadsheet are 24 hour flows.

8 Blowdown constituents based on letter from Sheppard T. Powell ref. Newington Project
TSS based on Chevron operating experience.

9 Rev 1 - The water analysis included in the spreadsheet for Bay water is from data collected during July and August, 1993-1997 at the circulating water intake to the Plant. (NB1R)

10 Rev 1 - Cooling tower blowdown, evaporation, and drift updated 3/30/99 per Jim Cuchens spreadsheet for over pressure mode.

11 Assumed same solid loading for condensate polisher as the multimedia filter for backwash TSS.

12 Seawater Silica number per Doug Helms email dated Thursday April 1 (792 ppb)

13 Adjusted boiler blowdown for Phosphate Treatment Assumed 10 ppm of phosphate in the blowdown.
This assumption is based on a letter from Jack Siegmund at Shepard T. Powell, letter dated January 18, 1999.

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario

(All elements are listed as Calcium Carbonate Equivalent, $CaCO_3$)

		Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
1																
2	Potable Water	1.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
3	Potable Water to Warehouse and Admin Building	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
4	Potable Water to Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
5	Potable Water to Admin. Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
6	Potable Water to Toilets, Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
7	Potable Water to Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
8																
9	Potable Water to Water Analysis Lab.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
10	Well Water to Evap. Coolers and Demineralizer	290.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
11	Well Water to Evap Coolers, and Demineralizer	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
12	Well Water to Demin Building	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
13	Well Water to HRSG A	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
14	Well Water to HRSG B and Evap. Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
15	Well Water to HRSG B	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
16	Well Water to Evaporative Coolers	36.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
17	Well Water to Evaporative Cooler B	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
18	Evaporative Cooler B - Evaporation	13.50				0.00					0.00					
19	Well Water to Evaporative Cooler A	18.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
20	Evaporative Cooler A - Evaporation	13.50				0.00					0.00					
21																
22	Well Water to Raw Water Storage Tank	254.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
23	Well Water to Fire Protection Pumps	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
24	Well Water to Water Analysis Panel Coolers	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
25																
26																
27																
28																
29																
30	Makeup Water to the Demineralizer	254.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
31	Green Sand Filter Effluent	254.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
32	Reverse Osmosis Permeate to Mixed Bed Polisher	190.16	1.25	0.16	4.38	5.80	3.74	0.02	2.44	0.00	6.20	6.17	0.26	0.00	60.00	0.00
33	Mixed Bed Effluent to Condensate Storage Tank	165.36	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
34	Green Sand Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00
35	Multi Media Filter Backwash	0.45	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	800.00	60.00	0.00
36	Filtered Water to Reverse Osmosis System	253.55	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
37	Reverse Osmosis Concentrate	63.39	965.33	123.00	571.73	1660.05	806.52	53.69	674.86	0.00	1535.07	7.40	59.23	0.00	60.00	0.00
38	Mixed Bed Regenerant Waste	24.80	0.00	0.00	460.00	460.00	1.97	459.00	0.00	0.00	460.97	7.00	0.00	0.00	60.00	0.00
39	Total Demineralizer Waste	89.09	689.26	87.82	536.32	1313.40	576.08	166.13	482.47	0.00	1224.68	7.25	42.30	8.08	60.00	0.00
40	Condensate to CT's	135.12	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
41	Condensate Makeup to CT B	67.56	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
42	CT B Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
43	Condensate Makeup to CT A	67.56	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
44	CT A Off-Line Wash Water	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
45	Off-Line Wash Water to Off-Site Disposal	0.00														
46	Condensate Makeup to HRSG's	28.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
47	Condensate Makeup to HRSG A	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
48	HRSG A Boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
49	Condensate Makeup to HRSG B	14.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario (Continued, Page 2 of 4)

(All elements are listed as Calcium Carbonate Equivalent, CaCO3)

		Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
50	HRSG B boiler water samples to Water Analysis	2.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
51	Boiler Water sample drains	4.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	9.6	0.01	0.00	77.00	0.00
52	Demin H2O to Cond. Polisher for Regen	2.24	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	5.64	0.01	0.00	60.00	0.00
53	Condensate Polisher Regenerant Waste	2.24	27.25	44.28	904.70	976.23	106.60	520.00	132.54	0.22	759.36	8.29	30.54	800.00	120.00	0.00
54																
55																
56		(All elements are listed as Calcium Carbonate Equivalent, CaCO3)														
57						Total					Total					
58		Flow (gpm)	Calcium	Magnesium	Sodium	Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Anions	pH	Silica	TSS	Temp	Oil&Grease
59		*24 hr avg.*														
60	Clean Drains from Demineralizer	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
61	Drains from Fire Protection Pump Room	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
62	Drains from CT Enclosure	0.00	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
63	Drains from Water Analysis Laboratory	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
64	Drain Header from Wtr Lab, CT's, and Fire Prot.	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
65	Floor Drains from Turbine/Boiler Building	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
66	Drain Header from Turb/Blr ,CT's ,Fire Prot ,Wtr La	0.50	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
67	Drains from Warehouse	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
68	Drains from Toilets, Lavatories, and Sinks	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	0.00
69	Sanitary Sewage Drain to Treatment System	0.25	241.50	30.50	146.06	418.06	168.00	13.79	229.14	3.00	413.93	7.50	15.30	0.00	60.00	0.00
70	HRSG B Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
71	HRSG A Blowdown	12.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	3.00	2.00	212.00	0.00
72	Total Blowdown from HRSG's	24.00	0.00	0.00	0.33	0.33	0.00	0.16	0.21	10.00	10.37	9.6	0.50	2.00	212.00	0.00
73	Clean Drains from Turbine/Boiler Building	28.75	0.00	0.00	0.27	0.27	0.00	0.13	0.18	8.35	8.66	9.61	0.42	1.67	187.69	0.00
74	Effluent from Oil Water Seperator	0.75	241.50	30.50	146.06	418.06	168.00	13.79	229.14	0.00	410.93	7.50	15.30	0.00	60.00	10.00
75																
76	Blowdown from Evaporitive Cooler A	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
77	Blowdown from Evaporitive Cooler B	4.50	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
78	River Water and Evap. Cooler Blowdown	5147.50	434.40	2345.36	11837.02	14616.78	62.87	2858.39	12082.73	0.00	15003.99	7.95	0.80	6.86	85.52	0.00
79																
80	Cooling Tower Makeup	5176.25	431.99	2332.33	11771.28	14535.60	62.52	2842.52	12015.62	0.05	14920.70	7.91	0.80	6.83	86.09	0.00
81	Cooling Tower Evaporation	2588.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.00	0.00	0.00	0.00
82	Cooling Tower Drift	1.25														
83	Cooling Tower Blowdown (2 COC)	2587.00	863.98	4664.66	23542.56	29071.20	125.03	5685.03	24031.24	0.09	29841.40	7.91	1.59	13.66	86.00	0.00
84																
85	CT - A Power Augmentation Steam to Atms.	67.56														
86	CT - B Power Augmentation Steam to Atms.	67.56														
87																
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Table 3.5.0-2. Water Balance Under Power Augmentation Scenario (Continued, Page 3 of 4)

	Flow (gpm) *24 hr avg.*	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
	(All elements are listed as Calcium Carbonate Equivalent, CaCO3)														
99															
100															
101															
102 Blowdown from Evaporative Coolers	9.00	483.00	61.01	292.12	836.13	336.00	27.58	458.28	0.00	821.86	7.50	30.60	0.00	60.00	0.00
103 Raw Water to the Cooling Tower	5047.17	430.00	2390.30	12061.94	14882.24	53.30	2912.00	12313.53	0.00	15278.83	7.98	0.00	6.50	86.00	0.00
104															
105															

Water analysis	North Bay mg/l	as CaCO3	Well Water mg/l	as CaCO3	RO Concentrate mg/l	as CaCO3	RO Permeate	as CaCO3	Mixed Bed	as CaCO3
Calcium	172.00	430.00	96.60	241.50	386.13	965.33	0.50	1.25	0.000	0.000
Magnesium	583.00	2390.30	7.44	30.50	30.00	123.00	0.04	0.16	0.000	0.000
Sodium	5533.00	12061.94	67.00	146.06	262.26	571.73	2.01	4.38	0.003	0.007
Total Cations		14882.24		418.06		1660.05		5.80		0.007
Bicarbonate	65.00	53.30	204.88	168.00	806.52	661.35	4.56	3.74	0.000	0.000
Sulfate	2800.00	2912.00	13.26	13.79	53.69	55.84	0.02	0.02	0.003	0.003
Chloride	8733.00	12313.53	162.51	229.14	674.86	951.55	1.73	2.44	0.003	0.004
Phosphate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000
Total Anions		15278.83		410.93		1668.74		6.20		0.007
pH	7.98		7.5		7.4		6.17		5.64	
Silica	0.792	0.66	15.3	12.70	59.23	49.16	0.26	0.22	0.01	0.01
TSS	6.5		0		0		0		0	
Temperature	86 F		60 F		60 F		60 F		60 F	
Oil and Grease	0		0		0		0		0	
							Note:CO2 Stripper on RO Effluent			
Boiler pH	9.6									
Cooling tower basin temperature	86 F									

Water analysis (Calculated in Spreadsheet)	Cooling Tower Blowdown mg/l	as CaCO3	Oil Water Seperator Effluent mg/l	as CaCO3
Calcium	345.59	863.98	96.60	241.50
Magnesium	1137.72	4664.66	7.44	30.50
Sodium	9417.02	23542.56	58.42	146.06
Total Cations		29071.20		418.06
Bicarbonate	152.48	125.03	204.88	168.00
Sulfate	13665.94	5685.03	33.15	13.79
Chloride	17043.44	24031.24	162.51	229.14
Phosphate	0.06	0.09	0.00	0.00
Total Anions		29841.40		410.93

Table 3.5.0-2. Water Balance Under Power Augmentation Scenario (Continued, Page 4 of 4)

	(All elements are listed as Calcium Carbonate Equivalent, CaCO3)														
	Flow (gpm) •24 hr avg.•	Calcium	Magnesium	Sodium	Total Cations	Bicarbonate	Sulfate	Chloride	Phosphate	Total Anions	pH	Silica	TSS	Temp	Oil&Grease
pH	7.91			7.50											
Silica	1.92	1.59		18.43	15.30										
TSS	13.66			0.00											
Temperature	86 F			60.00 F											
Oil and Grease	0			10.00											

Assumptions

1 1% Blowdown from the HRSG = 12 gpm/HRSG

2 Water Analysis panel coolers will utilize closed loop cooling system.

3 Water Analysis samples will flow continuously at an average of 750 ml/min. Newing will have 2 sample panels each consisting of 10 samples. Total flow .75 l/min x 10 x 2 = 15 l/min or 4 gpm

4 Line 33 & 34 - Backwash will be approximately 2X service flow.
Assume one backwash per week.
304 gpm for 15 min = 4560 gallons to the tank.
Drain tank at .45 gpm (24 hour flow).
Assume one pound of solids for each square foot of filter surface area.
152gpm/5 gpm/sqft = 30.4 sqft > 30.4 pounds of solids
(Line 33 & 34) ppm = pounds of solids / pounds of water = parts/1,000,000 = 800 ppm

5 Line 70,71 - Assumed 2 ppm TSS blown. Value obtained from Chevron Generation Facility.

6 Line 76, 77 - Evaporative coolers operate at 2 cycles of concentration.

7 All flows in spreadsheet are 24 hour flows.

8 Blowdown constituents based on letter from Sheppard T. Powell ref. Newington Project
TSS based on Chevron operating experience.

9 Rev 1 - The water analysis included in the spreadsheet for Bay water is from data collected during July and August, 1993-1997 at the circulating water intake to the Plant. (NB1R)

10 Rev 1 - Cooling tower blowdown, evaporation, and drift updated 3/30/99 per Jim Cuchens spreadsheet for over pressure mode.

11 Assumed same solid loading for condensate polisher as the multimedia filter for backwash TSS.

12 Seawater Silica number per Doug Helms email dated Thursday April 1 (792 ppb)

13 Adjusted boiler blowdown for Phosphate Treatment Assumed 10 ppm of phosphate in the blowdown.
This assumption is based on a letter from Jack Siegmund at Shepard T. Powell, letter dated January 18, 1999.

- Mechanical draft cooling tower.
- Circulating water pumps.
- Intake system for receiving cooling water makeup.
- Discharge system for discharge of cooling tower blowdown.
- Chemical treatment system for treatment of the cooling tower makeup.
- Steam condenser for condensing the exhaust of the steam turbine.
- Heat exchanger interface with the service water cooling system.
- Heat exchangers within the service water cooling system for equipment cooling.

The system utilizes a closed loop cooling circuit that circulates cooled water from the mechanical draft cooling tower to the equipment heat exchangers. Heated water is returned to the mechanical draft cooling tower where it is cooled via an evaporative cooling process. In the evaporative cooling process, a certain amount of water is lost through evaporation and drift. A certain amount of water must also be discharged from the cooling tower in order to maintain the required water quality within the cooling tower. These cooling tower losses must be replaced with water from an outside source.

The cooling tower will use bay water taken from the existing Lansing Smith cooling water system to makeup all losses. The existing system for Units 1 and 2 uses once-through cooling with water taken from North Bay passing directly through the condenser and being discharged directly into a discharge canal, which leads to West Bay. The cooling water makeup system for Smith Unit 3 will actually use hot water exiting the existing Unit 1 and 2 system and will discharge water back to the discharge canal from the cool water side of the new Unit 3 cooling tower. In essence, the new facility will act to reduce the amount of heat currently discharged into the cooling water discharge canal.

The mechanical draft cooling tower will be of a counter flow design The system is expected to have an overall heat duty of 1,445 MMBtu/hr. Based on operation with two cycles of concentration the amount of makeup water for Unit 3 is expected to average approximately 5,120 gallons per minute (gpm) or 7,372,800 gallons per day (gpd). The discharge from the existing Units 1 and 2 cooling system averages 190,000 gpm or 274 MGD.

3.5.1.2 Source of Cooling Water

The source of cooling water will be the existing discharge flow of the existing Lansing Smith generating units which uses bay water from North Bay. The average annual water intake for the new cooling system is estimated to be approximately 7.5 MGD.

3.5.1.3 Dilution System

A new dilution system will not be included as part of the facility. As the cooling tower blowdown is discharged into the existing cooling water canal, some dilution effects will be realized from the existing discharge canal before the water mixes with the receiving waters in West Bay. The addition of the new cooling water cycle has been designed to lower the total discharge temperature for both the new and existing units.

3.5.1.4 Blowdown, Screened Organisms, And Trash Disposal

The cooling tower blowdown will be discharged into the existing cooling water discharge canal. The average annual discharge rate is expected to be 2,587 gpm or 3.7 MGD. As the makeup water will be taken from the existing cooling water system, no new trash screens will be used; therefore there will be no additional disposal of organisms or trash.

3.5.1.5 Injection Wells

Injection wells will not be used.

3.5.2 DOMESTIC/SANITARY WASTEWATER

All domestic and sanitary wastewater will be routed to the existing Lansing Smith Plant sewer system. That existing system has the permitted capacity to handle the increased flows generated by Smith Unit 3. Based on a conservative consumptive rate of 35 gpd per person, the total average flow is expected to be 1,015 gpd. However, a more realistic figure is 20 gpd per person or 580 gpd for total average flow.

3.5.3 POTABLE WATER SYSTEMS

Potable water will be taken from the existing potable water system at the Lansing Smith Plant. Based on an average consumptive rate of 35 gpd per person the average consumption rate is expected to be approximately 1,015 gpd based on 29 full-time employees. This existing system already has adequate production and treatment capacity to serve the demands of the proposed Unit 3.

3.5.4 PROCESS WATER SYSTEMS

The following systems will require process water of varying qualities:

- Gas turbine evaporative coolers (filtered water).
- Gas turbine on-line compressor water wash (demineralized water for both on-line wash and off-line wash).
- Gas turbine steam injection system (demineralized water—increases steam cycle makeup).
- General steam cycle makeup (demineralized water).
- Plant washdown (potable water).
- Fire protection (filtered water).
- HRSG chemical cleaning (filtered/potable water—typically occurs once every 3 to 5 years)

Raw ground water taken from the existing Lansing Smith Plant well system will be used as the precursor for both filtered water production and demineralized water production. A reverse osmosis water treatment facility with a multimedia filter and a mixed bed polisher will be used for producing demineralized water.

3.5.4.1 <u>Gas Turbine Evaporative Cooling</u>

Evaporative coolers will be provided on the CTGs for operation during the hot months of the year. During warm days when the ambient air temperature exceeds 65°F, the turbine inlet ambient air is cooled by the evaporative cooler, thus providing denser air for combustion and improving the electrical power output. Based on GE standard practice, approximately 18 gpm (based on 24 hours a day) of filtered water will be required for makeup to the evaporative coolers for each CT. Assuming four cycles of concentration, approximately 9 gpm from each enclosure will be blown down to a drain. The blowdown rate is a function of the makeup water quality. The better the makeup water quality, the higher the allowable cycles of concentration within the system. Filtered water will be used for this service.

3.5.4.2 Gas Turbine Off- and On-Line Compressor Water Wash

GE makes provisions for on-line and off-line washes of the CTG. In both cases, demineralized water will be required. In the on-line wash case, the wash water will evaporate in the CTG exhaust stream. In the off-line case, the waste water will be collected and tested to determine if the waste water is hazardous or not. The waste water will be collected and trucked from the site for disposal in a manner appropriate to its waste classification. Off-line wash flow rate will be about 80 gpm for approximately 20 minutes. Table 3.5.4-1 presents the CTG cleaning wash water quality requirements.

Table 3.5.4-1. GE CTG Cleaning Water Quality Requirements
(GEK-103623B applies to water or water and detergent solution)

Constituent	Units	Concentration
	Off-Line Washing	
Total solids (suspended and dissolved)	ppm	100
Total alkali metals	ppm	25
Other metals which may promote hot corrosion (i.e., lead, vanadium)	ppm	1.0
pH		6.5 to 7.6
	On-Line Washing	
Total solids (suspended and dissolved)	ppm	5
Total alkali metals and other metals which may promote hot corrosion (i.e., lead, vanadium)	ppm	0.5
pH		6.5 to 7.5

Note: ppm = part per million.

Source: Gulf Power, 1999.

3.5.4.3 Gas Turbine Power Augmentation

Power augmentation will require 113,450 lb/hr of steam for each gas turbine for up to 1,000 hr/yr. This will require approximately 227 gpm of demineralized water per CTG or 454 gpm for both gas turbine units to meet the steam requirement. Water will be available to support power augmentation for a normal schedule of 10 hours per day for 5 days a week, with storage capacity to support a peak power augmentation event for 2 weeks at 12 hours per day for 5 days a week.

3.5.4.4 Steam Cycle Makeup

All steam cycle makeup will be achieved with demineralized water. Makeup requirements to the steam cycle will be a function of operation. Makeup will replace high pressure and intermediate pressure drum blowdown and replace steam lost during power augmentation. At 1 percent blowdown, 12 gpm will be required for each HRSG and 227 gpm per CTG will be required for power augmentation. For two HRSG/CTG operation, 478 gpm of makeup will be required during power augmentation and 24 gpm for non-power augmentation operation.

3.5.4.5 Other

Other water usage will include water for fire protection, equipment washdown, and HRSG chemical cleaning. In general, the requirements for these uses will be for either filtered or potable water. Usage for these applications will not occur everyday but will occur infrequently.

3.6 CHEMICAL AND BIOCIDE WASTE

The following waste streams will be produced:

- Cooling tower blowdown.
- Gas turbine off-line compressor water wash drains.
- Gas turbine and equipment drains.
- Waste water sump.
- Transformer enclosure drains.
- Storm water runoff
- Chemical cleaning wastes.
- Greensand filter backwash.
- Multimedia filter backwash.
- Reverse osmosis concentrate.
- Reverse osmosis waste cleaning.
- Mixed bed regenerate.

3.6.1 COOLING TOWER BLOWDOWN

Generally, the tower cooling water will require a scale inhibitor and possibly a silt dispersant to maximize the tower operation. A biocide such as sodium hypochlorite will be used to control microbiological fouling in the system. As part of the biocide program, the blowdown valve will be closed during chlorination until chlorine residuals are at an acceptable level. At this time, no dechlorination system is planned.

3.6.2 GAS TURBINE OFF-LINE COMPRESSOR WATER WASH DRAINS

The off-line compressor water wash will produce waste water that will be collected and tested to determine if the waste water is hazardous or not. The waste water will be collected and trucked from the site for disposal in a manner appropriate to its waste classification. Off-line wash flow rate will typically be about 80 gpm for approximately 20 minutes.

3.6.3 GAS TURBINE AND EQUIPMENT DRAINS

The drainage from various pieces of equipment or areas where there is the possibility of oil spills or oil contamination will be drained to an oil-water separator before draining to the site waste water sump. These areas include selective areas at the steam turbine, both gas turbine generator acoustic enclosures, and both gas turbine enclosures.

3.6.4 WASTEWATER SUMP

The wastewater sump will collect the wastewater from the oil-water separator and pump the combined waste to the cooling tower basin.

3.6.5 TRANSFORMER ENCLOSURE DRAINS

Transformers containing oil will be curbed to contain any oil leakage. The contents of the enclosure will be checked periodically for oil contamination. If contaminated, the oil will be removed and disposed in an appropriate manner. Uncontaminated water will be drained and released to the site runoff water system.

3.6.6 STORM WATER RUNOFF

The site storm water runoff will be designed for sheet runoff for collection in two holding ponds.

3.6.7 CHEMICAL CLEANING WASTES

Periodically (approximately once every 3 to 5 years) the HRSGs will require chemical cleaning. Strong phosphate and acid solutions are used in the chemical cleaning process and the resulting waste streams are unsuitable for typical disposal methods. Nonhazardous chemical cleaning waste streams will be diverted to the existing onsite metals cleaning pond for disposal.

3.6.8 GREENSAND FILTER BACKWASH

Greensand filters are utilized to remove dissolved iron, manganese, and hydrogen sulfide from the makeup water prior to the demineralization equipment. The greensand contained in the filters is designed to oxidize the iron, manganese, and hydrogen sulfide to their insoluble states and then capture the elements as a suspended solid. The greensand is regenerated by backwashing and then feeding potassium permanganate to restore the oxidization potential of the media. The backwash/rinse water will contain suspended solids comprised of mainly ferric hydroxide and small amounts of unreacted potassium permanganate.

3.6.9 MULTIMEDIA FILTER BACKWASH

When the multimedia filter differential pressure is exceeded, filter water will be pumped through the filter in reverse flow to remove the collected suspended solids. The multimedia backwash will contain suspended solids trapped by the media that passed through the pretreatment equipment. The frequency of backwashes is dependent on the solids loading from the pretreatment equipment. There is no chemical addition to the multimedia filter during backwash.

3.6.10 REVERSE OSMOSIS CONCENTRATE

A reverse osmosis system operates by forcing makeup water across a membrane to make demineralized water. The reverse osmosis system operates at 75 percent recovery, meaning that 75 percent of the inlet water is made into demineralized water and 25 percent goes to waste. The wastewater contains four times the inlet concentration of dissolved solids and is routed to the cooling tower basin for use as part of the cooling water makeup. The reverse osmosis system will produce concentrate only during operation.

3.6.11 REVERSE OSMOSIS WASTE CLEANING

The reverse osmosis cleaning waste contains dissolved solids and suspended solids trapped on the membrane surface and in the membrane spacers. The reverse osmosis system is cleaned if the permeate flow reduces by 10 to 15 percent or the differential pressure increases by 15 to 25 percent. These contaminants are removed by conducting a low pH followed by a high pH clean. Sulfuric acid will be used as the low pH cleaner and sodium hydroxide will be used as the high pH cleaner. The sulfuric acid will remove scale formations in the membranes. The sodium hydroxide targets organics.

3.6.12 MIXED BED REGENERATE

Mixed bed polishers are regenerated by adding sulfuric acid to the cation resin and sodium hydroxide to the anion resin. The sulfuric acid gives up the hydrogen molecule to replenish the cation with exchangeable hydrogen molecules. The waste from the cation regeneration will contain cations, such as calcium, magnesium, and sodium, attached to a sulfate molecule from the sulfuric acid. The anion is regenerated with sodium hydroxide, with the hydroxide molecule replenishing the anion resin. The sodium portion of the sodium hydroxide will combine with the anions from the resin to form the waste product. In general, sulfates and sodium salts are waste products from the mixed bed ion exchangers. The mixed bed regenerate will be routed to the cooling tower basin.

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 SOLID WASTES

Solid wastes produced by the facility include the following materials:

- Water treatment wastes.
- Used gaskets for piping flanges, pumps, etc.
- Spent air filters.
- Spent turbine parts removed during major maintenance activities.
- Other items typical of a power generating facility.
- Used oils and lubricants.

All solid waste will be hauled offsite for disposal in an approved landfill or, if appropriate, recycled. Used oils and lubricants will be hauled offsite for either proper disposal or recycling, if possible. An estimated 220 gallons of used oils and lubricants will be collected per month. All other solids are estimated to comprise approximately 300 pounds per month.

The suspended solids produced during the greensand filter and the multimedia filter backwash will be discharged to the cooling tower. The backwash streams will produce approximately 9 pounds per day of suspended solids.

3.7.2 HAZARDOUS WASTES

The existing Smith facility is categorized as a conditionally exempt small-quantity generator of hazardous wastes in accordance with Resource Conservation and Recovery Act (RCRA) standards. It is not anticipated that Smith Unit 3 will change this status. Waste streams are expected to be limited to painting and general maintenance operations. No process waste streams should meet the criteria of hazardous wastes.

The following hazardous chemicals are expected to be utilized onsite:

- Closed loop cooling water
    - o Nitrite or molybdate corrosion inhibitor—used to prevent corrosion in metal pipes and valves

  - o Ethylene glycol or propylene glycol antifreeze
- HRSG
  - o Ammonia—used for pH control and to prevent corrosion
  - o Trisodium phosphate—used to prevent caustic corrosion of boiler
- Cooling tower
  - o Sodium hypochlorite—biocide
  - o Polyacrylate or polyacralmide-dispersant—prevents solids from building up in circulating water loop
- Water treatment plant
  - o Sulfuric acid—used to clean reverse osmosis system
  - o Sodium hydroxide—used as high pH cleaner in reverse osmosis
  - o Sodium bisulfite—removes oxidizing agents
  - o Sodium hypochlorite—chlorinates the water
  - o Scale inhibitor—removes precipitants; prevents fouling
  - o Potassium permanganate—regeneration of greensand filter
- General
  - o Miscellaneous detergents
  - o Lubricating oils and greases

All usage and handling of these hazardous chemicals will be done in a manner to fully contain and properly control both the use of the chemical/mixture and the disposal of any resulting effluent of waste stream. All wastes will be managed in accordance with FDEP and EPA rules. Collection and disposal at offsite facilities will be performed by licensed contractors and appropriately licensed treatment/disposal facilities.

In addition, all chemical handling, storage and usage will be in accordance with Department of Transportation (DOT) and Occupational Safety and Health Administration (OSHA) HazCom standards. Proper controls will be established to avoid hazardous chemical accidental leaks or spills.

Adequate emergency response mechanisms will be maintained should an accidental spill or release of hazardous chemicals or substances occur.

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) is included in Appendix 10.2.2.

3.8.1 DESIGN CONCEPTS

The site drainage facilities for the new Smith Unit 3 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 FDEP and Bay County criteria for control of quality and quantity of runoff. Offsite drainage will be diverted around the site to existing conveyance systems. The onsite drainage system will be independent systems consisting of swales, channels, pipes, and culverts arranged and sized to intercept runoff from the various pervious and impervious surfaces. The runoff will be conveyed to two wet detention ponds. Discharge from both storm water ponds will be to adjacent wetland systems.

The onsite wet detention ponds are sized to control runoff rates from the 24-year, 24-hour storm event. Interior drainage collection systems are sized for the 100-year, 24-hour storm event.

3.8.2 SITE LAYOUT AND IMPERVIOUS AREAS

As shown on the site plan (Figure 3.2.0-1), approximately 10.33 acres of the site is impervious surface, inclusive of the normal pool wet area of the ponds. The remaining 22.37 acres of the site will be pervious surfaces of grass or landscaping. Roads and parking will make up 2.01 acres of impervious area, with the remainder attributed to buildings, equipment, and foundations.

3.8.3 SURFACE RECEIVING WATERS

Discharge from the wet detention ponds will be to adjacent wetlands following natural drainage patterns. The pond in the southeastern portion of the site will discharge to existing wetlands that drain through an 18-inch culvert to a ditch along the south side of the site. The northwestern pond will discharge to a channelized wetland system to the west.

3.8.4 GROUND RECEIVING WATERS

Infiltration of storm water both on- and offsite will be minimal since ground water levels are typically at or near ground elevations.

3.8.5 DIVERSION OF OFFSITE DRAINAGE

The proposed grades onsite will somewhat impede existing drainage patterns. To allow flow to continue along current drainage patterns, a ditch will be constructed along the northwest corner of the site, diverting flows around the site and back to the existing flow channel. Drainage areas to the east of the site will continue to flow south into improved culverts along the access road. The culverts will continue to outfall to the existing drainage ditch along the south side of the road.

3.8.6 EROSION CONTROL MEASURES

Prior to the initiation of construction activities, silt fencing or straw bales will be placed along the outside edge of the site boundary. Silt fencing and straw bales will be utilized to control 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 proposed drainage collection system will utilize swales, culverts, and sloped surfaces to convey runoff to the wet detention ponds. Swales will have a maximum of 3:1 horizontal to vertical side slopes. Longitudinal slopes are minimized in order to limit velocities. Culverts are designed to withstand heavy equipment loading and accommodate preexisting flow conditions. The onsite collection system will route runoff to the storm water ponds in such a manner as to limit ponding onsite to the maximum extent possible.

3.8.8 LOCATION OF DISCHARGE POINTS FOR STORM RUNOFF

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

3.8.9 STORM WATER DETENTION PONDS

The storm water detention ponds will be constructed during the initial phase of construction to provide control of storm water runoff and sedimentation during site work.

The ponds are located in upland areas adjacent to wetlands which normally receive runoff. Berms will contain the runoff, since the normal water levels are considered to be at the existing ground surface. The northwest and southeast ponds have normal pool elevations of 6.4 and 6.9 ft-NGVD, respectively.

Planted littoral shelves will cover at least 35 percent of the normal pool elevation. The permanent pool volume is controlled by a minimum residence time of 14 days during the wet season (June to October).

The 1-inch treatment volume is controlled by orifices located in the outfall structures. Treatment storage is from 6.4 to 7.7 ft in the northwest pond, and 6.9 and 8.15 ft in the southeast pond. A 1.75-inch orifice controls the treatment volume in the northwest pond, such that no more than the first half of the volume is discharged within the first 60 hours following the storm. A minimum elevation of 7.08 ft is maintained at hour 84 (24-hour duration storm plus 60 hours). Similarly, a 2.5-inch orifice controls the discharge in the southeast pond to a minimum of 7.6 ft.

Weirs are located above the required treatment volume for both ponds. These weirs are used to attenuate flows at the predevelopment rates of 58 and 128 cfs. These rates are high due to the significant wet areas associated with the predevelopment condition. The post-development discharges from both ponds are less than the allowable rates. Discharge rates of 46 and 68 cfs result in high water levels of 8.54 and 8.98 ft for the northwest and southeast ponds, respectively.

During construction, the ponds will serve as sedimentation basins to prevent silt and debris from being transported to downstream wetlands. The detention basins will be constructed to allow removal of accumulated sediments via 10-ft access berms around the top of both ponds.

3.9 MATERIALS HANDLING

3.9.1 CONSTRUCTION MATERIALS AND EQUIPMENT

The Smith Unit 3 Project site is located approximately 5 miles southwest of the intersection of SR 77 and CR 2300. Access to the site is provided by an existing road originating from CR 2300. Materials and equipment required for construction of the Smith Unit 3 Project will be delivered to the site using existing roads and waterways.

During the construction phase of the Smith Unit 3 Project, the entrance to the plant access road off CR 2300 will be improved (graded and surfaced with gravel) to support construction activities. A detailed transportation analysis for the Smith Unit 3 Project was not required due to the below-threshold traffic volumes expected for construction and the fact that existing road and waterways are adequate for the projected construction-related traffic and material delivery.

After construction of Smith Unit 3 is complete, a permanent access road will be constructed (sub-base, base course, grading, paving and striping, etc.) in accordance with Florida Department of Transportation (FDOT) requirements.

Most materials and equipment required for the construction of the Smith Unit 3 will be delivered to the site via standard transport trucks. Some of the larger items such as the HRSG modules, steam turbines, generators, and transformers, will be delivered by barge via the Port of Panama City to an offloading site at the existing Lansing Smith Plant. Materials and equipment will be unloaded and moved around the site using cranes, trucks, and forklifts.

The total laydown and storage space needed for construction will be located onsite at the Smith Unit 3 Project site. Construction materials and plant equipment will be stored such that they do not create safety or environmental hazards. Bags, containers, bundles, etc., will be stacked, interlocked (if possible), and limited in height so that they are stable and secure against sliding or collapse. Storage areas will be kept free from an accumulation of materials that constitute hazards from fire, explosion, or spills. Suitable fire extinguishing equipment will be kept near flammable materials.

Storm water runoff control measures for the laydown areas include surface runoff collection in swales. Storm water runoff collected in the swales servicing the onsite laydown and storage area, will be routed to the storm water detention ponds.

During the construction phase of the Smith Unit 3, the plant access road and site area will be sprayed with water, as necessary, to minimize fugitive dust emissions generated from construction activities during dry weather conditions. Water for dust control will be acquired from the storm water detention ponds or onsite wells.

3.9.2 OPERATIONS MATERIALS

Materials and supplies used for the operation of the Project will be delivered by truck. Natural gas will be delivered via an underground pipeline to the Project site gas metering station. The handling and storage of fuels and other operational chemicals are discussed in Sections 3.3 and 3.6, respectively. Handling and management of hazardous wastes are discussed in Section 3.7. Other operational wastes will be handled and stored in compliance with applicable safety and environmental regulations.

REFERENCES

Gulf Power Company. 1999. Personal communication with Florida Gas Transmission.

U.S. Environmental Protection Agency (EPA). 1990. New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting. Office of Air Quality, Planning, and Standards; Research Triangle Park, NC.

U.S. Environmental Protection Agency (EPA). 1996. Office of Air Quality Planning and Standards Control Cost Manual. Fifth Edition. EPA 453/B-96-001. Research Triangle Park, NC.

4.0 EFFECTS OF SITE PREPARATION AND PLANT ASSOCIATED FACILITIES CONSTRUCTION

This chapter identifies and discusses the potential impacts from construction of the proposed power plant on the social, physical, and natural resources of the site and vicinity. In accordance with the FDEP instructions, this chapter includes the following sections:

- 4.1—Land Impact.
- 4.2—Impact on Surface Water Bodies and Users.
- 4.3—Ground Water Impacts.
- 4.4—Ecological Impacts.
- 4.5—Air Impacts.
- 4.6—Impact on Human Populations.
- 4.7—Impact on Landmarks and Sensitive Areas
- 4.8—Impact on Archaeological and Historic Sites.
- 4.9—Noise Impacts.
- 4.10—Special Features.
- 4.11—Variances.

The potential impacts are presented in terms of their relationships with the resources and populations described in Chapter 2.0 as well as in terms of compliance with applicable regulations and standards.

4.1 LAND IMPACT

As discussed in Section 2.3.5, the area to be utilized for the construction of Smith Unit 3 is approximately 32.7 acres of the 50-acre Project site. The remainder of the property will remain as planted pine, subject to harvesting, or as undisturbed wetlands. The 32.7-acre area includes the power block, the construction laydown area, the new switchyard, ancillary facilities, the gas metering station, and the storm water ponds. Approximately 28 of the total acres will be filled to overcome the limitations of the native soils, to provide a stable base for the proposed development, and to minimize the likelihood of flooding. The proposed elevation of Smith Unit 3 will be similar to that of the existing adjacent Lansing Smith plant site. The existing elevation of the Project site is approximately 5 to 8 ft-msl. The proposed elevation is approximately 10 ft-msl. The remaining 4± acres proposed for development are for the construction of storm water treatment and storage ponds.

4.1.1 GENERAL CONSTRUCTION IMPACTS

The general site preparation and construction activities associated with the overall development of the Project site include the following:

- Construction of temporary storm water basins/ditches.
- Sequential dewatering of low areas of the site.
- Clearing/grubbing of all uncleared portions of the construction area and laydown area.
- Stabilizing, grading, filling, and contouring the area for power plant facilities.
- Construction of permanent storm water management basins.
- Performing ground work as necessary for construction of facility footings; foundations; and underground utilities, including electrical, water, wastewater, and other piping systems.
- Power plant facilities construction.
- Earthmoving, grading, recontouring, and landscaping.

Site preparation will consist of clearing and grubbing, followed by grading and leveling. Approximately 32.7 acres of the 50-acre site will require clearing. Vegetative debris from site clearing will be disposed in accordance with local requirements. Topsoil that is suitable for reuse will be stockpiled for landscaping and in establishing vegetation after construction has been completed. During early site preparation activities, temporary storm water management structures and soil erosion and sedimentation control devices (e.g., ditches, retention basin, berms, siltation fencing, and/or hay bales) will be used to minimize runoff during the construction phase. Site preparation and construction activities will not require any explosives. Suitable clean fill material will be imported to the site from one or two local Bay County borrow pits.

In addition to fill material used from outside sources, Gulf has proposed the use of fly ash generated by Smith Units 1 and 2 as a fill material. Fly ash is an industrial coal-combustion by-product generated at the existing coal-fired units. The fly ash is currently stored in the ash pond, but can be dewatered and used for fill material. EPA, in its March 8, 1999, report to Congress, recognizes coal combustion by-products as generally benign substances possessing low risk as an environmental contaminant and encourages the utilization of coal combustion by-products. FDEP has reviewed the composition of Smith's fly ash and supporting documentation which is included in Attachment 10.5-H in Appendix 10.5. The use of fly ash as a fill substitute will reduce the outside fill requirements by as much as 235,000 cubic yards and could eliminate up to 11,000 truckloads of fill hauling (22,000 trips on local roadways). The following subsections provide additional details on general construction impacts.

4.1.1.1 Use of Explosives

The Project will not use explosives for any portion of the construction work.

4.1.1.2 Laydown Areas

Laydown areas for storage of construction materials and plant equipment components will be required for construction of the Project. Approximately 14 acres of land will be needed for storage and staging of materials and equipment. The area north of the Smith Unit 3 power block will be used as onsite laydown and storage.

Laydown areas will be cleared of existing vegetation, graded for proper drainage, and a course of gravel base material applied (if necessary). Wood timbers will be used, as appropriate, to help keep plant equipment components and materials stored safely off the ground. After construction is complete and laydown areas are no longer needed, wood timbers will be removed and the surface areas will be graded for drainage and planted with grass.

4.1.1.3 Temporary and Permanent Plant Roads

An existing unpaved road originating from CR 2300 provides access to the Project site. This plant access road will be improved and maintained during the construction phase of the Project. Road improvements during the construction phase include grading the existing surface and applying base course and gravel materials to the graded surface to accommodate construction traffic.

After construction of the power plant is complete, final improvements will be made to the site access road to convert it into a permanent plant road. The permanent plant road will be designed to handle the heaviest expected load during the life of the plant. Runoff collected from the road will be directed to the onsite collection system and routed to the storm water treatment ponds for treatment and storage.

4.1.1.4 Railroads

There are no railroads within or proximate to the Project site. Heavy plant equipment components, including the CTGs, HRSGs, transformers, condenser, and boiler feed water pumps, will be shipped to the site via barge. The equipment will be offloaded at the Lansing Smith plant via the existing intake canal from Alligator Bayou. Heavy haul trailers will be used to deliver the equipment to the site.

4.1.1.5 Bridges

There are no overhead bridges within or proximate to the Project site. Most of the heavy plant equipment will arrive by barge to the existing Lansing Smith site.

4.1.1.6 Service Lines

The Smith Unit 3 CTGs will operate on natural gas. FGT will design, furnish, install, and maintain an underground pipeline (and gas metering station) that will supply natural gas to the site on a continuous basis.

Pipelines for well water, sanitary sewer, and potable water will be installed, as necessary, to provide these services to the Smith Unit 3 as interconnections with existing facilities of the Lansing Smith plant.

4.1.1.7 Disposal of Trash and Other Construction Wastes

No significant impacts from construction wastes are anticipated. During construction, the craft and management labor force will utilize portable chemical toilets. A qualified and licensed contractor will furnish the toilets, along with routine maintenance and service. Sanitary wastes generated during construction will be removed from the site, transported, and properly disposed by the contractor in an approved disposal and treatment facility. All portable toilets will be removed from the plant site upon completion of the construction phase of the Project.

The Project will attempt to minimize the amount of construction waste generated and will seek to segregate and recycle as much waste material as possible. As mentioned earlier, Gulf proposes reuse of fly ash from Smith Units 1 and 2 for fill material. Certain construction wastes, such as scrap steel, aluminum, copper, lumber, paper, and cardboard, etc., may be segregated for recycling, providing there is sufficient interest from local recycling firms. An authorized and licensed waste handling contractor will remove all other construction waste materials from the site for proper disposal at the Bay County Steelfield landfill.

4.1.1.8 Clearing, Site Preparation, and Earthwork

The Project area will be cleared of all vegetation and organic matter. Rough grading, excavation, and backfill activities will be performed to prepare the site for underground utilities, concrete foundations, and surface drainage. Backfill materials will be imported to the site from Bay County borrow pits for constructing concrete foundations, to raise the existing site elevation to overcome native soil limitations, to provide a stable base, and to approximately match the elevation of the existing Lansing Smith plant site.

After construction of the new Project is essentially complete, any remaining areas that do not have an impervious surface will be revegetated with native grasses and plant life.

4.1.1.9 <u>Impact of Construction Activities on Existing Terrain</u>

The existing terrain is relatively flat with an average of less than 0.5 percent slope. The majority of site runoff drains to the west. As previously stated, the Project site will be cleared, graded, and contoured to ensure adequate drainage, and to raise the existing site elevation to approximately that of the existing Lansing Smith plant site.

A storm water gravity flow collection system and detention ponds will be constructed to attenuate the required volume of runoff collected from the Project site. A series of swales, ditches, and basins will collect surface storm water and transport it to the detention ponds. The postdevelopment drainage pattern for the site will very closely match the predevelopment drainage pattern. The storm water detention ponds will discharge to existing wetlands located west of the Smith Unit 3 site.

Construction activities will involve equipment, such as dozers, scrapers, graders, loaders, haul trucks, compactors, dewatering pumps, cranes, welding machines, air compressors, concrete pumps, cranes, forklifts, etc. Fugitive dust and internal combustion engine emissions and noise will be generated during the construction phase of the Project and are discussed in greater detail in Sections 4.5 and 4.9, respectively.

4.1.2 ROADS

Access for the construction activities will be provided by an existing access road from CR 2300. CR 2300 connects to SR 77 in a "T" intersection. No new roads are proposed for construction as a result of this Project.

4.1.3 FLOOD ZONES

The Project site is located in flood zone C, an area of minimal flooding. Construction of the Project with the attendant drainage plan should not increase flooding potential on the site nor subject adjacent properties to increased flooding.

4.1.4 TOPOGRAPHY AND SOILS

The Project site will be altered to construct the new facilities. Existing vegetative cover will be cleared and grubbed on the eastern side of the existing power line easement, and structural and general fill will be added to elevate the site to design elevations. Soil excavated for the storm water detention ponds and major equipment foundations may be used as general fill or structural fill, if appropriate. Fill will be required to raise the site to overcome the limitations of the native soils, to provide a stable base, and to approximate the elevation of the existing Lansing Smith plant site.

Since the site is in a generally flat area (i.e., little topographic relief), the fill should not cause adverse impacts to site topographic conditions. Very little, if any, runoff currently flows onto the proposed site. Therefore, the fill will not impede existing drainage patterns. Added fill, with compaction, will shift areas of any percolation within the site. Percolation will be limited to pervious areas and the storm water ponds. Runoff will be managed with the storm water management system (i.e., ponds, weirs, orifices, etc.) to mimic preconstruction conditions.

A discussion of the potential for subsidence and sinkhole formation was provided in Section 2.3.1. Based on their low probability of occurrence, construction activities are not expected to cause these phenomena.

Certain structures at the plant will be visible from varying distances because the structures will protrude above the existing tree line. There is only limited residential development located east of the Project site and, thus, there are few if any developments that would have their views obstructed by the plant. Only the relatively taller plant structures (e.g., exhaust stacks, HRSG, cooling tower, etc.) will be visible from public viewpoints in the vicinity of the plant. The taller structures (which range up to 121 ft tall) will be an addition to the existing structures at Smith Units 1 and 2.

During construction, erosion at the site will be managed with the erosion control plan (see Sections 3.8.6 and Appendix 10.2.2). After construction, pervious areas will be planted predominantly with native grasses to control erosion. Sediments suspended in collected runoff water will be controlled in the storm water detention ponds. Maintenance of the detention ponds will include excavation of deposited materials as necessary to maintain the required storage volume. Sediments cleaned from the ponds will be used onsite for landscaping purposes.

4.2 IMPACT OF SURFACE WATER BODIES AND USES

4.2.1 IMPACT ASSESSMENT

4.2.1.1 Fresh Water Systems

Portions of the plant will be located on existing wetland systems. Natural drainage patterns through the wetland systems are from the east to the southwest. Two locations are impacted where flows move through the existing site. The wetland system on the southern portion of the site currently discharges to a ditch located on the south side of the site boundary through an 18-inch culvert. To accommodate offsite areas draining to this area, two 18-inch culverts will be installed just east of the site to allow flows to continue discharging to the same ditch. Pre-existing flow which currently moves through the ditch on the northwest corner of the site will be re-routed around the proposed plant site. The re-routing will allow for the same capacity of flow to discharge through the redirected channel.

Adjacent wetland systems will be protected with sediment and erosion control systems as described in Appendix 10.2.2. Silt fencing, hay bales, sediment sumps, vegetative covers, and other methods will be used to minimize impacts during construction.

Wetland systems adjacent to the site will not be used by the Project for any specific purpose other than as a buffer from other development. The wetlands will remain viable through the maintenance of site hydrology.

4.2.1.2 Marine Waters

The construction impacts on the marine water quality will be limited to construction activities in the existing plant's discharge tunnel. No additional dredging of the intake canal is needed to accommodate the supply barges. The canal is currently used to barge coal to the facility.

Water quality impacts in the discharge canal during construction will be limited to activities during construction of the cooling tower blowdown discharge structure and the new intake structure for cooling tower makeup water. Both these pipes will be installed within the existing Smith cooling water discharge housing. The impacts are expected to be limited to minor increases in turbidity during construction. Approved construction techniques will be used and the extent of the turbidity will be minimized by using silt screens as practical. The impacts are expected to be temporary with no long-term effects.

4.3 GROUND WATER IMPACTS

4.3.1 IMPACT ASSESSMENT

The proposed site preparation and facility construction activities for Smith Unit 3 Project are not expected to cause any long-term ground water impacts on- or offsite.

Temporary dewatering activities will be required during the initial phase of construction of the Project, as discussed in the previous section. Existing grade elevations are between approximately 5 and 8 ft-msl. Ground water levels are estimated to occur anywhere from existing grade to 2 ft below existing grade. Fluctuations in ground water levels are expected to occur throughout the year due to rainfall, natural drainage systems, and man-made drainage systems.

Minor dewatering systems will be installed and maintained throughout the civil engineering phase of construction. The dewatering systems are necessary for excavation, backfill, and certain construction operations. It is anticipated that well point(s) and a ditch system will be used to lower the ground water elevation sufficiently below the bottom of excavation to preclude problems with backfilling, soil compaction, and other related activities.

The storm water detention ponds will be installed immediately after clearing and grubbing activities are complete and will be utilized during the construction phase of the Project for collection of ground water. Water from the dewatering process will be pumped to a drainage ditch system. Silt fencing and bales of straw or hay will be used in the ditch system to remove the majority of silt before entering the detention ponds. Additional silt and sand will settle out in the detention ponds, after which water from the detention ponds will either percolate or be discharged offsite with all offsite discharges monitored for turbidity (see Section 4.2.1).

The storm water detention ponds will be excavated to a depth that guarantees a permanent pool volume adequate to provide a 14-day residence time during the wet season (June to October). The storm water detention ponds will be designed to retain 1.1 acre-feet of storm water runoff volume (design volume will also accommodate dewatering flow), in addition to the permanent pool volume. The storm water detention ponds are designed to release the retained volume in a controlled fashion such that 50 percent of the retained volume will be released during the first 48 hours after receipt. An outlet pipe located in the storm discharge structure maintains the permanent pool elevation.

After excavation, backfill, compaction, construction of the permanent plant drainage system, and certain concrete construction activities are complete, the dewatering system will be removed.

Much of the dewatering discharge volume from the surficial aquifer will be offset by the increased infiltration and recharge of water to the aquifer system from the new detention ponds, and by the decreased evapotranspiration that accompanies a lowered water table. Therefore, any potential surficial aquifer impacts from dewatering activities will be insignificant and short term.

Minor chemical effects can result from dewatering activities through the mobilization of constituents from the soils into the dewatering discharge and from oxidation of the ground water. The surficial aquifer sediments at the site are composed predominantly of fine- to coarse-grained quartz sands (which are not readily soluble), with low amounts of several soluble constituents (including calcite, phosphate, and iron). Oxidation can cause the dissociation of calcite, releasing bicarbonate and calcium anions, which can increase the hardness of water. Oxidation of the dissolved iron can cause ferrous iron to form ferric iron. However, because the surficial aquifer stratum is composed primarily of silica sands, oxidation reactions will be minimal and potential ground water quality impacts will be insignificant. The shallow aquifer materials will also act to filter out the suspended solids, absorb dissolved constituents, and thereby limit or preclude migration of these constituents in the surficial aquifer.

Construction contractors will be required to implement practices to minimize the potential for spills of fuels or chemicals. Maintenance will be performed only in designated areas. In the unlikely event that spills do occur, they will be managed in an approved manner, in accordance with local, state, and federal regulations.

The use of fly ash as fill material will not pose a threat to ground water supplies. Toxicity testing on the fly ash generated at the existing Smith Plant shows the composition to be nonhazardous and nontoxic.

Construction activities are not anticipated to have any effect on the Upper Floridan aquifer because a low permeability confining layer (the intermediate system) separates the surficial and Floridan aquifer systems (see Section 2.3.1). Similarly, temporary dewatering activities in the surficial aquifer will not affect drinking water supplies or other uses of the Floridan aquifer system.

In conclusion, the proposed construction activities for the Project are not expected to adversely impact onsite or offsite ground water resources.

4.3.2 MEASURING AND MONITORING PROGRAM

Ground water monitoring is not proposed as part of the construction activities for the Project. Construction activities are not expected to cause permanent ground water impacts. In the unlikely event that there is a fuel spill or other release, assessment and recovery of the spill or release would be conducted in accordance with FDEP requirements.

4.4 ECOLOGICAL IMPACTS

4.4.1 IMPACT ASSESSMENT

4.4.1.1 Aquatic Systems—Fresh Water

As discussed in Section 2.3.6.1, there are no onsite natural open water aquatic systems (ponds, lakes, or streams). The only aquatic resources potentially impacted by this Project are manmade ditches located onsite. Ditches on the site consist of roadside ditches and the drainage ditch connection to the natural forested wetlands on the property. The latter of these ditches will be rerouted around the construction area to maintain pre-construction flows. The SWMP addresses this issue (Appendix 10.2.2).

There is a possibility of offsite secondary impacts to the downstream reaches of the drainage features onsite. Land clearing and construction activities could cause increased turbidity and siltation due to eroded materials being transported by surface runoff. By using best management practices (BMPs) during construction (e.g., silt fencing and/or hay bales), potential increases in turbidity and sedimentation in downstream reaches will be minimized (Appendix 10.2.3). With these controls in place, aquatic species will not be significantly impacted by construction activities.

4.4.1.2 Aquatic Systems—Marine

The construction impacts to the marine aquatic ecology will be limited to the construction activities in the existing discharge canal near the plant. The use of the intake canal for delivery of construction supplies via barge should have minimal effect on the aquatic ecology because the canal is already being used to barge coal to the facility. No additional construction in the intake canal is required.

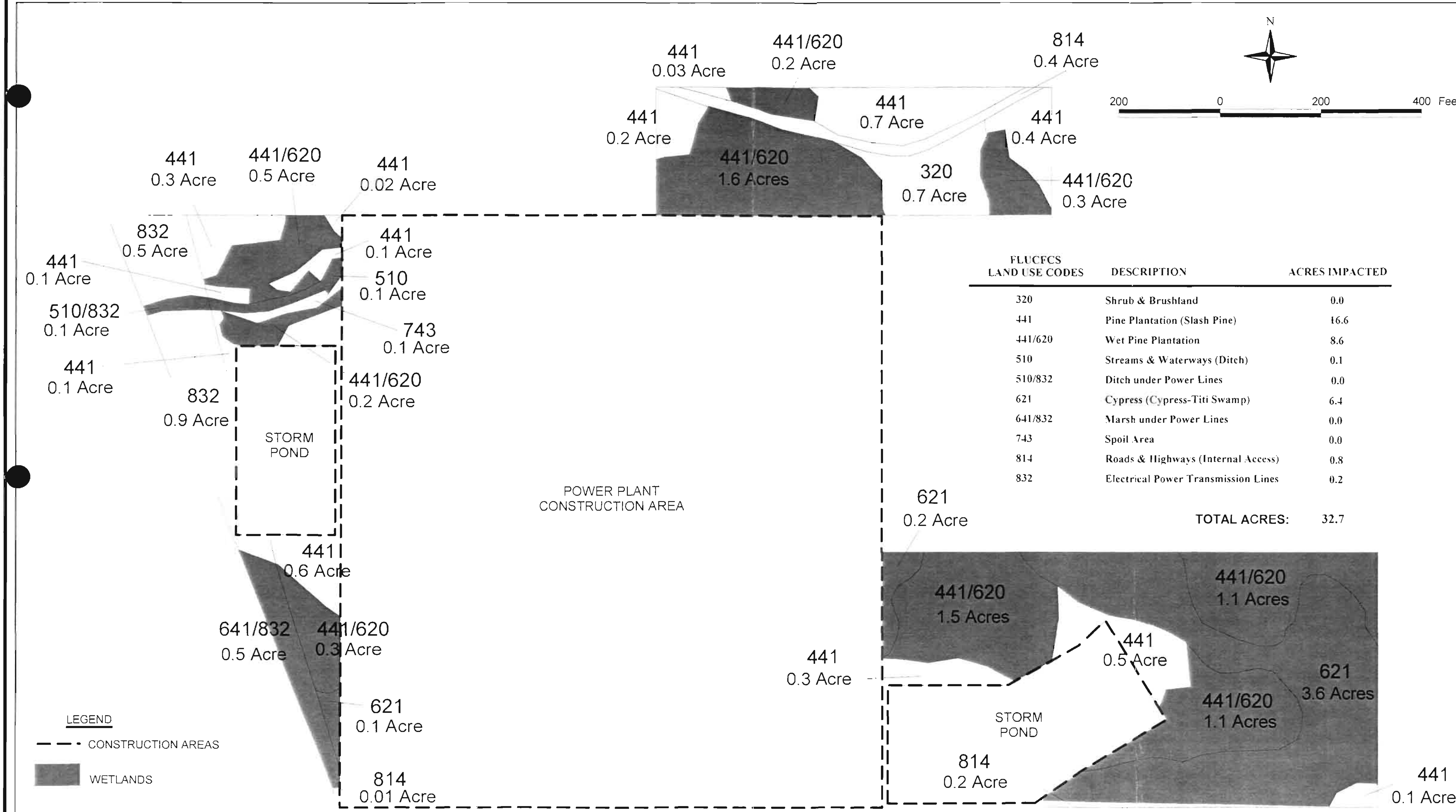
The construction impacts on the aquatic ecology in the discharge canal will be limited to increased turbidity from installation of the cooling tower intake and discharge structures. Approved construction techniques will be used and the extent of the turbidity will be minimized by using silt screens as practical. Impacts are expected to be temporary with no long-term effect.

4.4.1.3 Terrestrial Systems—Flora

The power plant and associated onsite facilities such as parking lots, maintenance building, offices, storm water retention and sedimentation ponds, switchyard, gas metering station, water treatment facilities, cooling towers, and construction laydown areas will occupy approximately 32.7 acres of land. Of this, approximately 16.7 acres are upland communities and 15.2 acres are wetlands. The remaining 0.8-acre consists of internal access roadway. Figure 4.4.1-1 shows the areas impacted and the locations and extent of the remaining land use and vegetation types occurring within the Project area to be developed. To compensate for the loss of 15.2 acres of wetlands resulting from construction of the proposed Project, a mitigation plan has been proposed for agency approval. This plan is included in the USACE 404/FDEP dredge-and-fill permit application.

Approximately 0.7 acre of shrub and brush; 3.4 acres of upland slash pine; 6.8 acres of wet pine plantation; 0.2 acre of ditch, 3.8 acres of cypress-titi swamp; 0.5 acre of marsh; 0.1 acre of spoil; 0.5 acre of road; and 1.4 acres of ruderal, maintained upland habitat under the power lines will be left intact. The upland and wetland communities and wildlife habitats to be left intact on the site and other undisturbed uplands and wetlands in the Project vicinity have the potential to be indirectly affected. These secondary effects could include a temporary lowering of ground water levels, increased sedimentation, increased surface runoff, erosion, fugitive dust, and damage due to heavy equipment movement. However, the utilization of BMPs during construction should ensure minimal or no secondary impacts to offsite plant communities.

All of the plant species considered to be of local and/or regional importance by USFWS, FNAI, and FGFWFC (FDACS) were reviewed for actual presence or likelihood of occurrence on the site based upon range and habitat suitability. Of the 63 plant species reviewed which are known to occur in Bay County (Table 2.3.6-2), 27 species were determined as possibly occurring on the site due to the availability of suitable habitat. Of these, four were observed on the site. These are royal fern (*Osmunda regalis*), cinnamon fern (*Osmunda cinnamomea*), Chapman's crownbeard (*Verbesina chapmanii*), and panhandle spiderlily (*Hymenocallis henryae*). Royal fern and cinnamon fern are listed by the



FLUCFCS LAND USE CODES	DESCRIPTION	ACRES IMPACTED
320	Shrub & Brushland	0.0
441	Pine Plantation (Slash Pine)	16.6
441/620	Wet Pine Plantation	8.6
510	Streams & Waterways (Ditch)	0.1
510/832	Ditch under Power Lines	0.0
621	Cypress (Cypress-Titi Swamp)	6.4
641/832	Marsh under Power Lines	0.0
743	Spoil Area	0.0
814	Roads & Highways (Internal Access)	0.8
832	Electrical Power Transmission Lines	0.2
	TOTAL ACRES:	32.7

FIGURE 4.4.1-1.

LAND USE/VEGETATION CONSTRUCTION IMPACTS

Source: ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

State due to the potential for commercial exploitation rather than any endangerment; they are common and found throughout Florida. Royal ferns and cinnamon ferns were observed to be occasional within the wetlands situated within areas of proposed power plant construction. Since royal ferns and cinnamon ferns are common throughout the region, no significant impacts to regional populations will be associated with power plant development. Only a very small portion of the existing transmission line right-of-way (0.2 acre) is scheduled for development of a storm water pond. Chapman's crownbeard was observed growing throughout the open, maintained grassy areas underneath the transmission lines. No significant impacts to regional populations of Chapman's crownbeard should be associated with the proposed activities. Panhandle spiderlilies are extremely rare and only occur within a few counties in the Florida Panhandle. Currently, this state-listed endangered species is a candidate for federal listing. Several populations of this rare spiderlily are located within the wetlands to be developed on the site. These spiderlilies should transplant easily. Therefore, to mitigate for any potential impacts to regional populations, all of the spiderlilies growing within the areas of construction will be relocated into similar wetland habitats on Gulf's property that will not be disturbed by the proposed development activities.

4.4.1.4 Terrestrial Systems—Fauna

Construction impacts to wildlife resources at the Project site may occur in the form of direct impacts (displacement, mortality) in the proposed construction area or indirect impacts (noise, human presence) in preserved onsite and surrounding natural habitats. In the area to be cleared for construction, mobile fauna will be displaced. Less motile or fossorial species may be lost during clearing and earth-moving activities.

The most conspicuous faunal elements are birds. It is unlikely that the clearing of about 32.7 acres of natural habitat will impact regional bird populations due to their mobility and abundance of similar, adjacent habitat. Also, many of the bird species observed are adaptable to human-induced habitat changes. Reptiles and amphibians are more likely to be affected by construction. To decrease the risk of mortality of these less motile animals, the site will be directionally cleared to provide opportunity for these animals to retreat to the offsite pine flatwoods to the west, north, and east of the construction site.

Power plant construction is not expected to affect regional wildlife populations of any endangered, threatened, or species of special concern. Of the 18 important wildlife species evaluated for this Project (Table 2.3.6-1), none were observed onsite. Two listed species, the bald eagle and eastern brown pelican, were observed along the shore of the existing Lansing Smith property. The brown pelican also utilizes the existing discharge canal. However, due to the lack of suitable foraging/nesting habitat on the proposed Project site, no impacts from construction are anticipated to these or other listed species. Construction of the intake/discharge pipes in the existing discharge canal will represent a temporary disturbance to any wildlife foraging activities in the canal. If any listed species do reside onsite, they will seek adjacent identical habitats off the Project site during construction.

4.4.2 MEASURING AND MONITORING PROGRAM

The results of the ecological measuring program conducted on the site in support of this SCA are described in Section 2.3.6. No continued monitoring programs are warranted or proposed for biological resources during the construction phase of the proposed Project. Any mitigation required as a result of state and federal wetlands permitting may require monitoring, but the extent of such mitigation and resultant monitoring is to be determined.

4.5 AIR IMPACTS

4.5.1 EMISSIONS

Three general activities will generate air emissions during construction of the Smith Unit 3 Project. First, land clearing, site preparation, and vehicle movement will generate fugitive dust emissions. Second, open burning of cleared land debris may be required and would result in air emissions. And third, internal combustion engines will release NO_x, CO, and other combustion products.

The quantity of any emissions released during the construction process will generally be very low, but will vary on an hourly and daily basis as construction progresses. Fugitive dust emissions will be greater during the land clearing and site preparation phases. Fugitive dust emissions will also be greater during the more active construction periods as a result of increased vehicle traffic on the site.

Open burning would result in emissions of PM, CO, NO_x, and hydrocarbons. This activity would be conducted intermittently for short periods of time. The land clearing and construction debris to be burned would generally consist of wood products and other relatively clean-burning components. Emissions would depend upon the amount and moisture content of the debris. This site has been periodically burned in the past to support the silvicultural operation.

Increased emissions from internal combustion engines will occur during the site preparation and facility construction due to the amount of onsite construction equipment using engines for site excavation and grading, concrete placement, and structural steel and major equipment installation. Potential minor sources of VOCs include:

- Evaporative losses from onsite painting.
- Refueling of construction equipment.
- The application of adhesives and waterproofing chemicals.

4.5.2 EMISSION CONTROL MEASURES

Fugitive dust emissions from the construction site will be minimized using appropriate dust suppression control methods. These standard control methods will include paving or placement of gravel on roads, applying water to roads and other exposed surfaces, or other methods, as needed. Existing public access roads (i.e., SR 77 and CR 2300) leaving the site are currently paved to serve the existing station. No new access roads to the Project site are proposed. Spilled and tracked dirt (or other materials) will be removed from SR 77, CR 2300, and other paved areas in a timely manner. Of course, all construction-related fugitive dust emissions will be temporary and will stop once construction is completed. Emissions from open burning will be limited by removing materials whose burning would produce excessive smoke (e.g., green vegetative materials), and by conducting this activity in compliance with applicable state and local regulations and ordinances.

4.5.3 POTENTIAL IMPACTS AND MONITORING PROGRAMS

The air quality impacts caused by construction activity will vary as a function of the level of activity, the specific nature of the activity, the weather conditions while the activity is occurring, and the emission controls applied to the activity. However, even under worst-case conditions, the maximum ambient impacts caused by construction emissions are expected to be very small and limited to the specific area of the site under construction. Also, any potential emissions are expected to be well below any applicable AAQS. Therefore, no air quality monitoring programs are needed or will be conducted during the construction of the Smith Unit 3 Project.

4.6 IMPACT ON HUMAN POPULATIONS

4.6.1 LAND USE IMPACTS

The existing land uses in the area surrounding the Project site are silviculture to the east, north, and west, and the existing Lansing Smith plant (designated industrial) to the south. There is an electrical transmission line located along the western Project boundary. The Lansing Smith plant is the only development within 2 miles of the Project site.

Gulf has submitted a large-scale (over 10 acres) plan amendment to Bay County to change the FLUM designation from Agriculture to Industrial in order to accommodate the development of Smith Unit 3. The zoning district is coincident with the land use designation in Bay County.

4.6.2 CONSTRUCTION EMPLOYMENT

As shown in Table 4.6.2-1, the number of estimated construction personnel over the 21-month construction ranges from 75 to 325, with an average of 180 employees/month. It is estimated that approximately 75 percent of the construction workers will be daily commuters (living within commuting distance currently) and approximately 25 percent will be weekly commuters (temporary residents). A small percentage of these construction workers will be from out of state. Construction will normally occur during daylight hours and occur during one shift per day.

Table 4.6.2-1. Estimated Manpower and Payroll During Construction

	Sept. 1, 2000 to Dec. 31, 2000	Jan. 1, 2001 to June 30, 2001	July 1, 2001 to Dec. 31, 2001	Jan. 1, 2002 to May 31, 2002
Manpower	75	225	325	100
Hours/Period	78,000[2,3]	234,000	338,000	88,000
Estimated payroll	$1,950,000[1,4]	$5,850,000	$8,450,000	$2,200,000
Total construction payroll	$1,950,000	$7,800,000	$16,250,000	$18,450,000

[1]Expected average pay of $25 per hour.
[2]Forty-hour standard work week.
[3] One-shift per day.
[4]Base salary/hourly wage only.

Source: Gulf Power Company.

Total construction costs, excluding equipment, are estimated at $63 million, and the construction payroll and indirect costs are estimated to be approximately $23.7 million, of which a portion of the money will be spent locally on goods/services, rent, etc. According to the U.S. Department of Commerce (1999) multipliers specific to Bay County, the impact of construction on industrial output is estimated to be $113.5 million. The construction impacts on local employment opportunities, therefore, are beneficial although short term. Indirect employment in the local area will occur primarily in retail and wholesale trade, business services, health services, and eating and drinking establishments.

4.6.3 CONSTRUCTION TRAFFIC IMPACTS

Some construction-related transportation impacts are expected as a result of the movement of construction workers and vehicles to and from the Smith Unit 3 Project site. All access to the site will be via CR 2300 and SR 77.

Based on past construction experience and traffic analyses for similar power plants, a construction-related trip generation rate of 2.0 and a vehicle occupancy rate of 1.4 is expected for Smith Unit 3. Based on these trip generation and vehicle occupancy rates, a maximum of 464 trips per day will be generated at the peak construction period, which lasts approximately 6 months. During the entire construction period, an average of 257 trips per day is projected. In addition, an estimated 20 to 60 deliveries per day are expected for the duration of construction.

Using only imported fill for construction, Gulf estimates up to 20,000 truckloads of fill will be required from one or two borrow pit locations in Bay County. However, assuming the use of fly ash is approved as fill material, up to 11,000 truckloads of fill could be eliminated.

In either case, Gulf proposes to stockpile fill on developed portions of the Lansing Smith Generating Plant months in advance of the construction start date. This will spread the number of fill deliveries out over a longer period, further minimizing impacts to traffic. If warranted, Gulf will place appropriate "truck entering highway" warning signs at the borrow pit locations as well as at SR 77 and CR 2300.

Based on current LOS numbers provided by FDOT, construction traffic will not adversely affect traffic flows on SR 77 nor require traffic improvements.

4.6.4 HOUSING IMPACTS

Based on the anticipated 25 percent of construction workers commuting on a weekly basis, these workers would not impact housing availability. Rental units and hotels in nearby Panama City and Panama City Beach, both tourist and seasonal visitor destinations, should be ample to provide for the projected workforce. It is not anticipated that a significant number of these workers will permanently relocate to Bay County as a result of the Project. Construction of Smith Unit 3 will not have a significant impact on housing availability in Bay County. The construction phase of the Project will increase the use of rental units/hotels and will provide a positive economic benefit.

4.6.5 PUBLIC FACILITIES AND SERVICES

Construction-related impacts to public services, such as police, fire, and medical are not expected to be significant. Potable water will be provided from permitted wells at the Lansing Smith plant site. The Steelfield landfill has adequate capacity to accept solid waste and construction debris. Wastewater disposal will be accommodated by temporary facilities; no public sewer service is currently available to the Project site. With minimal relocations to Bay County as a result of the proposed development of Smith Unit 3, existing facilities and services will be adequate to meet the demands on these services.

4.7 IMPACT ON LANDMARKS AND SENSITIVE AREAS

No construction-related environmental impacts are expected on those offsite, sensitive areas identified in Section 2.2.5. As discussed in Section 4.5, fugitive dust emissions will be properly controlled so that no impact on visibility will occur. The Project site itself is surrounded on three sides by planted pine and on the fourth by the existing Lansing Smith plant site. As discussed in Section 4.9, due to attenuation with distance, construction noise will not affect the quality of the recreational experiences in the area. The recreational and historic resources in the area are located at least 3 miles northeast or southeast of the Project site. Therefore, there are no impacts expected to occur to offsite landmarks or sensitive areas due to construction of this Project.

4.8 IMPACT ON ARCHAEOLOGICAL AND HISTORIC SITES

No archaeological or historic sites have been identified within the Project site (see Section 2.2.6). Therefore, no impacts to such resources are anticipated as a result of the construction of this Project. If such resources should be discovered during site clearing activities, the Florida Department of Historic Resources will be notified.

4.9 NOISE IMPACTS

Construction of the Project is expected to be typical of other power plants in terms of schedule, equipment utilized, and types of activities. Power plant construction can generally be divided into several phases, with the noise level varying with the construction phase (based on Barnes *et al.*, 1977). The various construction phases are:

- Site preparation and excavation.
- Concrete pouring.
- Clean up.
- Steel erection.
- Mechanical and electrical.
- Startup and testing.

The typical high-pressure steam- or air-blow activity, a repetitive, short-duration noise, is generally assessed separately because of the high noise levels and the potential for significant impact.

A complete construction equipment inventory was developed with the high noise level equipment identified for evaluation. The loudest equipment types generally operating at a site during each construction phase are presented in Table 4.9.0-1. The composite average or equivalent site noise level, representing noise from all equipment averaged over the work day, is also presented.

Average (equivalent) construction noise levels projected at the north, east, and west property boundaries are presented in Table 4.9.0-2. Construction noise levels were not projected for a residence because the nearest residence is approximately 2 miles from the site. These noise results are conservative because the only attenuating mechanism assumed was divergence of the sound waves; no attenuation from vegetation or intervening structures was factored into the analysis. Average noise levels during the loudest construction activities are projected to be between 51 and 63 dBA to the north, 38 and 50 dBA to the east, and 44 and 56 dBA to the west. The highest construction noise will be due to the use of pile drivers.

Table 4.9.0-1. Construction Equipment and Composite Site Noise Levels

Construction Phase	Loudest Construction Equipment	Equipment Noise Level at 50 ft (dBA)	Composite Site Noise Level at 50 ft (dBA)
Site clearing and excavation	Bulldozer	90	89
	Truck	82	
	Backhoe	84	
	Grader	85	
	Tractor scraper	87	
	Compactor	83	
Concrete pouring	Ready-mix truck	84	102
	Mobile crane	85	
	Concrete pump	82	
	Pile driver	102	
Steel erection	Pneumatic tools	90	90
	Air Compressor	76	
	Mobile crane	85	
	Cherry picker	80	
Mechanical	Pneumatic tools	90	89
	Air compressor	76	
	Mobile crane	85	
Cleanup	Truck	84	86
	Front-end loader	87	

Sources: Barnes *et al.*, 1977.
Gulf Power Company, 1999.

Table 4.9.0-2. Average Construction Noise Levels (dBA) at Gulf Power Property Boundaries

Construction Phase	Noise Level (dBA)		
	North	East	West
Site clearing and construction	50	37	43
Concrete pouring	63	50	56
Steel erection	51	38	44
Mechanical	50	37	43
Cleanup	47	34	40

Source: ECT, 1999.

High-pressure steam- or air-blows to clean piping systems produce noise levels of approximately 130 dBA at 50 ft. This noise source translates to a level of approximately 91 dBA at the nearest property boundary which is to the north. This level of noise could represent a significant, though short-term (i.e., occurring sporadically over a 4- to 6-week period) noise impact. However, no adverse impacts are expected because the steam- or air-blows have a duration of only a few minutes and noise receptors (residences) are located nearly 2 miles away.

4.10 SPECIAL FEATURES

There are no unusual products, raw materials, garbage disposal services, incinerator effluents, or residues produced during construction that will have an adverse affect on the environment and ecological systems of the site and the adjacent areas. Construction debris can be accepted at the existing Bay County Steelfield landfill.

4.11 VARIANCES

Construction of the Project will meet all applicable local, state, and federal regulations. No variances for construction will be required.

REFERENCES

Barnes, J.D., Miller, L.N., and Wood, E.W. 1977. Power Plant Construction Noise Guide. Report No. 3321, Bolt Beranek and Newman, Inc., Cambridge, MA.

U.S. Department of Commerce. 1999. RIMS II Multipliers for Bay County, FL. Economics and Statistics Administration, Washington, DC.

5.0 EFFECTS OF PLANT OPERATION

This section provides a description and assessment of impacts the plant's operations will have on the site and vicinity. Where practicable, the impacts are quantified and described in terms of short-term, long-term, local, etc. Where required, descriptions of operational monitoring and measurement programs are presented. Consistent with FDEP requirements, this chapter provides the following sections:

- 5.1—Effects of the Operation of the Heat Dissipation System.
- 5.2—Effects of Chemical and Biocide Discharges.
- 5.3—Impacts on Water Supplies.
- 5.4—Solid/Hazardous Waste Disposal Impacts.
- 5.5—Sanitary and Other Waste Discharges.
- 5.6—Air Quality Impacts.
- 5.7—Noise.
- 5.8—Changes in Non-Aquatic Species Populations.
- 5.9—Other Plant Operation Effects.
- 5.10—Archaeological Sites.
- 5.11—Resources Committed.
- 5.12—Variances.

As was the case in Chapter 4.0, the existing environmental conditions described in Chapter 2.0 constitute the baseline for assessing impacts. In addition, applicable rules and regulations are employed to assess impacts.

5.1 EFFECTS OF THE OPERATION OF THE HEAT DISSIPATION SYSTEM

5.1.1 TEMPERATURE EFFECT ON RECEIVING BODY OF WATER

The existing Gulf facility uses once-through cooling water at a flow rate of about 190,000 gpm (273.6 MGD) with a permitted temperature increase of 18.0°F for April to September and 20°F for October to March.

The proposed facility will withdraw cooling tower makeup water from the discharge canal of the existing facility at a rate of about 5,120 gpm (5,048 gpm during power augmentation). This makeup water will be supplemented with water collected from the evaporative coolers, the demineralizer, the condensate polisher, and the clean drains from the turbine/boiler building such that the total makeup water to the cooling tower will be 5,176 gpm for both normal and power augmentation modes. The cooling tower will be operated at approximately two cycles of concentration such that water loss from evaporation and drift will be about 2,589 gpm. The resulting cooling tower blowdown will be 2,587 gpm and will be discharged from the cold side of the cooling tower into the existing discharge canal downstream of the cooling tower makeup water intake. Consequently, there will be no increase in the temperature of the water returned to the discharge canal, but there will be a reduction in volume from 5,120 to 2,587 gpm (from 5,047 to 2,587 gpm for power augmentation operation). The net impact of the operation of the proposed facility will be no increase in the temperature of the existing discharge and a reduction in the discharge volume of 2,587 gpm (2,587 gpm for power augmentation) from the existing 190,000 gpm. Consequently, the Smith Plant site's heat rejection rate will be reduced by about 1.3 percent, which will slightly reduce the size of the thermal plume and resultant thermal impacts and provide a positive effect in the receiving waters of West Bay. Gulf's modified NPDES permit application for the Smith Unit 3 Project is included as Appendix 10.2.5.

5.1.2 EFFECTS ON AQUATIC LIFE

As presented in the previous section, the existing thermal discharge temperature is projected to remain about the same, and the volume discharge (because of evaporative losses from the new cooling tower) is expected to be reduced by 1.3 percent for both the normal and power augmentation operation. The reduced volume will result in a slightly smaller thermal plume and, consequently, will have a small positive effect on the marine aquatic ecology.

Should the proposed facility be offline for maintenance such that the cooling tower ceases operation, the effects of the shutdown would be minimal on the existing discharge, and no effects on the aquatic ecology of the discharge canal would be expected.

5.1.3 BIOLOGICAL EFFECTS OF MODIFIED CIRCULATION

Since the proposed facility will withdraw cooling tower makeup water from the discharge of the existing facility, the impacts of the cooling water withdrawal and return (blow-down) to the existing canal are expected to be minimal. The cooling tower makeup water withdrawal will not change any of the entrainment or impingement values of the once-through cooling system because no additional water from North Bay will be needed. Because of the small volume relative to the existing discharge, no effects of scouring or sedimentation are expected.

5.1.4 EFFECTS OF OFFSTREAM COOLING

5.1.4.1 <u>Impacts</u>

The cooling tower will transfer heat from plant processes to the atmosphere through the evaporation and dispersion of cooling water. Depending on the meteorological conditions, warm, moist air leaving the tower may become cooled to the point of saturation causing the water to condense and form a visible plume. Ground level fogging may occur if this plume does not rise. The drift from the tower carries dissolved and suspended solids which are deposited locally and may have the potential to affect soils and vegetation. The magnitude of these impacts was assessed using the Seasonal/Annual Cooling Tower Impact (SACTI) model.

SACTI was developed by Argonne National Laboratory for the Electric Power Research Institute (EPRI) (1984) and is generally accepted for plume impact analysis by industry and regulatory agencies. The code used for this modeling study was the most current release (dated September and November 1990). The model requires both meteorological data and cooling tower design information to evaluate plume characteristics.

Hourly surface meteorological data collected at the Apalachicola and Pensacola stations and twice daily mixing height data collected at the Apalachicola station by NWS were used for the years 1986 through 1990. Long-term monthly clearness indices and daily solar insolation values were obtained from the SACTI documentation.

The Project's linear mechanical draft cooling tower will consists of ten cells. Each cell will house a 33-ft diameter fan. The cooling tower will be arranged in an approximately northeast-southwest orientation. The circulating flow rate through the tower will be approximately 125,000 gpm per cell, and the drift loss rate will be a maximum of 0.001 percent, producing approximately 1.25 gpm of drift. The effective air flow rate of the tower will be about 11,764,000 standard cubic feet per minute and will reject approximately 1,250 MMBtu/hr.

The SACTI model calculations utilized a polar coordinate receptor grid system centered on the tower. Receptors were placed surrounding the tower at 22.5-degree intervals at varying distances. For the salt deposition and plume length computations, 100-meter intervals out to 10,000 meters were used. For plume fogging hours computations, 100-meter intervals out to 1,600 meters were used. For plume height computations, 10-meter intervals up to 1,000 meters were used.

The results of the SACTI modeling on a seasonal and annual basis are given in Table 5.1.4-1.

A cooling tower plume may reduce visibility if it crosses the path of ground-based or air traffic. CR 2300 is located about 1,200 meters west of the cooling tower. At CR 2300, the SACTI model predicts a plume height of 137 meters above the ground. The occurrence of the plume is predicted to be 2 percent of the time. Because terrain around the plant site is

Table 5.1.4-1. SACTI Modeling Results for the Gulf Power Project

Season	Maximum Salt Deposition (kg/km^2/month)	Fogging (hours/season)	Typical Plume Length (meter)	Typical Plume Height (meter)
Winter	4,844 @ 100 meters SSE of tower	0.4 @ 1,200 meters W of tower	600 meters SW of tower	150 meters SW of tower
Spring	8,735 @ 200 meters NW of tower	0.5 @ 1,100 meters ESE and SE of tower	600 meters SW of tower	150 meters SW of tower
Summer	4,432 @ 100 meters NW of tower	0.3 @ 200 meters NW and SSE of tower	600 meters SSW of tower	150 meters SSW of tower
Fall	6,407 @ 100 meters WNW of tower	0.2 @ 1,200 meters S of tower	600 meters SW of tower	150 meters SW of tower
Annual	5,456 @ 100 meters WNW of tower	0.4 @ 1,200 meters S and W of tower	600 meters SW of tower	150 meters SW of tower

Source: ECT, 1999.

flat, visibility on the nearby roadway is not expected to be degraded by the formation of this elevated visible plume.

The frequency of visible plume formation in all directions decreased to about 17 percent on an annual basis at 700 meters downwind of the tower. With respect to potential visibility impacts to air traffic, the nearest airport is located approximately 3 miles south of the plant site. At that distance, the visible plume is not expected to hinder the safe operation of aircraft during take-off or landing.

Induced ground-level fogging may infrequently occur during plume downwash conditions. However, this locally induced fog will dissipate rapidly due to the high winds associated with such plume downwash conditions. Most ground-level fogging is predicted to occur within 900 meters of the tower. Plume fogging is predicted to persist from the south and west at a distance of 1,100 meters for only 1.5 hours per year. Based on experience with existing cooling towers, typical meteorological conditions, local terrain, land use, and the conservative nature of the SACTI model predictions, plume fogging on CR 2300 is not expected.

Seasonal and annual salt deposition rates were calculated to a distance of 10,000 meters downwind of the cooling tower. The maximum salt deposition was predicted to be 8,735 kilograms per square kilometer per month (kg/km^2/month) in the spring within 200 meters of the tower. The maximum annual average deposition onsite was predicted to be 5,456 kg/km^2/month. The maximum annual average offsite salt deposition rate was predicted to be 460 kg/km^2/month. This valued occurred 700 meters north of the tower.

Saline drift can impact plants by absorption of salt accumulated in the soil. Accumulation will occur if the annual deposition rate of salt exceeds the rate at which the salt is washed from the soil by precipitation. The result of studies (Mulchi, C.L. *et al.*, 1978) with sandy loam soil suggest that a deposition rate of about 10,000 kg/km^2/month of sodium chloride can cause some accumulation of salt in the soil. Because the maximum annual average offsite deposition rate and the overall maximum deposition rate in the spring are lower than the monthly threshold value that could cause salt accumulation in the soil, no significant soil impacts are expected.

An investigation of the potential effects of cooling tower drift on vegetation was conducted in which predicted salt deposition rates were compared to known salt injury thresholds. A predicted salt deposition rate is presented as the amount of salt deposited over a unit area per season and year at a certain direction and distance away from the tower.

Near the proposed power plant site boundary, predicted salt deposition rates on an annual basis range from 1,164 to 5,520 kilograms per square kilometer per year ($kg/km^2/yr$). The greatest predicted depositions are located to the north and south of the proposed power plant.

Native vegetation associated with pine flatwoods occurs onsite and along property boundaries. Salt deposition could range from 4,092 to 5,520 $kg/km^2/yr$ of salt on the north and south property boundaries, and at higher rates within the site. Two plant species found onsite that are considered intolerant or having a very low resistance to salt have been identified. These are sedge (*Carex glaucescens*) and royal fern (*Osmunda regalis*). FPC (1988) states that these two plants have a leaf injury threshold similar to that of the flowering dogwood (*Cornus florida*). Curtis *et al.* (1976) found that the leaf injury threshold for the dogwood was 9,000 $kg/km^2/yr$. Given that the sedge and royal fern have the same threshold as the dogwood, it can be concluded that the salt deposition should have no adverse effect on natural vegetation onsite or near the property boundary based on salt deposition projections.

5.1.4.2 <u>Monitoring</u>

No monitoring of cooling tower operations is proposed.

5.1.5 MEASUREMENT PROGRAM

Since the operation of the proposed facility is expected to slightly reduce the existing thermal impacts, no additional monitoring other than that required by the issued NPDES permit is recommended.

5.2 EFFECTS OF CHEMICAL AND BIOCIDE DISCHARGES

5.2.1 INDUSTRIAL WASTEWATER DISCHARGES

Four industrial waste streams from the proposed facility will be indirectly discharged to the existing discharge canal. These include discharges from the (1) demineralizer (17.03 gpm for normal operation and 89.09 gpm during augmentation); (2) condensate polisher (2.24 gpm); (3) evaporative coolers (9.0 gpm); and (4) clean drains from the turbine/boiler building (28.0 gpm). These four streams combine with the cooling tower makeup water from the discharge canal and the total volume is pumped to the cooling towers. After approximately two cycles of concentration, the cooling tower blowdown water is returned to the discharge canal. The impacts of the cooling tower blowdown are discussed in the next section. Appendix 10.2.5 contains Gulf's modified NPDES application.

5.2.2 COOLING TOWER BLOWDOWN

The cooling water will be treated to control fouling, scaling, and biofouling. The biocide used will be sodium hypochlorite. The cooling tower blowdown will be closed until the residual chlorine dissipates; therefore, no impacts to aquatic communities are expected.

Generic chemicals will be used to control fouling, and include polyacrylate or a polyacralimide. The cooling tower blowdown containing these water treatment chemicals will be discharged to the existing discharge canal and will be diluted by approximately 71:1 prior to reaching the NPDES point of discharge (POD) Outfall D001. The water treatment chemicals will be at very low levels such that there will be no expected impacts to the aquatic system.

The cooling tower is designed for two-cycle operation, which means that most water quality parameters will be concentrated two-fold prior to discharge to the existing discharge canal. The water quality of the makeup water from the once-through cooling water in the discharge canal (used for design purposes) and the projected water quality of the cooling tower blowdown for normal operation and power augmentation are provided in Table 5.2.2-1. In addition, the water quality of the mixed discharges as the effluent enters

Table 5.2.2-1. Water Quality Parameters of the Gulf Smith Unit 3 Cooling Water

	Makeup Water (normal)	Makeup Water (Augmentation)	Blowdown (Normal)	Blowdown (Augmentation)	POD (D001) (Normal)	POD (D001) (Augmentation)	Class II Marine Standards†
Flow (gpm)	5,120	5,048	2,587	2,587	187,467	187,539	—
Calcium (mg/L)	172	172	343	346	174	174	—
Magnesium (mg/L)	583	583	1,154	1,139	591	591	—
Sodium (mg/L)	5,416	5,416	10,955	10,809	5,493	5,491	—
Total cations (mg/L)	6,171	6,171	12,452	12,294	6,258	6,256	—
Biocarbonate (mg/L)	65	65	135	152	66	66	—
Sulfate (mg/L)	2,801	2,801	5,544	5,470	2,839	2,838	—
Chloride (mg/L)	8,730	8,730	17,275	17,043	8,848	8,845	—
Phosphate (mg/L)	0	0	0.09	0.09	<0.01	<0.01	—
Total anions (mg/L)	11,596	11,596	22,954	22,665	11,755	11,751	—
pH (units)	7.98	7.98	7.97	7.91	7.98	7.98	6.5-8.5
Silica (mg/L)	0.00	0.00	0.5	1.9	0.007	0.026	—
TSS (mg/L)	6.5	6.5	13.8	13.7	6.6	6.6	—
Temperature (°F)	86	86	86	86	86	86	—
Oil and grease (mg/L)	0.00	0.00	0.00	0.00	0.00	0.00	≤5.0
Antimony (mg/L)*	<0.02	<0.02	<0.04	<0.04	<0.02	<0.02	≤4.3
Arsenic (mg/L)*	<0.01	<0.01	<0.01	<0.01	<0.02	<0.02	<0.05
Beryllium (mg/L)*	<0.04	<0.04	<0.08	<0.08	<0.04	<0.04	≤0.00013
Cadmium (mg/L)*	<0.005	<0.005	<0.01	<0.01	<0.005	<0.005	≤0.0093
Chromium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.05
Lead (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.0056
Nickel (mg/L)*	<0.04	<0.04	<0.08	<0.08	<0.04	<0.04	≤0.0083
Selenium (mg/L*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.071

Table 5.2.2-1. Water Quality Parameters of the Gulf Smith Unit 3 Cooling Water (Continued, Page 2 of 2)

	Makeup Water (normal)	Makeup Water (Augmentation)	Blowdown (Normal)	Blowdown (Augmentation)	POD (D001) (Normal)	POD (D001) (Augmentation)	Class II Marine Standards†
Silver (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	—
Thallium (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤0.0063
Zinc (mg/L)*	<0.02	<0.02	<0.04	<0.04	<0.02	<0.02	≤0.086
Mercury (mg/L)*	<0.0002	<0.0002	<0.0004	<0.0004	<0.0002	<0.0002	<0.000025
Copper (mg/L)*	<0.002	<0.002	<0.04	<0.04	<0.02	<0.02	<.0029
Cyanide (mg/L)*	<0.01	<0.01	<0.02	<0.02	<0.01	<0.01	≤1.0

* Because of two cycles of concentration, the concentration will approximately double in the blowdown. Input from process streams to the cooling tower are expected to be below detection limits for these parameters. Values shown as less than ("<") are below the detection limits.

† Pursuant to the facility's NPDES permit, "the actual limit shall be the water quality standard set forth in F.A.C. 62-302.530 for Class II waters…or the concentration of the intake cooling water, whichever is greater."

Source: Gulf, 1999.
ECT, 1999.

public waters at the POD (NPDES Outfall D001) is provided. The water quality parameters of the cooling tower blowdown listed in Table 5.2.2-1 include the contributions of the internal industrial waste streams that are cycled through the cooling tower.

The water quality parameters listed exhibit the approximate two-fold increase in the water quality parameters with relatively small variances caused by the addition of the internal waste streams (comparing the makeup water with the blowdown). Two exceptions to this are silica (increases to a maximum of 1.9 mg/L) and phosphate (increases to a maximum of 0.09 mg/L), which are higher because of constituents in the waste streams and chemical additives. However, both of these parameters are still within applicable water quality standards.

As the cooling tower blowdown is discharged to the existing discharge canal (the original source of the makeup water), it will be diluted in the discharge from Units 1 and 2 by approximately 71:1 prior to reaching Outfall D001. The net result of withdrawing the makeup water and concentrating the constituents approximately two-fold in the cooling tower prior to reintroducing the water to the canal is to increase the concentration of the constituents of the final mixture of cooling water in the canal by approximately 1.3 percent. In addition, there will be a slight increase in some of the water quality parameters resulting from the process streams being recycled to the cooling tower. The net result of the two-cycle concentration, the inclusion of the internal process streams to the cooling tower makeup water, and the final mixing with the existing once-through cooling water is provided in Table 5.2.2-1. The parameter values presented in the table are the final projected concentrations at Outfall D001 and all parameters are expected to comply with Class II and Class III marine water quality standards on established permit limits as shown in the modification to the NPDES application presented in Appendix 10.2.5. Consequently, no long-term adverse impacts are expected on the water quality or aquatic systems in the receiving water (the thermal impacts were discussed in Section 5.1).

5.2.3 MEASUREMENT PROGRAMS

The analyses provided above were completed using historical data and engineering estimates of process streams for the proposed facility modification. The water quality of the intake and discharge water for the existing facility was supplemented with water quality samples collected in April 1999.

5.3 IMPACTS ON WATER SUPPLIES

5.3.1 SURFACE WATER

The Smith Unit 3 Project proposes to use cooling water from the existing discharge canal for the existing Smith plant and to use process water supplied by ground water from existing permitted wells onsite. As shown in the water balance diagram presented in Figures 3.5.0-1 and 3.5.0-2, surface water withdrawals from the discharge canal will be 5,120 gpm and 5,048 gpm (during power augmentation). Consequently, the Smith Unit 3 Project will not affect surface water quantities or quality, or affect the surface water hydrology of the surrounding area. The plant's proposed use of ground water will not affect surface waters. The operation of the proposed plant is expected to have no impacts on surface water supplies.

5.3.2 GROUND WATER

5.3.2.1 Impacts from Plant Pollutants

The proposed power plant will not have any direct discharges to ground water other than percolation from onsite storm water ponds. Therefore, the normal plant operations will not adversely affect ground water quality.

Use of fly ash mixed with clean fill as a base for the power plant will not affect ground water from any leaching of constituents. Toxicity testing results on the proposed fly ash are in Attachment 10.5-H of Appendix 10.5.

The plant design includes preventive measures to isolate any impacts from plant pollutants on ground water resources as a result of accidents or other unusual circumstances. These preventive measures are discussed in Sections 5.2, 5.3.4, and 5.4. Even if pollutants were to escape and permeate downward into the aquifer systems, they could be controlled and recovered with relative ease. The surficial aquifer includes appreciable amounts of organic matter, silts, and clays which would attenuate migration by adsorbing pollutants. Horizontal migration in the surficial aquifer would also be minimal because the natural hydraulic-gradient is essentially flat which limits the velocity of ground water flow.

The presence of the intermediate system, including the Jackson Bluff, between the surficial and Floridan aquifer systems will serve to attenuate downward migration, by retarding downward flow due to its low permeability.

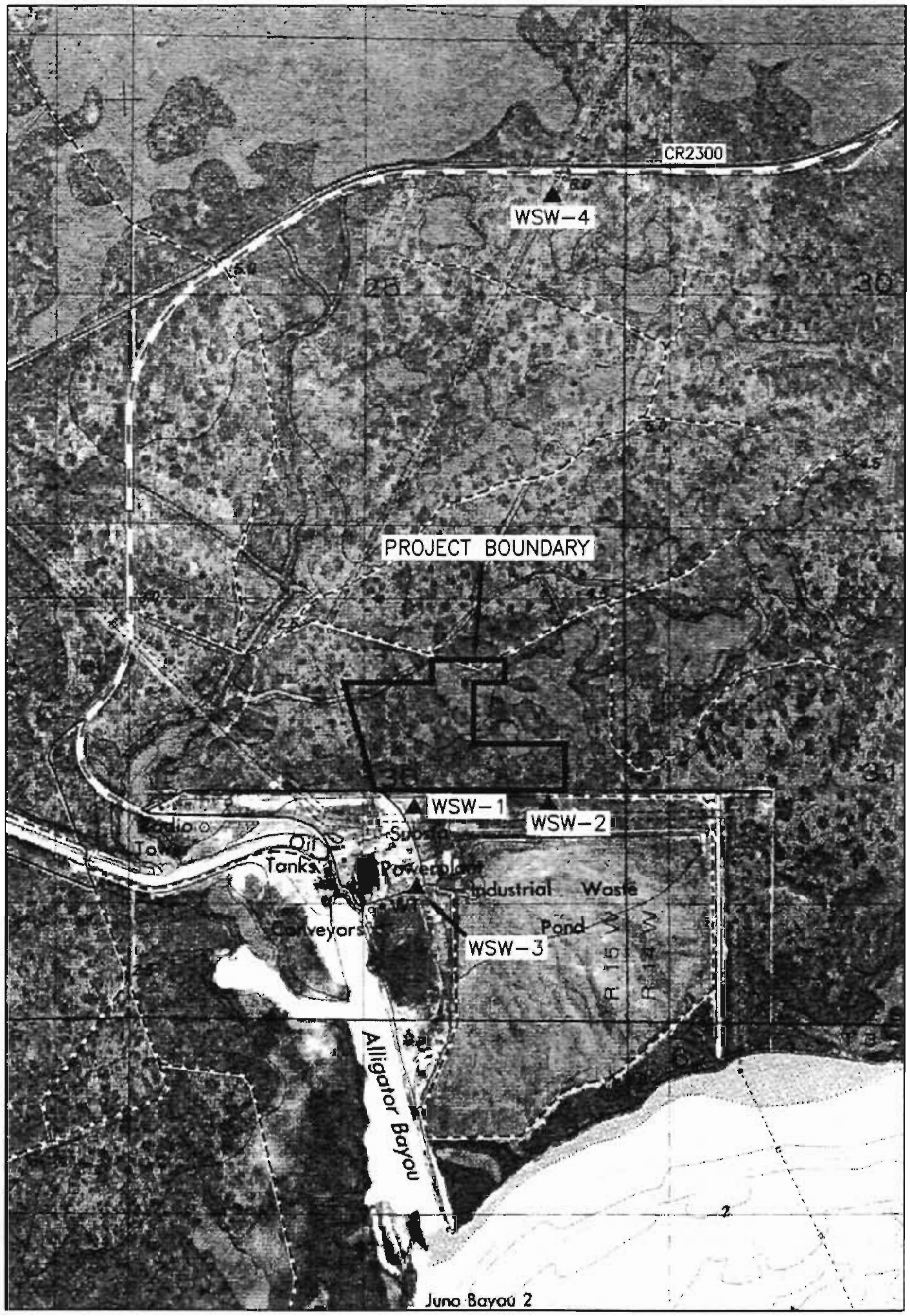
5.3.2.2 Impacts from Ground Water Withdrawals

Gulf Power has made significant efforts to evaluate the existing water supply for the operation of the plant. These efforts are discussed in the modeling study included in Appendix 10.5, Attachment 10.5-G. The total additional daily water requested is an increase of 0.5 MGD over the permitted amount of 0.7 MGD (a total Smith plant site requirement of 1.2 MGD for high quality process water). The additional water will be obtained from a previously approved new well to be installed in Fall 1999 at the location shown on Figure 5.3.2-1 and described in Appendix 10.5, Attachment 10.5-G.

The ground water modeling evaluations determined that 1.2 MGD of ground water can be reasonably and safely withdrawn from the Floridan aquifer system at the Project site. It was also determined that 0.72 MGD (annual average) can be withdrawn from the new well without causing significant adverse impacts.

Results of the ground water withdrawal study show that:

- Adding the fourth well will not adversely affect the Floridan aquifer system or the nearest major user.
- Regional head declines are only attributable to countywide water production increases over time.
- Operating the four permitted wells will not affect the surficial aquifer system or its related wetlands.
- Some minor upconing of chloride-bearing water will occur but will not significantly affect the Floridan aquifer system or the nearest major user, the City of Lynn Haven.
- The upconing is local in nature, will not degrade the Floridan aquifer system, and is expected to dissipate rapidly.



1000 0 1000 2000 3000 4000 5000 FEET

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FIGURE 5.3.2-1.

NEW WELL LOCATION (WSW-4)

Source: SCS, 1999.

ECT

Environmental Consulting & Technology, Inc.

- Operating the new well will allow the existing plant wells to operate at a lower rate, which will allow their chloride levels to decrease.

For each criterion, the conclusion is that the proposed annual average withdrawal rate of 1.2 MGD is not expected to cause significant adverse impacts. The current permitted allowable withdrawal rate is 0.7 MGD. Section 5.3.5 describes the ground water monitoring program that will be used to document water level, flow, and water quality conditions both prior to and during operation of the power plant. This monitoring will further ensure that significant impacts do not occur.

5.3.3 DRINKING WATER

The small quantity of drinking water and other potable water required by Smith Unit 3 personnel (slightly over 1,000 gpd) will be supplied by the four permitted wells onsite. There will be no discharges from the plant to any drinking water sources. Cooling tower blowdown will be discharged to the existing discharge canal which empties into Warren Bayou on West Bay. Process wastewater and sanitary wastewater will be sent to the existing Lansing Smith WWTP for treatment. That facility currently has ample capacity to handle the small amount of wastewater generated by Smith Unit 3.

No impacts to the regional drinking water supplies are anticipated as discussed in Section 5.3.2.

5.3.4 LEACHATE AND RUNOFF

Following construction, the SWMP (see Appendix 10.2.2) will provide guidance in protecting adjacent water bodies. Erosion and sedimentation should be minimal due to grass and other vegetative cover reducing velocities of runoff, which inhibits suspension of soils. Most silts that do reach suspension will be deposited within the storm water ponds. The ponds will also treat runoff through biological uptake from vegetation on the littoral shelf. Regular maintenance of the ponds will include removal of sediments and other debris which may have been washed from the site.

Increased attention on source control has shifted the NPDES program to not only look at point sources, but also non-point sources. Non-point sources are loosely defined as storm water runoff outfalls. To clean up the outfalls, the program proposes to limit the sources which may contribute to pollution associated with runoff. BMPs are proposed to limit pollution potential. The BMPs for the Project are detailed in the BMP plan (Appendix 10.2.3). Included are measures to contain spills in secondary containment, placing high-risk materials under cover, employee training, storage systems, and tracking of materials. These measures will help in the prevention of impacts to adjacent water bodies.

5.3.5 MEASUREMENT PROGRAMS

Chloride sampling is proposed to occur quarterly from existing wells 1 through 4. In addition, flow measurements will also be recorded on water withdrawn from the onsite supply wells. Monitoring will be in accordance with all conditions issued with the modified water use permit.

5.4 SOLID/HAZARDOUS WASTE DISPOSAL IMPACTS

5.4.1 SOLID WASTE

The anticipated types and quantities of solid waste that will be generated by the Smith Unit 3 Project are described in Section 3.7. All solid wastes generated at the plant will be disposed at an offsite licensed landfill designed and permitted to receive such wastes. No onsite impacts will result from these wastes.

Internal facility processes and general maintenance activities at the facility are expected to periodically generate nonhazardous petroleum-contaminated products. Petroleum products such as waste oils or spent lubricating oils will be collected onsite and transferred to a permitted aboveground storage tank and burned for energy recovery in Smith Unit 2. Materials such as petroleum-contaminated liquids and sludges from oil/water separators and hydrocarbon liquids from fuel/gas filter separators will be periodically serviced by a contractor and transported offsite to a permitted facility for appropriate treatment and disposal. Used oil filters generated through general maintenance processes will be collected and recycled as scrap metal. No onsite impacts will result from the handling of these waste oil products.

5.4.2 HAZARDOUS WASTE

Small quantities of hazardous wastes will be routinely generated at the proposed Smith Unit 3 Project plant site as discussed in Section 3.7.2. It is anticipated that the Smith Unit 3 Project will be a conditionally exempt small-quantity generator. As such, the facility will not be required to meet requirements for large-quantity generators or other small-quantity generators, as specified in 40 CFR Parts 260 through 263 and Parts 270 through 272. Specialty contractors conducting activities such as metal cleaning of the HRSG will be responsible for proper removal of waste products resulting from their contracted activities.

5.5 SANITARY AND OTHER WASTE DISCHARGES

Sanitary wastewater from the plant will be discharged via sewer line to the adjacent Smith Plant package wastewater treatment facility, which has available permitted capacity to handle Smith Unit 3 wastewater. There will be no sanitary discharges other than to the WWTP. All discharges from the WWTP will meet Gulf's existing industrial wastewater permit limits. Therefore, sanitary effluent from the Smith Unit 3 Project will have no effect on the environment. Wastewater from the oil/water separator and wastewater from the neutralization tank will be discharged to the cooling tower basin. Cooling tower blowdown will be discharged to the existing Lansing Smith discharge canal which empties into Warren Bayou and West Bay. The point of discharge for this system will meet all applicable state and federal water quality standards per the industrial wastewater treatment permit conditions.

5.6 AIR QUALITY IMPACTS

5.6.1 IMPACT ASSESSMENT

5.6.1.1 Introduction

Analyses were conducted to calculate the potential air quality impacts of emissions from Smith Unit 3. These analyses are described in detail in the PSD permit application contained in Appendix 10.2.7. This section presents a summary of the approach used and the results obtained. The results demonstrate that the operation of Smith Unit 3 will not cause or contribute to a violation of any PSD increment or AAQS.

5.6.1.2 Regulatory Applicability and Overview of Impact Analyses

Under federal PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and approved by EPA or by the state agency if PSD review authority has been delegated or approved for the state. A *major stationary source* is defined as any 1 of 28 named source categories that has the potential to emit 100 tons per year (tpy) or more, or any other stationary source that has the potential to emit 250 tpy or more, of any pollutant regulated under CAA. *Potential to emit* means the capability at maximum design capacity to emit a pollutant after the application of control equipment.

The existing Lansing Smith Plant is classified as a major facility because it falls into one of the named source categories (i.e., fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input) and has the potential to emit more than 100 tpy of at least one pollutant regulated under CAA (see Table 5.6.1-1). Smith Unit 3 constitutes a major modification to a major facility because Unit 3 will result in a significant net emission increase of at least one pollutant regulated under CAA. Therefore, the facility must undergo PSD review. Furthermore, more than one pollutant is subject to review. Table 5.6.1-1 summarizes the facility's proposed annual emissions and compares the projected totals to the significant emission rate thresholds for PSD review. Note that NO_x emissions from Smith Unit 3 are not subject to PSD review because there will be a net reduction in NO_x emissions from the Lansing Smith Plant due to the installation of low-NO_x burner technology and an improved burner management system for Lansing Smith Unit 1.

Table 5.6.1-1. Projected Emissions Compared to PSD Significance Rates

Pollutant	Projected Annual Emissions (tpy)*	Significance Rate (tpy)	Subject to PSD Review?
PM	263	25	Yes
PM (PM_{10})	263	15	Yes
SO_2	105	40	Yes
NO_x	-9	40	No
CO	701	100	Yes
Ozone/VOC	93	40	Yes
Lead	0.0006	0.6	No
H_2SO_4 mist	12	7	Yes
Fluorides	0	3	No
Mercury	Neg.	0.1	No
Beryllium	0	0.0004	No
Total reduced sulfur (including hydrogen sulfide)	0	10	No
Reduced sulfur compounds (including hydrogen sulfide)	0	10	No
Vinyl chloride	0	1	No
Asbestos	0	0.007	No

*See Table 3.4.1-3 for details.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. PSD review requirements are contained in Chapter 62-212.400, F.A.C., *Prevention of Significant Deterioration*. Major sources may be required to undergo the following reviews related to PSD for each pollutant emitted in significant amounts:

- Control technology review.
- Air quality analysis (monitoring).
- Source impact analysis.
- Source information.
- Additional impact analyses.

The control technology review includes determination of BACT for each applicable pollutant. BACT emission limits cannot exceed applicable emission standards (e.g., NSPS). The air quality analysis (monitoring) portion of PSD review may require continuous ambient air quality monitoring data to be collected in the impact area of the proposed source. The source impact analysis requires demonstration of compliance with federal and state AAQS and allowable PSD increment limitations. Projected ambient impacts on designated nonattainment areas and federally promulgated Class I PSD areas must also be addressed, if applicable. Source information, including process design parameters and control equipment information, must be submitted to the reviewing agencies. Additional analyses of the proposed source's impact on soils, vegetation, and visibility, especially pertaining to Class I PSD areas, must be performed, as well as analysis of impacts due to growth in the area associated with the proposed source.

In addition to PSD review requirements, FDEP has developed a strategy to control toxic emissions from stationary sources so that these emissions will not endanger public health. The strategy is based on comparing the predicted ambient impact of individual toxic air contaminants with each chemical's *air reference concentration*. A reference concentration is an ambient exposure level that is not likely to cause appreciable health risks. Due to recent legislative changes to the Administrative Procedures Act, FDEP's air toxics strategy is no longer used in the evaluation of air permits; reference the Division of Air Resources Management *Revised Guidance on the Permitting of Sources Emitting Hazardous Air Pollutants* guidance memo dated November 20, 1998. However, the FDEP's former air toxics policy and air reference concentrations are still considered useful in evaluating toxic air pollutant impacts. Because the Smith Unit 3 CTGs will be fired exclusively with natural gas, the only toxic air contaminant emitted in more than trace amounts is H_2SO_4 mist. An analysis of the Project's impacts of H_2SO_4 mist with respect to FDEP's air reference concentration for this air contaminant is provided in Section 7.3 of the PSD permit application contained in Appendix 10.2.7.

5.6.1.3 Analytical Approach

Air Quality Models

Two air quality dispersion models were used in the analysis of impacts for the Smith Unit 3 Project. These models were:

- SCREEN3.
- ISCST3.

SCREEN3 is a screening model that calculates 1-hour average concentrations from a single source over a range of meteorological conditions. SCREEN3 was used to provide conservative estimates of impacts from the CTGs in order to select the worst-case operating configurations.

The Industrial Source Complex Short-Term (ISCST3) model (EPA, 1998) was used for refined analyses. The ISCST3 model is a steady-state Gaussian plume model that can be used to assess air quality impacts from a wide variety of sources. It is capable of calculating concentrations for averaging times ranging from 1 hour to annual.

Meteorological Data

Detailed meteorological data are needed for modeling with the ISCST3 model. For this effort, meteorological data were selected consistent with EPA (1995) guidance and FDEP practice. Specifically, surface data from Apalachicola Municipal Airport (1988—1990) and Pensacola Regional Airport (1986, 1987) and mixing height data from Apalachicola Municipal Airport for the 5-year period 1986 through 1990 were approved by FDEP and employed.

Emission Source Input Data

Emission parameters for Smith Unit 3 sources were based primarily on information provided by equipment vendors for the Project. Some emission inputs were derived using EPA and other emission factors and facility design data (see Attachments B and C of PSD Application in Appendix 10.2.7).

5.6.1.4 Summary of Air Quality Impacts

Criteria pollutant emissions from the two CTG/HRSG units were modeled using the ISCST3 model. Table 5.6.1-2 summarizes the results of the maximum facility impact modeling runs for the criteria pollutants. As appropriate, the maximum impacts are compared to the modeling significance levels. Table 5.6.1-2 shows that impacts were found to be less than significant for all averaging times and all pollutants subject to review. Due to the low Project impacts, no further analysis of air quality impacts is required (i.e., evaluation of other, existing air emission sources in the area).

In addition, modeled Project impacts are below the PSD *de minimis* ambient impact levels for all pollutants and averaging periods. Accordingly, by rule the Project qualifies for an exemption from preconstruction ambient air quality monitoring requirements for all pollutants.

5.6.1.5 Other Air Quality-Related Impacts

Impacts Due to Associated Growth

Construction of Smith Unit 3 will occur over an approximate 15-month period. There will be an average of approximately 180 workers during that time with a peak employment of approximately 325 construction workers. It is anticipated that most of these construction personnel will be drawn from within Bay County (e.g., the Panama City area) and will commute to the job site. While not readily quantifiable, the temporary increase in vehicle-miles-traveled (VMT) in the area would be insignificant, as would any temporary increase in vehicular emissions.

Table 5.6.1-2. Maximum Smith Unit 3 Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
SO_2	Annual	0.1	1.0
	24-hour	1.7	5.0
	3-hour	7.6	25.0
PM_{10}	Annual	0.5	1.0
	24-hour	13.4	5.0
CO	8-hour	38.4	500
	1-hour	111.2	2,000

Source: ECT, 1999.

The Smith Unit 3 Project will employ a total of 29 operational workers at Project build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. It is expected that most of these persons will be drawn from outside the region.

In the year 2000, the population of Bay County is estimated to be 150,099 persons. The workforce needed to operate the proposed plant, therefore, represents a small fraction of the population already present in the immediate area. While some small increase in area VMT could occur, associated air quality impacts in Bay County will be minimal.

Finally, a new industrial facility can sometimes generate growth in other industrial or commercial operations needed to support the new facility. Given the site's proximity to Panama City, however, the existing commercial infrastructure should be more than adequate to provide any support services that the proposed facility might require. Therefore, no air quality impacts due to associated industrial/commercial growth would be expected. Any significant industrial development resulting from the establishment of Smith Unit 3 would be independently subject to PSD and other environmental review requirements.

Impacts on Visibility and on Soils, Vegetation, and Wildlife

No visibility impairment at the local level is expected due to the types and quantities of emissions projected from Smith Unit 3 emission sources. The opacity of combustion exhausts from the facility will be low due to the exclusive use of clean, natural gas. Emissions of primary particulates and sulfur oxides due to combustion will also be low due to the exclusive use of natural gas. The potential for regional haze formation in the area due to Smith Unit 3 emissions of SO_2, NO_x, and PM/PM_{10} is expected to be minimal. Based on the relatively isolated location of the Lansing Smith Plant and existing land use, the proposed Smith Unit 3 will not adversely affect aesthetic or visual qualities in the area.

Certain air pollutants in acute concentrations or chronic exposures can impact soils, vegetation, or wildlife resources. Based on available literature and air emissions projected for this

Project, the following summary of potential impacts is provided. The PSD application (Appendix 10.2.7) provides a more detailed analysis of potential air emissions on natural resources.

Soils impacts can result from SO_2 and NO_x deposition creating an acidic reaction or lowering of soil pH. In this case, the site soils are naturally acidic, and the low SO_2 and NO_x emissions from the Project will not adversely affect plant vicinity soils.

Vegetation is sometimes affected by acute exposures to high concentrations of pollutants, often resulting in foliar damage. Lower dose exposure over longer periods of time (chronic exposure) can often affect physiological processes within plants causing internal and external damage. Based on an evaluation of the literature for effects from SO_2, acid rain (H_2SO_4 mist), NO_x, CO, and combinations of these pollutants (synergistic effects), no impacts to regional vegetation are anticipated due to the low emission rates from the Project.

Releases of pollutants can also affect wildlife through inhalation, exposure through skin, or ingestion. However, based on low emission levels from this Project, natural dispersion of emissions, and mobility of wildlife, no impacts to regional wildlife resources are expected.

Based on this assessment, it was concluded that emissions from Smith Unit 3 will not result in impacts that will cause harm to soils, vegetation, or wildlife.

5.6.2 MONITORING PROGRAMS

No specialized monitoring of ambient air quality is planned, nor is additional ambient monitoring warranted given the low impacts on air quality predicted for the Project. Gulf Power will continue to operate its existing ambient air monitoring sites for SO_2, NO_x, and PM.

The Smith Unit 3 CTGs will be subject to 40 CFR 60, Subpart GG (NSPS) and 40 CFR 75 (*Acid Rain Program*). Continuous monitoring of fuel consumption will be conducted for the Smith Unit 3 CTGs as required by Subpart GG. Monitoring of fuel sulfur and nitrogen content will also be performed pursuant to Subpart GG, 60.334(b). Initial performance testing of the CTGs for NO_x and SO_2 emissions will be conducted as required by Subpart GG, 60.335.

Continuous emissions monitoring of NO_x and a diluent (O_2 or CO_2) will be conducted in accordance with the provisions of 40 CFR 75. Monitoring of SO_2 and CO_2 emissions will be conducted using procedures specified in 40 CFR 75, Appendices D and G, respectively.

Initial and periodic compliance testing of pollutants emitted by Smith Unit 3 will be conducted pursuant to FDEP requirements as specified in the SCA Approval Order. FDEP test methods are specified in Section 62-297.401, F.A.C.

5.7 NOISE

Potential operational noise impacts were assessed for three Gulf property boundaries (not Project boundaries). Figure 5.7.0-1 shows the location of the model receptors assessed in this analysis. Noise level data for the operating equipment were obtained from vendors and constructing engineers. The noise data are presented in Table 5.7.0-1.

While some portions of the site perimeter will remain vegetated or be revegetated after construction is complete, for this analysis, noise from the proposed operation was conservatively assumed not to be attenuated due to vegetation buffers at the modeled receptors. A substantial vegetative buffer exists between the facility and the property boundaries; however a conservative approach was again used for this noise analysis in that no credit was taken for the noise attenuation that will occur because of this vegetation. Similarly, while other noise attenuating factors will be present (e.g., screening of noise by structures), no credit other than distance was taken at any receptor for any noise attenuation that will occur.

Table 5.7.0-2 presents the results of the noise analysis at each of the receptor locations. The predicted noise levels at the north, east, and west property boundaries are all less than the Bay County sound level limit of 75 dBA (Bay County Land Use Code Section 6.05.01) for agricultural, silvicultural, and industrial land use types. Given the conservatism associated with this analysis, it can be concluded that the Project will comply with the county standard. As noted above, the attenuation effects of the vegetative barrier located between the power plant and the property boundaries were not included in the evaluation. The actual noise impact due to the facility is expected to be lower.

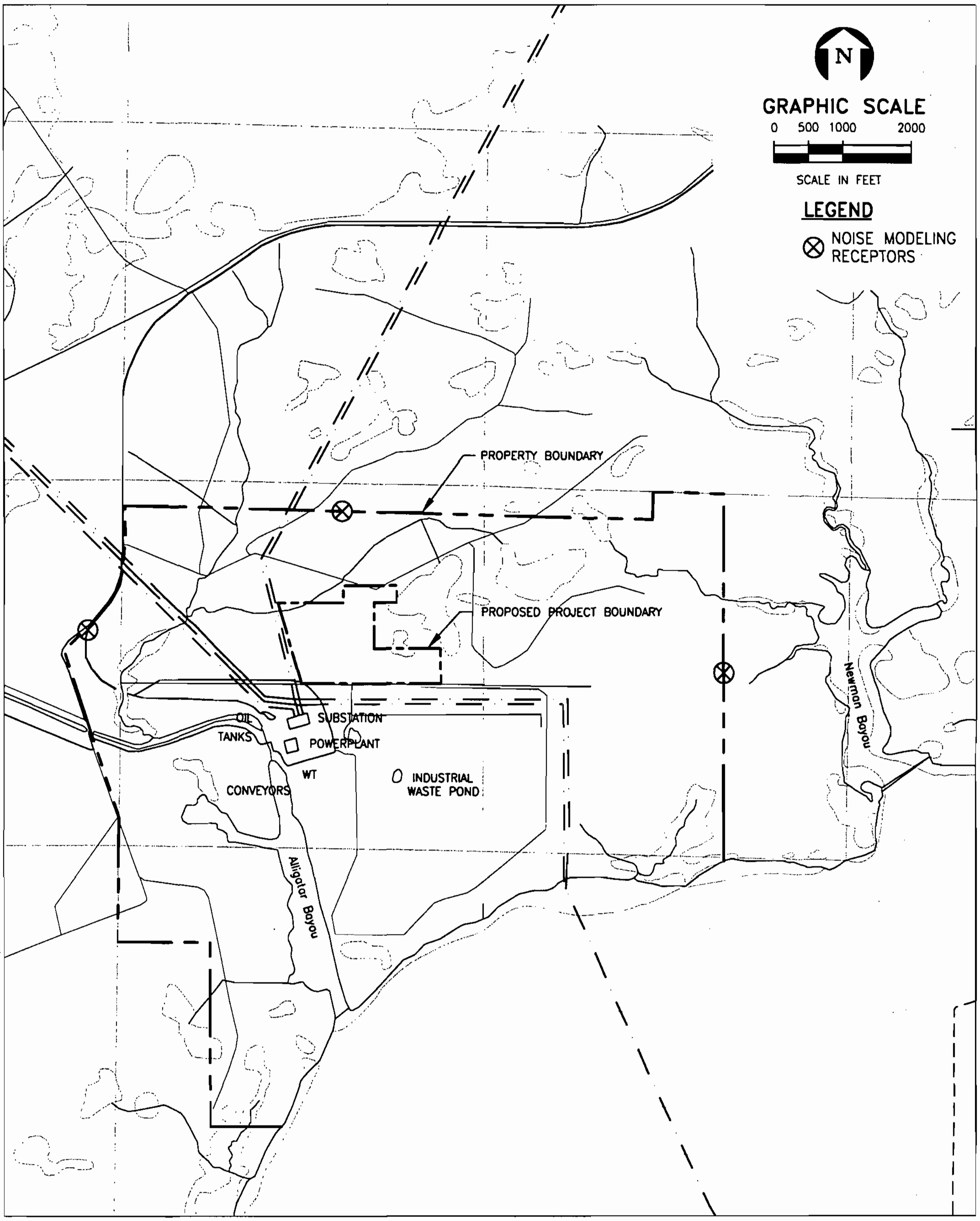

FIGURE 5.7.0-1.

NOISE MODELING RECEPTORS

Source: US Geodata, 1997; ECT, 1999.

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Table 5.7.0-1. Operating Equipment Noise Levels

Equipment Description	Sound Pressure Level (dB re 20 μPA) Octave Band Center Frequency (hertz)									Sound Level (dBA)	Reference Distance (ft)
	31.5	63	125	250	500	1,000	2,000	4,000	8,000		
Boiler Feed Pump 1	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump 2	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump 3	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump 4	NA	89	86	87	90	87	85	80	85	92	3
Boiler Feed Pump Motor 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Boiler Feed Pump Motor 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Boiler Feed Pump Motor 3	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Boiler Feed Pump Motor 4	NA	NA	NA	NA	NA	NA	NA	NA	NA	93	3
Steam Turbine	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Gas Turbine 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Gas Turbine 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Condensate Pumps and Motor 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	86	3
Condensate Pumps and Motor 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	86	3
Circulating Water Pump and Motor 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Circulating Water Pump and Motor 2	NA	NA	NA	NA	NA	NA	NA	NA	NA	85	3
Cooling Tower	NA	64	65	65	72	75	76	78	78	84	25

NA = not available.

Source: GPC, 1999.

Table 5.7.0-2. Modeled Ambient Noise Impacts

Receptor	Smith Unit 3 Sound Level (dBA)	Sound Level Limit (dBA)*
North Property Boundary	42	75
East Property Boundary	29	75
West Property Boundary	35	75

*Bay County Land Use Code Section 6.05.01.

Source: ECT, 1999.

5.8 CHANGES IN NON-AQUATIC SPECIES POPULATIONS

5.8.1 IMPACTS

Potential adverse effects to onsite or local upland and wetland habitats due to power plant operations are commonly a result of air emissions and cooling system operation. As stated in Section 5.6 of this SCA, no significant impacts to either onsite or local/regional plant and wildlife communities are anticipated from the air emissions or cooling system operation associated with power plant operation. In addition, no impacts on listed plant or animal species discussed in Section 2.3.6 will result from plant operations.

5.8.2 MONITORING

Monitoring programs are not proposed due to the negligible impacts to ecological resources associated with plant operation.

5.9 OTHER PLANT OPERATION EFFECTS (TRAFFIC)

5.9.1 IMPACTS

All of the traffic to be generated by the proposed development will access and leave the Project site from CR 2300. For a worst-case scenario, all of the expected new trips to be generated are assigned to the road segment from SR 77/CR 2300 to the south approach to Bailey Bridge. The estimated number of new trips is based on trip generation rate for power plants of 2.35 and a vehicle occupancy rate of 1.4. The proposed development will generate approximately 49 new daily trips based on 29 new plant employees. The existing, projected, and acceptable average daily traffic (ADT) and LOS are as follows:

	Existing ADT/LOS (1998)	Projected ADT/LOS (2002)	Acceptable ADT/LOS
SR 77/CR 2300 south to Bailey Bridge	15,800 (C)	17,456 (C)*	24,800 (D)

*From CR 388 South to Bailey Bridge.

Source: FDOT, 1999.

The impact of the proposed operation of Smith Unit 3 on the state and county road system will not degrade the existing LOS of C on this roadway segment. If the proposed Smith Unit 3 is approved, the plant is anticipated to be operational in June 2002. The anticipated ADT on SR 77 from south of CR 388 to Bailey Bridge in 2002 is approximately 17,456 and with the Project traffic would be 17,505, well below the maximum acceptable LOS (D) of 24,800.

According to FDOT District 3 personnel, the SR 77 segment from Bailey Bridge to CR 2300 is scheduled to begin project development and engineering studies in 2000 with right-of-way acquisition to also begin in 2000. The four-laning of this road segment is scheduled to begin in 2005 (but is not in the current FDOT 5-year plan through 2004).

5.9.2 MONITORING

Due to the small traffic volume created as a result of operation of Smith Unit 3, no traffic monitoring studies are required or proposed.

5.10 ARCHAEOLOGICAL SITES

Based on a review of cultural resources potentially occurring onsite (see Sections 2.2.6 and 4.8), the Division of Historic Resources concluded no significant historical or archaeological sites are expected to be found at the proposed site (Appendix 10.5, Attachment 10.5-A). Therefore, no onsite post-construction monitoring or restoration activities are required.

5.11 RESOURCES COMMITTED

The major irreversible and irretrievable commitments of state and local resources due to the operation of the Smith Unit 3 Project are as follows:

- Use of land.
- Consumption of natural gas.
- Consumptive use of water (ground water).
- Consumption of air quality increments.

The use of land by the Project, while irreversible, will be relatively small. The site consists of 50.1 acres, and approximately 32.7 acres will be cleared for the Project. The remaining acreage, including wetlands, will remain in its natural state.

Natural gas will be consumed by the CTGs. The quantities are presented in Chapter 3.0. While the Smith Unit 3 Project will produce electricity in an efficient manner using state-of-the-art technology, which will result in efficient use of fuel, the natural gas consumed represents an irreversible and irretrievable commitment of energy resources for the production of electricity.

Water evaporated by the cooling tower as part of the heat rejection process represents a consumptive use of water. This consumptive use will be minimized by the reuse of heated cooling water discharged to the outfall. Ground water consumed for high quality uses by the operation of the plant will be withdrawn in a manner which will result in acceptable impacts, as determined using criteria developed by the NWFWMD.

The air quality increments consumed by air pollutant emissions from the Project will be negligible. The Project's emissions will create no impediment to any additional industrial growth in the area, nor will they have significant impacts on the area's air quality.

5.12 VARIANCES

No variances from any federal, state, or local regulations, standards, or guidelines will be needed for operation of this Project.

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6.0 TRANSMISSION LINES AND OTHER LINEAR FACILITIES

In this application, Gulf Power is not seeking certification of any new transmission line corridors or natural gas pipeline corridors.

This particular site was selected largely in part because of its proximity to Gulf's existing Lansing Smith Generating Station. Smith Unit 3 will be able to share many facilities already in place at the site including transmission line access.

6.1 TRANSMISSION LINES

As discussed in Section 3.2 of this SCA, Smith Unit 3 will be constructed with its own onsite substation which will be connected to the existing Lansing Smith 230-kV substation by means of approximately 1,000 ft of wire bus. The wire bus will be located and constructed on already developed plant site property and, therefore, will not require any new transmission corridor. No environmental or land use impacts are expected from this transmission tie.

As also mentioned in Section 3.2, certain transmission system improvements will be required on Gulf's existing transmission grid within Bay County (see Figure 3.2.0-4). These all involve re-conductoring on existing transmission lines and existing rights-of-way. Reconductoring involves the replacement of the wires or conductor in a transmission line. The basic method used to reconductor the lines will be to remove the old conductor from the suspension clamp at each structure, place the old conductor in a wire roller (pulley), attach a pulling rope to the old conductor, pull the rope in by pulling out the old conductor, attach the new conductor to the rope, pull the new conductor in place with the rope, remove the conductor from the rollers, and install the conductor into the suspension clamp. The removal of the old wire and installation of the new conductor will be accomplished by standard tension stringing methods at each end of the line sections. Existing right-of-way access roads will be utilized for this effort. No new transmission line corridors, structures, access roads, etc., will be necessary for the re-conductoring. Similarly, no dredging or filling of wetlands will be required. Therefore, no environmental or land use impacts are expected from these system upgrades. The reconductored lines will meet FDEP's standards for electric-magnetic field (EMF) levels as outlined in Chapter 62-814, F.A.C.

6.2 NATURAL GAS PIPELINE

The Smith Unit 3 Project will burn natural gas only and, as discussed in Section 3.3, a new natural gas pipeline will have to be built to serve the Project. A pipeline lateral is proposed to connect with FGT's pipeline system in Washington County.

Gulf Power is not proposing to permit, build, or own the gas pipeline. FGT will be responsible for the permitting, engineering, construction, operation, and maintenance of the new gas pipeline. The gas pipeline route has not been finalized, but is expected to interconnect with the existing FGT system south of the town of Wausau in Washington County. The new pipeline will be approximately 29 miles long and most likely will follow SR 77 south to Bay County. At the point where SR 77 intersects Gulf's existing transmission line at SR 388, the gas pipeline is expected to follow the transmission line to the Smith Plant (see Figure 6.2.0-1).

The pipeline lateral will be permitted, constructed, and operated by FGT. FGT will submit appropriate state and federal permit applications separate from this application. It is expected that permitting of the pipeline will occur in the same timeframe as certification of Smith Unit 3.

A gas meter station will be required at the Smith Unit 3 site. This facility will be owned by Gulf Power and, therefore, is included in the site plan for this Project's certification.

6.3 OTHER LINEAR FACILITIES

The only other linear facilities required for this Project will be various onsite pipes connecting the Unit 3 site with the existing Lansing Smith Generating Station's facilities. The most notable of these will be the required cooling water intake and discharge pipelines which will connect Smith Unit 3 to Gulf's existing discharge canal on the property. The new pipelines will be constructed on cleared, already developed property at the

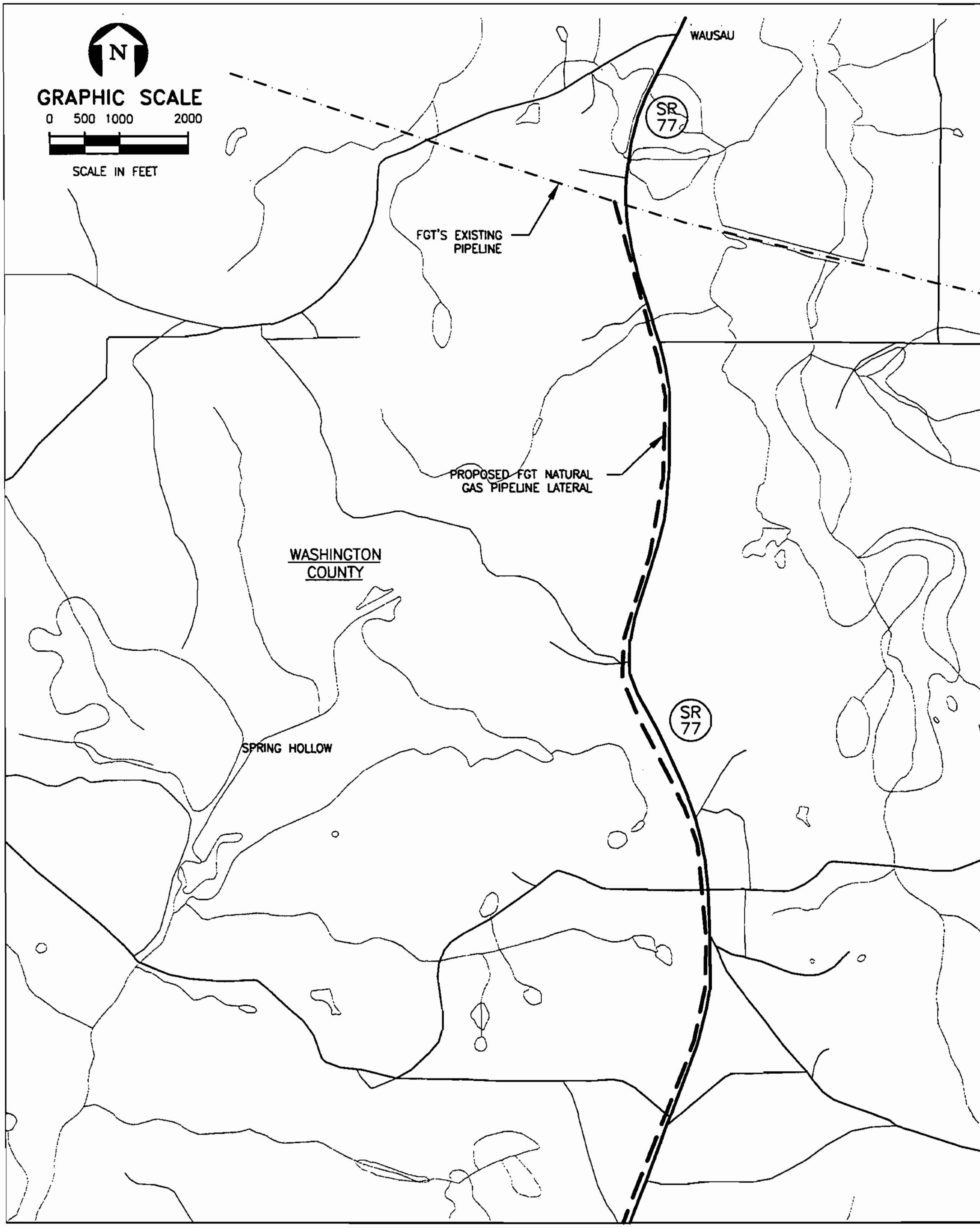

FIGURE 6.2.0-1. (PAGE 1 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

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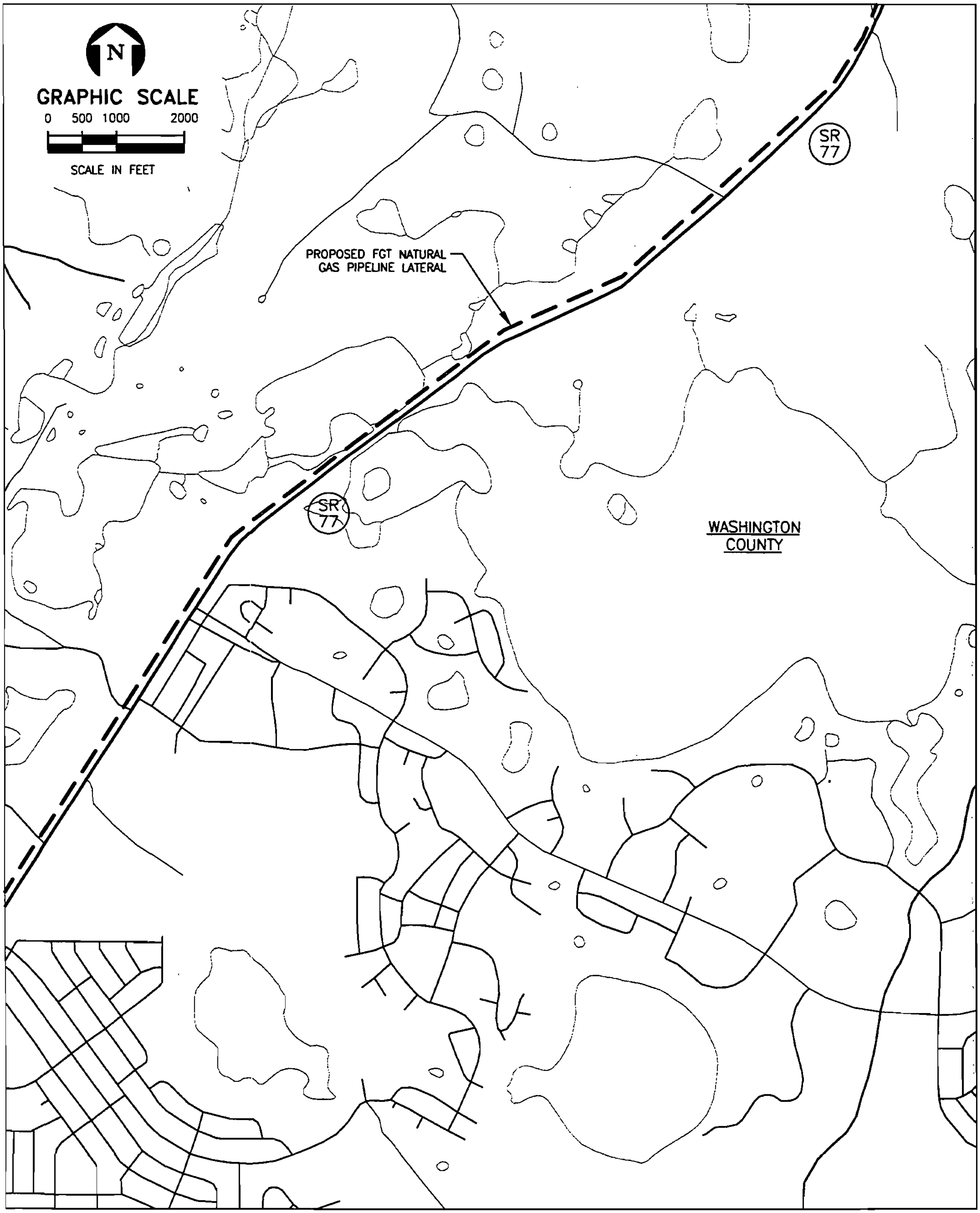

FIGURE 6.2.0-1. (PAGE 2 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: US Geodata, 1997; ECT, 1999.

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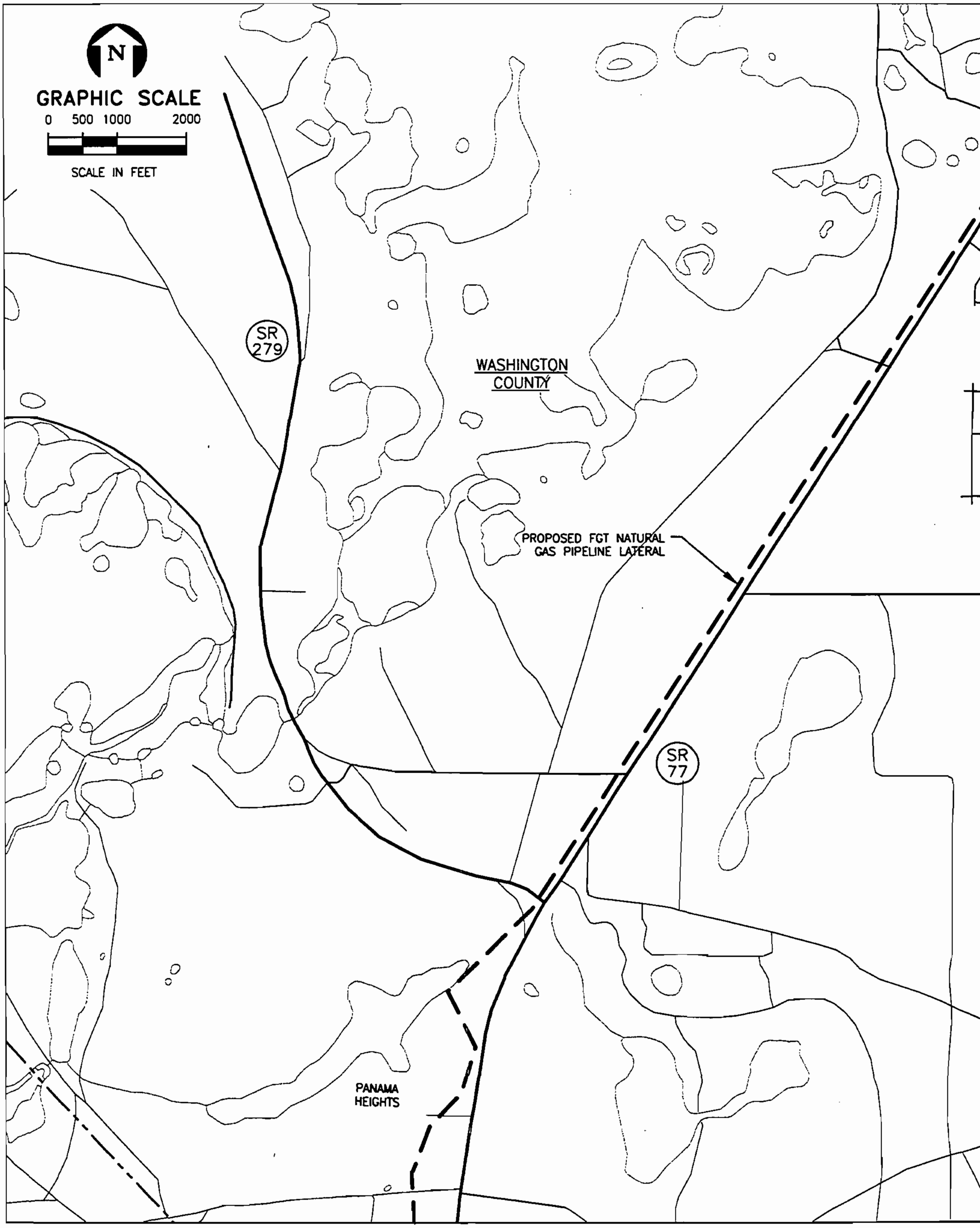

FIGURE 6.2.0-1. (PAGE 3 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

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Environmental Consulting & Technology, Inc.

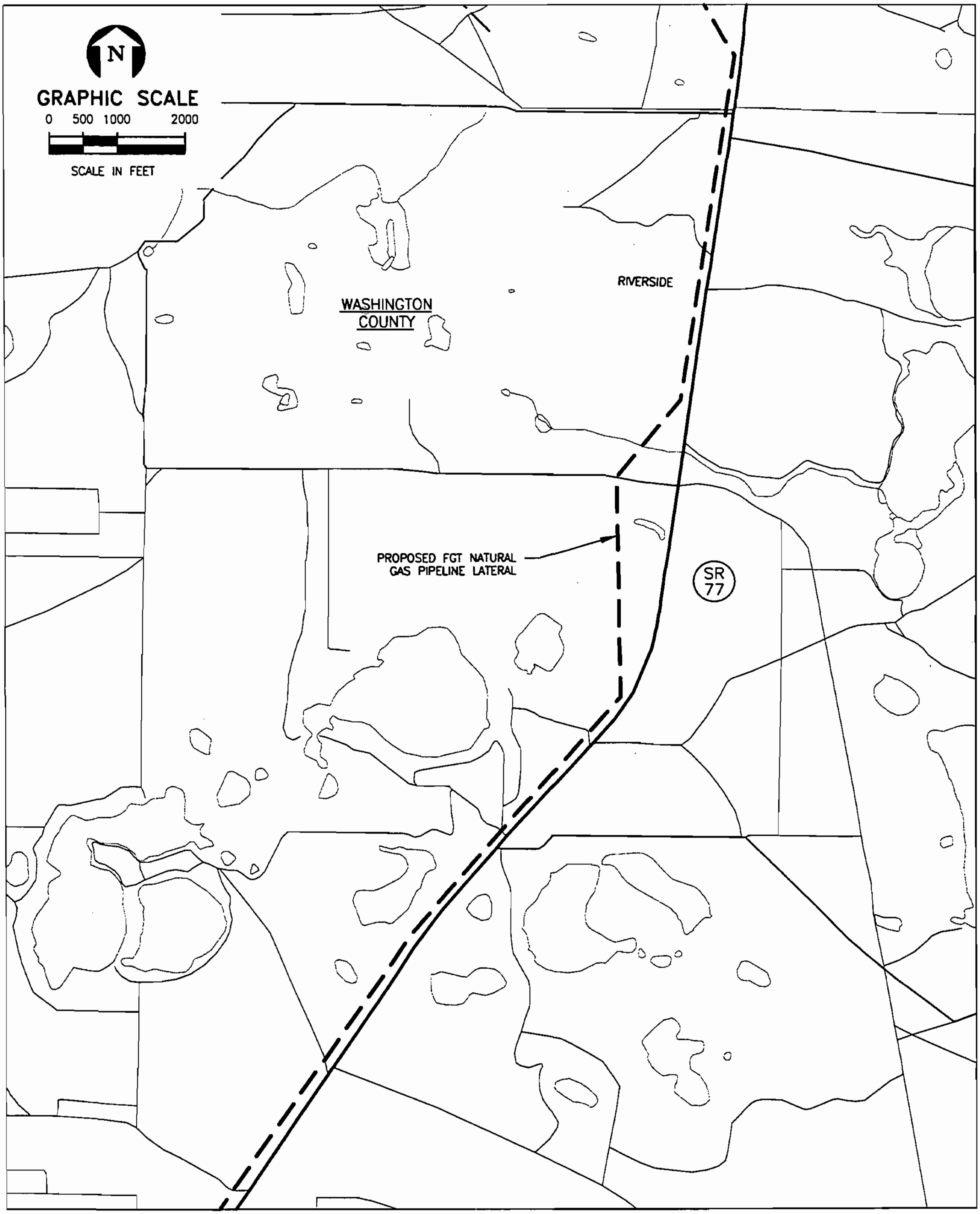

FIGURE 6.2.0-1. (PAGE 4 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

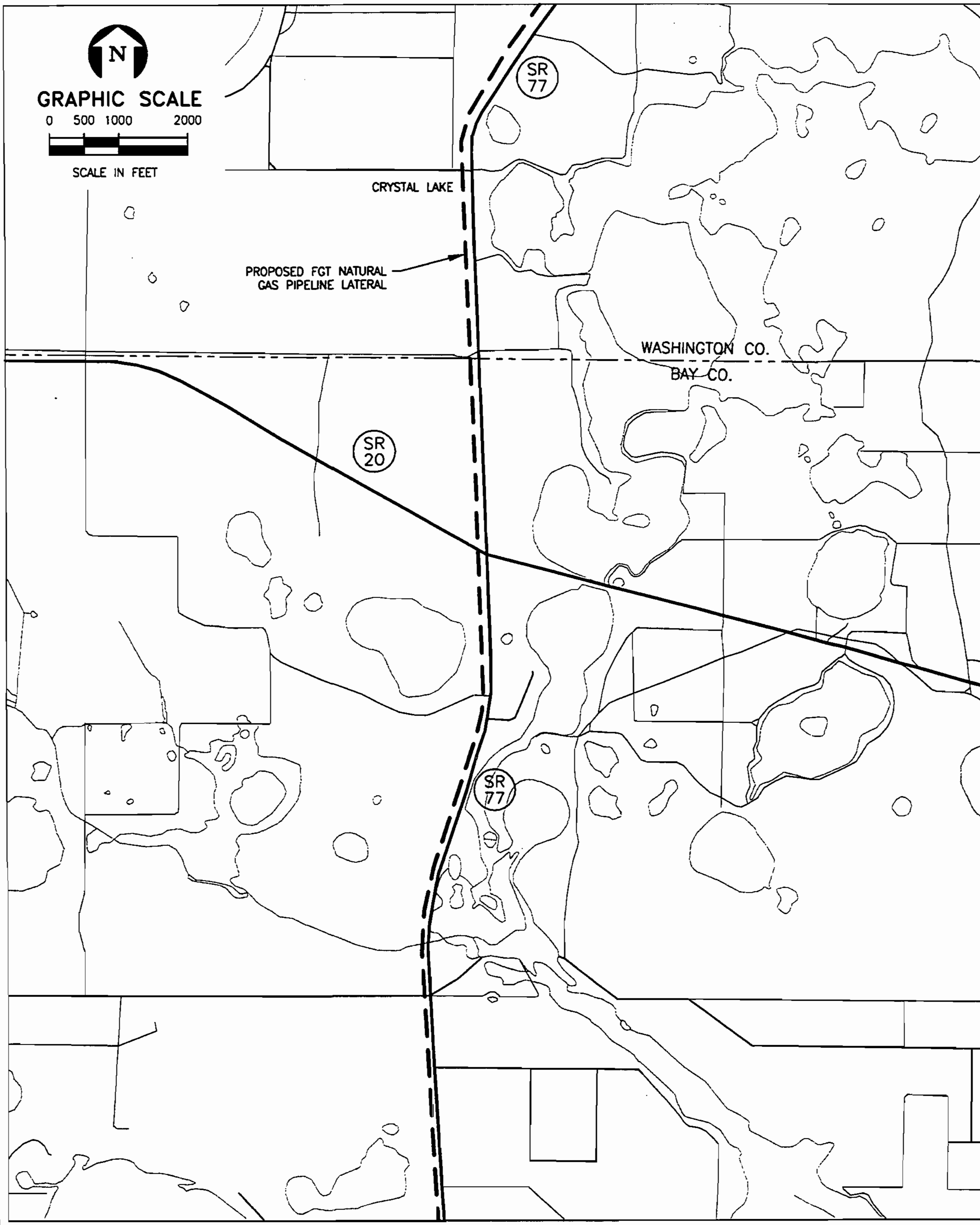

FIGURE 6.2.0-1. (PAGE 5 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

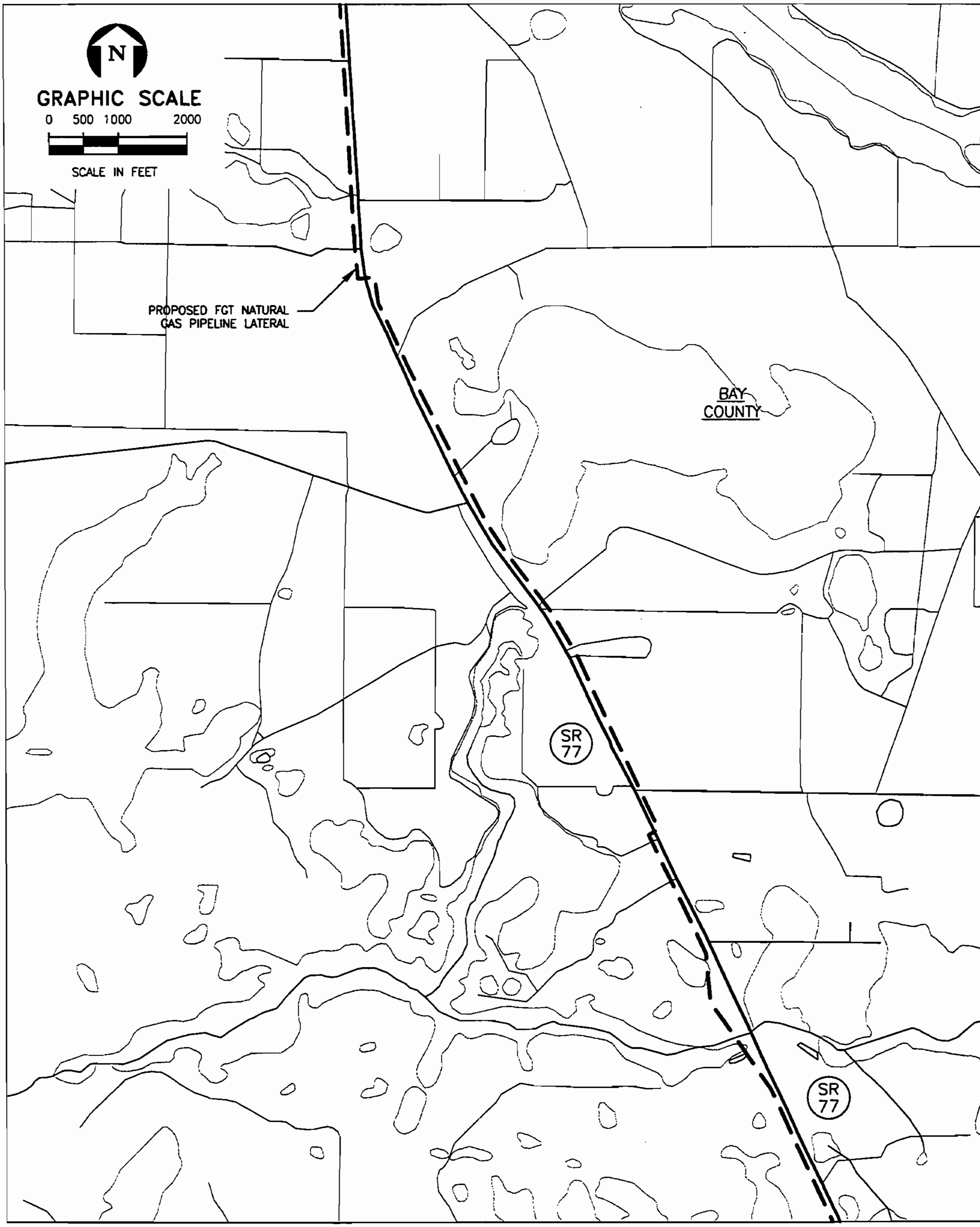

FIGURE 6.2.0-1. (PAGE 6 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

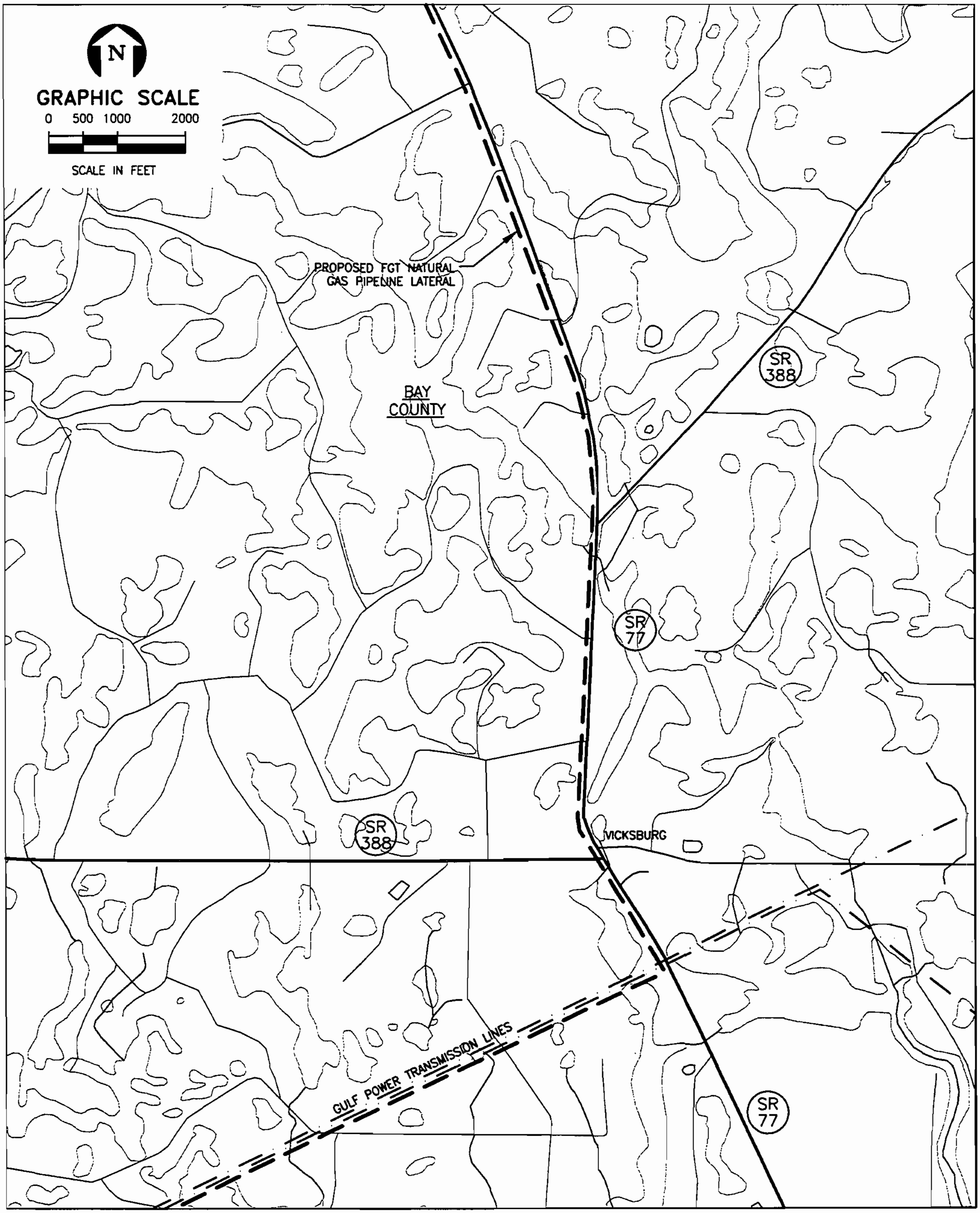

FIGURE 6.2.0-1. (PAGE 7 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodata, 1997; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

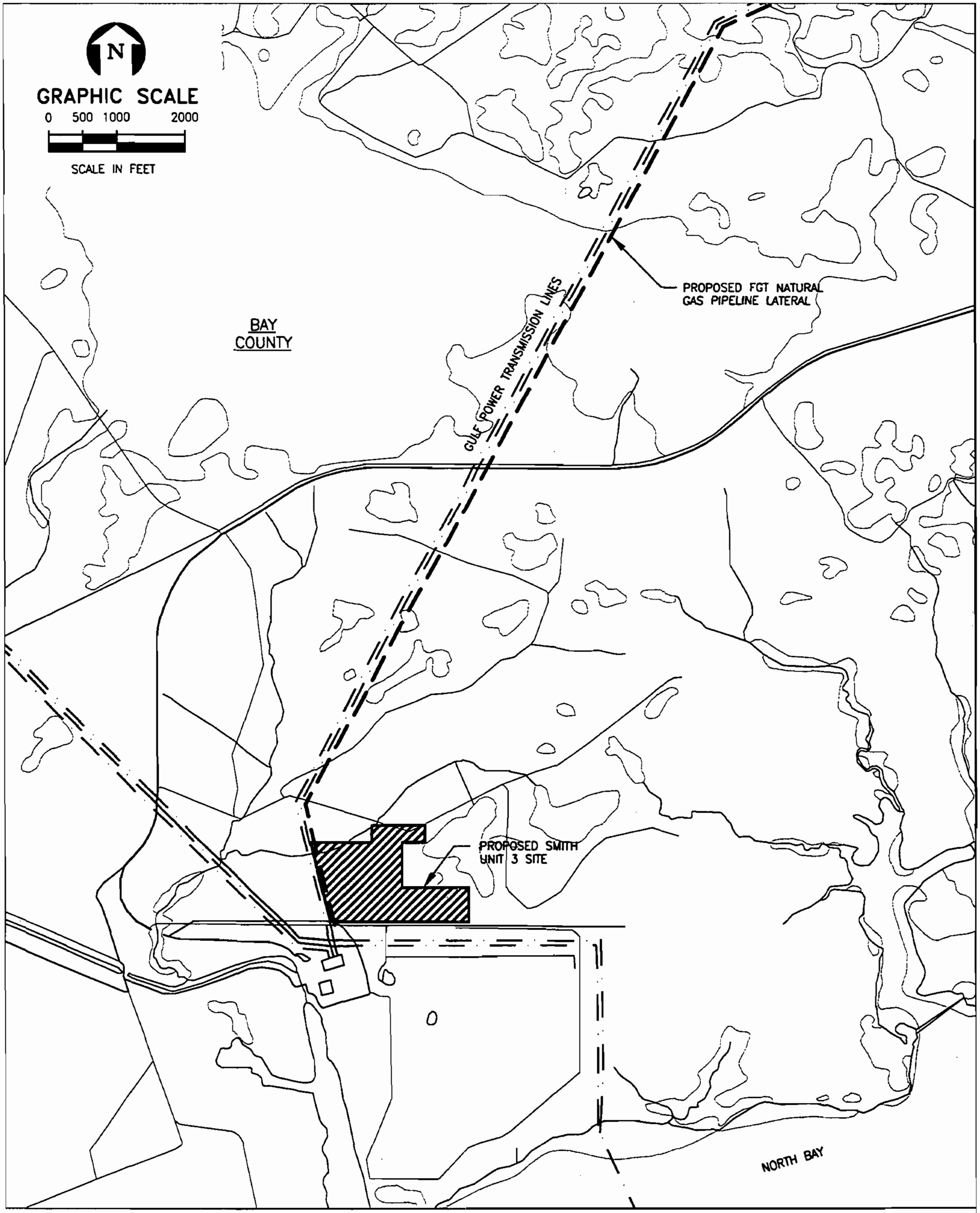

FIGURE 6.2.0-1. (PAGE 8 OF 8)

PROPOSED FGT NATURAL GAS PIPELINE LATERAL

Source: U.S. Geodoto, 1997; ECT, 1999.

ECT
Environmental Consulting & Technology, Inc.

Smith plant. The water balance diagrams (Figures 3.5.0-1 and 3.5.0-2) show schematically the various interconnections required.

No new corridors for any other linear facilities are proposed. No land use or environmental impacts for construction of these pipes are anticipated.

7.0 ECONOMIC AND SOCIAL EFFECTS OF PLANT CONSTRUCTION AND OPERATION

Construction and operation of the Smith Unit 3 Project will result in largely beneficial economic and social effects. This chapter describes the socioeconomic benefits and costs of this Project.

7.1 SOCIOECONOMIC BENEFITS

The primary benefit to the region as a result of the construction of Smith Unit 3 will be the provision of a new, clean, and reliable energy source provided to the public. As described in Chapter 1.0 of this document, Smith Unit 3 will meet the need for new electrical generation resources and meet generating reserve margin requirements. The Project will provide benefits to Bay County, nearby municipalities, and the State of Florida in terms of employment, revenues, and such sustainable practices as reuse of the existing intake waters for plant operation.

7.1.1 TAX REVENUES

The construction and operation of the Smith Unit 3 will create both direct and indirect tax benefits. Construction costs are currently estimated at $63 million. Construction of the Project will generate significant revenues through sales tax assessments on goods purchased directly for the plant or indirectly from purchase of goods and services by workers/employees currently estimated at $6 to $8 million. Based on current federal multipliers (U.S. Department of Commerce, 1999) specific to Bay County, the impact of construction on industrial output is estimated to be over $113.5 million.

7.1.2 CONSTRUCTION EMPLOYMENT

Additional construction employment, even though short term, will be a positive socioeconomic benefit to the region. As previously discussed in Section 4.6, construction employment will average 180 workers for the 21-month construction period. A peak of 325 workers will be needed for approximately 6 months.

Construction payroll and indirect costs will total approximately $23.7 million. Approximately 75 percent of the workforce will consist of daily commuters and the remaining 25 percent will be weekly commuters. It can be anticipated that a majority of the construction wages will be generated for County residents. Another economic benefit from construction will be the use of local subcontractors and vendors to provide labor and goods. Although included in the construction workforce estimates, use of these local subcontractors and vendors will contribute to the local economy. Examples include local contractors who will be awarded the site work valued at $1.5—$2 million. Clean fill for the site will be purchased at nearby Bay County borrow pits and is estimated to cost up to $1.6 million. Other local contractors expected to be used will include surveyors, concrete and soils testing companies, and suppliers of goods and services currently used at the Lansing Smith plant. Locally purchased materials will include:

- Concrete.
- Lumber.
- Welding supplies.
- Small bore piping/valves.
- Conduits/cables.
- Miscellaneous building supplies.

7.1.3 OPERATION EMPLOYMENT

The Smith Unit 3 will employ approximately 29 full-time employees. It is estimated that all employees will be hired locally. All employees will most likely reside in unincorporated Bay County or nearby municipalities. Annual operations labor payroll will total over $1.5 million. Since it is presumed that the operations workforce will reside locally, they will pay taxes and purchase housing and other goods and services locally, providing further positive benefits to the local economy. Using federal multipliers (U.S. Department of Commerce, 1999) the indirect increase to household earnings in the community, region, and state will be over $1.8 million. Additionally, Gulf expects approximately $1.8 million per year to be contracted locally for maintenance services/equipment.

7.2 SOCIOECONOMIC COSTS

7.2.1 TEMPORARY EXTERNAL COSTS

The temporary external costs associated with this Project deal primarily with short-term traffic impacts due to construction. This may result in increased wear on existing roadways and cause minor traffic congestion along SR 77 during morning or evening hours when workers are arriving or departing. Temporary traffic impacts will be closely monitored, and flagmen will be employed to enhance traffic flow should conditions warrant.

Residential areas are expected to experience no impacts from this Project due to distance from the site and adequacy of existing forested vegetation to screen plant facilities. Most onsite activities will not be visible to residents in the area.

7.2.2 LONG-TERM EXTERNAL COSTS

The operational impacts resulting from Smith Unit 3 are expected to be minimal and localized. The following summarizes some of these minor potential impacts.

7.2.2.1 Aesthetics

The Project location is not near any recreational areas, parks, or scenic viewsheds. Although the plant's tallest structures (exhaust stacks) will be approximately 121 ft tall, the lack of these scenic resources and the low population density of the area will minimize aesthetic impacts. Motorists driving SR 77 will see the plant's tallest structures but the view will be short term and not incongruous with the adjacent existing Smith Units 1 and 2 facilities. Therefore, impacts to aesthetic quality of the vicinity are negligible.

7.2.2.2 Public Services/Facilities

Operation of the proposed power plant will not negatively affect essential services or facilities. While it will rely on local police and fire protection, the plant site will be equipped with its own fire protection systems, and the site will be secured with controlled, fenced access and security guards.

The number of employees working at the plant during operation is expected to be 29. This low number of employees will not materially affect provision of services, schools, or degrade roadways. Local medical facilities are sufficient to handle staff medical emergencies.

7.2.2.3 Land Use

The conversion of the land use of the site from an Agriculture to an Industrial designation in order to accommodate the development of Smith Unit 3, is consistent with the assumptions and expectations for additional industrial lands as discussed in the Future Land Use Element of the adopted Bay County Comprehensive Plan. Future industrial acreage requirements were based on the assumptions that firms seeking industrially designated land will be distributed within the county in much the same pattern as has existed in the past, and that space requirements for industrial firms will not significantly change. Smith Unit 3 is an approximately 50-acre expansion to the existing adjacent approximately 600-acre Lansing Smith Plant.

Development of Smith Unit 3 will remove approximately 50 acres from the county's inventory of land used for silvicultural activities. According to the Future Land Use Element, the total existing silvicultural acreage in 1990 was 259,426, and no additional acreage was indicated as being needed in 1995 or 2000. The Future Land Use Element identified 813 acres designated as industrial use in 1990 with a need for 195 additional acres in 1995 and 242 additional acres between 1995 and 2000. The development of Smith Unit 3 will provide approximately 11.4 percent of the additional industrial acreage projected to be needed by 2000.

No residents will be displaced or caused an economic loss as a result of this facility being constructed. The site will not displace any scenic, recreational, or unique lands.

REFERENCES

U.S. Department of Commerce. 1999. RIMS II Multipliers for Bay County, FL. Economics and Statistics Administration, Washington, DC.

8.0 SITE AND DESIGN ALTERNATIVES

This chapter is provided to highlight the efforts of Gulf Power to minimize or mitigate the environmental impacts due to construction or operation of the Smith Unit 3 Project. Site selection and conceptual design were dictated, in large part, by the environmental suitability of various options. Some of these alternatives are discussed in the following sections.

8.1 ALTERNATIVE SITES

As part of its self-build option, Gulf evaluated four options:

- Participation in MPCo's Daniel CC Project.
- Construction of CTGs at Smith Plant.
- Construction of a CC unit at Smith Plant.
- Participation in a cogeneration project in the Pensacola area.

The evaluation process, which began in the fall of 1997, was completed in April 1998. In the final analysis, the evaluation considered options that were comparable in size to a 2-on-1, F-Class CC technology (~500 MW), and included all incremental costs associated with the installation of each alternative.

The process of selecting a site for the new generation was driven by two factors: (1) the need to be in Panama City and surrounding areas, and (2) the objective of locating close to existing power plant-related infrastructure. The results of the evaluation showed that the Smith CC unit, with the construction of a new gas pipeline, was the lowest cost alternative. Although energy savings was a major factor in the evaluation process, the primary factor that eliminated many of the options was the cost and potential environmental impacts of the transmission improvements required to support new generation at any location outside of the Panama City area. Regarding existing infrastructure, the most logical site in the Panama City area was Gulf Power's existing Lansing Smith Electric Generating Facility. This site required almost no additional transmission line work, additional surface water withdrawals, or wastewater provisions. Additionally, the site is well buffered from other land uses, residences, and area developments.

Gulf owns 600+ acres surrounding the site for Lansing Smith Units 1 and 2. The current location for the Smith Unit 3 Project represents the best available location on the property for a number of environmental and engineering reasons.

From an engineering/environmental perspective, the current location best utilizes existing infrastructure at the Smith Plant and thereby avoids additional environmental impacts. This is manifested in the following ways:

- The chosen site is sufficiently close to the existing discharge canal which will serve as the cooling water makeup and discharge source for Unit 3. A new intake and discharge pipe will connect the canal to Unit 3 by traversing already developed power plant property. No new cooling water intake canal or discharge canal will be required, and no environmental impacts from the interconnection will occur. Any other location on the property would most likely require a longer connection to the discharge canal and would potentially impact additional natural vegetated communities and wetlands.
- The chosen site is immediately adjacent to an existing 230-kV transmission line which will allow interconnection to the existing electric grid. No new transmission corridors will be required which could impact wetlands or other natural vegetation communities.
- The chosen site is immediately adjacent to developed plant property where interconnections (potable water, sanitary, and other wastewater systems) will be made with the existing Smith Plant. No new corridors for any of these facilities will be required.
- The proposed FGT pipeline will be routed, in part, to the Unit 3 site via the existing electric transmission line corridor. Utilization of the existing transmission corridor to the Unit 3 property will minimize environmental/land use impacts associated with the proposed pipeline development.
- The proximity of the proposed site to the existing developed plant property also means that no new access roads will be required, which again minimizes potential wetland impacts.

- The proposed site is well buffered from potential future development around Gulf's property, especially to the east where residential development is proposed near Newman Bayou.

From a strictly environmental standpoint, the chosen site, compared to other locations on Gulf's property, represents a viable choice for the following reasons:

- Although the 600-acre Gulf property contains some areas with more upland habitats, the general site composition is a roughly 50-50 mix of wetlands/uplands. Placing the proposed site further from its designated location will trade off wetland impacts of the Unit 3 site with wetland impacts from the numerous additional linear facility interconnections to utilize another area of the site (discussed earlier).
- The location of Unit 3 adjacent to the Smith Plant means natural communities and wildlife habitats on Gulf's property will not be fragmented as they would if the Unit 3 site were removed from the developed area surrounding Smith Units 1 and 2.

A further alternatives analysis of the Smith site is described in the joint FDEP/USACE 404 dredge-and-fill application.

8.2 ALTERNATIVE TECHNOLOGIES AND DESIGNS

Alternative technologies and designs were considered by Gulf for the Smith Unit 3 Project for each of the following categories and are discussed in the following paragraphs.

- Alternative technologies/fuels.
- Air emission control system alternatives.
- Alternative cooling systems.
- Biological fouling control alternatives.
- Wastewater treatment/discharge alternatives.

8.2.1 ALTERNATIVE TECHNOLOGIES/FUELS

Preparation of the SES IRP requires the identification of a manageable number of generating unit alternatives to be evaluated in the generation mix analysis. For each candidate technology, inputs must be developed for the option's conceptual capital cost, design configuration, reliability data, and O&M costs. It is important to note that the information developed is not site-specific and is intended to be representative of average cost and performance data for a "generic" site.

Technology screening begins with a preliminary review of both mature and emerging technologies to identify those that are potentially suitable for installation on the SES during the planning horizon. Three technologies which had been evaluated in prior years were deleted from the list developed for the 1998 IRP. These were the intermediate load cycling coal fired, intermediate load compressed air energy storage (CAES), and peaking compressed air energy storage technologies. However, three new technologies were added, including inlet cooled combined cycle using advanced technology systems (ATS), air blown integrated gasification combined cycle (IGCC), and the topping pressurized circulating fluidized bed (PCFB). The following technologies were included for consideration in the screening process:

1. Base load pulverized coal.
2. Base load IGCC.
3. Base load PCFB.
4. Base load CC "F"-technology.
5. Base load CC "G"-technology.
6. Intermediate load low heat rate "G"-type CT.
7. Peaking CTG (3- and 6-unit sites).
8. Pumped storage hydro (PSH).
9. Inlet cooled CC with ATS technology.

In addition to a general plant description and major performance assumptions, the following information was developed for each technology under consideration:

- Heat rate and output.
- Capital cost.

- Fixed and variable O&M cost.
- Capital expenditures for maintenance.
- Emissions estimates.
- Plant life.
- Maintenance time.
- Equivalent forced outage rate (EFOR).
- Performance degradation.
- Project schedule.
- Cash flow table.

Certain information regarding Project schedule, performance degradation, emissions, EFOR and cash flow was not available for all of the technologies.

There are four categories of cost estimates. These include very conceptual, conceptual, budgetary and definitive. Below is a definition of each cost category:

Very Conceptual—The cost is as conceptual as the technology. As these technologies are developed, the costs will become more refined.

Conceptual—The technology is being developed. However, the first units have not been produced. Estimates are supplied by researchers, vendors, and governmental agencies. As these technologies are developed, the costs will become more refined.

Budgetary—This is a mature technology. There are actual costs of existing plants. The vendors offer market driven pricing and/or Southern Company Services has developed cost models.

Definitive—None of the cost information used in the technology screening process is definitive. Definitive estimates are within 5 percent of the final cost and are based on specific site and owner requirements. Definitive estimates are based on definitive scopes.

The cost models developed for mature technologies in prior years are reviewed for consistency and updated with information from ongoing projects. All cost projection dollars are based on values as of January 1, 1998. An escalation factor of 2 percent was applied for inflation on all technologies, except that the base load pulverized coal was not escalated and IGCC was escalated at 1 percent. The CC and simple cycle cost models were carefully reviewed and updated given the probability that these technologies would be chosen for near term capacity additions. Revised budgetary estimates were obtained from the vendors, and the lowest cost was incorporated in the cost model. The contingency was held to 2.5 percent for major equipment and 10 percent for the balance of plant to reflect the actual confidence in the estimate. In case of coal technologies, contingency was held to 5 percent for major equipment and 10 percent for the balance of plant.

All cost models were separated into Engineering, Procurement and Construction (EPC), site related, and owner's costs. EPC cost is equivalent in scope to what a turnkey contractor would quote for the Project. EPC cost includes the design engineering, procurement of materials and equipment, and the contractor's scope. Site cost includes land, site preparation, water treatment system, switchyard and site related engineering. Owner's cost includes Project and construction management, startup, and overheads.

Project schedules were developed for the new additions. Schedules for the remaining technologies were reviewed, but were not changed from the prior year. It should be noted that actual Project schedules would vary based on the unique requirements of the Project. Construction spending curves were expressed in percentages instead of dollar amounts to allow the flexibility to use either the EPC cost or total plant cost. Non-recoverable turbine degradation in output and heat rate was included for each technology in the technology documentation.

The nine listed technologies were reviewed and screened for reasonableness to select the final candidate technologies to be included in the generation mix process. Some technologies are eliminated when they are evaluated on an economic bus-bar analysis. The bus-bar evaluation estimates the relative cost per kilowatt-hour for the various alternatives at varying capacity factors. After this screening was completed, the following three technologies were retained as candidates for the generation mix analysis: (1) nominal 670-MW pulverized coal unit, (2) nominal 500 MW F-class CC unit, and (3) simple cycle combustion turbine unit.

Although these technologies are used as generic unit addition candidates for the resources planning process, it is left up to the individual operating companies of the SES to ultimately determine what capacity resource to install. The process used by Gulf to ultimately select its resource addition resulted in selection of the CC technology using natural gas.

8.2.2 AIR EMISSIONS CONTROL SYSTEM ALTERNATIVES

The PSD air permitting regulations require detailed consideration of alternative means of emission control on a pollutant-by-pollutant basis. The purpose of this control technology review process, described in more detail in the PSD application (Appendix 10.2.7), is to determine the best means of control that is reasonably justifiable, or BACT. Please refer to the PSD application for a detailed discussion of the air emission control system alternatives that were considered. In summary, the use of advanced technology and clean fuel will result in very low air emissions.

8.2.3 ALTERNATIVE COOLING SYSTEMS

A power plant cooling or heat rejection system involves the transfer and/or rejection of waste heat from the condensation of the steam turbine exhaust. Optimization of the heat rejection system will minimize plant capital and operation costs, as well as potential environmental impacts of the operations. In general, five alternative plant cooling systems are available for power plant facilities involving steam turbine generating technology:

- Once-through cooling
- Cooling reservoir
- Wet cooling tower
- Dilution
- Air-cooled condenser

Once-through cooling requires the availability of large quantities of water compared to the other cooling systems because the cooling water is only used once and then discharged back into the environment, along with the waste heat it has picked up from the condensation process. The discharge of this heat back into the initial body of water can have adverse environmental impacts due to the raising of the overall water temperature. Due to the large amount of cooling water required and the potentially adverse environmental impacts, a once-through cooling system alone was not considered to be a reasonable alternative.

A similar system to once-through cooling is a dilution system. In this system, significant amounts of cold inlet water are added downstream of the condenser to cool the hot condenser discharge before it is discharged back into the environment. This lessens the environmental impact by lowering the overall temperature of the water being discharged, but does not totally alleviate higher temperature water being discharged back into the marine environment and the adverse environmental impacts that could result from this. Additionally, this system requires a larger capital cost than a once-through system due to the additional pumps and piping required for the dilution water and requires larger initial withdrawals from the source body of water. Therefore, this system is not considered a reasonable alternative for this Project.

Cooling reservoirs require large areas of suitable land. Given the large number of acres that would be needed and the extensive earthwork that would be needed to create the reservoir, this alternative was determined to be infeasible.

An air-cooled condenser was also determined to be an unacceptable alternative. An air-cooled condenser, which uses air as the coolant instead of water, requires larger amounts of space than a cooling tower, is significantly more expensive to construct, requires a substantial amount of energy to operate, and generates a significant amount of noise when operated. This alternative was, therefore, not evaluated further.

The use of a mechanical draft wet cooling tower system utilizing the existing Smith facility once-through cooling system is the clear choice for the Smith Unit 3 Project. Cooling towers conserve precious water supplies by recycling and recirculating the water within the system (versus the much larger quantities of water needed in a once-through system). They also require modest space (versus the large acreage required for an air-cooled condenser or a reservoir). Cooling towers generate only moderate noise (versus the elevated noise levels generated by an air-cooled condenser). Finally, by transferring the waste heat to the atmosphere instead of leaving it in the cooling water (as a once-through or dilution system), cooling towers avoid potential adverse impact on the marine environment. Utilizing the "hot" side discharge water of the existing Smith once-through cooling system, the cooling tower will not be using any additional surface water resources. The cooling tower will serve to cool this water below the existing discharge water to yield a small, positive effect on the marine environment. Therefore, for this Project the selected cooling tower system represents both a cost-effective and environmentally favorable alternative.

8.2.4 BIOLOGICAL FOULING CONTROL ALTERNATIVES

Biocide treatment of the circulating water is necessary to control biological fouling of the condenser, the associated piping, and cooling tower. Available biocides include chlorine gas, sodium hypochlorite, bromochlorination, chlorine dioxide, and ozone.

Treatment with sodium hypochlorite or hypobromite is the most widely used, accepted, and least expensive biocide treatment currently used in the power industry. Alternative biocides (e.g., chlorine gas, bromochlorination, chlorine dioxide, and ozone) involve safety issues and high operating costs and, therefore, have not gained wide acceptance for treatment of large volumes of recirculating cooling water. Sodium hypochlorite is the preferred biocide for biological fouling control in the recirculation cooling water system.

Sodium hypochlorite use will be minimized by practicing shock treatment, in which sodium hypochlorite is periodically fed to the circulating water. Through proper management of the biocide treatment program, total residual chlorine will not be discharged in the circulating water discharge (blowdown). In order to ensure this, the blowdown discharge valve will remain closed during treatment with the sodium hypochlorite. Alternative biocides are not expected to be used unless required for chlorine-resistant biofouling.

8.2.5 WASTEWATER TREATMENT/DISCHARGE ALTERNATIVES

The proposed Smith Unit 3 facility has been designed to minimize both water use and wastewater discharges. Gulf will utilize water treatment equipment specifically designed to minimize chemical usage and discharge to the environment. The service water system will be a closed loop system to again minimize water consumption. Cooling tower blowdown and small-volume process wastewater streams are the only discharge streams. Potential wastewater treatment discharge alternatives include:

- Deep well injection.
- Zero discharge

A discharge alternative to the proposed system would involve disposing of the cooling tower blowdown and other wastewaters in a deep injection well. This well would need to be of sufficient diameter and depth to reach strata that are capable of receiving the anticipated quantities of the discharge water. This potential discharge alternative would require extensive hydrogeologic studies even to demonstrate its engineering feasibility and would also be costly. Furthermore, with an injection well, there may be a permanent risk that the effluent would migrate upward or laterally and thus contaminate valuable ground water resources. Therefore, this potential alternative was not considered reasonable for further analysis.

Another alternative is to have zero discharge, although potential environmental concerns would not be eliminated. The implementation of this zero-discharge alternative would be technically feasible but extremely expensive and requires more land space (and potentially greater overall impact) than the current design. The system would involve additional equipment to concentrate the wastewater discharge to a brine, then to produce a solid material from the residual solids. The end result would be solid salts, which would require landfilling. This alternative would involve a substantial increase in both capital and operating cost. Due to the complexity, costs and transformation of liquid waste to solid waste, the zero discharge process was not considered.

9.0 COORDINATION

Various federal, state, regional, and local agencies were contacted by Gulf/Southern Company and its licensing team to provide inputs for the Smith Unit 3 Power Project. Through these contacts, Gulf obtained comments and inputs on the applicable regulatory requirements of the various agencies, and key issues to be addressed in the licensing program. These agency contacts occurred throughout the approximately 4-month period of the licensing efforts prior to submission of this SCA. Table 9.0.0-1 presents an overall listing of the agencies that were contacted regarding the Smith Unit 3 Power Project.

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts

Date	Agency	Person(s) Contacted	Type of Contact: Meeting with	Type of Contact: Telcon with	Type of Contact: Letter to	Type of Contact: Letter from	Subject
01/08/99	FDEP (PPSA)	Hamilton S. Oven, Jr.	X				Strategy meeting
01/25/99	FDEP	Clair Fancy/Al Linero	X				Air permitting
02/17/99	NWFWMD	Larry Gordon/Alan Baker	X				Consumptive use permit
02/23/99	FDOT	Pam Day		X			Traffic counts
02/23/99	WFRPC	Lel Czeck		X			Strategic regional policy plan (SRPP)
02/25/99	WFRPC	Lel Czeck			X		Request copy of SRPP
03/02/99	FGFWFC	George Wallace		X			Listed species for the site
03/03/99	FGFWFC	George Wallace			X		Listed species for the site
03/03/99	USFWS	Gail Carmody			X		Listed species for the site
03/03/99	EPA	Greg Worley		X			Air permitting
03/04/99	Florida Division of Historic Resources	George Percy			X		Historic and archaeological resources
03/05/99	Bay County Planning Dept.	Kristen Anderson		X			Comprehensive plan status
03/09/99	Bay County Planning Dept.	Kristen Anderson	X				Socioeconomic data collection
03/10/99	WFRPC	Lel Czeck		X			North Florida hurricane study
03/10/99	FDEP	Cliff Street	X				Storm water
03/10/99	FDEP	Martin Gawronski	X				Dredge-and-fill

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 2 of 5)

Date	Agency	Person(s) Contacted	Type of Contact: Meeting with	Type of Contact: Telcon with	Type of Contact: Letter to	Type of Contact: Letter from	Subject
03/11/99	FNAI	Jonathan Oetting				X	Listed species for the site
03/22/99	FDEP	Clair Fancy/Al Linero	X				Air permitting
03/22/99	NWFWMD	Larry Gordon			X		Submitted pump test and slug test results
03/23/99	Bay County Planning Dept.	Kristen Anderson		X			Plan amendment
03/31/99	Bay County Planning Dept.	Kristen Anderson		X			Plan amendment
03/31/99	USFWS	Stan Simpkins		X			Ecological impacts of dredge/fill
04/03/99	Bay County Planning Dept.	Kristen Anderson			X		Plan amendment
04/05/99	USFWS	Gail Carmody				X	Listed species for the site
04/06/99	EPA	Greg Worley			X		Air permitting
04/07/99	Florida Division of Historic Resources	George Percy				X	Historic and archaeological resources
04/09/99	Bay County Planning Dept.	Kristen Anderson		X			Plan amendment
04/14/99	Panama City Police Dept.	Officer Mason		X			Police response
04/14/99	Bay County Sheriff's Office	Receptionist		X			Police response
04/14/99	Lynn Haven Police and Fire	Cindy		X			Police and fire response
04/14/99	Bay County Fire Department	Receptionist		X			Fire response

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 3 of 5)

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
04/14/99	Bay County Solid Waste Division	Receptionist		X			Steelfield Landfill
04/15/99	Bay County Planning Commission	Commission members	X				Plan amendment
04/21/99	USACE	Don Hambrick/Doug Gilmore			X		Request for wetlands jurisdiction
04/21/99	FDEP	Jason Steele/Bob Taylor			X		Request for wetlands jurisdiction
04/21/99	Bay County Chamber of Commerce	Carmel Goren		X			Bay County economic multipliers
04/22/99	USACE	Don Hambrick	X				Site visit—wetlands delineation
		Doug Gilmore	X				
04/22/99	FDEP	Jason Steele	X				Site visit—wetlands delineation
04/22/99	FGFWFC	Barbara Cerauskis				X	Listed species for the site
04/26/99	NWFWMD	Larry Gordon/Alan Baker	X				Consumptive use permit
04/27/99	USACE	Doug Gilmore		X			Wetlands permitting
04/28/99	FDEP	Richard Cantrell			X		Petition package for formal wetland jurisdictional determination
04/29/99	FDOT	Marvin Stuckey, Virgie Bowen, Jerry Campbell	X				Construction traffic

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 4 of 5)

Date	Agency	Person(s) Contacted	Type of Contact: Meeting with	Telcon with	Letter to	Letter from	Subject
04/30/99	FDEP	Tom Lubysinski	X				Ash reutilization
05/04/99	Bay County County Commission	County commission members	X				Plan amendment
05/05/99	US Dept. of Commerce	Paul Szczesnick			X		Bay County economic multipliers
05/11/99	FDEP	Bill Hinkley, Richard Tedder, Tom Lubysinski, Mike Kennedy, Jack McNulty	X				Ash reutilization as fill at combined cycle site
05/13/99	NMFC	Mark Thompson		X			Wetland mitigation projects
05/17/99	USFWS	Mike Brim		X			Wetland mitigation projects
05/18/99	FDEP	Ashley O'Neil, Jim Cooper, John Toby	X				Wetlands jurisdiction
05/18/99	USACE	Doug Gilmore	X				Wetlands jurisdiction
05/19/99	FDOT	Virgie Bowen, Jerry Campbell, Charles Odom	X				Construction traffic
05/19/99	NWFWMD	Alan Baker			X		Water quality data for onsite wells
05/21/99	FDEP	Bill Hinkley		X	X		Ash reutilization
05/21/99	FDEP	Mike Kennedy	X	X	X		Ash reutilization
05/23/99	FDEP	Bill Hinkley			X		Ash reutilization

Table 9.0.0-1. Smith Unit 3 Power Project Agency Contacts (Continued, Page 5 of 5)

Date	Agency	Person(s) Contacted	Type of Contact				Subject
			Meeting with	Telcon with	Letter to	Letter from	
05/23/99	FDEP	Mike Kennedy	X	X	X		Ash reutilization
05/24/99	FDOT	Jerry Campbell				X	Traffic levels on SR 77
05/25/99	FDEP	Cliff Street	X				Storm water
05/26/99	USFWS	Mike Brim		X			Wetland mitigation projects
05/27/99	NWFWMD	Lawrence Gordon			X		Water use permit modification

Source: ECT, 1999.

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10.1 NEED PETITION

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Gulf Power Company to Determine Need for Proposed Electrical Power Plant in Bay County, Florida
_______________________________________/

Docket No.:____________________
Date Filed: March 15, 1999

PETITION TO DETERMINE NEED FOR ELECTRICAL POWER PLANT

Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned attorneys, hereby petitions the Florida Public Service Commission ("Commission") pursuant to Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code, to determine the need for the proposed electrical power plant described herein, and to file its order making that determination with the Department of Environmental Protection ("DEP") pursuant to Section 403.507(2)(a)(2), F.S. In support thereof, Gulf states:

1. Gulf's full name and business address is:

   Gulf Power Company
   One Energy Place
   Pensacola, FL 32520-0780

2. The name and address of Gulf's representatives to receive communications regarding this docket are:

   Jeffrey A. Stone
   Russell A. Badders
   Beggs & Lane
   P. O. Box 12950
   Pensacola, FL 32576-2950

   Richard D. Melson
   Hopping Green Sams & Smith, P.A.
   P.O. Box 6526
   Tallahassee, Florida 32314

with copies to:

   Susan D. Ritenour
   Assistant Secretary and Assistant Treasurer
   Gulf Power Company
   One Energy Place
   Pensacola, FL 32520-0780

3. Gulf is a corporation with its headquarters located at 500 Bayfront Parkway, Pensacola, Florida 32501. The Company is an investor-owned utility operating under the jurisdiction of this Commission. Gulf serves approximately 350,000 customers in Northwest Florida.

4. Gulf meets its power supply needs through a combination of Gulf-owned generation, generation co-owned with sister companies, a contract for capacity with a co-generator and wholesale power purchases. As a member of the Southern electric system, Gulf can rely to some extent on system-wide reserves to meet its capacity needs. Gulf has a corresponding obligation, however, to maintain a reasonable share of those reserves.

5. By 2002, a number of factors combine to require Gulf to add generating resources to meet its customers' needs. The last 143 MW of Gulf's existing short-term firm power purchase arrangements expires at the end of 2001, leaving Gulf with a negative reserve margin on a Company-only basis. At the same time, system-wide reserve margins are declining, limiting Gulf's ability to rely on those reserves to offset its own reserve shortfall. Due to the decreasing availability and increasing cost of power purchase arrangements, Gulf cannot meet its 2002 need through additional short-term power purchases.

6. Gulf employed a competitive request for proposal ("RFP") process, in combination with an evaluation of Gulf-owned generation options, to choose the most cost-effective alternative to meet its need beginning in the year 2002. That process identified a 540 MW combined cycle generating facility, to be constructed at the existing Lansing Smith

generating plant site located in Bay County, Florida as the best alternative. The new unit, to be known as Smith Unit 3, consists of two "F" class combustion turbine/generators and two heat recovery steam generators that will power a single steam turbine/generator.

7. As indicated above, Smith Unit 3 will provide sufficient resources to enable Gulf to maintain an adequate reserve margin which, without additional new capacity, will decrease to a negative number in 2002. In addition, the construction and operation of Smith Unit 3 will replace power currently obtained through purchased power contracts totaling 143 MW which expire in 2001.

8. The Smith Unit 3 project is the most cost-effective option to meet the Gulf's generating needs. Compared to the lowest-cost alternative submitted to Gulf in response to its RFP, the Smith Unit 3 project saves approximately $90 million (2002$) in cumulative present worth of revenue requirements ("PWRR") over a 20-year period.

9. Pursuant to the Florida Electrical Power Plant Siting Act, Section 403.519, F.S., and Rules 25-22.080 to 25-22.081, F.A.C., the Commission has jurisdiction to determine the need for the proposed electrical power plant, applying the standards set forth in Section 403.519, F.S.

10. As authorized by Rule 25-22.080(1), F.A.C., Gulf has elected to commence this proceeding for a determination of need prior to the filing with DEP of a Site Certification Application (SCA) for the proposed electrical power plant.

11. The information supporting this petition is contained in Gulf's Need Determination Study (the "Need Study") which is attached as an exhibit to this petition and incorporated herein by reference. The Need Study contains Gulf's analysis of the need for the proposed electrical power plant and includes the information required by Rule 25-22.081, F.A.C.

12. The accompanying information demonstrates the need for the proposed electrical power plant in the proposed time frame as the most cost-effective alternative available, taking into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and other relevant matters.

(a) Smith Unit 3 will provide sufficient resources to enable Gulf to maintain an adequate reserve margin. By providing sufficient resources for Gulf to meet its reliability requirements upon termination of contract purchased power of 143 MW, the proposed plant will contribute to the reliability of the Gulf's system.

(b) The unit's location at the Smith Generating Plant also allows the unit to provide voltage support for the Eastern area of the Gulf's system at low cost, thereby contributing to the integrity of Gulf's electric system.

(c) The proposed unit will ensure that Gulf has an adequate supply of power to serve its customers' needs at a reasonable cost.

(d) The proposed unit is the most cost-effective alternative available for meeting Gulf's 2002 capacity need, saving approximately $90 million PWRR (2002$) over a 20-year period compared to the least cost alternative identified through the Gulf's competitive RFP process.

(e) Gulf has implemented cost-effective demand-side management programs which have resulted in significant demand and energy reductions, projected to reach 365 MW of summer peak demand reduction by 2002. Even with the demand and energy reductions from those programs, Smith Unit 3 is required to enable Gulf to reliably meet its customers' power supply needs.

13. As set forth in more detail in the Need Study, the Smith Unit 3 project has a number of advantageous features, including the following:

(a) The facility will be located at the existing Smith site which is presently connected to Gulf's load center by an existing 115 kV and 230 kV transmission system into which the new unit will connect through a 230 kV bus. No additional off-site transmission will be required to integrate the unit into the electric grid.

(b) The project will minimize environmental impacts by utilizing clean burning natural gas as the primary fuel, utilizing an air emission strategy resulting in a net reduction in NOx for the entire plant, and utilizing a closed-cycle cooling system with make-up water coming from the existing once-through cooling water discharge canal currently in use by the existing Smith Units 1 and 2.

14. Gulf has coordinated with the Commission staff to arrange a schedule which calls for the need determination hearing to commence on or about June 7, 1999.

WHEREFORE, Gulf respectfully requests that:

(1) pursuant to Rule 25-22.080(2), F.A.C., the Commission within seven days set a date no later than June 7, 1999 for commencement of a hearing on this petition;

(2) the Commission give notice of the commencement of the proceeding as required by Rule 25-22.080(3), F.A.C.; and

(3) the Commission determine that there is a need for the proposed electrical power plant described in this petition, and file its order making such determination with the DEP pursuant to Section 403.507(2)(a)2., F.S.

RESPECTFULLY SUBMITTED this 15th day of March, 1999.

By: J A Stone

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THE NEED STUDY

IN SUPPORT OF

GULF POWER COMPANY'S PETITION FOR DETERMINATION OF NEED OF LANSING SMITH UNIT 3

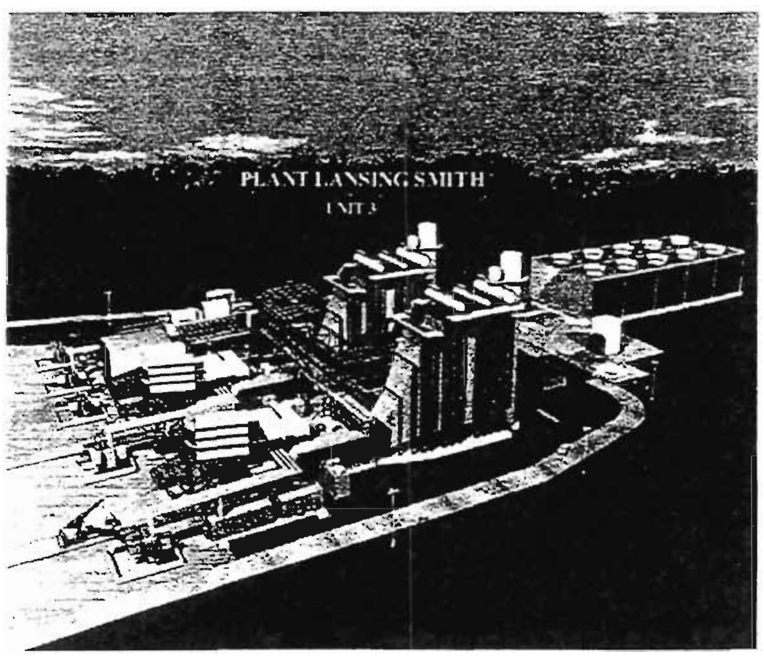
BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

MARCH 15, 1999

THE NEED STUDY

IN SUPPORT OF

GULF POWER COMPANY'S
PETITION FOR
DETERMINATION OF NEED
OF LANSING SMITH UNIT 3



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

MARCH 15, 1999

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1. EXECUTIVE SUMMARY

Gulf Power Company (Gulf) has determined that in order to provide reliable, cost-effective service to its customers, it must add at least 427 MW of generating resources to its system by the summer of 2002. The most cost-effective way for Gulf to meet this need is to construct a 540 MW natural gas-fired combined cycle unit at its existing Lansing Smith Electric Generating Plant. This unit will be designated as Smith Unit 3.

Smith Unit 3 is subject to the Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes. This Need Study document is being filed with the Florida Public Service Commission (FPSC) to support Gulf's petition to the FPSC for a determination of need for the project under Section 403.519, Florida Statutes.

This Need Study demonstrates that Gulf has a clear need for more capacity and that Smith Unit 3 is the most cost-effective alternative available, taking into consideration both other Gulf-constructed capacity options and options offered by third parties in response to Gulf's Request for Proposals (RFP) for power supply alternatives.

Gulf is a subsidiary of the Southern Company, which owns operating companies in Florida, Georgia, Alabama and Mississippi. As such, Gulf's planning process is part of the overall Integrated Resource Planning (IRP) process conducted for the Southern electric system (SES). As a member of Southern, Gulf can rely to some extent on system-wide reserves to meet its capacity needs. Gulf has a corresponding obligation, however, to maintain a reasonable share of those reserves.

This Need Study is an outgrowth and continuation of Southern's annual IRP process and of Company-specific studies supporting Gulf's Revised 1998 Ten-Year Site Plan (1998 TYSP) filed with the FPSC in June, 1998. This TYSP contained detailed documentation of Gulf's existing resources, planning processes, load and fuel forecasts, other planning assumptions, and its future capacity needs.

The 1998 TYSP showed that Gulf is relying on firm purchased power contracts totaling 143 MW, along with the Company's reliance on Southern capacity resources, to meet its capacity needs through the year 2001. Due to the decreasing availability of firm power purchases, it is not feasible to replace the purchased power contracts when they expire in 2001. As shown in the 1998 TYSP, Gulf would require an additional 352 MW of capacity in 2002 in order to provide its share of Southern's 13.5% minimum reserve margin target. Subsequent updates to Gulf's planning studies show that the summer 2002 capacity shortfall has increased to 427 MW without the addition of new capacity resources. In fact, if no additional capacity is added by 2002, Gulf will have a negative reserve margin on an individual company basis.

The load forecast on which this 427 MW need is based included substantial demand reductions resulting from Gulf's

DSM programs and other conservation initiatives. These measures reduced Gulf's summer peak demand by 255 MW in 1998 and will reduce it by a total of 365 MW by the end of 2002. Due to the size of Gulf's need in 2002, Smith Unit 3 cannot be avoided or delayed further by additional DSM programs.

Gulf's planning process showed that a 500 MW class combined cycle generating unit located near Panama City (the self-build option) was the most cost-effective way of meeting this need with Gulf-constructed resources. On August 21, 1998, Gulf issued a capacity RFP to approximately 100 potential respondents to seek alternatives to the Gulf-constructed combined cycle unit. Gulf initially received four offers from three separate entities in response to this solicitation. The offers included purchases of varying terms and MW size from proposed combined cycle units, combustion turbine units, and a cogeneration facility.

After evaluating the proposals received in response to the RFP, Gulf determined that the self-build option represented by Smith Unit 3 is the most cost-effective alternative. It has a 20-year net present value (NPV) of costs (2002$) of $279/KW, compared to $496/KW for the next best alternative identified through the RFP process. This amounts to a savings for Gulf's customers of at least $90 million over those 20 years. The location of the proposed unit in the Panama City area eliminates the need for additional transmission to integrate the unit into the Northwest Florida electric grid, and the unit will provide needed voltage support in the eastern portion of Gulf's service territory. Gulf is in the final stages of negotiating a firm natural gas supply for the unit.

Any delay in the licensing of Smith Unit 3 could adversely impact the summer 2002 in-service date. Due to Gulf's deteriorating reserve margin situation, this would leave Gulf short of needed resources during the 2002 peak summer season.

The balance of this document contains a detailed discussion of Gulf's need for capacity and the factors that led to Gulf's conclusion that Smith Unit 3 is the most cost-effective alternative available for meeting that need.

2. INTRODUCTION

2.1 DESCRIPTION OF GULF POWER COMPANY

Gulf Power Company ("Gulf" or the "Company") is a wholly-owned subsidiary of the Southern Company. Gulf serves approximately 350,000 customers in Northwest Florida. Gulf's service area is bounded by the Apalachicola River on the east and the Florida/Alabama state line on the west. Gulf's service area is shown on the system map contained in Appendix A of this Need Study.

2.2 DESCRIPTION OF EXISTING FACILITIES

2.2.1 GENERATION RESOURCES

Gulf owns and operates eleven fossil steam units, one peaking combustion turbine, and one cogeneration facility in Northwest Florida. In addition, Gulf has a 50% ownership in two coal units at Mississippi Power Company's Plant Daniel, and has a 25% ownership in Georgia Power Company's Plant Scherer Unit #3. The following is a tabulation of Gulf's current generating facilities:

TABLE 2-1

EXISTING GENERATING FACILITIES

UNIT	LOCATION	TYPE	FUEL	COMM. SERVICE DATE	RET. DATE	SUMMER NET CAPACITY IN MW
Crist 1	Escambia Co.	FS	Gas	1/45	12/11	24.0
Crist 2	Escambia Co.	FS	Gas	6/49	12/11	24.0
Crist 3	Escambia Co.	FS	Gas	2/52	12/11	35.0
Crist 4	Escambia Co.	FS	Coal	7/59	12/14	78.0
Crist 5	Escambia Co.	FS	Coal	6/61	12/16	80.0
Crist 6	Escambia Co.	FS	Coal	5/70	12/15	302.0
Crist 7	Escambia Co.	FS	Coal	8/73	12/18	495.0
				CRIST TOTAL		1,038.0
Scholz 1	Jackson Co.	FS	Coal	3/53	12/11	46.0
Scholz 2	Jackson Co.	FS	Coal	10/53	12/11	46.0
				SCHOLZ TOTAL		92.0
Smith 1	Bay Co.	FS	Coal	6/65	12/15	162.0
Smith 2	Bay Co.	FS	Coal	6/67	12/17	192.6
Smith A	Bay Co.	CT	Oil	5/71	12/06	31.6
				SMITH TOTAL		386.2
Pea Ridge	Escambia Co.	Cogen	Gas	5/98	12/28	14.4
		GULF TERRITORIAL UNIT TOTAL				**1,530.6**
Daniel 1	Mississippi	FS	Coal	9/77	12/27	265.0
Daniel 2	Mississippi	FS	Coal	6/81	12/31	265.0
				DANIEL TOTAL		530.0
Scherer 3	Georgia	FS	Coal	1/87	12/42	223.3
		GULF OFF-SYSTEM UNIT TOTAL				**753.3**
		GULF OWNED GENERATION TOTAL				**2,283.9**

As shown in Table 2-1 above, the units owned and operated by the Company within its service area provide a net summer capability totaling 1,531 megawatts. Including Gulf's ownership interests of 753 MW in Daniel Units #1 and #2 and Scherer Unit #3, Gulf has a total net summer generating capability of 2,284 MW and a total net winter generating capability of 2,292 MW as of June 1, 1999. In addition to the Company's installed generating resources, Gulf has a contract with Solutia Corporation for 19 MW of firm capacity that will be in effect until May 31, 2005.

2.2.2 TRANSMISSION FACILITIES

Gulf owns approximately 1,426 miles of 115 kV and 230 kV transmission line. Within this transmission system, the Company has 14 points of interconnection with Alabama Power Company, Georgia Power Company, Alabama Electric Cooperative, and Florida Power Corporation. There are no additional transmission improvements required to integrate Smith Unit 3 into the Northwest Florida grid. The existing Gulf system in Northwest Florida, including generating plants, substations, transmission lines and service area, is shown on the system map designated as Appendix A.

2.3 OVERVIEW OF THE PLANNING PROCESS

The planning process for Gulf is tightly coordinated with Southern's Integrated Resource Planning (IRP) process. The Company participates in that process along with the other Southern operating companies, Alabama Power, Georgia Power, Mississippi Power, and Savannah Electric and Power.

Gulf shares in the benefits gained from planning a large system such as Southern, without the costs of a large planning staff of its own.

The capacity resource needs of Gulf and the entire Southern electric system (SES) are driven by the summer peak demand forecast and by the Southern reliability criterion of a 13.5% reserve margin target. The demand forecast used for capacity planning is a net number, which already reflects the impact of demand-side measures (DSM). Given the demand forecast and the target reserve margin, the planning process uses a computer simulation model called PROVIEW® to produce a listing of preferred capacity resource plans which provide sufficient capacity to reliably meet the system's needs. The best, most cost-effective plan for the entire Southern system is identified by considering the cost of the various plans on a present worth of revenue requirements (PWRR)[1] basis. The resulting system resource needs are allocated among the operating companies based on reserve requirements. Each company then performs the company-specific studies needed to choose the best way to meet its own capacity and reliability needs.

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1 Throughout this document, the analyses are conducted on a Present Worth of Revenue Requirement basis, even though the results may appear as Net Present Value (NPV).

2.4 CAPACITY ADDITIONS

Gulf's need for additional supply-side resources through 2001 will come from the reliance upon Southern system generation resources as well as purchased power. However, such purchases are only available on a short-term basis. When these arrangements expire at the end of 2001, Gulf must replace them with additional generating capacity to meet its share of system reserve margin requirements.

Beginning in 1997, Gulf performed a number of economic evaluations of potential supply options to determine the Company's most cost-effective means of meeting its 2002 capacity needs. Based on those evaluations, Gulf determined in early April, 1998, that a 500 MW class combined cycle unit at its Lansing Smith Generating Plant (Smith Unit 3) was its best internal choice for meeting the 2002 needs. This option saved over $40 million NPV (1998 $s) compared to the next best self-build alternative. In order to determine if other more cost-effective alternatives were available, and to comply with the Florida Public Service Commission's (FPSC) rules, Gulf issued a Request for Proposals (RFP) in August, 1998 to solicit alternatives to Gulf's construction of this combined cycle unit. After evaluating the proposals, Gulf determined that the self-build option represented by Smith Unit 3 was the most cost-effective alternative available, providing 20-year savings of over $90 million NPV (2002 $s) compared to the best option resulting from the RFP process.

3. THE INTEGRATED RESOURCE PLANNING PROCESS

3.1 OVERVIEW

Gulf Power Company's resource planning process begins as a part of the Southern electric system (SES) Integrated Resource Planning (IRP) process. The Company is one of the five operating companies of the Southern Company. Together the five operating companies -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power -- comprise a centrally dispatched resource pool. As such, the companies coordinate resource planning for the entire system. Individually, each company provides input regarding its customers' load and energy needs in the future. These forecasts are used as input into the generation planning process to formulate overall capacity resource needs for the SES.

The SES integrated resource planning process involves a significant amount of manpower and computer resources in order to produce a least-cost, integrated demand-side and supply-side resource plan. The process examines a broad range of alternatives in order to meet the system's projected summer peak demand and energy requirements. The result of the Southern integrated resource planning process is an integrated plan that meets the needs of the system's customers in a cost-effective and reliable manner.

Gulf receives many benefits from being a part of a large system planning process. The Company comprises only about 6.5% of the total Southern summer peak demand. Since Gulf's needs are relatively small compared to the whole system, many times the Company can meet its demand and reserve requirements by relying on temporary surpluses of capacity which are available on the Southern system. This ability to rely on the large system reserves allows Gulf to defer capacity additions until the timing is right to add a cost-effective block of capacity for Gulf's specific customer needs, as opposed to having to add smaller, more costly amounts of capacity. Another important benefit to Gulf is that it does not have to employ an entire planning staff, but can share in the utilization of the staff at Southern Company Services which performs Southern's IRP function.

3.2 INPUTS AND ASSUMPTIONS

The IRP process uses many inputs and assumptions that are ultimately fed into the analysis to develop the SES's most cost-effective capacity resource plan. These inputs and assumptions result from a number of activities that are conducted in parallel with one another in the IRP process. These activities include energy and demand forecasting, fuel price forecasting, technology screening analysis and evaluation, and the development of miscellaneous assumptions. Gulf's load forecast is discussed in Section 4 and Appendix B. The fuel price forecast used in the most recent IRP studies is discussed in Section 5. Financial assumptions are detailed in Section 6. The following subsections discuss the Southern reserve margin criterion and the technology screening process used to identify candidate generating units.

3.2.1 RESERVE MARGIN CRITERION

One of the major assumptions in the IRP process is the Southern summer peak reserve margin target. The reserve margin target is the optimum economic point at which the system can reasonably meet its summer peak energy and demand requirements taking into account load forecast error, abnormal weather conditions, and unit-forced outage conditions. This reserve margin target is developed by comparing (1) the Customer's perceived costs of experiencing outages due to generation and (2) the costs of additional resources to eliminate those outages. Essentially this involves assessing the costs of expected unserved energy (EUE) at various reserve levels along with the costs to install generation to meet that reserve level. The optimum level of reserves is where these two parameters, combined, reach the minimum cost point. Of course, the optimum level of reserves is primarily driven by the customer's perceived cost of outages, EUE, and the cost of adding reliability through generation equipment installations.

The Southern system has, for many years, analyzed the factors that determine target reserve margin. Until 1999, the target reserve margin for the system was set at 15% on an entire Southern basis. It is important to note that due to summer peak demand diversity among the companies of the SES, each individual operating company would be expected to maintain a 14.1% reserve margin as its share of this 15% Southern reserve margin. As a result of a 1996 re-evaluation of the customers' perceived cost of various levels of unavailable power and other factors, it was determined that the optimal target reserve margin for the SES was 13.5% beginning in 1999. This 13.5% Southern reserve margin translates into a 12.6% individual utility share. However, because of capacity supply adequacy issues that affected many utilities during the summer of 1998, and potential changes in that value customers place on not experiencing an outage, Southern is re-evaluating its target reserve margin criterion to account for this new information. After that analysis is completed later this year, there may be an adjustment to the Southern target reserve margin.

3.2.2 TECHNOLOGY ALTERNATIVES

The reasonably acceptable technology alternatives are also analyzed and screened to determine the best options to be included as candidates in the mix analysis. An overview of the SES technology screening process is contained in Appendix C. Once the technologies have been screened to identify those that will be candidates in the mix, the fixed costs of each option are scaled to a common 300 MW block size in order to simplify modeling and put the candidates on a level playing field. This allows the mix program to select a number of technology combinations over the planning horizon without placing undue bias on any particular technology because of its size or other factors.

3.3 GENERATION MIX ANALYSIS

Once the necessary assumptions are determined the technologies are screened to the suitable candidates, and the necessary planning inputs are defined, then the generation mix analysis is initiated. The optimization tool used in the mix analysis is the PROVIEW® model. PROVIEW® uses a dynamic programming technique to develop the optimum resource mix using combinations of the generic supply-side options identified in the technology screening process. This technique allows PROVIEW® to evaluate, for every year, all the combinations of generation additions that satisfy the reserve margin constraint.

In performing its optimization, PROVIEW® calculates a net present value (NPV) for each mix of generating alternatives. This NPV includes the capital costs of the unit additions, together with the operating and maintenance costs for both the existing system and the unit additions. The program produces a report that ranks all of the different combinations by the total net present value (NPV) cost over the entire planning horizon. The leading combinations from the program are then evaluated for reasonableness and validity. It is important to note that supply option additions produced by the PROVIEW® model at this stage of the analysis are for the entire Southern electric system and are reflective of the various technology candidates selected. This process produces the lowest cost resource plan for the entire SES. The additions included in that plan are then allocated, according to reserve needs, to the individual operating companies.

The Integrated Resource Planning process is a very manpower-intensive activity. In the mid-1990s, the Southern electric system decided that it would only perform a "full-blown" IRP every third year, with "updates" for the interim years. Both the full IRP process and the interim updates involve development of fuel forecasts and load and energy forecasts, since these forecasts are required for a number of business purposes in addition to resource planning. The technology assessment, however, needs to be updated only as changing conditions dictate, and typically undergoes a complete review only in connection with the full IRP process.

From a quantitative standpoint, the updates take the changes in the demand and energy forecast and perform a manual remix to assure the companies that their resource requirements are still valid, or to make the necessary resource changes. From a qualitative standpoint, changes in the fuel forecasts and technology improvements are reviewed, and if a major change has occurred in these factors, its effect will be analyzed along with the updated mix.

3.4 RESULTS OF RECENT IRP PROCESSES

Since the decision was made to limit full IRP processes to a three-year cycle, these "full" IRP's were performed in 1995 and 1998, with updated manual mixes in the interim years.

3.4.1 1995 FULL IRP

The Southern IRP for 1995 showed the need for a mixture of combined cycle units and combustion turbines for the entire system with the first need in the year 1999.

The load forecast for Gulf in the 1995 IRP is shown in the table below. The technology screening performed for the 1995 IRP identified (1) Conventional Pulverized, Base-Load Coal, (2) Advanced E-Class Intermediate Combined Cycle, and (3) Standard and Advanced E-Class Peaking Combustion Turbines as the candidate units for all years of the mix analysis. In addition, F-Class Combustion Turbines and F-Class Combined Cycle units which provide a cost and efficiency benefit over the E-Class technology were considered to be suitable for the year 2000 and beyond.

TABLE 3-1

GULF'S FORECASTED DEMAND
AS OF THE 1995 IRP

YEAR	GULF LOAD (MW)
1995	1,944
1996	1,969
1997	1,985
1998	2,013
1999	2,042
2000	2,067
2001	2,093
2002	2,119
2003	2,148
2004	2,178

For Gulf, the 1995 resource plan, as described in its 1995 Ten-Year Site Plan (TYSP), indicated that the Company should construct 200 MW of combustion turbine (CT) capacity to meet its needs beginning in 1999, with an additional 100 MW of CT capacity in 2002. This plan also showed Gulf adding a 48 MW share of a system combined cycle (CC) unit in the year 2004. In total, this 1995 plan indicated that Gulf needed 300 MW of CT capacity by 2002 and an additional 48 MW of combined cycle in 2004. This is much like the mixture of CT's and CC's that formed the entire Southern IRP in 1995.

3.4.2 1996 IRP UPDATE

The 1996 IRP update, which formed the basis of Gulf's 1996 TYSP, showed an increased megawatt demand need for Gulf and a change in the preferred resource plan to meet these needs. The 1996 TYSP indicated that Gulf would purchase 180 MW of capacity beginning in 1999 and replace 80 MW of this purchase with the installation of 200 MW of combustion turbine capacity in 2002. Once again, the Company showed a need for 300 MW of capacity by the year 2002; however, this update indicated that Gulf's intention was to meet its near term need through purchased power.

As a part of the individual utility resource requirement decision process, in 1996, Mississippi Power Company (MPCo) decided to meet its short-term needs by means of capacity purchases through the year 2000, allowing MPCo to procure smaller amounts of power until it was the optimum time to construct a cost-effective generating unit. MPCo's purchased power solicitation in 1996 resulted in a fairly large number of cost-effective offers, as well as a large amount of megawatts offered. Gulf was still a year away from needing to seek short-term power purchases to meet its 1999 needs, but viewed the results of MPCo's solicitation as very promising when considering its future prospects.

Since the 1996 IRP indicated that Southern did not have any need for units to be constructed until after the year 2001, the F-Class technology became the new assumption for combined cycle and combustion turbine unit additions. This change in technology assumption was not significant enough to warrant a new mix analysis.

3.4.3 1997 IRP UPDATE

The 1997 IRP update that formed the basis for Gulf's 1997 TYSP showed that the Company's demand had increased and

SOUTHERN reserves were lower, increasing Gulf's allocated responsibility. As a result, the Company's need for purchased power was advanced from 1999 to 1998 and increased from 180 MW to 235 MW. The Gulf demand forecast for the 1997 IRP is shown in the table below.

TABLE 3-2

GULF'S DEMAND FORECAST
AS OF THE 1997 IRP UPDATE

YEAR	GULF DEMAND (MW)
1997	2,031
1998	2,067
1999	2,102
2000	2,122
2001	2,137
2002	2,154
2003	2,175
2004	2,193

The 1997 TYSP showed the Company purchasing 235 MW beginning in 1998, growing to 335 MW in the year 2002. This plan also indicated that Gulf would install 200 MW of combustion turbine capacity to replace all but 150 MW of this capacity by summer 2003.

The following table provides a comparison of the annual incremental differences for the 1995 - 1997 resource plans for Gulf Power Company. Each of these plans was based on an allocation to Gulf of an appropriate share of the system-wide capacity need resulting from the IRP process.

TABLE 3-3

COMPARISON OF CAPACITY NEEDS
BETWEEN THE 1995, 1996, & 1997
RESOURCES PLANS

	1995 PLAN (MW)			1996 PLAN (MW)			1997 PLAN (MW)		
YEAR	CT	CC	PURCH	CT	CC	PURCH	CT	CC	PURCH
1998	0	0	0	0	0	0	0	0	235
1999	200	0	0	0	0	180	0	0	0
2000	0	0	0	0	0	0	0	0	50
2001	0	0	0	0	0	0	0	0	0
2002	100	0	0	0	0	0	0	0	50
2003	0	0	0	200	0	-80	200	0	-185
2004	0	48	0	0	0	0	0	0	0

The update performed for the 1997 IRP did reveal some changes with regard to technologies and the timing of Gulf's need based on the revised load and energy forecast. On the technology radar screen was the announcement of the design and promotion of the G-Class CT technology. The Southern technology group considered the viability of this new class of CT and determined that it was not mature enough to be considered in the 1997 update cycle. The group decided to continue to monitor its development for possible inclusion in the 1998 IRP.

3.4.4 1997 CAPACITY SOLICITATION

Based on the need shown by the 1997 IRP Update, Southern Company Services issued a solicitation for short-term purchased power on behalf of Gulf Power Company (Gulf), Alabama Power Company (APCo), and Savannah Electric and Power (SEPCo) for up to five years beginning summer of 1998.

The results of this solicitation were quite different from the 1996 MPCo solicitation in that there were far fewer cost-effective offers and a much smaller number of total megawatts offered. This was a fairly strong signal that not only were short-term purchased power offers becoming scarce, but what was available was becoming high-priced and was not cost-effective. As a result of this solicitation, SCS secured 350MW for 1998, 300MW for 1999, and 200MW for the years 2000 and 2001, with the remaining need to come from spot market firm energy and capacity purchases in the future. Gulf's share of these purchases is 178 MW in 1999 and 143 MW for 2000 and 2001.

The revelation that short-term purchased power was becoming scarce led MPCo and APCo to begin evaluating their options for capacity additions beginning in 2001. These site-specific evaluations determined that the most cost-effective capacity additions were a combined cycle plant at MPCo's existing Daniel plant near Pascagoula and a combined cycle plant at APCo's existing Barry plant near Mobile. The certification for these additions began in August of 1997.

3.4.5 1998 FULL IRP

The 1998 IRP process began in the fall of 1997 and included MPCo's and APCo's plans for constructing combined cycle units at Plants Daniel and Barry.

This study indicated that Gulf Power Company would need 120 MW of combustion turbines (CT) and 240 MW of combined cycle (CC) capacity for the year 2002, when the Company will no longer have any purchased power agreements on which to rely. This advancement and shift in type and timing of Gulf's need was driven by a change in the system summer peak demand requirements and changes in the relative economics of combined cycle technology. The following table shows the results of the 1998 IRP for Gulf:

TABLE 3-4

GULF'S RESOURCE NEEDS AS OUTLINED
IN THE 1998 IRP

YEAR	COMB. TURB.	COMB. CYCLE	PURCHASES
1998	0	0	240
1999	0	0	2
2000	0	0	-15
2001	0	0	-15
2002	240	120	-178
2003	0	30	0
2004	0	30	0
2005	0	60	0
2006	60	0	0

3.5 GULF POWER COMPANY'S SPECIFIC CAPACITY NEEDS

During the latter part of 1997, it was clear that Gulf would need to add significant capacity resources by 2002. As mentioned before, the purchased power on which Gulf is currently relying for part of its resource needs will no longer be available beginning in 2002. Even with this purchased power, Gulf's individual reserves get extremely low by 2001.

As mentioned in Section 3.4.5 above, the 1998 IRP showed Gulf's resource needs to be 120 MW of CT's and 240 MW of CC in the year 2002, which would cover Gulf's 352 MW share of the Southern reserve margin target. This amount of capacity is in the range that can be added to a system of Gulf's size in a cost-effective manner due to technology economies of scale. As a result, it became clear to Gulf that generating capacity additions would need to be explored.

The 1999 IRP Update, whose preliminary results were being distributed in late fall of 1998, indicated that because of some existing generator unit deratings and summer demand increases, Gulf had a larger capacity resource need than indicated in the 1998 IRP. Based on the 1999 Load and Energy Forecast, the new capacity need for the Company to meet its share of the Southern reserve margin target in 2002 is 427 MW. This megawatt need for Gulf further underscores that not only is a large amount of resource capacity needed, but the size of Smith Unit 3 is an appropriate and cost-effective alternative means to meet this need.

After the purchased power contracts expire, Gulf's reserve margin, using the 1999 Load and Energy Forecast, would go negative in 2002 without the addition of capacity resources. The following table shows the reserve situation that evolves through the year 2002, absent any capacity additions:

TABLE 3-5

GULF'S RESERVES WITHOUT THE
ADDITION OF CAPACITY RESOURCES

YEAR	PEAK DEMAND (MW)	STARTING CAPACITY (MW)	PURCH. POWER (MW)	ENDING CAPACITY (MW)	PERCENT RESERVES
1999	2,175	2,123	198	2,321	6.7%
2000	2,207	2,321	-55	2,266	2.7%
2001	2,234	2,266	0	2,266	1.4%
2002	2,265	2,266	-143	2,123	-6.3%

Although Gulf is able to call on total SES reserves to reliably serve its customers through 2001, this table shows that Gulf has an obligation to add capacity in 2002 in order to avoid undue dependence on those reserves.

In order to determine the best way to meet its needs for 2002 and beyond, Gulf began site-specific analyses in late 1997. Unlike the earlier system-wide IRP studies, which had considered generic unit additions, Gulf's analysis took into account site-specific factors such as transmission system impacts, construction requirements, and the availability and cost of fuel transportation.

As discussed in Section 7, by April, 1998, Gulf's site-specific studies indicated that Smith Unit 3 was the most cost-effective self-build alternative.

This unit will be a 540 MW combined cycle unit made up of 2 - F Class combustion turbines and 1 - steam turbine of approximately 170 MW, commonly referred to as a 2-on-1 CC unit. Because of its size and configuration, this unit is more cost-effective than a smaller combined cycle unit, that is commonly referred to as a 1-on-1 CC unit. Smith Unit 3 is also of the size that fits Gulf's needs in the 2002 through 2007 time frame without creating excessive amounts of reserves. Based on a 2002 in-service date, the reserves after the addition of Smith Unit 3 would be as shown in the following table:

TABLE 3-6

GULF'S FUTURE RESERVES BEGINNING
IN 2002 WITH THE ADDITION OF SMITH UNIT 3

YEAR	PEAK DEMAND (MW)	STARTING CAPACITY (MW)	CAPACITY ADDITION (MW)	ENDING CAPACITY (MW)	PERCENT RESERVES
2002	2,265	2,123	540	2,655	17.6%
2003	2,280	2,655	0	2,655	16.8%
2004	2,309	2,655	0	2,655	15.4%
2005	2,347	2,655	-19	2,636	12.7%
2006	2,383	2,636	0	2,636	11.0%
2007	2,425	2,636	148	2,784	15.0%
2008	2,466	2,784	0	2,784	12.9%

Table 3-6, above, demonstrates that Smith Unit 3 puts Gulf in the position of having an appropriate level of generating capacity to meet its customers' needs and maintain a suitable level of reserves for reliability purposes. As shown in Section 7, it also is a very cost-effective means of meeting these needs when compared to the other self-build options evaluated.

4. LOAD FORECAST AND DSM PROCESS

4.1 OVERVIEW

The following is a summary of Gulf Power Company's 1999 Load and Energy forecast of customers, energy sales and peak demands. The forecast horizon spans the ten-year period from 1998 through the year 2008. This is the latest in a series of annual forecasts prepared by the Marketing Services section of Gulf's Marketing and Load Management Department.

The forecast includes the estimated impact of conservation programs currently approved by the Florida Public Service Commission, as well as other conservation initiatives designed to influence patterns of demand in a manner that is mutually beneficial to both Gulf and its customers, such as Gulf's GoodCents Home program.

Gulf's annual load forecast is aggregated with those of the other Southern electric system operating companies for use in the Southern IRP process.

4.2 ASSUMPTIONS

Gulf's projections reflect the current economic outlook for its service area as provided by Regional Financial Associates (RFA), a renowned economic service provider. Gulf's forecast assumes that service area population growth will remain near that of the nation. Additionally, the projections incorporate Gulf's most recent electric price assumptions. Natural gas prices are derived from the 1998 Southern Company Services (SCS) Fuel Panel, as described in Section 5. The following tables provide a summary of the assumptions associated with Gulf's forecast:

TABLE 4-1

ECONOMIC SUMMARY
(1998-2008)

GDP Growth	2.9 - 2.3%
Real Interest Rate	5.4 - 3.7%
Inflation	1.7 - 3.1%

TABLE 4-2

AREA DEMOGRAPHIC SUMMARY
(1998-2008)

Population Gain	161,491
Net Migration	115,420
Average Annual Population Growth	1.7%
Average Annual Labor Force Growth	1.5%
Share of Population Served	96.3%

4.3 METHODOLOGY

Gulf's total forecast employs a number of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts. These efforts are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of Gulf's customers and actively promoting wise and efficient uses of energy which satisfy customer needs. The following provides a brief description of Gulf's forecasting methodology. A more detailed description is provided in Appendix B.

4.3.1 CUSTOMER FORECAST

4.3.1.1 RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district personnel based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated customer gains.

For the remaining forecast horizon, the Gulf Economic Model, an econometric model developed by RFA, is used in the development of residential customer projections. Projections of births, deaths, household size, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model.

4.3.1.2 COMMERCIAL CUSTOMER FORECAST

As in the residential sector, the immediate short-term forecast (0-2 years) of commercial customers is prepared by Gulf's district personnel utilizing recent historical customer gains information and their knowledge of the local area economies and upcoming construction projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers and total real disposable income, reflecting the growth of commercial services to meet the needs of new and existing residents.

4.3.2 ENERGY SALES FORECAST

4.3.2.1 RESIDENTIAL SALES FORECAST

The short-term (0-2 years) residential energy sales forecast is developed utilizing multiple regression analyses.

The long-term residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. REEPS produces forecasts of appliance installations, operating efficiencies, and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses for a large number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population.

The energy forecast output from REEPS reflects the continued impacts of Gulf Power's GoodCents Home program and efficiency improvements undertaken by customers as a result of Residential Energy audits, as well as conversions to higher efficiency outdoor lighting. This output is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the residential conservation programs and program features are provided in Section 4.3.4.

4.3.2.2 COMMERCIAL SALES FORECAST

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses.

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for Gulf's long-term commercial energy sales forecast.

Annual building data from RFA and Gulf's most recent Commercial Market Survey provide much of the input data required for the COMMEND model. The model produces forecasts of energy use for the space heating, cooling and ventilation equipment and the lighting, water heating, cooking, refrigeration, and other end-uses within each of 12 different business categories.

The energy forecast output from COMMEND reflects the continued impacts of Gulf Power's Commercial GoodCents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficiency outdoor lighting. The output from COMMEND is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the Commercial Conservation programs and program features are provided in Section 4.3.4.

4.3.2.3 INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-four of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions, replacements or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self-generation installations. The industrial sales forecast is also adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the conservation programs and program features are provided in Section 4.3.4.

4.3.2.4 STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service by fixture type.

The projected numbers of fixtures by fixture type are developed from analyses of recent historical fixture data to discern the patterns of fixture additions and deletions. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium conversions.

4.3.2.5 WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced utilizing multiple regression analyses.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

4.3.2.6 COMPANY USE ENERGY FORECAST

The annual forecast for Company energy usage is based on recent historical values, with appropriate adjustments to reflect short-term increases in energy requirements for anticipated new Company facilities. The monthly spreads are derived using historical relationships between monthly and annual energy usage.

4.3.3 PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The HELM model provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for user-specified end-uses. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

4.3.4 CONSERVATION PROGRAMS

Gulf has been a pacesetter in the energy efficiency market since the development and implementation of the GoodCents Home program in the mid-70's. This program brought customer awareness, understanding and expectations regarding energy efficient construction standards in Northwest Florida to levels unmatched elsewhere. Since that time, the GoodCents Home program has seen many enhancements, and has been widely accepted not only by customers, but by builders, contractors, consumers, and other electric utilities throughout the nation, providing clear evidence that selling efficiency to customers can be done successfully.

Gulf's forecasts of energy sales and peak demand reflect the continued impacts of the Company's conservation programs. These forecasts also reflect the anticipated impacts of the new programs submitted in Gulf's Demand Side Management plan filed February 22, 1995 (Docket No. 941172-EI) as approved by the FPSC. The demand and energy reductions associated with these new programs have been updated to reflect a revised implementation schedule for the Advanced Energy Management (AEM) program in the residential sector.

The following is a listing of Gulf's conservation programs:

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment®*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Bldg.
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

Table 4-3, below, provides estimates of the total savings (reductions in peak demand and net energy for load) resulting from Gulf's conservation programs. These estimates include the impacts of Gulf's existing programs that have been in place for several years and the anticipated impacts of Gulf's newer programs, submitted in Gulf's Demand Side Management Plan filed in 1995. These reductions are verified through on-going monitoring of Gulf's major conservation programs and reflect estimates of conservation undertaken by customers as a result of Gulf's involvement. Conservation which has taken place without Gulf's involvement has contributed to further unquantifiable reductions in demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in the energy forecasts and in demand model projections. Additional detail on Gulf's conservation programs is provided in Appendix B.

TABLE 4-3

CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	Summer Peak (MW)			Winter Peak (MW)			Net Energy for Load (GWH)		
	Existing	New	Total	Existing	New	Total	Existing	New	Total
1997	214	30	244	263	6	269	514	9	523
2002	253	112	365	295	128	423	573	77	650
2008	290	199	489	334	256	590	625	145	770

As indicated in this table, in 1997, Gulf's DSM programs successfully reduced summer peak demand by 244 megawatts (MW), winter peak demand by 269 MW, and net energy for load by 523 million kilowatt-hours (KWH). By the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from

1997 through 2002. These reductions are expected to grow to a total savings of 489 MW of summer peak demand, 590 MW of winter peak demand and an annual energy savings of over 770 million KWH by the year 2008.

4.3.5 RENEWABLE ENERGY

Gulf has begun implementation of a "Green Pricing" pilot program, *Solar for Schools,* to obtain funding for the installation of solar technologies in participating school facilities combined with energy conservation education of students. Initial solicitation began in September, 1996 and has resulted in participation of over 333 customers contributing $18,171 through December, 1998. A prototype installation at a local middle school has been completed and the experience gained at this site will be used to design future *Solar for Schools* installations.

4.4 FORECAST RESULTS

The following table summarizes the major forecast results. Detailed forecast results are provided in Appendix B.

Table 4-4

History and Forecast Summary							
	1989 history	1998 history	2003 forecast	2008 forecast	CAAG 1989-1998	CAAG 1998-2003	CAAG 1998-2008
Population	662,784	810,649	891,566	960,867	2.3%	1.9%	1.7%
Residential Customers	250,038	304,413	337,784	367,016	2.2%	2.1%	1.9%
Customer Gains					54,375	33,371	62,603
KWH / Customer	13,173	14,577	14,677	14,995	1.1%	0.1%	0.3%
Energy (GWH)	3,294	4,438	4,958	5,503	3.4%	2.2%	2.2%
Commercial Customers	33,500	45,510	51,208	55,836	3.5%	2.4%	2.1%
KWH / Customer	64,761	68,379	68,275	69,507	0.6%	0.0%	0.2%
Energy (GWH)	2,169	3,112	3,496	3,881	4.1%	2.4%	2.2%
Net Energy for Load (GWH)	8,378	10,402	11,658	12,661	2.4%	2.3%	2.0%
Summer Peak Demand	1,698	2,154	2,280	2,466	2.7%	1.1%	1.4%
Winter Peak Demand	1,554	1,692	2,139	2,258	0.9%	4.8%	2.9%
Load Factor (%)	56.3%	55.1%	58.4%	58.6%			

The growth rates associated with the 1999 peak demand forecast are slightly higher than the 1998 TYSP. The summer peak demand projections for the 1999 forecast are about 31 MW higher than the 1998 TYSP forecast by 2002, the proposed in-service date of Smith Unit 3. As described in Section 3, the 1998 TYSP forecast was used to establish the need for Smith Unit 3. The additional summer peak demand projected in the most recent forecast simply underscores the need for additional capacity in 2002.

4.5 DEMAND SIDE MANAGEMENT (DSM) PROGRAM RESULTS

As shown in Table 4-3 in Section 4.3.4, by the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from 1997 through 2002. The impacts of Gulf's conservation programs are shown in Figures 4-1 through 4-3.

It should be noted that Gulf's conservation goals are currently being reviewed and revised in a separate docket and the reductions achieved as a result of these revisions may vary slightly from those included in the 1999 Forecast. However, because of the factors driving the need for additional capacity in 2002, including the expiration of purchased power contracts and dwindling reserve margins, the need for Smith Unit 3 cannot be avoided or delayed any further by additional DSM.

Figure 4-1

Gulf Power Company

History and Forecast of Summer Peak Demand

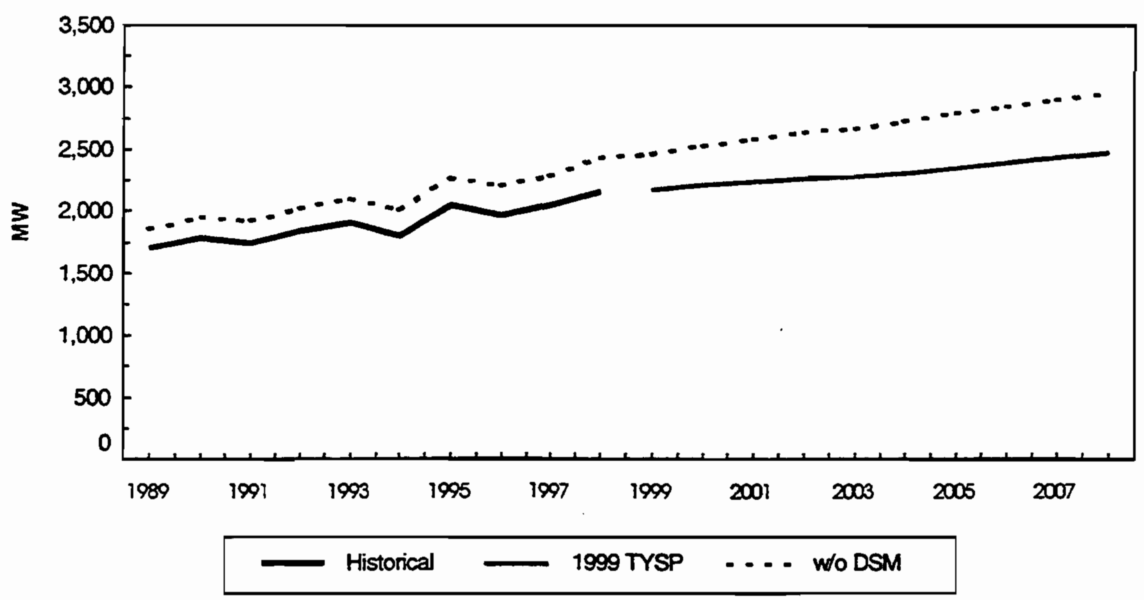


Figure 4-2

Gulf Power Company

History and Forecast of Winter Peak Demand

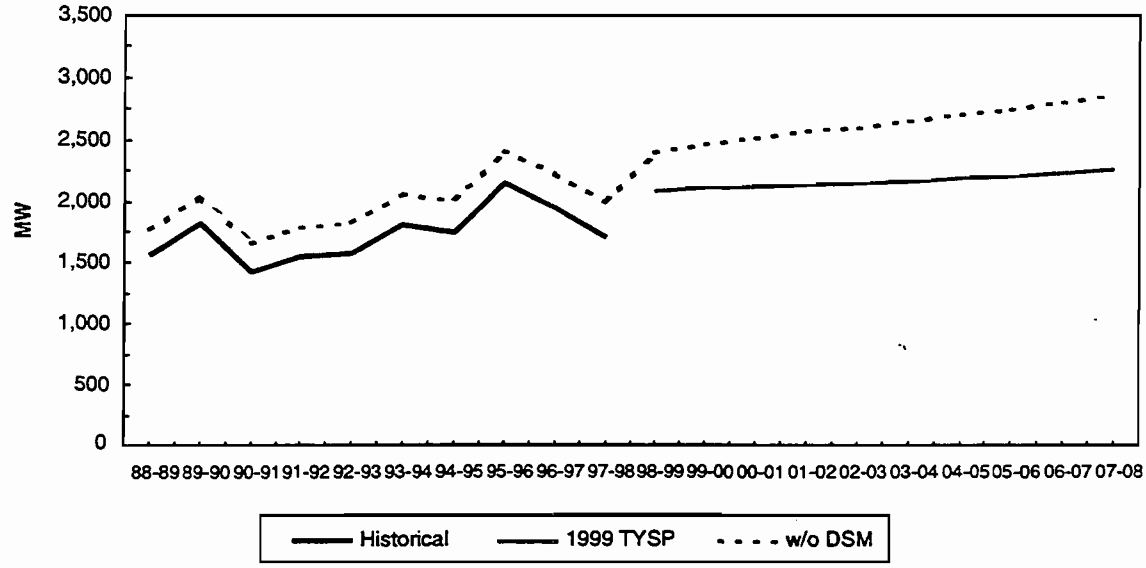
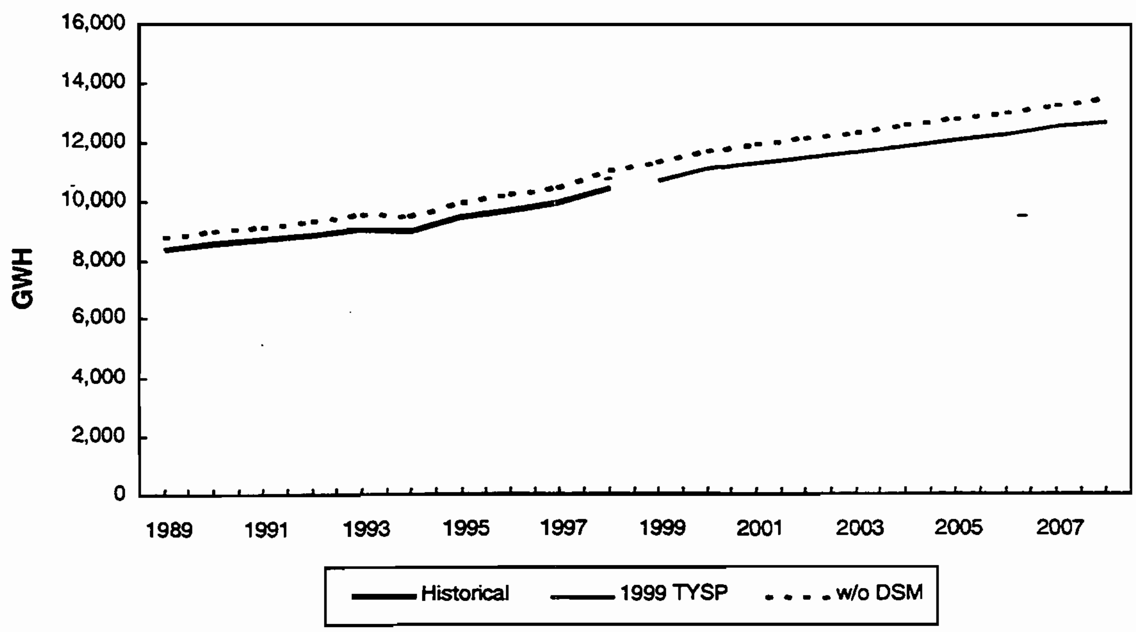


Figure 4-3

Gulf Power Company

History and Forecast of Annual Net Energy for Load



4.6 HISTORICAL FORECAST PERFORMANCE

Gulf's forecasts have traditionally been accurate. The FPSC's Review of Electric Utility 1998 Ten-Year Site Plans indicated that, of the nine reporting utilities in the state with sufficient available historical data, Gulf's average absolute percent error in retail sales forecast accuracy for the period from 1993 through 1997 was 2.5% and ranked third best in the state. Gulf's average forecast error for the same period was estimated to be an under-forecast of 1.19%, which also ranked third in the state.

5. FUEL PRICE FORECAST PROCESS

5.1 FUEL PRICE FORECASTS

Fuel price forecasts are used for a variety of purposes within the Southern electric system (SES), including such diverse uses as long-term generation planning and short-term fuel budgeting. Southern's fuel price forecasting process is designed to support these various uses.

The delivered price of any fuel consists of two components, the commodity price and the transportation cost. Commodity prices are forecast as mine-mouth prices for coal or well-head prices for natural gas. Because mine-mouth coal prices vary by source, sulfur content and Btu level, Southern prepares commodity price forecasts for 12 different coal classifications used on the Southern system. Because natural gas and oil prices do not experience the same variations, Southern prepares a single commodity price forecast for each of these fuels.

The level of detail with which transportation costs are projected depends on the purpose for which the forecast will be used. Generic transportation costs that reflect an average cost for delivery within Southern's territory are used in the delivered price forecast used for modeling generic unit additions in the Integrated Resource Planning (IRP) process. Site-specific transportation costs are developed for existing units to produce delivered price forecasts for use both in the IRP process and in fuel budgeting. Similarly, when site-specific unit additions are under consideration, site-specific transportation costs are developed for each option.

Given the purpose of this Need Study, the following discussion will focus on the commodity price forecasts for coal and natural gas, and on the site-specific forecasts for Smith Unit 3 and the generating facilities proposed in response to Gulf's Request for Proposals (RFP).

5.2 SOUTHERN GENERIC FORECAST

Each year, Southern develops a fuel price forecast for coal, oil, and natural gas, which extends through the Company's 10-year planning horizon. This forecast is developed by a fuel panel consisting of fuel procurement managers at each of the five operating companies, with input from Southern Company Services fuel staff and outside consultants ("Fuel Panel").

The fuel price forecasting process begins with an annual Fossil Fuel Price Workshop that is held with representatives from recognized leaders in energy-related economic forecasting and transportation-related industries. Presenters at the last fuel price workshop included representatives from Resource Data International, J. D. Energy Inc., Hill and Associates, Data Resource International, Fieldston Company, and Criton Company.

During the Fossil Fuel Price Workshop, each fuel procurement representative presents their "base case" forecast and assumptions, and high and low fuel price scenarios are discussed. A question and answer period allows for opposing views and debates on forecasts.

After the workshop, presentations by the SCS Fuel Services group reference the outside consultant forecasts and identify any major assumption differences. The Fuel Panel then consolidates both internal and external forecasts and assumptions to derive its commodity forecast for each type of fuel. The Fuel Panel's 1998 commodity price forecasts for 1.0% sulfur coal, oil, and natural gas, which were used in the economic analysis of Gulf's generating alternatives, are included in Table 5-1 below.

TABLE 5-1

SOUTHERN GENERIC FUEL PRICE FORECAST
($/MMBtu)

	COAL	NAT. GAS	OIL
1999	1.071	2.28	3.94
2000	1.080	2.28	4.06
2001	1.089	2.28	4.18
2002	1.098	2.28	4.30
2003	1.107	2.28	4.43
2004	1.115	2.28	4.58
2005	1.125	2.47	4.72
2006	1.134	2.62	4.87
2007	1.143	2.79	5.02
2008	1.152	2.96	5.18

5.3 COAL PRICE FORECAST

The information provided during the Fuel Panel meeting is used to develop the SES forecast of generic coal prices. The major influences that drive the assumptions for the coal forecast are relative expected demand for specific qualities of coal and transportation from the source. As Phase II of the Clean Air Act of 1990 approaches, the variety of suitable coal quality narrows and tends to have an upward pressure on coal commodity prices. However, as more substitution of natural gas for coal as an energy resource for new resource additions takes place, it is expected that coal prices will once again stabilize.

The generic coal price used in the IRP process is based on an average expectation of coal commodity cost combined with average transportation fees. This serves as a basis for the fuel costs associated with the pulverized coal candidate technology in the mix analyses. This generic fuel commodity price is also used with plant specific transportation fees in combination with a plant's contract coal prices to develop the existing fuel price projection for the Company's budget process.

5.4 NATURAL GAS PRICE FORECAST

The natural gas price forecast for wellhead natural gas reflects a "relaxed" view of the scarce resource theory. Past views by consultants and the U.S. Department of Energy

(DOE) would suggest that natural gas resources were rapidly declining and that reserves would be more difficult and costly to find. However, new technological innovations have resulted in a paradigm shift in the "scarce resource" theory. The new consensus is that gas resources are sufficient to meet the growing demand with moderate nominal dollar increases in price during the planning period. Dramatic improvements in producers' ability to find and develop natural gas reserves have prompted suppliers to have a bullish outlook on future markets. In the past two years, success rates in drilling offshore exploration wells have improved from 25% to 90% for most producers. In addition, new completion techniques such as horizontal drilling have increased production per well substantially. Lastly, new production methods are allowing producers to drill in very deep water at a lower cost. The result is expected to be a plentiful supply of relatively inexpensive volumes of gas in the near future.

5.5 NATURAL GAS AVAILABILITY

Assuming the construction of additional pipeline facilities, there are sufficient natural gas supplies available in the Southeastern United States to support full load operation of Smith Unit 3.

During the winter months, U.S. natural gas demand can reach 100 billion cubic feet (Bcf) per day. Unfortunately, the current maximum natural gas supplied through imports and domestic production volumes peaks at 56 to 60 Bcf per day. In order to offset this capacity shortage, storage delivery is necessary.

Since U.S. natural gas demand in the summertime is significantly less, only about 42 to 45 Bcf per day, large end users and local distribution companies, such as Alagasco, buy extra volumes to fill huge underground gas storage fields. Typically, the markets purchase from 10 to 12 Bcf per day to fill storage during the summer months. This activity results in average gas demand reaching usage levels of 52 to 57 Bcf per day. This allows producers to operate wells at 90-95% of capacity year round.

There are indicators that during the time period 1999 and 2005, gas supply in the SES region will improve substantially. Major producers and interstate pipelines have proposed wide-scale expansion of pipelines in the Louisiana, Mississippi, and Alabama offshore areas. Suppliers forecast that an additional 2 Bcf per day will be delivered to the market by 1999. Another 4 Bcf per day should be available by the year 2005. Additionally, Canadian producers and pipelines have announced their plans to increase gas imports by 2 Bcf per day by 2000. These developments suggest that by 2005, U.S. gas supplies (specifically the SES region) should increase 15-16% above current levels. This translates into sufficient gas being available for all new gas-fired electric generation, including Smith Unit 3. It also means that average annual gas prices should drop in the 1998 to 2000 time period as reflected in the natural gas price forecast discussed in Section 5.2 above.

5.6 SITE-SPECIFIC FUEL PROJECTIONS

Although the generic fuel forecast is useful in the IRP process for determining the preferred type of generating unit additions, it is inappropriate for use when evaluating site specific generation alternatives. For site-specific reviews, it is necessary to develop a fuel projection that specifically addresses the fuel supply that would be available to that site. This is the process that was used during both the self-build and RFP evaluations for Gulf.

The evaluations of both the RFP responses and the final self-build option were based on the gas commodity prices contained in the Fuel Panel's 1998 forecast. This provided a uniform basis for comparison. If necessary, adjustments were made to reflect any cost differences due to natural gas supply at a point other than the Henry hub, and any differences due to the specifics of the proposal, such as a commodity price adder.

To obtain site-specific costs for each alternative, transportation costs were added to the commodity forecast. In the case of the RFP respondents, the transportation adders were those quoted in the respective proposals. In the case of Gulf's self-build option, the transportation adders reflected the rates offered in response to Gulf's September, 1998 solicitation for firm natural gas transportation.

In some cases, an RFP respondent stated that it planned to use either interruptible transportation or recallable released firm transportation, but would supply fuel oil backup. In those cases, fuel oil was assumed to be used for periods when gas transportation would likely be unavailable. The Fuel Panel's generic oil price forecast was used for this purpose, with transportation adjustments for delivery to the specific plant site.

By using the Fuel Panel's commodity price forecast in all the evaluations, SCS ensured that the competing proposals were compared on a fair, consistent basis.

6. FINANCIAL ASSUMPTIONS

The following financial assumptions were developed by Southern Company Services Financial Planning Department based on its annual assessment of regional and national economic factors. These assumptions were applied on a uniform basis in the analysis of Gulf's self-build options, the offers from respondents to Gulf's RFP, and the transmission improvements that were necessary for the alternatives. These financial factors are representative of what the Company could expect to experience when raising equity and debt at this time. Even if these assumptions turn out to be slightly different from actual rates in the near future, the relative rankings of the alternatives would not be changed.

The financial assumptions used in the evaluation processes are as follows:

Cost of Debt	7.29 %
Cost of Preferred	6.79 %
Cost of Equity	13.50 %
Percentage of Debt	45.00 %
Percentage of Preferred	10.00 %
Percentage of Equity	45.00 %
Construction Escalation	3.02 %
General Inflation	2.78 %
Ad Valorem Tax Rate	1.08 %

State Tax Rate	5.50 %
Federal Tax Rate	35.00 %
Depreciation Life	20 Years

7. SELF-BUILD OPTION SELECTION PROCESS

7.1 INITIATION OF SITE-SPECIFIC STUDIES

By the summer of 1997, it was apparent that Gulf would need to add generating resources by 2002 to reliably meet its customers' needs. This need was the result of several factors. Gulf's existing short-term power purchase agreements were scheduled to expire at the end of 2001, at which time the Company would be left with a negative reserve margin. Continuing to meet Gulf's capacity needs with new short-term power purchase options was not feasible, since such purchases were becoming not only scarce, but extremely expensive as a resource option. In addition, total SES reserve margins were declining, and Gulf could no longer rely on system-wide reserves to offset its own reserve shortfall. Two of the other operating companies in the Southern electric system, Alabama Power Company (APCo) and Mississippi Power Company (MPCo) had engaged in a study to determine their best self-build alternatives in the early part of 1997. This led to the filing for certification of APCo's Barry combined cycle unit and MPCo's Daniel combined cycle unit in August of 1997. As a member of the Southern system, Gulf was offered the opportunity to participate in the ownership of the proposed Daniel CC unit.

Based on all these circumstances, the Company in late 1997 began evaluating a number of site-specific, self-build generation options for meeting its future demand needs. The following is a listing of the self-build alternatives that were ultimately considered in this evaluation process:

- Participation in MPCo's Daniel Combined Cycle Unit scheduled for a 2001 in-service date
- Construction of CT's at Smith Plant
- Construction of a CC unit at Smith Plant
- Participation in a cogeneration unit in the Pensacola area

The self-build evaluation process required the development of plant-specific cost and operating data for each of the alternatives. This data was then used to calculate the total 20-year net present value (NPV) of costs for each of the generating alternatives. The components of cost considered in the analysis included capital expenditures, fuel supply and transportation costs, operating and maintenance expense, transmission improvements, and system energy savings. These options were compared on both a $/KW and total NPV basis.

7.2 SELF-BUILD UNIT SIZE

The initial self-build evaluation began by analyzing projects of comparable size to a 1-on-1, F-Class combined cycle unit, which has an output of approximately 266 MW. If a particular option being evaluated was of a different size, its characteristics were scaled either up or down to make it comparable to the 1-on-1 CC unit. This allowed the alternatives to be evaluated on an equal basis.

This size of self-build option was initially used in the evaluation process. It became apparent that a 500 MW, F-Class, 2-on-1 combined cycle unit not only better matched the Company's demand needs, but also provided an alternative with attractive economies of scale. The major economic difference in going from a 1-on-1 to a 2-on-1 configuration is that the Company could get twice the generating capability for only about 70% in additional capital costs. Once again, some scaling was necessary to put all alternatives on equal footing in the analysis.

7.3 SIGNIFICANT COST DRIVERS

There are several significant cost drivers in the 20-year NPV cost analysis of site-specific alternatives. These include the cost of natural gas transportation, the cost of required transmission improvements, and the amount of energy savings that result from the displacement of less efficient generation.

7.3.1 NATURAL GAS TRANSPORTATION COSTS

One of the key elements in the cost analyses was the development of natural gas (fuel) supply costs for the self-build options. As discussed in Section 5, the Southern electric system's Fuel Panel creates a forecast of generic fuel costs by type; however, a more refined and site-specific projection must be used in the self-build analysis. Since most of the self-build options were natural gas fired alternatives, a number of different fuel assumptions were explored in the evaluation.

Natural gas commodity prices and storage costs are fairly competitive throughout the region and can be treated as basically equivalent for any of the specific sites under consideration. On the other hand, there is a great variety in the natural gas transportation rates, particularly when the cost of gas delivered into the state of Florida is compared to gas delivered outside of Florida.

The gas transportation cost for the Daniel CC unit is quite low, since the plant is located only about 5 miles away from a natural gas pipeline called the Destin Dome pipeline. This gave the option of participation in the Daniel CC a distinct fuel cost and energy savings advantage over the other self-build options. The cogeneration project, referred to in the analysis as Mulat Tower, is located near Pensacola and would receive its gas from the Koch Gas Transmission System in that area. Therefore, its transportation costs are fairly well established by existing tariffs. In contrast, there is no existing gas supply to the Smith Plant and therefore, the analyses explored a number of possible alternative supply options.

The closest natural gas pipeline to the Smith site is operated by Florida Gas Transmission (FGT) and would require the installation of approximately a 29-mile section of gas lateral to the plant. It was assumed for purposes of this analysis that FGT would build the new lateral and Gulf could either transport the gas over FGT's system at the published tariff rate or could arrange to get release-firm gas transportation from others not using their capacity all of the time. The other alternative investigated for the Smith CC unit was the possibility of Gulf constructing its own pipeline to the Atmore, Alabama area. This new pipeline would offer the benefits of lower gas transportation costs from that area. This benefit would be impacted by the pipeline construction costs that would have to be considered in the overall economics of the option.

7.3.2 SYSTEM ENERGY SAVINGS

Another key economic factor is the amount of system energy savings associated with each alternative. System energy savings are dependent on the marginal fuel cost of the alternative. Units with lower delivered fuel prices will dispatch earlier and will run at higher capacity factors than units with higher fuel costs. In turn, these units displace a greater amount of high-priced generation from other units and maximize system energy savings. This factor tended to penalize lower efficiency combustion turbine units, as well as units with fuel purchased under currently existing gas tariff rates inside the state of Florida. The Daniel CC provided the greatest system energy savings because of its low gas transportation costs. The energy savings of the Smith CC with the new pipeline option were slightly less than those of the Daniel unit, although the pipeline capital cost would be an offset to any savings of this option.

7.3.3 TRANSMISSION COSTS

The geographic location of the alternatives surfaced as a major factor in the cost evaluations due to the impact of location on the electric transmission system and the associated cost of needed improvements. Each of the self-build options was analyzed separately to determine any incremental transmission impacts resulting from its installation. These studies revealed that the prevailing network flows through Gulf's system are from the west to the east. As generation is added, particularly west of Gulf's service area, transmission improvements are required to reliably transport the power and provide voltage support to the Company's load centers. It was determined that capacity additions located almost anywhere except near the Panama City, Florida area had some negative impact on the transmission system. In fact, the study revealed that the further west the generation alternative was located, the greater the impact on Gulf's transmission system. The cost of overcoming these impacts was added to the overall cost of each self-build alternative in the evaluation.

7.3.4 CAPITAL AND O&M COSTS

The various options' capital and operating and maintenance costs were probably the most straight forward elements of the evaluation. It was clear that participating in a sister company project would have the least capital cost by enabling Gulf to take advantage of economies of scale. It was also clear that combustion turbines had lower capital cost and higher operating costs than the combined cycle units.

7.4 ECONOMIC EVALUATION

The economic evaluation of the self-build alternatives was approached from a total cost basis using common financial factors to develop a total net present value (NPV) for each alternative over a 20-year period. The capital costs for the units, pipeline, and transmission were calculated for each self-build alternative as a traditional present worth of revenue requirement (PWRR). The capacity costs of the cogeneration project and other fixed annual costs were treated like an expense and discounted to yield a NPV of cost. Each self-build option was modeled as an input to the entire Southern electric system to determine its effect on the total production and energy costs or savings to the system. The final result of combining these cost components was the total NPV of cost for all of the self-build options.

The evaluation process, which began the previous fall, was completed in April of 1998. As mentioned earlier, in the final analysis the evaluation considered options that were comparable in size to a 2-on-1, F-Class combined cycle technology (~540 MW) and included all incremental costs associated with the installation of each alternative.

7.5 RESULTS

The results of the evaluation showed that the Smith combined cycle unit, with the construction of a new pipeline, was the lowest cost alternative. Although energy savings was a major factor in the evaluation process, the primary factor that eliminated many of the options was the cost of the transmission improvements required to support new generation at any location outside the Panama City area: The table below provides the results of the self-build analyses which demonstrate that Smith Unit 3 is the Company's most cost-effective self-build alternative.

TABLE 7-1

SELF-BUILD ALTERNATIVE	NET PRESENT VALUE OF COSTS (98$ MIL)
Smith Unit 3	117.1
Smith Combustion Turbine	158.5
Daniel Combined Cycle	236.7
Mulat Tower (cogeneration)	239.0

The selection of a combined cycle unit of the size of Smith Unit 3 dictated that Gulf Power follow the rules established pursuant to the Florida Electrical Power Plant Siting Act (PPSA). This included initiating a solicitation process under Rule 25-22.082 Florida Administrative Code, which must be completed prior to filing for a determination of need before the FPSC. The results of that solicitation process are covered in Section 8 of this Need Study.

8. REQUEST FOR PROPOSALS (RFP) PROCESS

8.1 OVERVIEW

Gulf began working with Southern Company Services' purchase power team early in 1998 on development of a Request for Proposals (RFP) for supply-side resources needed beginning in the summer of 2002. The Company desired a market test to determine what potential new generation option was the most cost-effective alternative for its customers. Gulf's RFP process began with the development of the RFP document, and moved through stages which included distributing the RFP, receiving proposals from respondents, initial screening of the proposals, requesting additional information from respondents, and final screening and results.

8.2 DEVELOPMENT OF THE RFP

Southern Company Services began to draft a solicitation for Gulf in February 1998, during the same time period Gulf was finalizing the study of its self-build options. The solicitation incorporated the requirements of the Commission RFP rule, such as the requirement for published notice of the respondents' sites and for Gulf's disclosure of costs for its next planned generating unit.

The RFP solicited proposals for all types of generating resources to meet all or part of a 350 - 500 MW need beginning in the summer of 2002. The RFP requested long-term proposals lasting at least five years and specified a 50 MW minimum proposal size. The RFP advised potential respondents that resources in the Panama City area would have a significant transmission advantage. A copy of Gulf's RFP is contained in Appendix E.

8.3 DISTRIBUTION OF THE RFP

On August 21,1998, Southern Company Services publicly issued the RFP on behalf of Gulf to approximately 100 potential respondents. As a normal course of business, Southern Company Services maintains a mailing list of developers who are active in the Southeastern United States. This list was updated for Gulf's RFP.

Additionally, Gulf published a notice of the solicitation in appropriate local and statewide newspapers and three national trade journals. All of the public notices included the name and address of the RFP contact in Birmingham as well as a schedule of critical dates for the RFP process. Gulf's objective was to attract any interested developers who may not have been on Southern Company Services' original distribution list.

8.4 PROPOSALS RECEIVED

On October 16, 1998, Southern Company Services received, on behalf of Gulf, four offers from three separate respondents. The proposals were of various terms and MW sizes, but all offers were in the form of new generating facilities:

- A combined cycle unit in Hardee County, Florida
- A combustion turbine facility in Holmes County, Florida
- A combined cycle unit in Holmes County, Florida
- A family of cogeneration facilities in Mobile, Alabama and in Santa Rosa County, Florida

After receiving additional required information from one respondent, all offers were determined to be 'responsive' and the initial screening analysis began.

8.5 INITIAL SCREENING

In any supply side evaluation, the goal is to determine which alternative is the most cost-effective on a $/KW basis. Although it penalizes the self-build alternative, Gulf chose to make the cost comparisons on a 20-year NPV of costs basis. Theoretically, the cost of any new generating facility constructed by Gulf would be recovered from its customers using declining revenue requirements over a thirty-year or longer time frame. A uniform 20-year analysis compresses all of those costs into a shorter timeframe, making the self-build alternative appear more expensive than what customers would really be asked to pay on a year-by-year basis.

For the initial screening in October and November, 1998, all of the proposals were modeled in PROVIEW® using only the costs contained within the offers. To facilitate this evaluation, SCS-Fuel Services provided a forecast of delivered natural gas prices for each of the facilities offered. Although the same fundamental commodity price for natural gas was used for all of the offers, there are additional site- specific variable costs of the natural gas which must be accounted for in the production cost model. To ensure the fairness of the evaluation, it is critical that the basis of the fuel forecast for the candidate unit is consistent with the fuel forecasts for generic unit additions and other competing units in the dispatch order.

To place all of the offers on equal footing, each proposal was scaled to a 600 MW size in the production cost run. This scaling method allows all offers to be compared equally, against the same base case, and it provides a consistent method of calculation on a $/KW basis. This evaluation technique is critical to smaller projects which may have more value on a $/KW basis, but may not meet the entire needs of the utility. Southern Company Services' goal was to evaluate the offers on an "apples to apples" basis and to eliminate any size bias in the evaluation.

Because none of the original proposals were 20-year offers, Southern Company Services allowed the PROVIEW® model to replace each offer at the end of its term with the most appropriate generic resource addition. In Southern Company Services' experience, this technique is the best method for direct comparison of alternatives with unequal lives. When using this technique, SCS always reviews the year-by-year results to ensure that the replacement technology does not skew the results for the alternative being evaluated.

The results of the initial screening are shown below:

TABLE 8-1

INITIAL SCREENING RESULTS

Summer Rating	Proposal	Location	NPV ($/KW)
500 MW	Combined Cycle	Holmes County, FL	273.8
486 MW	Combustion Turbine	Holmes County, FL	332.1
350 MW	A family of cogeneration facilities	Mobile, AL and Santa Rosa County, FL	432.3
532 MW	Combined Cycle	Hardee County, FL	565.2

Because this initial screening was based entirely on numbers supplied by the respondents, it was clear that Gulf Power needed to understand more about these proposals before proceeding to the final detailed evaluation. For example, the relative firmness of fuel supply was an important issue for these proposals. After conducting the initial screening analysis, formal correspondence was initiated by Southern Company Services to allow respondents to provide the additional information required.

8.6 REQUESTS FOR FURTHER INFORMATION

On November 19, 1998, letters were sent to each of the respondents asking clarifying questions that would potentially resolve any outstanding issues. Most of the uncertainty at this stage of the analysis concerned the firmness of the fuel supply, unit ratings, unit heat rates, and overall availability of the offers.

The Company wanted to make sure that all of the alternatives would have reliability and other characteristics comparable to those of its self-build option in order to make a fair assessment.

As a result of this dialogue with the respondents, the original proposals were modified and five additional proposals were made to Gulf from these participants. All of these offers were carried forward into the next phase of the evaluation.

8.7 GULF'S SELF-BUILD COSTS FOR SMITH UNIT 3

Concurrent with receipt by SCS of the RFP responses, Gulf submitted a site-specific cost estimate for Smith Unit 3. This submission did not include fuel transportation costs, which were the subject of a separate RFP issued in September, 1998, for firm natural gas service to the Lansing Smith site.

Six separate offers to build and own new pipeline facilities necessary to supply firm natural gas to the Smith site were received on October 16, 1998. These proposals were significantly less expensive than was originally anticipated. Negotiations continue with a short list of respondents with the best offers. In addition to the solicited offers, SCS-Fuel Services developed an independent cost estimate for a Gülf self-build pipeline that was used to determine if having a third party perform this service was the least cost alternative.

8.8 DETAILED EVALUATION AND ANALYSIS RESULTS

In January 1999, a final detailed evaluation was conducted which directly compared the revised proposals to the Smith Unit 3 self-build alternative. The analysis methods for the detailed evaluation were similar to the screening analysis. Both the scaling technique and the replacement technology techniques were continued for the detailed evaluation. In addition to the generation analysis, transmission interconnection costs, system losses and transmission grid improvement costs were calculated and included for each of the supply side alternatives. Table 8-2 provides a summary of the relative ranking resulting from this detailed evaluation.

Although this detailed evaluation could have led to a list of finalists, the updated fuel cost for Smith Unit 3 really distinguished it as the best supply side alternative for Gulf's customers. As shown in the table, Smith Unit 3 produces over a $200/KW advantage over 20 years compared to the best external proposal. Based on these results, Gulf advised each of the respondents that its proposal was not the most cost-effective alternative.

8.9 CONCLUSION

Gulf's RFP process fully complied with both the letter and the spirit of the Florida Public Service Commission's rules governing the selection of generating capacity. Consequently, the process has confirmed that the best capacity resource alternative for Gulf's customers is Smith Unit 3. Because the size of the steam turbine exceeds 75 MW, Gulf now seeks a determination of need and certification of this unit under the Florida Electrical Power Plant Siting Act (PPSA).

TABLE 8-2

Gulf RFP Relative Ranking

Rank	MW	Respondents	NPV Total Cost $/KW (2002$)
1	540	Self-Build	279
2	486	Respondent B CT (20 Year Pricing)	496
3	500	Respondent B CC (10 Year Pricing)	505
4	532	Respondent C	511
5	500	Respondent B CC (7 Year Pricing)	522
6	486	Respondent B CT (10 Year Pricing)	527
7	486	Respondent B CT (7 Year Pricing)	539
8	500	Respondent B CC (20 Year Pricing)	553
9	350	Respondent A	592
10	532	Respondent C (Fixed Energy)	616

9. SUMMARY OF SMITH UNIT 3

9.1 OVERVIEW

Smith Unit 3 will be what is commonly referred to as a 2-on-1 combined cycle unit, using the General Electric "F" Class combustion turbine technology. The two combustion turbines (CT) comprising this unit will have a net generating capability of approximately 176 megawatts each in the absence of power augmentation. The exhaust gases from each of these CTs will flow through its own heat recovery steam generator (HRSG). On a combined basis, the HRSG's will produce 1,800 psig steam in sufficient quantities to power about 170 megawatts of steam turbine/generator capacity.

Smith Unit 3 will be a highly efficient, state-of-the-art combined cycle generating unit. Because the new unit will be fueled by natural gas, the environmental concerns associated with the project are minimal. Smith Unit 3 is expected to provide the customers of Gulf with many years of low cost, clean energy.

Smith Unit 3 will have a firm supply of natural gas that will come from a new pipeline installation to the Smith Plant. Currently, the Company does not have any plans to provide for a secondary fuel source for this unit because of the expected firmness of the natural gas supply. Since this new natural gas pipeline is to be built and owned by someone other than Gulf, the cost estimate does not include any major gas pipeline costs, but does include connection and metering costs.

Smith Unit 3 will be located approximately 1,000 feet north of the existing Smith Plant substation. The unit's output will reach the Company's transmission grid by means of less than 1,000 feet of 230 KV bus. The existing transmission system out of Smith Plant is sufficient to handle the unit's output.

Smith Unit 3 will have an average annual output of 521 megawatts at an efficiency of 6,741 Btu/KWH. The unit will have the capability for power augmentation by steam injection to generate up to 540 megawatts of peaking generation at a reduced efficiency of 7,139 Btu/KWH. The costs for the necessary equipment associated with the power augmentation operation are included in the estimate below.

The following is a listing of some of the specific unit characteristics:

Forced outage rate	3.4%
Scheduled maintenance outage	2 weeks/year (Ave.)
Equivalent availability	92%
Expected average capacity factor	62%
Fuel consumption (full load)	3,900 MMBtu/hour
Annual fixed O & M (98$)	$2.84/KW-yr.
Variable O & M (98$)	$1.89/mWh

9.2 PROJECTED UNIT CONSTRUCTION COSTS

The following is a breakdown of estimated installed costs for Smith Unit 3, excluding any costs associated with the construction of the natural gas pipeline. This estimate is based on a combination of actual vendor quotes and refined engineering cost analyses and includes the costs necessary to comply with all applicable environmental regulations. With respect to most of the components that comprise the following costs, this estimate can be considered relatively firm (±10%).

TABLE 9-1

INSTALLED COST ESTIMATE FOR SMITH UNIT 3

DESCRIPTION:	AMOUNT
Indirects	$ 23,661,966
Site, General	2,701,846
Steam Generator Area	36,741,570
Turbine & Generator Area	91,143,505
Fuel Facilities (metering only)	856,111
Plant Water Systems	13,443,351
Electrical Distribution & Switchyard	12,177,183
Plant Instrumentation & Controls	2,591,303
Other	3,935,190
TOTAL	$187,252,025

9.3 ENVIRONMENTAL CONSIDERATIONS

Subsequent to filing the Petition for Need Determination before the Commission, the Company will file its Site Certification Application (SCA) with the Florida Department of Environmental Protection under the Florida Electrical Power Plant Siting Act (PPSA). Smith Unit 3 will be operated in compliance with all applicable federal and state environmental laws and regulations. Two principal environmental issues to be considered are air emissions and any thermal impacts due to the discharge of cooling water from Smith Unit 3.

As mentioned above, Smith Unit 3 will be fueled by natural gas and therefore the only major air emission issue is that of NO_x. Gulf is pursuing an air emission strategy that will reduce NO_x emissions from one of the existing Smith generating units leading to a net reduction in total NO_x emissions for the entire plant. However, in an abundance of conservatism, the cost estimate used in the self-build and RFP evaluations included the capital and O&M costs of a Selective Catalytic Reduction (SCR) system for Smith Unit 3 if needed to control NO_x emissions beyond levels achieved through this strategy.

Condenser cooling for Smith Unit 3 will be accomplished by a closed-cycle cooling tower system, which will minimize cooling water withdrawals and discharge. Make-up water for the closed-cycle cooling system will be withdrawn from the existing once-through cooling water discharge canal that serves existing Smith Units 1 and 2. Blow-down from the cooling tower will be routed to the existing discharge canal, downstream of the make-up structure. The blow-down, which will be taken from the cold side of the cooling tower, will result in a slight decrease in the temperature of the cooling water of the discharge canal.

The Company believes that Smith Unit 3 will be permitted for construction and operation under the conditions and strategy that Gulf plans to propose in its SCA. From an environmental standpoint, the proposed facility will have net positive impacts.

9.4 CONSEQUENCES OF PROJECT DELAY

Beginning with the decision in April 1998 to pursue the installation of Smith unit 3, Gulf established a project timeline to pinpoint critical dates associated with the successful completion of this unit. Among the major elements in this timeline are the RFP, need determination, fuel supply negotiations, environmental permitting, equipment procurement, and unit construction. Each one of these components has a time range for its successful completion and some elements may overlap others along the timeline. Figure 9-1 represents the timeline for Smith Unit 3.

The most rigorous element in the process leading to the in-service date of Smith Unit 3, is the environmental permitting. It is estimated that the permit process will last approximately 12 to 14 months.

There are a number of elements in the timeline that can and most likely will overlap. For example, the need determination can precede and overlap the permitting, which can overlap equipment procurement. The fact that these elements overlap does not necessarily affect the other processes. However, there are some elements that can affect other elements. For instance, if the need determination were delayed or denied, the environmental permitting would not proceed until the need is resolved. Of course, there can be no construction

FIGURE 9-1

SMITH UNIT 3 - PROJECT TIMELINE

August 21, 1998	Issue Request for Proposals (RFP)
October 16, 1998	Receive proposals and begin evaluations
November 13, 1998	Initial Screening complete
December 15, 1999	Begin Detailed Screening
January 9, 1999	Select Short list for negotiations or Move forward with Self-build option.
January 15, 1999	Begin final selection process for gas supplier
February 1, 1999	Solicit vendor proposals for equipment
March 15, 1999	Lock down preliminary engineering for environmental study work for SCA
March 31, 1999	File application for need determination
June 1, 1999	File environmental Site Certification Application (SCA)
June/July, 1999	Need Determination Hearings
July 21, 1999	Land use hearings for Bay Co. site
August 25, 1999	Final decision on Need Determination
October 31, 1999	Finalize plant design
November 22, 1999	Order remaining equipment
August 1, 2000	Issue bid package for erection of the unit
September 15, 2000	Receive environmental permits
October 1, 2000	Award Erection contract
November 1, 2000	Begin site preparation and begin construction and substation work
January 15, 2002	Complete natural gas supply to plant
February 1, 2002	Begin unit testing and performance checks
May 31, 2002	Project complete

activity for the unit until the environmental permits have been approved and issued, even if the equipment were procured and located on-site.

As mentioned in Section 3.4.4, recent inquiries in the purchased power market have resulted in fewer and far more costly offers for capacity and energy. Gulf has demonstrated through the steps taken to date that its selection of Smith Unit 3 is the most cost-effective available for the Company to meets its customers' load requirements beginning in 2002. Even with some minor delays, Gulf believes that its timeline is reasonable and achievable for a summer 2002 commercial in-service date for Smith Unit 3 in order to prevent having to use this high-priced purchased power. However, if there is a delay of Smith unit 3 that prevents meeting its June, 2002 in-service date, at a minimum Gulf's customers will pay more for their electrical energy than necessary. The Company is also concerned with the possibility that without this unit's timely installation, which helps to support Southern system reserves, there are additional reliability issues that could affect customer service.

LOAD FORECAST AND DSM DETAIL

OVERVIEW

This appendix includes a detailed description of Gulf's load forecasting methodology, a detailed discussion of its conservation programs, and tables presenting Gulf's detailed forecast results.

B.1 METHODOLOGY

Gulf's total forecast employs a number of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts. These efforts are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of its customers and actively promoting wise and efficient uses of energy which satisfy customer needs. The following provides a description of Gulf's forecasting methodology.

B.1.1 CUSTOMER FORECAST

B.1.1.1 RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district personnel. The districts remain abreast of local market and economic conditions within their service territories through direct contact with economic development agencies, developers, builders, lending institutions and other key contacts. The projections prepared by the districts are based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated customer gains. These projections are then analyzed for consistency and the incorporation of major construction projects and business developments is reviewed for completeness and accuracy. The end result is a near-term forecast of residential customers.

For the remaining forecast horizon, the Gulf Economic Model, an econometric model developed by Regional Financial Associates (RFA), is used in the development of residential customer projections. Projections of births, deaths, household size, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The number of households located in the eight counties in which Gulf provides service is computed by applying a household formation trend to the population by age group, and then by summing the number of households in each of five adult age categories. As indicated, there is a relationship between households, or residential customers, and the age structure of the population of the area, as well as household formation trends. The household formation trend is the product of initial year household formation rates in the Gulf service area and projected U.S. trends in household formation.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model. The number of residential customers Gulf expects to serve is calculated by multiplying the total number of households located in Gulf's service area by the percentage of customers in these eight counties for which Gulf currently provides service.

B.1.1.2 COMMERCIAL CUSTOMER FORECAST

As in the residential sector, the immediate short-term forecast (0-2 years) of commercial customers, is prepared by Gulf's district personnel utilizing recent historical customer gains information and their knowledge of the local area economies and upcoming construction projects. A review of the assumptions, techniques and results for each district is undertaken, with special attention given to the incorporation of major commercial development projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers and total real disposable income, reflecting the growth of commercial services to meet the needs of new and existing residents.

B.1.2 ENERGY SALES FORECAST

B.1.2.1 RESIDENTIAL SALES FORECAST

The short-term (0-2 years) residential energy sales forecast is developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather and projected price. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total residential class.

The long-term residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. The REEPS model integrates elements of both econometric and engineering end-use approaches to energy forecasting. Market penetrations and energy consumption rates for major appliance end-uses are treated explicitly. REEPS produces forecasts of appliance installations, operating efficiencies and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses. Each of these decisions is responsive to energy prices and demand-side initiatives, as well as household/dwelling characteristics and geographical variables.

The major behavioral responses in the simulation model have been estimated statistically from an analysis of household survey data. Surveys provide the data source required to identify the responsiveness of household energy decisions to prices and other variables.

The REEPS model forecasts energy decisions for a large number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population. The total service area forecast of residential energy decisions is represented as the sum of the choices of various segments. This approach enhances evaluation of the distributional impacts of various demand-side initiatives.

For each of the major end-uses, REEPS forecasts equipment purchases, efficiency and utilization choices. The model distinguishes among appliance installations in new housing, retrofit installations and purchases of portable units. Within the simulation, the probability of installing a given appliance in a new dwelling depends on the operating and performance characteristics of the competing alternatives, as well as household and dwelling features. The installation probabilities for certain end-use categories are highly interdependent.

The functional form of the appliance installation models is the multinomial logit or its generalization, the nested logit. The parameters of these models quantify the sensitivity of appliance installation choices to costs and other characteristics. The magnitudes of these parameters have been estimated statistically from household survey data.

Appliance operating efficiency and utilization rates are simulated in the REEPS model as interdependent decisions. Efficiency choice is dependent on operating cost at the planned utilization rate, while actual utilization depends on operating cost given the appliance efficiency. Appliance and building standards affect efficiency directly by mandating higher levels than those otherwise expected.

The sensitivity of efficiency and utilization decisions to costs, climate, household and dwelling size, and income has been estimated from historical survey data. Energy prices, income, and household and dwelling size significantly affect space conditioning and residual energy use. Household and dwelling size also influence water heating usage. Climate significantly impacts space heating and air conditioning.

Major appliance base year unit energy consumption (UEC) estimates are based on data developed by Regional Economic Research, Inc. (RER), the current EPRI contractor, from metered appliance data or conditioned energy demand regression analysis. The latter is a technique employed in the absence of metered observations of individual appliance usage, and involves the disaggregation of total household demand for electricity into appliance specific demand functions. All of the weather sensitive UEC estimates were adjusted for Gulf Power's weather conditions.

The energy forecast output from REEPS reflects the continued impacts of Gulf Power's GoodCents Home program and efficiency improvements undertaken by customers as a result of Residential Energy audits, as well as conversions to higher efficiency outdoor lighting. This output is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the residential conservation programs and program features are provided in Section B.1.4.

B.1.2.2 COMMERCIAL SALES FORECAST

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather and projected price. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total commercial class.

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for Gulf's long-term commercial energy sales forecast. The COMMEND model is an extension of the capital-stock approach used in most econometric studies. This approach views the demand for energy as a product of three factors. The first of these factors is the physical stock of energy-using capital, the second factor is base year energy use, and the third is a utilization factor representing utilization of equipment relative to the base year.

Changes in equipment utilization are modeled using short-run econometric fuel price elasticities. Fuel choice is forecast with a life-cycle cost/behavioral microsimulation submodel, and changes in equipment efficiency are determined using engineering and cost information for space heating, cooling and ventilation equipment and econometric elasticity estimates for the other end-uses (lighting, water heating, ventilation, cooking, refrigeration, and others).

Three characteristics of COMMEND distinguish it from traditional modeling approaches. First, the reliance on engineering relationships to determine future heating and cooling efficiency provides a sounder basis for forecasting long-run changes in space heating and cooling energy requirements than a pure econometric approach can supply. Second, the simulation model uses a variety of engineering data on the energy-using characteristics of commercial buildings. Third, COMMEND provides estimates of energy use detailed by end-use, fuel type and building type.

Annual building data from RFA and Gulf's most recent Commercial Market Survey provided much of the input data required for the COMMEND model. The model produces forecasts of energy use for the end-uses mentioned above, within each of the following business categories:

1. Food Stores
2. Offices
3. Retail and Personal Services
4. Public Utilities
5. Automotive Services
6. Restaurants
7. Elementary/Secondary Schools
8. Colleges/Trade Schools
9. Hospitals/Health Services
10. Hotels/Motels
11. Religious Organizations
12. Miscellaneous

The energy forecast output from COMMEND reflects the continued impacts of Gulf Power's Commercial GoodCents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficiency outdoor lighting. The output from COMMEND is adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the Commercial Conservation programs and program features are provided in Section B.1.4.

B.1.2.3 INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-four of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions, replacements or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self-generation installations. The industrial sales forecast is also adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan, approved in April, 1995. Additional information on the conservation programs and program features are provided in Section B.1.4.

B.1.2.4 STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service, for each of the following fixture types:

HIGH PRESSURE SODIUM	MERCURY VAPOR
5,400 Lumen	3,200 Lumen
8,800 Lumen	7,000 Lumen
20,000 Lumen	9,400 Lumen
25,000 Lumen	17,000 Lumen
46,000 Lumen	48,000 Lumen

The projected number of fixtures by fixture type is developed from analyses of recent historical fixture data to discern the patterns of fixture additions and deletions. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium conversions.

B.1.2.5 WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced utilizing multiple regression analyses.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

B.1.2.6 COMPANY USE ENERGY FORECAST

The annual forecast for Company energy usage is based on recent historical values, with appropriate adjustments to reflect short-term increases in energy requirements for anticipated new Company facilities. The monthly spreads are derived using historical relationships between monthly and annual energy usage.

B.1.3 PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

Load shape forecasts have always provided an important input to traditional system planning functions. Forecasts of the pattern of demand have acquired an added importance due to structural changes in the demand for electricity and increased utility involvement in influencing load patterns for the mutual benefit of the utility and its customers.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. Rapid increases in energy prices during the 1970's and early 1980's brought about changes in the efficiency of energy-using equipment. Additionally, sociodemographic and microeconomic developments have changed the composition of electricity consumption, including changes in fuel shares, housing mix, household age and size, construction features, mix of commercial services, and mix of industrial products.

In addition to these naturally occurring structural changes, utilities have become increasingly active in offering customers options which result in modified consumption patterns. An important input to the design of such demand-side programs is an assessment of their likely impact on utility system loads.

HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The HELM model provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for the user-specified end-uses. Inputs are also required to reflect new technologies, rate structures and other demand-side programs. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

The methodology embedded in HELM may be referred to as a "bottom-up" approach. Class and system load shapes are calculated by aggregating the load shapes of component end-uses. The system demand for electricity in hour i is modeled as the sum of demands by each end-use in hour i:

$$L_i = \sum_{R=1}^{N_R} L_{R,i} + \sum_{C=1}^{N_C} L_{C,i} + \sum_{I=1}^{N_I} L_{I,i} + Misc_i$$

Where:

L_i = system demand for electricity in hour i;

N_R = number of residential end-use loads;

N_C = number of commercial end-use loads;

N_I = number of industrial end-use loads;

$L_{R,i}$ = demand for electricity by residential end-use R in hour i;

$L_{C,i}$ = demand for electricity by commercial end-use C in hour i;

$L_{I,i}$ = demand for electricity by industrial end-use I in hour i;

$Misc_i$ = other demands (wholesale, street lighting, losses, company use) in hour i.

B.1.4 CONSERVATION PROGRAMS

Gulf Power Company has been a pacesetter in the energy efficiency market since the development and implementation of the GoodCents Home program in the mid-70's. This program brought customer awareness, understanding and expectations regarding energy efficient construction standards in Northwest Florida to levels unmatched elsewhere. Since that time, the GoodCents Home program has seen many enhancements, and has been widely accepted not only by customers, but by builders, contractors, consumers, and other electric utilities throughout the nation, providing clear evidence that selling efficiency to customers can be done successfully.

Gulf's forecast of energy sales and peak demands reflect the continued impacts of the Company's conservation programs. These forecasts also reflect the anticipated impacts of the new programs submitted in Gulf's Demand Side Management plan filed February 22, 1995 (Docket No. 941172-EI) as approved by the FPSC. The demand and energy reductions associated with these new programs have been updated to reflect a revised implementation schedule for the Advanced Energy Management (AEM) program in the residential sector.

The following provides a listing of Gulf's conservation programs:

Residential Programs:

1. GoodCents New Home
2. Heat Pump Upgrade
3. Resistance Heat to Heat Pump Upgrade
4. Air Conditioning Upgrade
5. Residential Energy Audit
6. Residential Mail-In Audit
7. *In Concert With The Environment®*
8. Geothermal Heat Pump
9. Advanced Energy Management
10. Outdoor Lighting Conversion

Commercial Programs:

1. Commercial GoodCents Bldg.
2. Commercial Energy Audit
3. Technical Assistance Audit
4. Commercial Mail-In Audit
5. Real Time Pricing Pilot
6. Outdoor Lighting Conversion

Street Lighting Conversion

The remainder of this section provides detailed descriptions of the conservation programs and program features in effect and estimates of reductions in peak demand and net energy for load reflected in the forecast as a result of these programs.

B.1.4.1 RESIDENTIAL CONSERVATION

In the residential sector, Gulf's GoodCents New Home program is designed to make cost effective increases in the efficiencies of the new home construction market. This is being achieved by placing greater requirements on cooling and water heating equipment efficiencies, proper HVAC sizing, increased insulation levels in walls, ceilings, and floors, and tighter restrictions on glass area and infiltration reduction practices. In addition, Gulf monitors proper quality installation of all the above energy features.

Gulf has several programs designed to make cost effective increases in efficiencies in the existing home market by requiring increased efficiency requirements on heating and cooling systems and improvements in air distribution system leakage. The A/C Upgrade program is designed to increase the efficiency of older central air conditioning units. The Heat Pump Upgrade program is designed to increase the efficiency of older heat pump units. The Resistance Heat to Heat Pump Upgrade program is designed to replace older heating and air conditioning systems with new high efficiency heat pump systems.

Further conservation benefits are achieved in the existing home market with Gulf's Residential Energy Audit program which is designed to provide existing residential customers with cost-effective energy conserving recommendations and options that increase comfort and reduce energy operating costs. The goal of this program is to upgrade the customer's home to the GoodCents Improved Home standard by providing specific whole house recommendations. As an extension to this program, Gulf offers a Residential mail-in audit option to enhance customer participation and increase the overall program effectiveness.

In Concert With The Environment® is an environmental and energy awareness program that is being implemented in the 8th and 9th grade science classes in Gulf Power Company's service area. The program shows students how everyday energy use impacts the environment and how using energy wisely increases environmental quality. *In Concert With The Environment®* is brought to students who are already making decisions which impact the country's energy supply and the environment. Wise energy use today can best be achieved by linking environmental benefits to wise energy-use activities and by educating both present and future consumers on how to live "in concert with the environment". The program encourages participation by all household members through a take-home Energy Survey, Energy

Survey Results, and student educational handbook and is considered an extension of Gulf's Residential Audit Program.

The Residential Geothermal Heat Pump Program reduces the demand and energy requirements of new and existing residential customers through the promotion and installation of advanced and emerging geothermal systems. Geothermal heat pumps also provide significant benefits to participating customers in the form of reduced operating costs and increased comfort levels, and are superior to other available heating and cooling technologies with respect to source efficiency and environmental impacts. Gulf Power's Geothermal Heat Pump program is designed to overcome existing market barriers, specifically, lack of consumer awareness, knowledge and acceptance of this technology. The program additionally promotes efficiency levels well above current market conditions.

The Advanced Energy Management (AEM) Program provides Gulf Power's customers with a means of conveniently and automatically controlling and monitoring their energy purchases in response to prices that vary during the day and by season in relation to the Company's cost of producing or purchasing energy. The AEM System allows the customer to control more precisely the amount of electricity purchased for heating, cooling, water heating, and other selected loads; to purchase electric energy on a variable spot price rate; and to monitor at any time, and as often as desired, the use of electricity and its cost in dollars, both for the billing period to date and on a forecast basis to the end of the period. The various components of the AEM System installed in the customer's home, as well as the components installed at Gulf Power, provide constant communication between customer and utility. The combination of the AEM System and Gulf's innovative variable rate concept will provide consumers with the opportunity to modify their usage of electricity in order to purchase energy at prices that are somewhat lower to significantly lower than standard rates a majority of the time. Further, the communication capabilities of the AEM System allow Gulf to send a critical price signal to the customer's premises during extreme peak load conditions. The signal results in a reduction attributable to predetermined thermostat and relay settings chosen by the individual participating customer. The customer's pre-programmed instructions regarding their desired comfort levels adjust electricity use for heating, cooling, water heating and other appliances automatically. Therefore, the customer's control of their electric bill is accomplished by allowing them to choose different comfort levels at different price levels in accordance with their individual lifestyles.

Additional conservation benefits are realized in the residential sector through Gulf's Outdoor Lighting program by conversion of existing, less efficient mercury vapor outdoor lighting to higher efficient high pressure sodium lighting.

B.1.4.2 COMMERCIAL/INDUSTRIAL CONSERVATION

In the commercial sector, Gulf's GoodCents Building program is designed to make cost effective increases in efficiencies in both new and existing commercial buildings with requirements resulting in energy conserving investments that address the thermal efficiency of the building envelope, interior lighting, heating and cooling equipment efficiency, and solar glass area. Additional recommendations are made, where applicable, on energy conserving options that include thermal storage, heat recovery systems, water heating heat pumps, solar applications, energy management systems, and high efficiency outdoor lighting.

The Commercial Energy Audit (EA) and Technical Assistance Audit (TAA) programs are designed to provide commercial customers with assistance in identifying cost effective energy conservation opportunities and introduce them to various technologies which will lead to improvements in the energy efficiency level of their business. The program is designed with enough flexibility to allow for a simple walk through analysis (EA) or a detailed economic evaluation of potential energy improvements through a more in-depth audit process (TAA) which includes equipment energy usage monitoring, computer energy modeling, life cycle equipment cost analysis, and feasibility studies. As an extension to this program, Gulf offers a Commercial mail-in audit option to enhance customer participation and increase the overall program effectiveness.

Gulf's Real Time Pricing pilot program is designed to take advantage of customer price response to achieve peak demand reductions. Initial participation was limited to a maximum of 12 customers with actual demand of 2,000 KW or higher for this pilot program. In 1997 Gulf received approval to increase the participation level to a maximum of 24 customers. Customer participation is voluntary. Due to the nature of the pricing arrangement included in this program, there are some practical limitations to a customer's ability to participate. These limitations include the ability to purchase energy under a pricing plan which includes price variation and unknown future prices; the transaction costs associated with receiving, evaluating, and acting on prices received on a daily basis; customer risk management policy; and other technical/economic factors. The RTP Pilot program has been very successful and is expected to play a major role in affording Gulf Power the opportunity to meet its conservation objectives. Information gained through this program is being used to design a permanent RTP program.

B.1.4.3 STREET LIGHTING CONVERSION

Gulf's Street Lighting conversion program is designed to achieve additional conservation benefits by conversion of existing less efficient mercury vapor outdoor, street and roadway lighting to higher efficient high pressure sodium lighting.

B.1.4.4 CONSERVATION RESULTS SUMMARY

The following Tables B-1 through B-11 provide detailed estimates of the reductions in peak demand and net energy for load resulting from Gulf's conservation programs. These reductions are verified through on-going monitoring of Gulf's major conservation programs and reflect estimates of conservation undertaken by customers as a result of Gulf Power Company's involvement. Conservation which has taken place without Gulf's involvement has contributed to further unquantifiable reductions in demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in Gulf's energy forecasts and in the demand model projections.

Tables B-1 through B-4 reflect the total impacts of Gulf's new and existing conservation programs. The impacts of the existing programs that have been in place for several years are shown separately in Tables B-5 through B-8 and the anticipated impacts of Gulf's newer programs, submitted in Gulf's Demand Side Management Plan filed in 1995, are provided in tables B-9 through B-11.

Table B-1, below, provides the total savings in peak demand and net energy for load achieved by Gulf through its conservation programs. In 1997, Gulf's DSM programs successfully reduced summer peak demand by 244 megawatts

(MW), winter peak demand by 269 MW, and net energy for load by 523 million kilowatt-hours (KWH).

As shown in this table, by the in-service date of Smith Unit 3 in 2002, Gulf expects to achieve a total cumulative annual reduction of 365 MW in summer peak demand, 423 MW in winter peak demand, and an annual energy savings of over 650 million KWH from what it would have been absent such programs. This includes 121 MW of incremental summer peak reductions over the period from 1997 through 2002. These reductions are expected to grow to a total savings of 489 MW of summer peak demand, 590 MW of winter peak demand and an annual energy savings of over 770 million KWH by the year 2008.

TABLE B-1

HISTORICAL
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	243,928	268,522	522,804,539

1999 FORECAST
TOTAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	10,865	13,620	22,225,417
1999	30,489	36,692	30,353,374
2000	29,077	37,123	30,034,257
2001	25,943	34,501	22,988,653
2002	24,236	32,955	21,829,790
2003	23,875	32,408	21,756,342
2004	24,095	32,793	21,948,046
2005	20,322	27,386	19,861,207
2006	20,353	27,393	19,872,752
2007	17,717	23,522	18,348,712
2008	17,729	23,526	18,324,246

1999 FORECAST
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	254,793	282,143	545,029,957
1999	285,282	318,835	575,383,331
2000	314,359	355,958	605,417,587
2001	340,301	390,460	628,406,241
2002	364,536	423,414	650,236,032
2003	388,410	455,821	671,992,375
2004	412,506	488,615	693,940,422
2005	432,828	515,999	713,801,629
2006	453,180	543,392	733,674,381
2007	470,897	566,914	752,023,094
2008	488,625	590,440	770,347,340

TABLE B-2

HISTORICAL
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	106,849	163,319	271,253,667

1999 FORECAST
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	10,922	11,511	11,755,771
1999	25,804	34,591	20,028,692
2000	25,592	35,022	19,718,790
2001	24,159	33,387	18,698,570
2002	22,585	31,842	17,553,458
2003	22,162	31,295	17,469,787
2004	22,369	31,680	17,700,793
2005	18,626	26,273	15,667,821
2006	18,633	26,280	15,682,688
2007	15,993	22,409	14,159,565
2008	15,995	22,413	14,165,936

1999 FORECAST
TOTAL RESIDENTIAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	117,771	174,831	283,009,439
1999	143,575	209,422	303,038,131
2000	169,167	244,444	322,756,920
2001	193,326	277,832	341,455,491
2002	215,910	309,674	359,008,948
2003	238,072	340,968	376,478,736
2004	260,442	372,649	394,179,529
2005	279,068	398,921	409,847,350
2006	297,701	425,201	425,530,038
2007	313,694	447,610	439,689,603
2008	329,689	470,023	453,855,539

TABLE B-3

HISTORICAL
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	137,080	105,203	241,038,261

1999 FORECAST
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	(58)	2,109	10,242,169
1999	4,685	2,101	10,115,326
2000	3,485	2,101	10,115,326
2001	1,784	1,114	4,092,695
2002	1,651	1,113	4,092,695
2003	1,713	1,113	4,092,695
2004	1,726	1,113	4,092,695
2005	1,696	1,113	4,092,695
2006	1,720	1,113	4,092,695
2007	1,724	1,113	4,092,695
2008	1,734	1,113	4,092,695

1999 FORECAST
TOTAL COMMERCIAL/INDUSTRIAL DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	137,022	107,312	251,280,430
1999	141,707	109,413	261,395,756
2000	145,192	111,514	271,511,082
2001	146,975	112,628	275,603,777
2002	148,626	113,740	279,696,473
2003	150,338	114,853	283,789,168
2004	152,064	115,966	287,881,864
2005	153,760	117,078	291,974,559
2006	155,479	118,191	296,067,254
2007	157,203	119,304	300,159,950
2008	158,936	120,417	304,252,645

TABLE B-4

HISTORICAL
TOTAL OTHER DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	0	0	10,512,611

1999 FORECAST
TOTAL OTHER DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	227,477
1999	0	0	209,356
2000	0	0	200,141
2001	0	0	197,388
2002	0	0	183,637
2003	0	0	193,860
2004	0	0	154,558
2005	0	0	100,691
2006	0	0	97,369
2007	0	0	96,452
2008	0	0	65,615

1999 FORECAST
TOTAL OTHER DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	10,740,088
1999	0	0	10,949,444
2000	0	0	11,149,585
2001	0	0	11,346,973
2002	0	0	11,530,611
2003	0	0	11,724,471
2004	0	0	11,879,029
2005	0	0	11,979,720
2006	0	0	12,077,089
2007	0	0	12,173,541
2008	0	0	12,239,156

TABLE B-5

HISTORICAL
TOTAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	213,772	262,789	513,626,118

1999 FORECAST
TOTAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	9,169	6,199	14,708,361
1999	8,542	6,693	13,636,079
2000	8,034	6,646	12,920,322
2001	6,710	6,539	9,374,828
2002	6,228	6,523	8,704,575
2003	6,237	6,533	8,733,912
2004	6,211	6,507	8,642,576
2005	6,211	6,507	8,587,647
2006	6,218	6,514	8,599,192
2007	6,228	6,524	8,618,452
2008	6,231	6,527	8,593,986

1999 FORECAST
TOTAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	222,941	268,989	528,334,480
1999	231,483	275,682	541,970,559
2000	239,517	282,328	554,890,880
2001	246,226	288,868	564,265,709
2002	252,453	295,390	572,970,285
2003	258,689	301,922	581,704,198
2004	264,901	308,430	590,346,775
2005	271,112	314,935	598,934,422
2006	277,329	321,449	607,533,614
2007	283,557	327,973	616,152,067
2008	289,787	334,500	624,746,053

TABLE B-6

HISTORICAL
RESIDENTIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	105,333	160,983	269,326,134

1999 FORECAST
RESIDENTIAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	7,273	5,968	8,941,405
1999	6,690	6,470	8,014,087
2000	6,182	6,423	7,307,545
2001	5,842	6,316	6,775,935
2002	5,360	6,300	6,119,433
2003	5,369	6,310	6,138,547
2004	5,343	6,284	6,086,513
2005	5,343	6,284	6,085,451
2006	5,350	6,291	6,100,318
2007	5,360	6,301	6,120,495
2008	5,363	6,304	6,126,866

1999 FORECAST
RESIDENTIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	112,606	166,952	278,267,540
1999	119,296	173,422	286,281,627
2000	125,478	179,845	293,589,171
2001	131,320	186,162	300,365,107
2002	136,679	192,462	306,484,539
2003	142,048	198,771	312,623,087
2004	147,392	205,056	318,709,600
2005	152,735	211,339	324,795,051
2006	158,085	217,630	330,895,369
2007	163,445	223,931	337,015,864
2008	168,808	230,235	343,142,730

TABLE B-7

HISTORICAL
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS
AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	108,439	101,806	233,787,373

1999 FORECAST
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	1,896	231	5,539,479
1999	1,852	223	5,412,636
2000	1,852	223	5,412,636
2001	868	223	2,401,505
2002	868	223	2,401,505
2003	868	223	2,401,505
2004	868	223	2,401,505
2005	868	223	2,401,505
2006	868	223	2,401,505
2007	868	223	2,401,505
2008	868	223	2,401,505

1999 FORECAST
COMMERCIAL/INDUSTRIAL EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	110,335	102,037	239,326,852
1999	112,187	102,260	244,739,488
2000	114,039	102,483	250,152,124
2001	114,906	102,706	252,553,629
2002	115,774	102,928	254,955,135
2003	116,641	103,151	257,356,640
2004	117,509	103,374	259,758,146
2005	118,377	103,596	262,159,651
2006	119,244	103,819	264,561,156
2007	120,112	104,042	266,962,662
2008	120,979	104,265	269,364,167

TABLE B-8

HISTORICAL
OTHER EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	0	0	10,512,611

1999 FORECAST
OTHER EXISTING DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	227,477
1999	0	0	209,356
2000	0	0	200,141
2001	0	0	197,388
2002	0	0	183,637
2003	0	0	193,860
2004	0	0	154,558
2005	0	0	100,691
2006	0	0	97,369
2007	0	0	96,452
2008	0	0	65,615

1999 FORECAST
OTHER EXISTING DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	0	0	10,740,088
1999	0	0	10,949,444
2000	0	0	11,149,585
2001	0	0	11,346,973
2002	0	0	11,530,611
2003	0	0	11,724,471
2004	0	0	11,879,029
2005	0	0	11,979,720
2006	0	0	12,077,089
2007	0	0	12,173,541
2008	0	0	12,239,156

TABLE B-9

HISTORICAL
TOTAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	30,156	5,733	9,178,421

1999 FORECAST
TOTAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	1,696	7,421	7,517,056
1999	21,947	29,999	16,717,295
2000	21,043	30,477	17,113,935
2001	19,233	27,962	13,613,825
2002	18,008	26,432	13,125,215
2003	17,638	25,875	13,022,430
2004	17,884	26,286	13,305,470
2005	14,111	20,879	11,273,560
2006	14,135	20,879	11,273,560
2007	11,489	16,998	9,730,260
2008	11,498	16,999	9,730,260

1999 FORECAST
TOTAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	31,852	13,154	16,695,477
1999	53,799	43,153	33,412,772
2000	74,842	73,630	50,526,707
2001	94,075	101,592	64,140,532
2002	112,083	128,024	77,265,747
2003	129,721	153,899	90,288,177
2004	147,605	180,185	103,593,647
2005	161,716	201,064	114,867,207
2006	175,851	221,943	126,140,767
2007	187,340	238,941	135,871,027
2008	198,838	255,940	145,601,287

TABLE B-10

HISTORICAL
RESIDENTIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	1,516	2,336	1,927,533

1999 FORECAST
RESIDENTIAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	3,649	5,543	2,814,366
1999	19,114	28,121	12,014,605
2000	19,410	28,599	12,411,245
2001	18,317	27,071	11,922,635
2002	17,225	25,542	11,434,025
2003	16,793	24,985	11,331,240
2004	17,026	25,396	11,614,280
2005	13,283	19,989	9,582,370
2006	13,283	19,989	9,582,370
2007	10,633	16,108	8,039,070
2008	10,632	16,109	8,039,070

1999 FORECAST
RESIDENTIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	5,165	7,879	4,741,899
1999	24,279	36,000	16,756,504
2000	43,689	64,599	29,167,749
2001	62,006	91,670	41,090,384
2002	79,231	117,212	52,524,409
2003	96,024	142,197	63,855,649
2004	113,050	167,593	75,469,929
2005	126,333	187,582	85,052,299
2006	139,616	207,571	94,634,669
2007	150,249	223,679	102,673,739
2008	160,881	239,788	110,712,809

TABLE B-11

HISTORICAL
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1997	28,641	3,397	7,250,888

1999 FORECAST
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	(1,954)	1,878	4,702,690
1999	2,833	1,878	4,702,690
2000	1,633	1,878	4,702,690
2001	916	891	1,691,190
2002	783	890	1,691,190
2003	845	890	1,691,190
2004	858	890	1,691,190
2005	828	890	1,691,190
2006	852	890	1,691,190
2007	856	890	1,691,190
2008	866	890	1,691,190

1999 FORECAST
COMMERCIAL/INDUSTRIAL NEW DSM PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1998	26,687	5,275	11,953,578
1999	29,520	7,153	16,656,268
2000	31,153	9,031	21,358,958
2001	32,069	9,922	23,050,148
2002	32,852	10,812	24,741,338
2003	33,697	11,702	26,432,528
2004	34,555	12,592	28,123,718
2005	35,383	13,482	29,814,908
2006	36,235	14,372	31,506,098
2007	37,091	15,262	33,197,288
2008	37,957	16,152	34,888,478

B.1.5 RENEWABLE ENERGY

Gulf initiated implementation of a "Green Pricing" pilot program, *Solar for Schools,* to obtain funding for the installation of solar technologies in participating school facilities combined with energy conservation education of students. Initial solicitation began in September, 1996 and has resulted in participation of over 333 customers contributing $18,171 through December, 1998. A prototype installation at a local middle school has been completed and the experience gained at this site will be used to design future *Solar for Schools* installations.

District heating and cooling plants are an older fundamental application of large central station heating and cooling equipment for service to multiple premises in close proximity. These systems are typically located in college or school settings as well as some military bases and industrial plants.

Within Gulf's service area there exist a number of these systems which were appropriate or seemed appropriate at the time of their installation. Current day considerations for energy pricing, operating and maintenance expenses have resulted in many of these systems becoming uneconomical and decommissioned. Future installations of district heating and cooling plants of any consequence hinge primarily upon the opportunity for optimum application of this technology. The very dispersed construction of low rise buildings which are characteristic of the building demographics in Gulf Power's service area yield no significant opportunities for district heating and cooling that are economically viable on the planning horizon.

B.1.6 DATA SOURCES

The following data sources were utilized in the development of Gulf's projections:

1. Gulf Power Company historical billing data.
2. Gulf Power Company historical survey data.
3. Gulf Power Company historical load research data.
4. Historical weather data from NOAA and Weather Service Corp.
5. Historical data from the Florida Statistical Abstracts produced by the Bureau of Economic and Business Research, University of Florida.
6. Economic outlook including population projections, households, and other economic indicators from Regional Financial Associates. Data sources cited by RFA include the Bureau of Labor Statistics, Bureau of Economic Analysis, and the U.S. Bureau of Census.

B.1.7 DETAILED FORECAST RESULTS

The following Tables B-12 through B-17 provide the detailed forecast results.

GULF POWER COMPANY

TABLE B-12
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population *	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
1989	662,784	2.65	3,294	250,038	13,173	2,169	33,500	64,761
1990	677,866	2.66	3,361	255,129	13,173	2,218	33,957	65,305
1991	689,901	2.66	3,455	259,395	13,320	2,273	34,372	66,120
1992	703,860	2.65	3,597	265,374	13,553	2,369	36,009	65,796
1993	726,046	2.67	3,713	271,594	13,671	2,433	38,477	63,242
1994	747,459	2.69	3,752	278,215	13,486	2,549	39,989	63,739
1995	760,195	2.68	4,014	283,717	14,148	2,708	41,007	66,043
1996	769,246	2.67	4,160	287,752	14,457	2,809	42,381	66,271
1997	791,009	2.67	4,119	296,497	13,894	2,898	43,955	65,928
1998	810,649	2.66	4,438	304,413	14,577	3,112	45,510	68,379
1999	830,557	2.66	4,558	312,479	14,587	3,147	46,614	67,512
2000	849,054	2.65	4,692	320,074	14,658	3,273	48,150	67,980
2001	863,541	2.65	4,772	326,118	14,632	3,346	49,347	67,812
2002	877,537	2.64	4,864	331,931	14,653	3,419	50,294	67,977
2003	891,566	2.64	4,958	337,784	14,677	3,496	51,208	68,275
2004	905,608	2.64	5,057	343,661	14,715	3,572	52,130	68,528
2005	919,427	2.63	5,170	349,473	14,793	3,650	53,059	68,793
2006	933,241	2.63	5,272	355,302	14,839	3,725	53,978	69,012
2007	947,114	2.62	5,382	361,172	14,901	3,805	54,904	69,295
2008	960,867	2.62	5,503	367,016	14,995	3,881	55,836	69,507
CAAG								
89-98	2.3%	0.1%	3.4%	2.2%	1.1%	4.1%	3.5%	0.6%
98-03	1.9%	-0.2%	2.2%	2.1%	0.1%	2.4%	2.4%	0.0%
98-08	1.7%	-0.2%	2.2%	1.9%	0.3%	2.2%	2.1%	0.2%

* Historical and projected figures include portions of Escambia, Santa Rosa, Okaloosa, Bay, Walton, Washington, Holmes, and Jackson counties served by Gulf Power Company.

GULF POWER COMPANY

TABLE B-13
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
1989	2,095	229	9,147,029	0	16	0	7,574
1990	2,178	247	8,817,297	0	17	0	7,774
1991	2,117	260	8,143,878	0	16	0	7,861
1992	2,179	262	8,318,456	0	16	0	8,161
1993	2,030	268	7,574,388	0	16	0	8,192
1994	1,847	280	6,596,837	0	16	0	8,164
1995	1,795	276	6,502,731	0	16	0	8,534
1996	1,808	281	6,434,470	0	17	0	8,794
1997	1,903	277	6,870,216	0	17	0	8,938
1998	1,834	263	6,971,767	0	18	0	9,401
1999	1,938	285	6,801,516	0	18	0	9,662
2000	2,029	294	6,902,869	0	18	0	10,013
2001	2,076	297	6,989,061	0	19	0	10,213
2002	2,095	300	6,982,317	0	19	0	10,396
2003	2,093	303	6,907,883	0	19	0	10,566
2004	2,091	306	6,833,259	0	19	0	10,739
2005	2,087	309	6,753,665	0	19	0	10,926
2006	2,091	312	6,703,402	0	20	0	11,108
2007	2,094	315	6,648,572	0	20	0	11,300
2008	2,071	318	6,511,389	0	20	0	11,475
CAAG							
89-98	-1.5%	1.6%	-3.0%	0.0%	1.5%	0.0%	2.4%
98-03	2.7%	2.9%	-0.2%	0.0%	1.0%	0.0%	2.4%
98-08	1.2%	1.9%	-0.7%	0.0%	0.9%	0.0%	2.0%

GULF POWER COMPANY

TABLE B-14
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net Energy for Load GWH	Other Customers (Average No.)	Total No. of Customers
1989	276	528	8,378	63	283,830
1990	294	545	8,612	68	289,400
1991	296	547	8,704	68	294,095
1992	299	389	8,849	74	301,719
1993	317	565	9,074	79	310,419
1994	316	487	8,967	93	318,578
1995	336	582	9,452	119	325,119
1996	347	521	9,662	157	330,571
1997	342	607	9,887	215	340,944
1998	356	645	10,402	262	350,447
1999	350	645	10,657	322	359,699
2000	361	668	11,041	352	368,870
2001	369	682	11,263	371	376,132
2002	378	694	11,468	382	382,906
2003	386	706	11,658	391	389,685
2004	393	718	11,850	400	396,496
2005	399	730	12,056	409	403,249
2006	406	743	12,257	418	410,009
2007	412	756	12,468	427	416,817
2008	418	768	12,661	436	423,605
CAAG					
89-98	2.9%	2.2%	2.4%	17.1%	2.4%
98-03	1.6%	1.8%	2.3%	8.3%	2.1%
98-08	1.6%	1.8%	2.0%	5.2%	1.9%

Note: Sales for Resale and Net Energy for Load include contracted energy allocated to certain customers by Southeastern Power Administration (SEPA).

GULF POWER COMPANY

TABLE B-15

History and Forecast of Summer Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Conservation	(10) Net Firm Demand
1989	1,858	60	1,799	0	0	79	0	81	1,698
1990	1,954	69	1,885	0	0	81	0	87	1,785
1991	1,923	64	1,860	0	0	83	0	92	1,748
1992	2,018	71	1,947	0	0	86	0	97	1,836
1993	2,096	76	2,021	0	0	88	0	102	1,906
1994	1,999	72	1,927	0	0	92	0	104	1,803
1995	2,265	82	2,183	0	0	96	0	122	2,048
1996	2,196	79	2,118	0	0	100	0	127	1,969
1997	2,284	75	2,208	0	0	107	0	137	2,040
1998	2,425	82	2,342	16	0	118	0	137	2,154
1999	2,460	76	2,385	29	0	144	0	142	2,175
2000	2,521	77	2,445	29	0	169	0	145	2,207
2001	2,574	78	2,496	29	0	193	0	147	2,234
2002	2,630	80	2,549	29	0	216	0	149	2,265
2003	2,668	81	2,587	29	0	238	0	150	2,280
2004	2,722	83	2,639	29	0	260	0	152	2,309
2005	2,780	84	2,696	29	0	279	0	154	2,347
2006	2,836	85	2,751	29	0	298	0	155	2,383
2007	2,896	87	2,809	29	0	314	0	157	2,425
2008	2,955	88	2,867	25	0	330	0	159	2,466
CAAG									
89-98	3.0%	3.6%	3.0%	100.0%	0.0%	4.6%	0.0%	6.0%	2.7%
98-03	1.9%	-0.2%	2.0%	12.7%	0.0%	15.1%	0.0%	1.9%	1.1%
98-08	2.0%	0.7%	2.0%	4.5%	0.0%	10.8%	0.0%	1.5%	1.4%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-16
History and Forecast of Winter Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm/Ind Load Management	(9) Comm/Ind Conservation	(10) Net Firm Demand
88-89	1,762	56	1,706	0	0	113	0	95	1,554
89-90	2,038	57	1,980	0	0	120	0	97	1,821
90-91	1,649	50	1,600	0	0	126	0	98	1,425
91-92	1,772	60	1,712	0	0	132	0	99	1,541
92-93	1,820	61	1,759	0	0	140	0	100	1,579
93-94	2,055	72	1,983	0	0	145	0	101	1,809
94-95	1,993	71	1,922	0	0	150	0	102	1,740
95-96	2,404	82	2,322	0	0	157	0	103	2,144
96-97	2,208	80	2,127	0	0	163	0	105	1,939
97-98	1,974	61	1,913	0	0	175	0	107	1,692
98-99	2,390	76	2,314	28	0	209	0	109	2,071
99-00	2,461	77	2,384	28	0	244	0	112	2,105
00-01	2,511	78	2,433	28	0	278	0	113	2,121
01-02	2,558	80	2,478	28	0	310	0	114	2,135
02-03	2,595	81	2,513	28	0	341	0	115	2,139
03-04	2,643	83	2,560	28	0	373	0	116	2,154
04-05	2,694	84	2,610	28	0	399	0	117	2,178
05-06	2,743	85	2,658	28	0	425	0	118	2,200
06-07	2,796	87	2,709	28	0	448	0	119	2,229
07-08	2,848	88	2,760	24	0	470	0	120	2,258
CAAG									
89-98	1.3%	1.0%	1.3%	100.0%	0.0%	5.0%	0.0%	1.3%	0.9%
98-03	5.6%	5.8%	5.6%	0.0%	0.0%	14.3%	0.0%	1.4%	4.8%
98-08	3.7%	3.7%	3.7%	-1.7%	0.0%	10.4%	0.0%	1.2%	2.9%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

NOTE 2: The forecasted interruptible amounts shown in col (5) are included here for information purposes only. The projected demands shown in column (2), column (4) and column (10) do not reflect the impacts of interruptible. Gulf treats interruptible as a supply side resource.

GULF POWER COMPANY

TABLE B-17
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1989	8,763	221	165	7,574	276	528	8,378	56.3%
1990	9,019	227	180	7,774	294	545	8,612	55.1%
1991	9,128	233	191	7,861	296	547	8,704	56.8%
1992	9,291	239	202	8,161	299	389	8,849	54.9%
1993	9,537	247	216	8,192	317	565	9,074	54.3%
1994	9,443	254	222	8,164	316	487	8,967	56.8%
1995	9,942	263	227	8,534	336	582	9,452	52.7%
1996	10,167	273	232	8,794	347	521	9,662	55.9%
1997	10,410	282	241	8,938	342	607	9,887	55.3%
1998	10,947	294	251	9,401	356	645	10,402	55.1%
1999	11,232	314	261	9,662	350	645	10,657	55.9%
2000	11,647	334	272	10,013	361	668	11,041	57.1%
2001	11,891	353	276	10,213	369	682	11,263	57.6%
2002	12,119	371	280	10,396	378	694	11,468	57.8%
2003	12,330	388	284	10,566	386	706	11,658	58.4%
2004	12,544	406	288	10,739	393	718	11,850	58.6%
2005	12,769	422	292	10,926	399	730	12,056	58.6%
2006	12,991	438	296	11,108	406	743	12,257	58.7%
2007	13,220	452	300	11,300	412	756	12,468	58.7%
2008	13,431	466	304	11,475	418	768	12,661	58.6%
CAAG								
89-98	2.5%	3.2%	4.8%	2.4%	2.9%	2.2%	2.4%	-0.2%
98-03	2.4%	5.7%	2.5%	2.4%	1.6%	1.8%	2.3%	1.1%
98-08	2.1%	4.7%	1.9%	2.0%	1.6%	1.8%	2.0%	0.6%

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA).

TECHNOLOGY SCREENING PROCESS

Preparation of the Southern electric system (SES) Integrated Resource Plan (IRP) requires the identification of a manageable number of generating unit alternatives to be evaluated in the generation mix analysis. For each candidate technology, inputs must be developed for the option's conceptual capital cost, design configuration, reliability data, and operation and maintenance costs. It is important to note that the information developed is not site-specific and is intended to be representative of average cost and performance data for a "generic" site.

The technology screening begins with a preliminary review of both mature and emerging technologies to identify those that are potentially suitable for installation on the SES during the planning horizon. Three technologies which had been evaluated in prior years were deleted from the list developed for the 1998 IRP. These were the intermediate load cycling coal fired, intermediate load compressed air energy storage (CAES), and peaking compressed air energy storage technologies. However, three new technologies were added, including inlet cooled combined cycle using ATS, air blown integrated gasification combined cycle (IGCC), and the topping pressurized circulating fluidized bed (PCFB). The following technologies were included for consideration in the screening process:

1. Base Load Pulverized Coal

1. Base Load Integrated Gasification Combined Cycle (IGCC)

3. Base Load Pressurized Fluidized-Bed Combustion (PCFB)

4. Base Load Combined Cycle, 'F' - Technology

5. Base Load Combined Cycle, 'G' - Technology

6. Intermediate Load Low Heat Rate 'G' Type CT

7. Peaking Combustion Turbine (3-Unit and 6-Unit Sites)

8. Pumped Storage Hydro (PSH)

9. Inlet Cooled Combined Cycle With ATS Technology

In addition to a general plant description and major performance assumptions, the following information was developed for each technology under consideration:

- Heat Rate and Output
- Capital Cost
- Fixed and Variable O&M Cost
- Capital Expenditures for Maintenance
- Emissions Estimates
- Plant Life
- Maintenance Time
- Equivalent Forced Outage Rate (EFOR)
- Performance Degradation
- Project Schedule
- Cash flow Table

Certain information regarding project schedule, performance degradation, emissions, EFOR and cash flow was not available for all of the technologies.

There are four categories of cost estimates. These include very conceptual, conceptual, budgetary and definitive. Below is a definition of each cost category:

Very Conceptual - The cost is as conceptual as the technology. As these technologies are developed, the costs will become more refined.

Conceptual - The technology is being developed. However, the first units have not been produced. Estimates are supplied by researchers, vendors, and governmental agencies. As these technologies are developed, the costs will become more refined.

Budgetary - This is a mature technology. There are actual costs of existing plants. The vendors offer market driven pricing and/or Southern Company Services has developed cost models.

Definitive - None of the cost information used in the technology screening process is definitive. Definitive estimates are within 5% of the final cost and are based on specific site and owner requirements. Definitive estimates are based on definitive scopes.

The cost models developed for mature technologies in prior years are reviewed for consistency and updated with information from ongoing projects. All cost projection dollars are based on values as of January 1, 1998. An escalation factor of 2% was applied for inflation for all technologies, except that the base load pulverized coal was not escalated and IGCC was escalated at 1%. The combined cycle and simple cycle cost models were carefully reviewed and updated given the probability that these technologies would be chosen for near term capacity additions. Revised budgetary estimates were obtained from the vendors, and the lowest cost was incorporated in the cost model. The contingency was held to 2.5% for major equipment and 10% for the balance of plant to reflect the actual confidence in the estimate. In case of coal technologies, contingency was held to 5% for major equipment and 10% for the balance of plant.

All cost models were separated into Engineering, Procurement and Construction (EPC), site related and owner's costs. EPC cost is equivalent in scope to what a turnkey contractor would quote for the project. EPC cost includes the design engineering, procurement of materials and equipment, and the contractor's scope. Site cost includes land, site preparation, water treatment system, switchyard and site related engineering. Owner's cost includes project and construction management, startup, and overheads.

Project schedules were developed for the new additions. Schedules for the remaining technologies were reviewed, but were not changed from the prior year. It should be noted that actual project schedules would vary based on the unique requirements of the project. Construction spending curves were expressed in percentages instead of dollar amounts to allow the flexibility to use either the EPC cost or total plant cost. Non-recoverable turbine degradation in output and heat rate was included for each technology in the technology documentation.

The nine listed technologies were reviewed and screened for reasonableness to select the final candidate technologies to be included in the generation mix process. Some technologies are eliminated when they are evaluated on an economic bus-bar analysis. The bus-bar evaluation estimates the relative cost per kilowatt-hour for the various alternatives at varying capacity factors. After this screening was completed, the following three technologies were retained as candidates for the generation mix analysis: (1) nominal 670 MW pulverized coal unit, (2) nominal 500 MW F-class combined cycle unit, and (3) simple cycle combustion turbine unit. More detailed information on these three candidate technologies is provided below.

PULVERIZED COAL
NOMINAL 670 MW

I. GENERAL DESCRIPTION OF THE PLANT

The major systems in the unit are based on a coal fired drum boiler operating at 2,400 psig, 1,000 deg. F. main steam temperature with a reheat temperature of 1,000 deg. F., driving a 3,600 rpm turbine-generator. Steam is condensed using circulating water that is cooled by hyperbolic natural draft cooling towers. The condensate/feedwater system utilizes four LP, three HP and one deaerating feedwater heater. A wet limestone scrubber with forced oxidation, designed for 95 % removal, is utilized for S02 reduction. Advanced low NOx burners as well as a selective catalytic reduction system, designed for 80% removal, are utilized for NOx control. A dry ash handling system is utilized for fly ash. Bottom ash is handled using hydrobins, a settling tank, and a clarifier. Both fly ash and bottom ash are either trucked away to landfill or sold.

State of Technology

This is a mature technology and currently available.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/kWh	Net Unit Output kW
a. Peaking Condition (kW) (DB = 95° F; WB = 76° F)		
Rated	9,455	661,205
b. Annual Average (kW) (DB = 64.4° F; WB = 58° F)		
Rated	9,289	672,961
75%	9,481	506,015
50%	9,800	341,545

Basis for Heat Rate Data:

- ABB Turbine - Generator
- 8 Feedwater Heaters
- Wet Limestone Scrubber with Forced Oxidation
- Selective Catalytic Reduction System
- 2,400 psig/1,000° F/1,000° F Cycle
- 1 % Make-up and Blow-down
- Average System Weather Conditions Calculated Based on Wet and Dry Bulb Temperature Near Macon, GA.

III. PLANT COSTS

(with 5% contingency on major equipment and 10% on balance of plant)

	Per Kilowatt *	Total
EPC	$ 840	$555,412,000
Site	$ 39	$ 25,725,000
Owner's	$ 53	$ 34,940,000

Scope of supply on the output side extends through the switchyard to the first breaker and disconnect. Plant costs are overnight costs as of 1/1/97. This is a budget grade estimate.

* Based on the peaking rating

IV.	FIXED O & M COSTS (Based on the Peaking Rating)	
	$/kW-Yr	9.92
	Total	$ 6,560,000
V.	VARIABLE O & M COSTS (Based on the Annual Average Rating and a 65% Capacity Factor)	
	Mills/KWH	1.65
	-Total -	$6,335,000
VI.	PLANT LIFE (yrs)	45
VII.	MAINTENANCE TIME (weeks/yr)	4
VIII.	EQUIVALENT FORCED OUTAGE RATE	6.5
IX.	EXPENDITURE DATA AVAILABLE?	Yes
X.	PROJECT SCHEDULE AVAILABLE?	Yes
XI.	EXPECTED PLANT DEGRADATION -OUTPUT	2.04%
	HEAT RATE	2.04%
XII.	CAPITAL EXPENDITURE FOR MAINTENANCE ($/kW-yr)	0.47

COMBINED CYCLE -'F'
NOMINAL 500 MW

I. GENERAL DESCRIPTION OF THE PLANT

The base load combined cycle unit is a nominally rated 500 MW plant based on a power cycle utilizing two (2) nominal 170 MW advanced design industrial combustion turbine-generators with evaporative coolers, two natural circulation triple pressure heat recovery steam generators (HRSGs) with reheat sections and integral deaerators, a single condensing reheat steam turbine, a steam condenser with a mechanical draft cooling tower system for condenser cooling and associated support systems. The combustion turbines will be housed in an individual weather-proofed outdoor enclosure which includes insulation for sound attenuation and thermal protection.

State of Technology

This technology is currently available.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/KWH	Net Unit Output kW
a. Peaking Condition (kW) (DB = 95° F; WB = 76° F)		
Rated	7,178	521,000

b. Annual Average (kW)
(DB = 64.4° F; WB = 58° F)

Rated	6,860	517,000

Basis for Heat Rate Data:

- (2) GE 7FA's with reheat steam turbine 1,815 psig/1,050° F/1,050° F
- Average annual based on dry low NOx control to 9 ppm
- Evaporative cooler in use at 95° F.
- 4.5" inlet / 12.0" exhaust loss on CT (at 64° F. design point)
- 2.0% station service
- 304 ft. site elevation
- Natural gas fuel (assume natural gas compressor not required)
- Corresponding relative humidities are 67% at 64 degrees F. dry bulb and 43% at 95 degrees F. dry bulb temperatures
- Peak rating based on 2/1 steam to fuel injection ratio for power augmentation

III. TOTAL PLANT COST

		Per Kilowatt *	Total
1 UNIT:			
	EPC	$ 338	$176,211,000
	Site	$ 19	$9,682,000
	Owner's	$ 11	$5,987,000

2 UNITS:

EPC	$ 325	$338,352,000
Site	$ 17	$18,088,000
Owner's	$ 11	$11,513,000

Capital cost for gas pipeline is not included. Scope of supply on the output side extends through the switchyard to the first breaker and disconnect. The plant costs are overnight costs as of 1/1/97. This is a budget grade estimate.

* Based on the peaking rating

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

1 UNIT:	$/kW-Yr	3.66
	Total	$1,908,000
2 UNITS:	$/kW-Yr	2.46
	Total	$2,561,000

V. VARIABLE O & M COSTS
(Based on the Annual Average Rating and a 65% Capacity Factor)

1 UNIT:	Mills/KWH	1.68
	Total	$4,934,000
2 UNITS:	Mills/KWH	1.56
	Total	$9,209,000

VI. PLANT LIFE (yrs) 40

VII. MAINTENANCE TIME (weeks/yr) 3.0

VIII. EQUIV. FORCED OUTAGE RATE 3.44%

IX. EXPENDITURE DATA AVAILABLE? Yes

X.	PROJECT SCHEDULE AVAILABLE?	Yes
XI.	EXPECTED PLANT DEGRADATION -OUTPUT	5.89%
	HEAT RATE	2.64%
XII.	CAPITAL EXPENDITURE FOR MAINTENANCE (S/kW-yr)	1.15

SIMPLE CYCLE COMBUSTION TURBINE
NOMINAL 350 MW

I. GENERAL DESCRIEPTION OF THE PLANT

The combustion turbine plant model consists of current generation state-of-the-art, heavy duty industrial Westinghouse 501D5A nominal 120 MW units with evaporative cooler. These units utilize firing temperatures in the range of 1,950°-2,200° F. Extensive factory modularization of systems and components results in low costs for peaking applications. The plant utilizes natural gas as the primary fuel with No. 2 distillate as the back-up fuel. NOx is controlled to 25 ppm on the primary fuel through the use of water injection. The simple cycle combustion turbine plant design is based on siting three (3) nominal 120 MW simple cycle combustion turbines at one plant site.

State of Technology

This peaking plant will utilize mature technology that is commercially available at the present time.

II. HEAT RATE AND OUTPUT DATA

The following performance data is based on a new and clean condition for major auxiliaries.

	Net Heat Rate (Based on HHV) Btu/KWH	Net Unit Output kW
Peaking Condition (kW) (DB = 95 Deg. F; WP = 76 Deg. F)		
Maximum Load:	11,728	364,770

Basis for Heat Rate Data:

- Natural Gas Fuel
- 95° F Dry Bulb Ambient Temperature
- 43% Relative Humidity
- Altitude is 304 Feet Above Sea Level
- Water Injection to Meet 25 ppm NOx For Natural Gas
- 4.5" Inlet Pressure Loss
- 5" Exhaust Pressure Loss
- Performance at Base Combustor Firing Temperature
- Evaporative Cooler with 85% Effectiveness

III. TOTAL PLANT COST
(with 2.5% CT contingency and 10% for balance of plant)

	Per Kilowatt	Total
One site with three (3) Nominal 120 MW CTs		
EPC Cost	198	$ 72,330,000
Site Cost	13	$ 4,674,000
Owner's Cost	11	$ 3,860,000

Capital cost for gas pipeline is not included. Scope of supply on the output side extends to the high side of the generator step-up transformer. Plant costs are overnight costs as of 1/1/97. This is a budgetary grade estimate.

IV. FIXED O & M COSTS
(Based on the Peaking Rating)

$/kW-Yr	2.64
Total	$ 962,000

V. VARIABLE O & M COSTS
(Based on the Peaking Rating and 300 hrs/year)

Mills/KWH	2.68
Total	$ 293,000

VI. PLANT LIFE (yrs)	40
VII. MAINTENANCE TIME (weeks/yr)	2.6
VIII. EQUIV. FORCED OUTAGE RATE (For periods of demand only)	3.0%
IX. EXPENDITURE DATA AVAILABLE?	Yes
X. PROJECT SCHEDULE AVAILABLE?	Yes
XI. AMBIENT TEMP. VS. CT OUTPUT AVAILABLE?	Yes
XII. EXPECTED PLANT DEGRADATION - OUTPUT	3.13%
HEAT RATE	1.85%
XIII. CAPITAL EXPENDITURE FOR MAINTENANCE ($/KW-YR)	0.30

LANSING SMITH GENERATING PLANT

The existing Lansing Smith Generating Plant is located on Alligator Bayou, which lies between North and West Bays north of Panama City in Bay County, Florida. The plant site consists of a total of 1,340 acres, of which only 400 acres are currently in utility use. This site has been used as an electric generation facility since June of 1965. When this site was originally purchased, it was intended to support eight coal-fired steam turbine/generating units, but because of changing conditions, only two fossil steam units and a combustion turbine are currently in service.

Smith Unit No. 1, a coal-fired steam unit with a net generating capability of 162,000 kilowatts, went into service in June, 1965. This unit is comprised of a Combustion Engineering boiler and a Westinghouse 3,600 rpm turbine/generator set. The boiler generates steam with a main steam pressure of 1,800 psig and a superheat/reheat steam temperature of 1,000/1,000 degrees Fahrenheit. Smith Unit No. 1 uses once-through salt water for its condenser cooling and a Buell Envirotech hot-side precipitator for particulate removal. This unit is a Clean Air Act (CAA) Phase II affected unit and currently burns a 1% domestic coal.

Smith Unit No. 2, a coal-fired steam unit with a net generating capability of 192,600 kilowatts, went into service in June, 1967. This unit is comprised of a

Combustion Engineering boiler and a Westinghouse 3,600 rpm turbine/generator set. The boiler generates steam with a main steam pressure of 1,800 psig and a superheat/reheat steam temperature of 1,000/1,000 degrees Fahrenheit. Smith Unit No. 2 uses once-through salt water for its condenser cooling and a Buell Envirotech hot-side precipitator for particulate removal. This unit is a CAA Phase II affected unit and currently burns a 1% domestic coal and has low-NOx burners to reduce nitrous-oxide emissions.

Smith Unit A is a Pratt & Whitney, aero-derivative combustion turbine with a net capability of 31,600 kilowatts and went into service in May of 1971. This combustion turbine unit is fueled with No. 2 fuel oil with a storage capacity of 750,000 gallons. Smith Unit A is used exclusively for peaking type service and is the only Gulf Power Company unit that is black-start capable.

The coal for Units No. 1 and No. 2 is brought into the plant by barge and unloaded by a derrick crane located on the Alligator Bayou canal. The coal stockpile at the plant typically maintains a level of approximately 30 days of combined unit nameplate ratings. Currently, there are no natural gas facilities available at the plant for generating unit consumption.

Electrically, the power generated by the plant's units is transmitted to the load centers via three 115 KV and four 230 kV transmission lines. The installation of Gulf's planned 540 MW combined cycle unit will not necessitate any transmission system upgrades or new facilities.

Because of the site's original plan to have eight fossil steam units, there are many suitable acres for future unit expansion such as that currently planned by Gulf with its installation of Smith Unit 3. The undeveloped land on this site is mostly planted with pine trees.

APPENDIX E

The Gulf Power Company Request for Proposals (RFP) follows and appears in its original state as issued.

August 21, 1998

Mr. Generic M. Respondent
The Company Name
The Company Address
City, State ZIPCODE

RE: Request for Proposals

Dear Mr. Respondent:

Gulf Power Company has determined that it will need additional firm capacity starting as early as the summer of 2002. The Company is seeking proposals for power supply from eligible Respondents to meet the Company's requirements for electric generation capacity as described in this Request For Proposal (RFP). Location, price, and reliability of the power offered will be major factors in the purchase decision. Creative supply side electric generation alternatives that provide exceptional value and economic benefits to Gulf Power and its customers will be appropriately considered in the proposal evaluations. The attached RFP document details the requirements and specifications that Respondents should meet and also outlines the information that should be provided in a proposal.

Respondents interested in submitting proposals under this solicitation should provide six completed copies and one original of the enclosed forms in both hardcopy and electronic format (3.5" floppy diskette). Any additional information that the Respondent deems necessary to evaluate the offer should be included along with the forms. All proposals must be received no later than 5:00 p.m., on Friday, October 16, 1998 at the following address:

Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Any portions of offers to be treated as confidential must be so identified.

Thank you for your interest in meeting the Company's power supply needs during this period.

Sincerely,

Garey C. Rozier
Director, Bulk Power Supply

REQUEST FOR PROPOSALS

August 21, 1998

Southern Company Services, Inc. (Southern), acting as agent for Gulf Power Company (The Company, or Gulf Power), issues this request for proposals (RFP) to acquire approximately 350-500 megawatts (MW) of supply-side resources beginning in the summer of 2002. The Company invites innovative proposals of various types of electric generation, including those representing base-load, intermediate, and peaking resources. Offers proposing new electric generating facilities located near Panama City, Florida will have a transmission cost advantage.

For purposes of this solicitation, the Company is interested in long term proposals lasting at least five years. In addition to "summer only" and "year round" offers, proposals reflecting various contract periods for the same resource will be considered. The Company is particularly interested in proposals that will offer exceptional value to the Company and its customers. Respondents are encouraged to be creative in crafting offers that will meet the Company's needs.

Proposals submitted pursuant to this solicitation will be considered and evaluated against each other and against any self-build options. Transmission and ancillary service studies will be conducted as appropriate to determine the total cost impacts. A short list will then be developed reflecting those Respondents whose proposals appear to demonstrate the most value (not necessarily the lowest price). Any Respondents so selected will be contacted for negotiations that may lead to a mutually-agreeable power purchase agreement. The Company naturally reserves the right to revise the capacity needs forecast at any point during the process or negotiations; any such change may reduce, eliminate, or increase the amount of power sought.

Respondents are asked to define the firmness of the capacity offered in their proposal in one of the following categories:

- Level A: "First Call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
- Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
- Level C: Capacity that is backed by the Respondent's purchase(s).
- Level D: "Financially firm" (replacement cost with no liquidated damages)
- Level E: No specified generation resources

To help defray the cost for performing the evaluation of each proposal, Respondents are required to submit a check for $8,000.00 for each proposal. Changes in the site, output, electrical characteristics (generator ratings), or technology changes (i.e. simple cycle, combined cycle, cogen, primary fuel) will require the submission of a separate proposal and payment of the fee. A change in financial terms is not considered a proposal change.

The Company reserves the right, without qualification and at its sole discretion, to reject any, all, or portions of the proposals received for any creditable reason or for failure to meet any criteria, and further reserves the right without qualification and at its sole discretion to decline to enter into a power purchase arrangement with any Respondent. Respondents should be aware, that the following (if submitted) will be classified as non-responsive and will not be considered or evaluated:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- proposals offering capacity and/or energy that is generated by facilities owned by the operating companies of the Southern Company;
- proposals involving resources that would result in increasing demand on resources owned by the operating companies of the Southern Company; or
- incomplete, or non-specific offers.

Those who submit proposals do so without recourse against the Southern Company or any of its affiliates or subsidiaries for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	August 21, 1998	
Proposals due	October 16, 1998	Proposals must be received or hand delivered to Southern's RFP Contact by 5:00 PM
Short-list determination	December 11, 1998	If applicable
Complete negotiations	March 1, 1999	If applicable
File contract(s) for certification with state public service commission	March 31, 1999	If applicable

The Company reserves the right to revise, suspend, or terminate this schedule at their sole discretion. Any changes to the schedule will be provided as appropriate.

RFP Contact

Proposals and questions should be submitted to Southern's RFP Contact:

Garey C. Rozier
Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Instructions for Completing Forms

1. All proposals should be submitted in the format shown in the RFP response form Attachment A. Additional information should be supplied (no particular format required) from the appropriate sections of Attachment B. Respondents should supply any additional information not included in these forms if such information may be needed for a thorough understanding and/or evaluation of the proposal.

2. Proposals must be signed by an officer of the Respondent.

3. A signed original and six (6) copies of the proposal forms and Respondent Questionnaire response should be submitted along with the electronic forms on a 3.5" floppy diskette. In the event of a discrepancy between the electronic forms and the hardcopy, the latter will be considered to be correct.

4. Prices and dollar figures quoted must be clearly stated as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

5. Energy prices must be quoted as indicated in the forms as either $/MW-hour or as heat rates to be applied to the designated published fuel index. The fuel index preferred (but not required) is the Henry Hub, as published in *Gas Daily*. Fuel transportation costs and any adjustments for energy pricing must be included in all prices.

Confidentiality

The Company will take reasonable precautions and use reasonable efforts to protect any proprietary and/or confidential information contained in an offer provided that such information is clearly identified by the Respondent as proprietary and confidential on the page on which it appears. Such information may, however, be made available under applicable state and/or federal law to regulatory commission(s), their staff(s) or other governmental agencies having an interest in these matters. The Company reserves the right to release such information to agents or contractors for the purpose of evaluating the Respondent's proposals, but such agents or contractors will be required to observe the same care with respect to disclosure as Gulf Power and Southern. Under no circumstances will the Southern Company, its subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure before, during, or after the solicitation process.

Transmission Information and Requirements

1. If power is to be provided from resources outside the Southern control area, Respondents must provide a transmission map that shows the expected contract path(s) to be used to deliver power to the Southern Company transmission system. Additionally, the map should show any site-specific electric generation resource, together with a list of control areas to be crossed. For information concerning the

Southern Company transmission systems such as: availability data on specific transmission routes, existing constraints, and interconnection points, Respondents should contact:

John E. Lucas, Manager Transmission Services
Southern Company Services, Inc.
Post Office Box 2625
Birmingham, AL 35202

2. Respondents are responsible for paying all charges and/or costs for delivering power to the Southern Company transmission system. Respondents are to include in their quotes any and all such charges.

3. The costs of any transmission upgrades to the Southern Company transmission system associated with the proposal will be considered in the evaluation. The Company will conduct transmission impact studies, as appropriate, to determine these costs. It should be noted that proposals for new electric generating facilities located near Panama City, Florida will have a significant transmission cost advantage.

4. For new facilities, Respondents are responsible for all costs related to interconnection of the facility to the Southern Company transmission network. Respondents should include all costs associated with a generator step-up transformer and synchronization to the transmission network using a Respondent supplied generator breaker. Interface between the Respondent and the company will be the high side of the Respondent supplied generator step-up transformer.

Regulatory Provisions

1. It shall be the complete and sole responsibility of the Respondent to take all necessary actions to satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on Respondent by any federal, state, or local law concerning the generation, sale and/or delivery of the power. The Company will cooperate with the Respondent to provide information or such other assistance, as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise provide such information to the Company.

2. The Respondent shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale and/or delivery of power.

3. The proposal is subject to approval and/or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation (including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission).

4. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

   Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

5. The Company's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW to be located in the Panama City, Bay County, Florida area. For a more detailed description of this planned unit, refer to Attachment C.

<u>Performance Assurances</u>

The Company will rely, in part, on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement. Performance guarantees and financial credit assurances may also be required of the Respondents, subject to negotiation, at the Company's discretion.

<u>Minimum Requirements for Proposals</u>

Proposals that meet these requirements will be considered responsive to this RFP. Non-responsiveness is a basis for rejecting an offer in the Company's sole discretion.

1. All forms, including both hardcopy and electronic versions, must be properly completed and returned to the RFP Contact, Garey C. Rozier, no later than 5:00 p.m. on Friday, October 16, 1998. Late or incomplete offers may be rejected in the sole discretion of the Company. Offers must remain open until at least March 31, 1999.

2. Complete information is needed to facilitate a timely evaluation. Issues that the Respondent prefers to negotiate later may be identified in the response; however, the Respondent must provide all explicit data requested on the forms. The Company may, at is sole discretion and judgment, choose to reject non-specific offers from further consideration.

3. Capacity offered must be firm. Proposals must clearly identify the firmness of the resource by the levels outlined in Attachment B. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources may not be evaluated or considered.

4. Capacity offered will have the most value if fully dispatchable and available for first-call by the Southern Company system 24 hours per day and 7 days per week for the contracted period. Acceptable availability of the power when called for will be negotiated, with higher availability rates being preferred.

5. Proposal prices must include all costs that the Company will be expected to pay for the capacity and energy proposed. Attempts by the Respondent to increase prices will be grounds for rejection of the proposal.

6. No proposal less than 50 MW will be considered acceptable.

<u>Proposal Evaluation</u>

1. Proposals that are considered to be adequately responsive to the requirements of this RFP will be ranked and screened on price to eliminate those that are clearly not competitive before detailed modeling is performed. The majority of the evaluation will focus on price consideration. However, qualitative and non-price attributes will be considered in the overall screening process.

2. Proposals that pass the preliminary responsiveness screens will be further evaluated using appropriate production costing methods and models so that all reasonable cost impacts can be quantified.
   a.) Preference will be given to proposals that offer shorter unit commitment notification and greater dispatch flexibility.
   b.) Preference will be given to proposals that offer more contract flexibility features, such as call/put options, early-out provisions, and variable term pricing. The Respondent must separately identify any additional costs associated with these features.
   c.) It is the Respondent's responsibility to submit additional information related to the proposal if such information will materially improve the quality of its offer or the Company's understanding thereof.

3. An appropriate selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will be evaluated against each other and with any self-build options before the Company makes any commitments regarding the resource(s) to meet its identified needs.

4. The Company reserves the right to contact Respondents to request additional information on any aspect of any proposal.

Attachment A

Respondent's Company Name	
Maximum Capacity (MW)	
Minimum Capacity (MW)	
Proposal Start Month	
Proposal Start Year	2002
Proposal End Month	
Proposal End Year	
Firmness Level	

Enter Level A,B,C,D, or E (see RFP for Level descriptions)

Option Information if Applicable	
Option Premium Price ($/KW-month)	
Option Strike Price ($/KW-month)	
Option Strike Date	

Annual / Monthly	2002	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/KW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/KW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	2003	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/KW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/KW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	[illegible]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/KW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/KW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	[illegible]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/KW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/KW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	[illegible]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/KW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/KW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Attachment B
Respondent Questionnaire

All Respondents, as appropriate, must supply the following information:

1) Please provide documentation of your company's previous experience providing the proposed product.

2) Please provide the following financial and credit information for your company and for your parent company (if applicable):
   - Annual reports and Form 10-K for the past three years. If these documents are not available, then audited financial statements for the last three years will be accepted
   - Dunn and Bradstreet identification number
   - Credit rating of the Respondent's senior debt securities
   - Any additional documentation needed to allow the Company to determine the Respondent's financial strength and/or the strength of any corporate parents.

1) Present a detailed description of any security/credit instruments proposed by the Respondent to back its performance obligation.

2) Please describe whether or not this capacity has been offered in another RFP and under what conditions it would be released to serve this proposed sale.

3) Please describe the firmness category that best describes your offer and provide documentation that supports your ranking:
   Level A: "First call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
   Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
   Level C: Capacity that is backed by the Respondent's purchase(s).
   Level D: "Financially firm" (replacement cost with no liquidated damages)
   Level E: No specified generation resources

4) For a Level A proposal involving a specific unit, please provide the following information:
   A. Unit name, location, and schedule for construction (if applicable)
   B. Monthly Unit ratings
   C. Electrical Data as required in performing load flow and stability studies
   D. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation.)
   E. Fuel type and source (primary and secondary) and heat rate (applicable if pricing is not quoted as a firm energy price)
   F. Guaranteed availability
   G. Maximum and minimum operating level
   H. Minimum run time per dispatch call
   I. Minimum contract quantity (energy) per year (summer and winter)
   J. Minimum down time
   K. Start up time from cold start and from hot start

L. Will the unit qualify for quick start capability? (less than 10 minutes)
M. Start up costs from cold start and from hot start
N. Descriptions (including models and manufacturers) of all of the major components
O. A detailed description of the fuel and water supplies
P. A thorough description of anticipated environmental impact and compliance.

1) For a Level A, B, or C system sale and other sales, please provide the following information:
   A. A description of the system from which the power will be provided, including the name, location, peak hour load, the installed capacity, capacity mix and reserve projections (with and without the proposed capacity sale) during the proposal period.
   B. An explanation of any criteria under which the supply of system power might be curtailed or interrupted and the priority of this proposed transaction relative to all other supply commitments (existing and future) of the Respondent.
   C. For a Level A system sale, the proposed supply commitment is assumed to be at least as firm as the Respondent's service to its own native load. Please confirm this assumption. If this is not correct, please explain.
   D. For a Level B system sale, please provide evidence of capacity available above Respondent's existing load commitments. (i.e., Current IRP documentation)
   E. For a Level B or C system sale, please provide methodology by which the Respondent will ensure that sufficient capacity will be available to support the proposed sale.

1) Please describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the Southern Company transmission network. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

2) Please describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

3) Please explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the purchase after it has been scheduled.)

4) Please describe any dispatch notice or scheduling requirements for this offer.

5) Please describe any minimum requirement for the numbers of consecutive dispatch hours or a minimum energy take for the contract term?

6) Please describe any other limitations on the use or availability of the power.

Attachment C – Planned Unit Data

These following data represent generic technology assessment estimates which Gulf Power utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on the Company's existing Lansing T. Smith Electric Generating Plant property in Bay County, Florida.

2. Planned Size 532 MW

3. Commercial Operation of the facility is proposed to be June 1, 2002.

4. The primary fuel is natural gas. No secondary fuel source is anticipated.

5. The estimated total direct cost is $265,768,000 (installed 2002$).

6. The estimated annual levelized revenue requirement is $36,912,000 over 20 years.

7. The estimated annual value of deferral of this unit is $55.25/kW-yr (98$).

8. The estimated annual fixed O & M is $1,458,000(98$). The estimated variable O & M is $1.85/MWH(98$).

9. The estimated delivered fuel cost is $ 2.42/MMBtu (98$).

10. The following are estimates for:

Planned outage rate	5.8 %
Forced outage rate	3.2 %
Heat rate	6,527 Btu/KWH
Minimum load	284 MW
Ramp Rate	1 Hr. (Hot); 4 Hrs. (cold)

11. The estimated transmission interconnection costs associated with this unit are $ 15 million. This unit will also have an estimated $90 million dollars of gas lateral pipeline costs.

12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.062 % per year
General escalation:	3.062 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.68 %
	10 % preferred @ 7.73 %
	45 % equity @ 13.5 %