ORIGINAL

Ten Year Site Plan

JEA[sm]

Building Community

April 2000

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1.0 Introduction

The objective of JEA's Integrated Resource Planning Study is to develop an environmentally sound power supply strategy, which provides reliable electric service at the lowest practical cost. This report represents the 2000 Ten Year Site Plan for JEA covering a planning period from 2000 to 2009.

2.0 Existing Facilities

2.1 Generation

Electric System

JEA's electric service area covers all of Duval County and portions of Clay County, Nassau County, and St. Johns County. JEA's service area covers approximately 900 square miles.

The generating capability of JEA's system currently consists of the Kennedy, Northside, and Southside generating stations, and joint ownership in St. Johns River Power Park and Scherer generating stations. The total net capability of JEA's generation system is 2,734 MW in the winter and 2,629 MW in the summer. Details of the existing facilities are displayed in Schedule 1.

JEA's transmission system consists of bulk power transmission facilities operating at 69 kV or higher. This includes all transmission lines and associated facilities where each transmission line ends at the substation's termination structure. JEA owns 684 circuit-miles of transmission lines at five voltage levels: 69kV, 115kV, 138kV, 230kV, and 500kV. JEA's transmission system includes a 230 kV loop surrounding JEA's service territory. The existing transmission system is shown in Figure 2-1. JEA is currently interconnected with Florida Power & Light (FP&L), Seminole Electric Cooperative (SECI), and Florida Public Utilities (FPU). Interconnections with FP&L are at 230 kV to the Sampson and Duval Substations. The interconnection to SECI is at 230 kV and at 138 kV to FPU. JEA closed breaker 801 at the Neptune 138 kV Substation to interconnect to the City of Jacksonville Beach (FMPA) through the Jacksonville Beach 138 kV Substation on March 20, 2000.

JEA and FP&L jointly own two 500 kV transmission lines that are interconnected with Georgia Power Company. JEA, FP&L, Florida Power Corporation (FPC) and the City of Tallahassee each own transmission interconnections with Georgia Power Company. JEA's entitlement over these transmission lines is 1,228 out of 3,600 MW of import capability.

JEA's system is interconnected with the 500 kV transmission lines at FPL's Duval Substation.

Jointly Owned Generating Units

The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and FP&L (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station. Unit 1 began commercial operation in March of 1987 and Unit 2 followed in May of 1988. Both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, the remaining 30 percent of capacity and energy output is reflected as a firm sale. The two units have operated efficiently since commercial operation. To reduce fuel costs and increase fuel diversity, a blend of petroleum coke and coal is currently being burned in the units.

JEA and FP&L have purchased an undivided interest in Georgia Power Company's Robert W. Scherer Unit 4. Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA purchased 150 megawatts of Scherer Unit 4 in July 1991 and purchased an additional 50 megawatts on June 1, 1995. Georgia Power Company delivers the power from the unit to the jointly owned 500 kV transmission lines.

Power Purchases

Southern Company and JEA entered a unit power sales contract in which JEA purchases 200 MW of firm capacity and energy from specific Southern Company coal units through the year 2010. JEA has the unilateral option, upon three years notice, to cancel 150 MW of the UPS.

JEA entered into a purchase power agreement in 1996 with Enron Power Marketing, Inc. for firm power from October 1, 1996 through December 31, 2002. The available capacity varies monthly, ranging from 64 to 85 MW in 1997 to 69 to 92 MW in 2002. JEA reserves capacity at the Florida/Georgia interface for delivery of this power.

JEA entered into an agreement with The Energy Authority (TEA) to purchase 25 MW of annual firm capacity and energy for the term March 1999 through May 31, 2001. Also, JEA acquired capacity through TEA to fill the 2000 winter (250 MW) and summer (175 MW) needs.

JEA has encouraged and continues to monitor opportunities for cogeneration. Cogeneration facilities reduce the demand from JEA's system and/or provide additional capacity to the system. JEA purchases power from four customer-owned qualifying facilities (QF's), as defined in the Public Utilities Regulatory Policy Act of 1978, having a total installed summer peak capacity of 17 MW and winter peak capacity of 19 MW. JEA purchases energy from these QF's on as-available (non-firm) basis.

The following JEA customers have Qualifying Facilities located within JEA's service territory.

Cogenerator Name	Unit Type	In-Service Date	Net Capability[3] - MW Summer	Winter
Anheiser Busch	COG[1]	Apr-88	8	9
Baptist Hospital	COG	Oct-82	7	8
Ring Power Landfill	SPP[2]	Apr-92	1	1
St Vincents Hospital	COG	Dec-91	1	1
			17	19

Notes:
1 Cogenerator
2 Small Power Producer
3 Net generating capability, not net generation sold to the JEA

Power Sales

JEA returned Kennedy Combustion Turbine Unit 4 (CT4) to service from retirement status in March 1994. Concurrently, JEA sold to SECI priority dispatch rights for one-seventh of the aggregate CT output capacity of the JEA system. JEA's CTs include Kennedy Units 3, 4, and 5, and Northside Units 3, 4, 5, and 6. For planning purposes, JEA and SECI assume SECI's base committed capacity is 53 MW. Full entitlement sales began January 1, 1995, and will continue through December 31, 2001. SECI has extended the term through May 21, 2004.

JEA also furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU until 2007. Sales to FPU in 1999 totaled 454 GWh (3.85 percent of JEA's total system energy requirements).

2.2 Transmission

JEA continues to monitor and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually reviews needs and options for increasing the capability of the transmission system. JEA has set forth the following planning criteria for the transmission system:

- Plan to limit the loading of transmission lines and auto transformers to provide safe and reliable transmission service under normal and single contingency conditions without undue expected loss of component life.
- Plan the transmission system to withstand single contingencies without loss of customer load.

- Plan the transmission system to operate within 5 percent of nominal voltage during normal and single contingency conditions.
- Plan the transmission system so that circuit breakers can interrupt the maximum available breaker fault current.
- Plan substation relays to sense breaker failures and clear faults in sufficient time to avoid generator instability problems. The worst case fault considered in planning is a three-phase fault.
- Meet the Florida Reliability Coordinating Council's (FRCC) operation guidelines.
- Meet or exceed the FRCC's reliability guidelines for transmission system interface Available Transfer Capabilities. This includes the use of single contingency criteria as well as considering the needs for operating reserve margin requirements, and capacity benefit margins.

2.3 Demand Side Management

DSM Plan (1996 – 2000)

In December 1995, the Florida Public Service Commission (PSC) approved a Demand-Side Management (DSM) plan for JEA. At that time JEA's DSM Plan contained three residential customer programs and one commercial/industrial program. The three residential customer programs included:

- Architect, contractor, and building inspector continuing education classes,
- Appliance efficiency education and
- Low income audits.

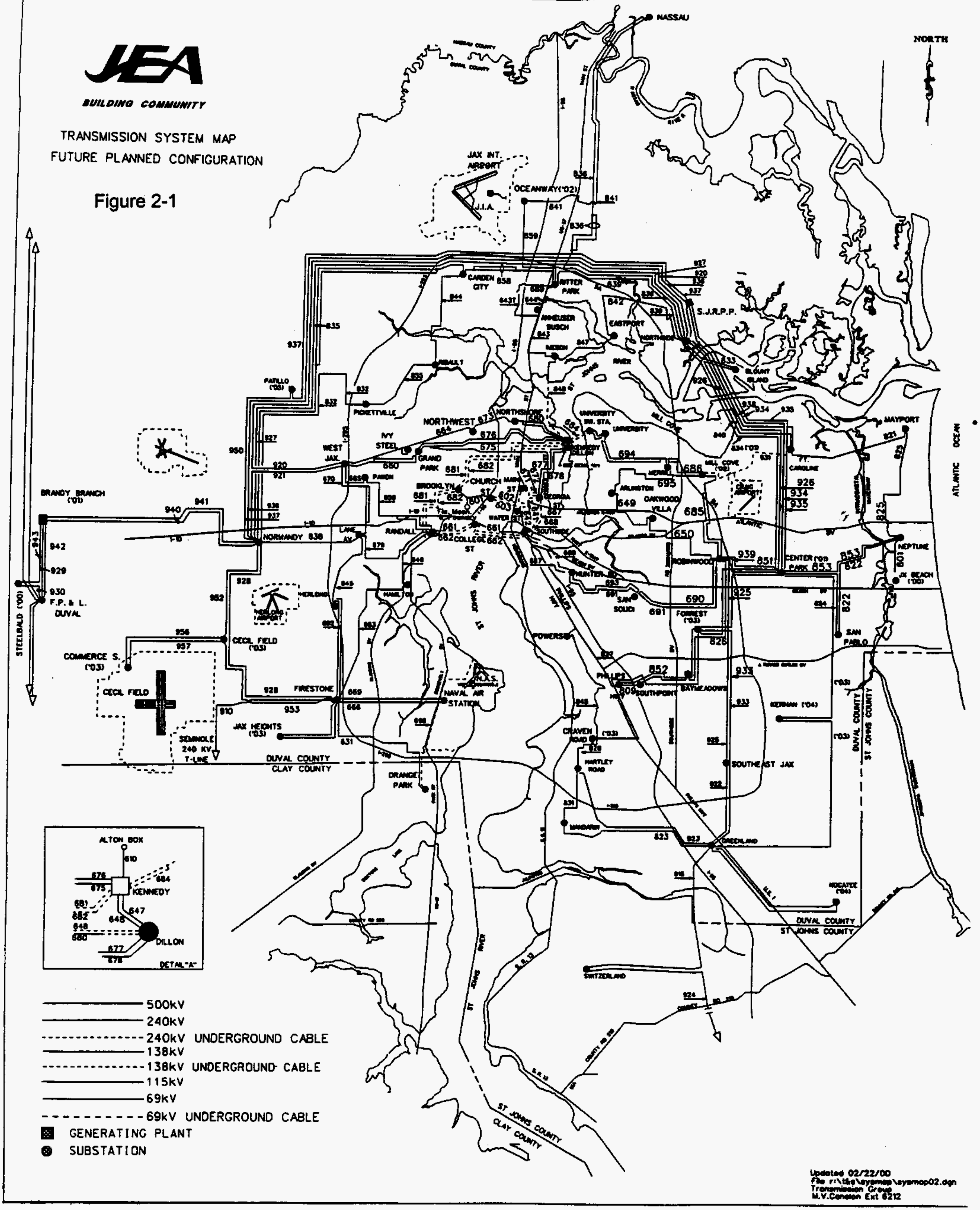
The commercial program was a lighting modification program that promoted energy savings and power quality improvements. These programs helped improve customer satisfaction by increasing the number of valuable energy services available to JEA's customers.

DSM Plan (2001 – 2010)

JEA studied numerous DSM measures, evaluated the measures using the Commission approved Florida Integrated Resourse Evaluator (FIRE) model and developed goals and a plan based upon these results. The Rate-Impact Measure or RIM test was used to determine the cost-effectiveness of the DSM alternatives appropriate for a municipal utility. Some investor-owned utilities in the state also use the RIM test to determine cost-effective DSM alternatives.

None of the alternatives tested was found to be cost-effective for JEA. The inability to find cost-effective DSM measures is primarily due to the low cost of new generation, high efficiency of new generation, low interest rates, low fuel price and low fuel price projections. On February 21, 2000, the PSC approved JEA's Plan for zero DSM for 2001-2010.

JEA has, however, agreed to continue several DSM programs, including the residential education seminars, residential energy audits, commercial educational programs, commercial energy audits, and community conservation programs. These programs will be monitored and re-evaluated to determine the best programs for the customers.



TRANSMISSION SYSTEM MAP
FUTURE PLANNED CONFIGURATION

Figure 2-1

3.0 Fuel Forecast

The fuel forecast represents a major economic factor in the selection of resources for future supply to JEA's electrical system. The base case fuel forecast includes coal, natural gas, residual fuel oil, distillate oil, and petroleum coke. High and low fuel price projections were also developed for sensitivity analyses. JEA currently purchases natural gas transortation from Florida Gas Transmission Company (FGT) under FTS-1. JEA's natural gas entitilesments include 40,000 Mbut/day for FGT FTS-1 and contract extensions are at JEA's option. JEA has committed to an additional 14,000 Mbtu/day of FGT FTS-2 beginning in spring 2002.

4.0 Load and Energy Forecast

JEA's load and electrical characteristics have many similarities to other Peninsular Florida utilities. JEA's calendar year 1999 peak demand was 2,427 MW, occurring in August. The net energy for load (NEL) for 1999 was 11,740 GWH. Summer peak demand has increased at an average annual rate of 3.45%, winter peak demand 1.99% and net energy for load 3.64% over the period from 1990 through 1999.

The 1999 forecasts of electric power demand, energy consumption, and number of customers were prepared by JEA. These forecasts are based on trend analyses of historical electric load data for the JEA system and adjusted for JEA's assessment of the strength of the local economy. While impacts of retail wheeling and other results of deregulation on the loads served by JEA have not been explicitly forecasted, the high and low energy growth forecasts provide a range to bracket potential effects.

The electric power demand forecast is based on a trend analysis of historical data and analysis of the local economy, weather-normalized to typical ambient temperatures. Schedule 3 and 4 provides a summary of the basecase peak and energy forecasts for the Ten-Year Site Plan.

The energy consumption forecast represents a trend analysis of historical data for the aggregate customer base. Sales to ultimate customers by rate class were derived by trending the historical use per customer data and multiplying by the forecast of number of customers. Historical and forecast load factors were compared as a reasonableness check of the independently developed demand and energy forecasts.

5.0 Facility Requirements

5.1 Unit Retirements and Shutdowns

The following three JEA oil/gas steam units are reaching the end of their useful lifetimes and are scheduled for retirement or shutdown.

Unit	Commercial Operation Date	Change in Status	Planned Date
Kennedy Unit 10	1961	Shutdown	April 2000
Southside Unit 4	1958	Retirement	October 2001
Southside Unit 5	1964	Retirement	October 2001

Upon retirement or shutdown, the units will be over 35 years of age. The units are exhibiting a history of age related equipment failures. Retirement of the units will allow JEA the opportunity to replace the capacity with newer more efficient technology that will have lower emissions. JEA has established the above dates for the unit retirements. Kennedy Unit 10 is scheduled to be shutdown beginning April 2000. Potential future repowering options for Kennedy 10 may be studied in the future.

5.2 Combustion Turbines

JEA has contracted with General Electric for the supply of four frame 7FA combustion turbines. One unit is being installed at the Kennedy Generating Station and three units will be installed on property owned by JEA at the Brandy Branch site near Baldwin, FL. Each simple cycle combustion turbine will operate primarily on natural gas with #2 distillate used as a backup fuel. The summer/winter output of each combustion turbine is 149,000/185,000 kW, respectively, operating on natural gas and 158,000/191,000 kW, respectively, operating on #2 distillate.

Each new combustion turbine utilizes a dry low NOx combustion system to regulate the distribution of fuel delivered to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution is calculated to maintain unit load and fuel split for optimal turbine emissions. In addition, when operating on #2 distillate, demineralized water is injected into the combustion chamber to reduce the firing temperature, which reduces the formation of NOx. The ratio of the flowrate of demineralized water to #2 distillate is approximately equal. The NOx emissions when operating on natural gas and #2 distillate will be controlled to 10.5 and 42 ppm, respectively.

Construction for the Kennedy unit began in May 1999 with a scheduled completion date of June 2000. The construction of the Brandy Branch units began in late 1999 with the scheduled completion of the first two units in January 2001 and the third unit in December 2001.

5.3 Northside Units 1 and 2

On May 21, 1997, JEA approved a plan to move forward with the repowering of Northside Units 1 and 2. The project involves the installation of new circulating fluidized bed (CFB) boilers, burning petroleum coke and coal. The project has been identified as a Clean Coal Project by the Department of Energy, which will contribute $73.07 million to the repowering of Northside Unit 2. During the first two years of operation, Unit 2 will burn coal and petroleum coke. Two coals and two coal / petroleum coke blends will be demonstrated over the two-year period.

The repowering project will include the following items:

- 2 - 265 net MW CFB boilers
- Limestone unloading, storage and reclaim
- Fuel unloading, storage, and reclaim system
- Ash handling and storage system
- Baghouses
- Chimney
- Polishing scrubbers
- Solid waste landfill
- Refurbishment of existing equipment

The repowering project will result in a plant wide (steam units only) 10 percent reduction of NO_x, SO_2, and particulate emissions and a 10 percent reduction in groundwater use, while providing 265 MW of additional electric supply capacity. These units are currently under construction with substantial completion dates of April 2002 for both Northside Units 1 and 2.

5.4 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, and unit retirements, JEA has evaluated future supply capacity needs for the electric system. The table below display the likely need for capacity when assuming the base case load forecast for JEA's system for a ten year period beginning in 2000.

Table 5-1
Resource Needs After Committed Units
Forecast of Capacity and Demand at Time Of Peak

Summer

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Capacity Required For 15% Reserves MW
2000	2,707	461	430	0	2,739	2,384	354	15%	3
2001	3,023	291	430	0	2,885	2,461	424	17%	0
2002	3,237	292	430	0	3,100	2,539	560	22%	0
2003	3,237	200	430	0	3,008	2,619	389	15%	4
2004	3,237	200	383	0	3,055	2,700	355	13%	50
2005	3,237	200	383	0	3,055	2,782	273	10%	145
2006	3,237	200	383	0	3,055	2,866	189	7%	241
2007	3,237	200	383	0	3,055	2,952	103	3%	340
2008	3,237	200	383	0	3,055	3,039	16	1%	440
2009	3,237	200	383	0	3,055	3,128	(73)	-2%	542

Winter

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Capacity Required For 15% Reserves MW
2000	2,731	552	445	0	2,839	2,464	375	15%	0
2001	3,207	303	445	0	3,066	2,548	517	20%	0
2002	2,927	280	445	0	2,763	2,634	128	5%	267
2003	3,454	200	445	0	3,210	2,722	487	18%	0
2004	3,392	200	383	0	3,210	2,812	398	14%	24
2005	3,454	200	383	0	3,272	2,903	369	13%	67
2006	3,454	200	383	0	3,272	2,996	276	9%	174
2007	3,454	200	383	0	3,272	3,091	181	6%	283
2008	3,454	200	383	0	3,272	3,188	84	3%	394
2009	3,454	200	383	0	3,272	3,286	(15)	0%	508

Committed Units:

1. Kennedy Unit 10 Shutdown - April 2000
2. Kennedy CT 7 On-Line - June 2000
3. Brandy Branch CTs 1 and 2 - Jan 2001
4. Brandy Branch CT 3 on-line - Dec 2001
5. Northside Unit 1 - Outage for Fuel Conversion - Jan thru April 2002
6. Northside Unit 2 - April 2002
7. Northside Unit 1 - April 2002

5.5 Resource Plan

The analysis of JEA's electric system to determine the current plan included a review of existing electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and availability, and an analysis of alternatives for resources to meet future capacity and energy needs.

Forecasts of system peak demand growth and energy consumption were utilized for the resource plan. A range of demand growth and energy consumption was reviewed, with the base case peak demand indicating a need for additional capacity to meet system reserve requirements beginning in the year 2004. This need encompasses the inclusion of existing supply resources, transmission system considerations, future changes in existing resources, the addition of 4 combustion turbines, and the Northside Units 1 and 2 CFB conversions.

Five self-build and four purchase power alternatives were modeled using EPRI's Electric Generation Expansion Analysis System (EGEAS), an optimal generation expansion model, to determine the least-cost expansion plan. The least-cost plan was based on the total present worth costs over a ten year planning horizon. Several sensitivity analyses were performed to determine the impact on the least-cost plan.

In addition to cost considerations, environmental and land use considerations were factored into the resource plans. This ensured that the least-cost plans selected were socially and environmentally responsible and demonstrated JEA's total commitment to building the community.

Since the 1999 TYSP was submitted, the Investor Owned Utilities (IOUs) voluntarily agreed to increase their reserve margin to 20 percent, beginning in 2004. Although this agreement did not apply to municipal utilities, JEA has begun an internal analysis to determine if increasing the current reserve margin to a level above 15 percent would be prudent. The increase would be accomplished by accelerating the combined cycle conversion of two of the CTs at Brandy Branch to 2003. In order to meet the 2003 schedule, the permitting process and determination of need filings with State agencies must begin now. Therefore, the combined cycle conversion is shown in JEA's 2000 TYSP filing to avert conflicts between the plan and other State filings, should JEA continue with the accelerated schedule.

Based on modeling of the JEA system, forecast of demand and energy, forecast of fuel prices and availability, and environmental considerations; Table 5-2 presents the expansion plan that provides JEA with the least-cost plan which meets strategic goals. The expansion plan demonstrates strength with small variance in supply alternatives over the numerous sensitivities.

Table 5-2
Reference Plan

Year	Month/ Season	Expansion Plan
2000	Winter	Purchase 250 MW
	April	Shutdown Kennedy Unit 10
	June	Build 1-168 MW CT at Kennedy
	Summer	Purchase 125 MW
2001	January	Build 2-168 MW CTs at Brandy Branch
	October	Retire Southside Unit 4
	October	Retire Southside Unit 5
	December	Build 1-168 MW CT at Brandy Branch
2002	Winter	Purchase 270 MW
	April	Northside 1 CFB Repowering
	April	Northside 2 CFB Repowering
2003	June	Convert 2 Brandy Branch CTs to Combined Cycle (186 Additional MWs)
2004		
2005		
2006	June	Build 1-250 MW CC @ a Greenfield Site
2007		
2008	Summer	Purchase 50 MW
2009	Winter	Purchase 50 MW
	June	Build 1-168 MW CT @ a Greenfield Site

6.0 Project Status

6.1 Combustion Turbines

Site Description

The simple cycle combustion turbine being installed at the existing Kennedy Generating Station, located at 4215 Talleyrand Avenue, Jacksonville, Florida, is scheduled for commercial operation by June 2000. Three additional simple cycle combustion turbines are under construction at JEA's Brandy Branch site. The Brandy Branch site is designed to accomodate a fourth generator, a combustion turbine or a CT conversion to combined cycle.

All four combustion turbines are GE PG7241 (FA) units with a nominal ISO output of approximately 170 MW each. Figures 5-1 and 5-2 display the plan views of the Kennedy and Brandy Branch sites, respectively.

Water Supply

The water usage of combustion turbines is essentially limited to water injection for NO_x control and periodic unit washes. Because of the low capacity factor planned for these generating units, annual water usage is expected to be minimal.

Land Use

The Kennedy Generating Station is located in the Talleyrand area of Jacksonville. The surrounding areas are zoned light and heavy industrial, with some commercial zoning. The Brandy Branch site is located in western Duval County near the city of Baldwin.

Environmental Features

The combustion turbines selected for this project are state-of-the-art machines capable of firing natural gas and distillate oil.

Emissions

State of the art single cycle combustion turbine utilizing natural gas with #2 diesel as back up fuel.

Fuel Storage

Existing fuel storage facilities at the Kennedy Generating Station will be utilized for storage of distillate oil. Distillate oil storage facilities at the Brandy Branch site are currently being designed. It is estimated that sufficient distillate oil will be stored on-site for 72 hours of fired operation for each CT located at Brandy Branch.

Noise

Various sound reduction methods are being utilized for this project. The combustion turbine manufacturer has guaranteed noise limits of 85dBA for near field and 65 dBA for far field.

Certification Status

The installation of simple cycle combustion turbines is not regulated by the Power Plant Siting Act. Individual permits will be obtained for these projects in accordance with regulations.

6.2 Northside Units 1 and 2

Site Description

The Northside Unit 1 and 2 repowering is under construction at the existing Northside Generating Station located at 4377 Hecksher Drive in Jacksonville, Florida, just south of the St. Johns River Power Park. The Northside Generating Station contains three steam turbine and four combustion turbine units. The steam generator (boiler) for Northside Unit 2 was dismantled 1994/95. The Northside site consists of 754 total acres, of which 204 acres are currently in use. Figure 5-3 presents the Northside site plan.

Water Supply

JEA has committed to reduce the 1996 groundwater usage rate of 630,000 gallons per day (gpd) by at least 10 percent as part of the Northside Unit 1 and 2 repowering project. The water conservation measures implemented in the last five years at the Northside facility have reduced demands on the Floridan aquifer by nearly 50 percent from previous levels. To achieve the 10 percent reduction from the baseline 1996 usage levels, which has been established as one of JEA's community commitments, the repowered facility will implement reuse and recycling as well as other water conservation measures to meet the daily groundwater usage level of 570,000 gpd.

Land Use

The Northside Generating Station is an existing site located in an industrial area on the north side of Duval County. It is surrounded by heavy industrial (IH), light industrial (IL), and industrial business park (IBP) zonings to the west and north and is bordered by the

the south. The St. Johns River and several of its tributaries border the Northside Generating Station and ancillary facilities to the west, south and east.

Environmental Features

The circulating fluidized bed (CFB) units to be utilized for this project have inherently low emissions. A polishing scrubber will also be utilized to meet JEA's community commitment to reduce SO_x 10 percent from 1994/1995 baseline levels for the Northside steam units. The CFB units produce low nitrogen oxides (NO_x) due to relatively low combustion temperatures (approx. 1650°F). In addition, selective noncatalytic reduction (SNCR) will be used to further reduce NO_x emissions in order to fulfill JEA's community commitment to reduce NO_x emissions by 10 percent from 1994/1995 levels for the steam units at Northside. Particulates will be controlled by an electrostatic precipitator or fabric filters.

Emissions

The permitted emission rates for these units were determined by a Best Available Control Technology requirements (BACT) analysis. In addition, JEA has a community commitment to reduce annual emissions of SO_x, NO_x, and particulate matter (PM) by 10 percent for the steam units at Northside from the historical 1994/95 baseline. The community commitment was voluntarily included as a permit specific condition.

Fuel Storage

Coal and petroluem coke fuels for the repowered facility will utilize on-site covered storage. BACT for control of fugitive particulate emissions will be utilized and additional controls such as paving of existing dirt roads and planting of additional vegetation will be considered.

Noise

Because this is an existing site, noise levels are not expected to increase significantly due to the repowering project.

Certification Status

Since the Northside Units 1 and 2 repowering project will not increase output of the steam turbines, the project is not required to be licensed under the Power Plant Siting Act.

6.3 Other Environmental Considerations

Environmental Programs

JEA participates in the American Public Power Association's (APPA) nationwide Tree Power program. Last year JEA exceeded it's five-year goal of 305,000 trees planted by reaching 323,000 actual trees planted through the JEA Future Tree and Free Tree programs.

JEA also participates in the Department of Energy (DOE) voluntary CO_2 reporting program. Projects receiving CO_2 reduction credits annually include the above mentioned programs as well as gas conversion projects at all three existing stations, landfill-gas utilization projects, free residential and non-residential energy audits, free new home construction workshops, heat rate improvements, and power factor improvements.

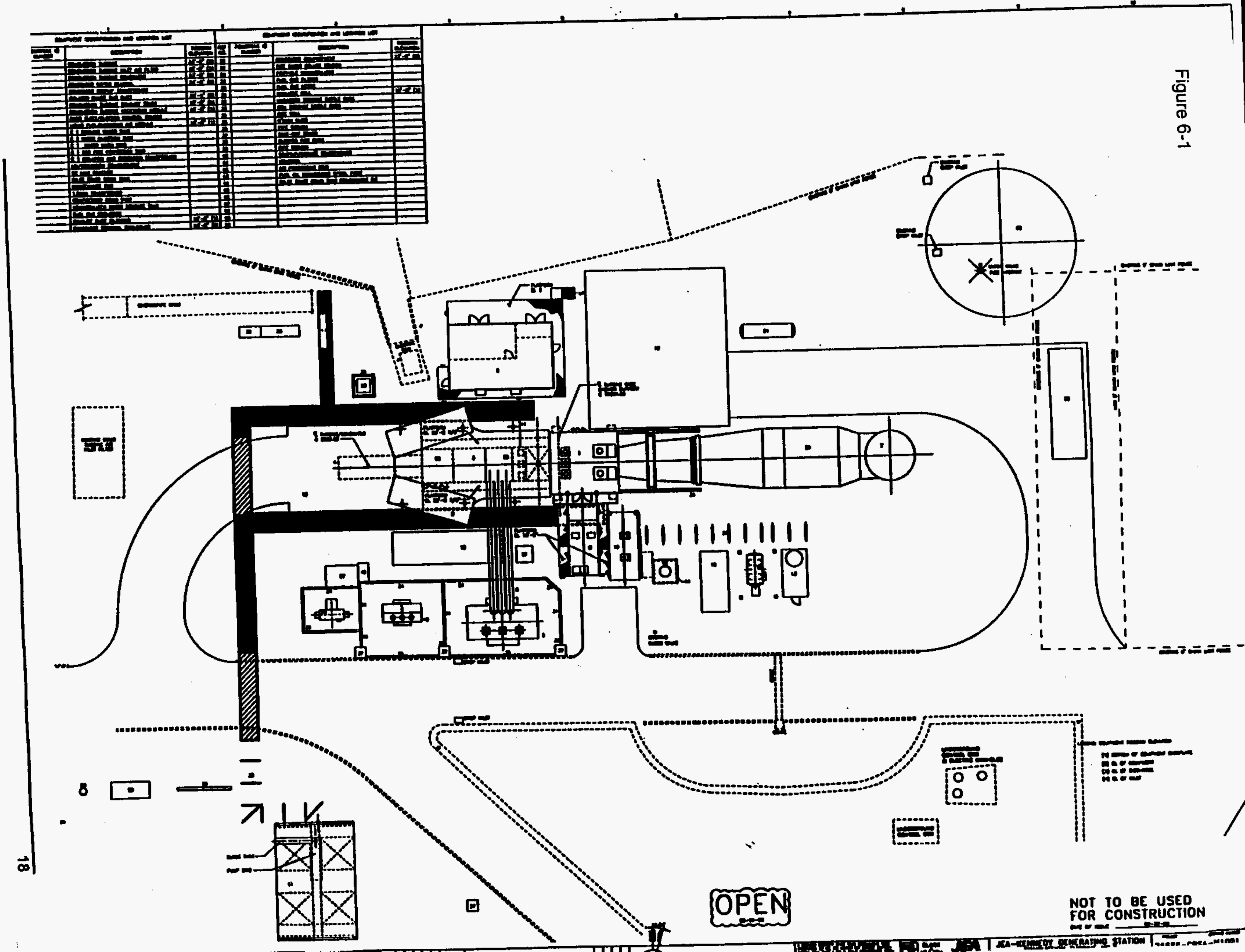

OPEN
NOT TO BE USED
FOR CONSTRUCTION
JEA-KENNEDY GENERATING STATION

Figure 6-1

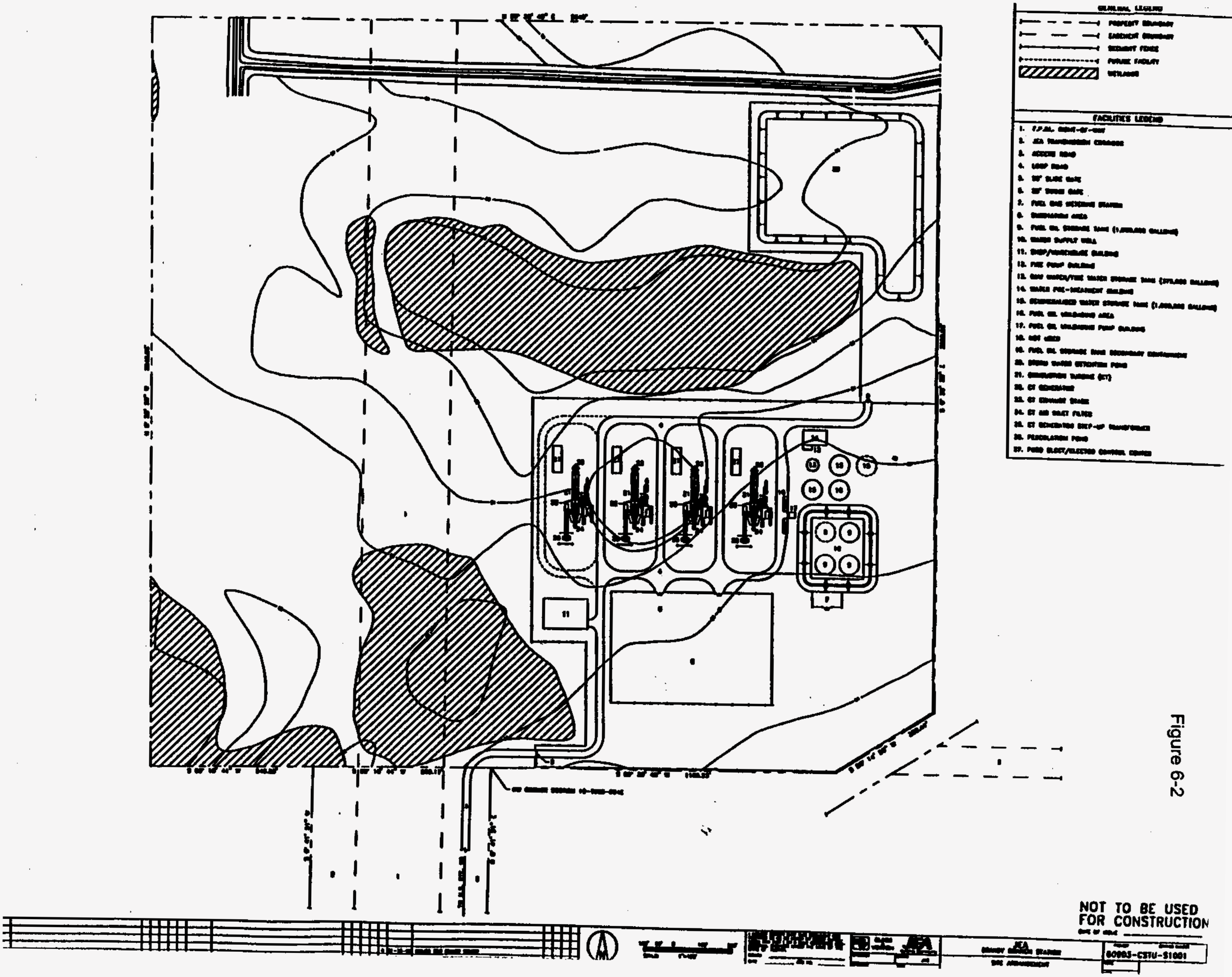
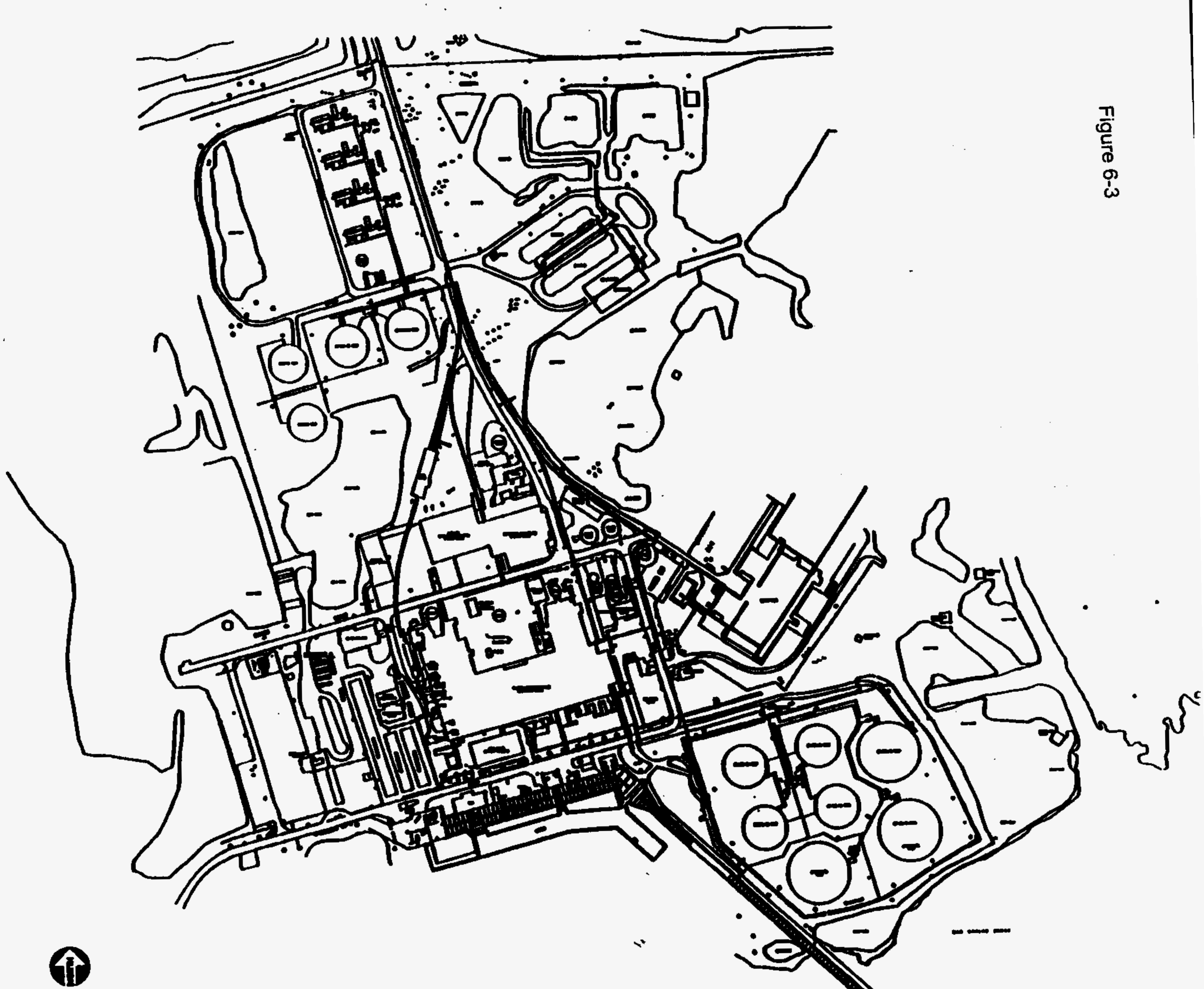


Figure 6-2

Figure 6-3



NORTHSIDE GENERATING STATION

7.0 Glossary

7.1 List of Abbreviations

Type of Generation Units

CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
CW	Combined Cycle – Steam Turbine Portion, Waste Heat Boiler (only)
GT	Combustion Turbine
FC	Fluidized Bed Combustion
IC	Internal Combustion
ST	Steam Turbine, Boiler, Non-Nuclear

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Underconstruction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
FO2	No. 2 Fuel Oil
FO6	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

8.0 Ten Year Site Plan Schedules

The following section presents the schedules required by the Ten-Year Site Plan rules for the Florida Public Service Commission.

Schedule 1
Existing Generating Facilities
As of January 1, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(13)	(14)		(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type Primary	Fuel Type Alt.	Fuel Transport Primary	Fuel Transport Alt.	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen Max Nameplate kW	Net MW Capability Summer	Net MW Capability Winter	Ownership	Status
Kennedy										418,200	241	286		(a)
	8	12-031	ST	FO6		WA		7/1955	(b)	50,000	43	43	Utility	M
	9	12-031	ST	NG	FO6	PL	WA	1/1958	(b)	50,000	43	43	Utility	M
	10	12-031	ST	NG	FO6	PL	WA	12/1961	3/2000	149,600	97	97	Utility	(e)
	3-5	12-031	GT	FO2		WA/TK		7/1973	(b)	168,600	144	189	Utility	
Northside										1,407,100	955	1,015		(a)
	1	12-031	ST	NG	FO6	PL	WA	11/1966	(b)	297,500	262	262	Utility	
	2	12-031	ST	FO6		WA		3/1972	(b)	297,500	262	262	Utility	M
	3	12-031	ST	NG	FO6	PL	WA	7/1977	(b)	563,700	505	505	Utility	
	3-6	12-031	GT	FO2		WA/TK		1/1975	(b)	248,400	188	248	Utility	
Southside										231,600	209	209		(a)
	4	12-031	ST	NG	FO6	PL	WA	11/1958	10/2001	75,000	67	67	Utility	
	5	12-031	ST	NG	FO6	PL	WA	9/1964	10/2001	156,600	142	142	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(b)	3	3	3	Utility	
St. Johns River Power Park										1,359,200	1,021	1,021		(c)
	1	12-301	ST	BIT/PC		RR,WA		3/1987	3/2027	679,600	510	510	Joint	(c)
	2	12-301	ST	BIT/PC		RR,WA		5/1988	5/2028	679,600	510	510	Joint	(c)
Scherer	4	13-207	ST	SUB	BIT	RR	RR	2/1989	2/2029	846,000	200	200	Joint	(d)
JEA System Total											**2,629**	**2,734**		(a)

NOTE:
(a) Plant and System total net capability do not include units designated as inactive reserve (M)
(b) Life extension will continue to be an evaluated consideration for future capacity additions.
(c) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(e) Unit derated from net 129 MW and will be shutdown, not retired, April 2000.

Schedule 2.1
History And Forecast of Energy Consumption and Number of Customers By Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		Rural and Residential				Commercial			Industrial		
Calendar Year	Duval County Population	Members Per Household	GWH Sales	Average No. of Customers	Average kWh/ Customer	GWH Sales	Average No. of Customers	Average kWh/ Customer	GWH Sales	Average No. of Customers	Average kWh/ Customer
1990	672,971	2.61	3,629	258,075	14,060	925	29,198	31,679	3,494	2,344	1,490,751
1991	681,631	2.60	3,602	262,376	13,730	874	28,995	30,133	3,590	2,477	1,449,326
1992	693,546	2.61	3,696	266,219	13,883	873	29,144	29,945	3,660	2,596	1,409,926
1993	701,608	2.59	3,830	270,818	14,143	862	29,378	29,327	3,889	2,670	1,456,427
1994	710,592	2.55	3,909	278,682	14,027	897	29,571	30,324	4,048	2,731	1,482,265
1995	721,900	2.55	4,137	283,551	14,589	937	29,972	31,269	4,174	2,742	1,522,385
1996	731,790	2.53	4,391	288,947	15,195	937	30,162	31,079	4,353	2,975	1,463,160
1997	740,791	2.50	4,165	295,916	14,075	949	30,709	30,903	4,526	3,025	1,496,198
1998	751,978	2.49	4,643	301,883	15,380	1,035	31,297	33,070	4,835	3,094	1,562,702
1999	*	*	4,529	305,916	14,805	1,036	31,873	32,516	5,130	3,203	1,601,623
2000	*	*	4,878	314,079	15,530	1,087	32,561	33,379	5,019	3,219	1,559,217
2001	*	*	5,045	320,361	15,749	1,126	33,213	33,892	5,164	3,283	1,572,686
2002	*	*	5,218	326,768	15,968	1,166	33,877	34,405	5,312	3,349	1,586,154
2003	*	*	5,395	333,303	16,187	1,207	34,554	34,917	5,464	3,416	1,599,623
2004	*	*	5,578	339,969	16,406	1,249	35,246	35,430	5,621	3,484	1,613,092
2005	*	*	5,765	346,769	16,625	1,292	35,950	35,942	5,781	3,554	1,626,560
2006	*	*	5,958	353,704	16,844	1,337	36,669	36,455	5,945	3,625	1,640,029
2007	*	*	6,156	360,778	17,064	1,383	37,403	36,968	6,114	3,698	1,653,498
2008	*	*	6,360	367,994	17,283	1,430	38,151	37,480	6,287	3,772	1,666,967
2009	*	*	6,570	375,354	17,505	1,479	38,914	38,000	6,465	3,847	1,680,545

* Duval County population not used in forecast projections

Schedule 2.2
History And Forecast of Energy Consumption and Number of Customers By Class

Calendar Year	(13) Street & Highway Lighting GWH	(14) Other Sales to Ultimate Customers GWH	(15) Total Sales to Ultimate Customers GWH	(16) Sales For Resale GWH	(17) Utility Use & Losses GWH	(18) Net Energy For Load GWH	(19) Other Customers (Average No.)	(20) Total No.of Customers
1990	57	0	8,105	175	258	8,538	0	289,617
1991	58	0	8,124	224	487	8,835	0	293,848
1992	59	0	8,288	309	431	9,028	0	297,959
1993	61	0	8,642	339	628	9,609	0	302,866
1994	63	0	8,917	304	388	9,609	0	310,984
1995	72	0	9,320	339	667	10,326	0	316,265
1996	70	0	9,751	363	401	10,515	0	322,084
1997	71	0	9,711	383	571	10,665	0	329,650
1998	77	0	10,590	438	442	11,470	0	336,274
1999	86	0	10,781	454	547	11,782	0	340,992
2000	90	0	11,073	442	607	12,123	0	349,859
2001	97	0	11,432	461	612	12,505	0	356,857
2002	105	0	11,800	479	614	12,894	0	363,994
2003	113	0	12,180	489	621	13,289	0	371,274
2004	123	0	12,570	517	605	13,692	0	378,699
2005	133	0	12,971	535	596	14,102	0	386,273
2006	143	0	13,383	554	582	14,519	0	393,999
2007	155	0	13,808	573	564	14,945	0	401,879
2008	167	0	14,244	591	543	15,378	0	409,916
2009	181	0	14,695	609	521	15,825	0	418,114

Schedule 3
History And Forecast of Seasonal Peak Demand and Annual Net Energy For Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Summer Peak Demand @ Generator - MW					Annual Net Energy for Load (GWH)				Winter Peak Demand @ Generator - MW				
Calendar Year	Retail	Wholesale	Total	Interruptible	Net Firm Demand	Retail	Wholesale	Total	Load Factor %	Retail	Wholesale	Total	Interruptible	Net Firm Demand
1990	1,749	40	1,789	0	1,789	8,358	180	8,538	48	1,939	73	2,012	0	2,012
1991	1,709	47	1,756	0	1,756	8,604	231	8,835	57	1,661	64	1,725	0	1,725
1992	1,825	56	1,881	0	1,881	8,710	318	9,028	55	1,812	69	1,881	0	1,881
1993	1,938	60	1,998	0	1,998	9,260	349	9,609	55	1,725	66	1,791	0	1,791
1994	1,865	53	1,918	0	1,918	9,296	313	9,609	57	1,866	70	1,936	0	1,936
1995	2,001	66	2,067	0	2,067	9,977	349	10,326	54	2,108	82	2,190	0	2,190
1996	2,050	64	2,114	0	2,114	10,141	374	10,515	50	2,313	88	2,401	0	2,401
1997	1,981	70	2,051	80	2,131	10,271	394	10,665	57	1,878	72	1,950	36	1,986
1998	2,146	86	2,232	106	2,338	11,019	451	11,470	56	1,842	68	1,910	65	1,975
1999	2,189	92	2,281	146	2,427	11,286	454	11,740	55	2,210	93	2,303	100	2,403
2000	2,286	98	2,384	150	2,534	11,668	455	12,123	54	2,366	98	2,464	102	2,566
2001	2,358	103	2,461	154	2,615	12,030	475	12,505	54	2,445	103	2,548	105	2,653
2002	2,431	108	2,539	158	2,697	12,400	493	12,894	54	2,526	108	2,634	107	2,742
2003	2,506	113	2,619	162	2,780	12,786	504	13,289	54	2,610	112	2,722	110	2,832
2004	2,582	118	2,700	166	2,865	13,159	533	13,692	53	2,695	117	2,812	113	2,924
2005	2,659	123	2,782	170	2,952	13,551	551	14,102	53	2,781	122	2,903	116	3,018
2006	2,738	128	2,866	174	3,040	13,949	571	14,519	53	2,869	127	2,996	118	3,114
2007	2,819	133	2,952	178	3,130	14,355	590	14,945	53	2,959	132	3,091	121	3,212
2008	2,901	138	3,039	183	3,222	14,770	609	15,378	53	3,051	137	3,188	124	3,312
2009	2,985	143	3,128	188	3,316	15,196	624	15,820	53	3,144	142	3,286	128	3,414

Note: Wholesale and interruptible peak demand for 1999 are estimated.

Schedule 4
Previous Year Actual and Two Year Forecast of Peak Demand And Net Energy For Load By Month
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 1999		Forecast 2000		Forecast 2001	
Month	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	2,403	907	2,566	999	2,653	1,031
February	2,182	798	2,330	867	2,409	894
March	1,823	846	1,973	867	2,040	894
April	1,939	905	1,805	843	1,862	869
May	2,055	978	2,114	999	2,181	1,031
June	2,147	1,058	2,415	1,132	2,492	1,167
July	2,376	1,243	2,534	1,252	2,615	1,291
August	2,427	1,274	2,476	1,264	2,555	1,304
September	2,172	1,024	2,329	1,119	2,403	1,155
October	1,922	947	2,149	944	2,221	973
November	1,677	818	1,915	869	1,979	896
December	2,052	943	2,271	969	2,347	999
Total		11,741		12,123		12,505

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Type	Units	Actuals 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Nuclear		1000 MBtu	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	3,670	3,341	3,343	3,917	3,554	3,213	2,958	3,022	3,082	2,966	3,152	3,187
(3)	Residual	Total	1000 BBL	4,985	4,544	2,672	3,041	1,077	613	683	834	724	830	931	973
(4)		Steam	1000 BBL	4,985	4,544	2,672	3,041	1,077	613	683	834	724	830	931	973
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	246	278	206	526	525	168	202	257	263	366	435	521
(9)		Steam	1000 BBL	36	28	26	31	28	25	23	24	24	23	25	25
(10)		CC	1000 BBL	0	0	0	0	0	1	7	8	114	180	205	218
(11)		CT	1000 BBL	210	250	180	495	497	142	171	225	125	163	206	278
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 mCF	6,166	14,036	14,764	15,407	12,098	11,933	14,429	15,090	16,101	17,543	17,383	17,661
(14)		Steam	1000 mCF	6,166	14,036	14,716	15,118	10,408	4,407	2,132	2,453	1,782	1,438	1,649	1,483
(15)		CC	1000 mCF	0	0	0	0	0	7,169	12,216	12,561	14,306	16,032	15,733	16,178
(16)		CT	1000 mCF	0	0	48	289	1,690	357	81	76	13	73	1	0
(17)		Diesel	1000 mCF	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Pet Coke	Total	1000 Ton	536	595	622	627	1,678	2,153	2,089	2,079	2,092	2,075	2,103	2,185
(19)		Steam	1000 Ton	536	595	622	627	1,678	2,153	2,089	2,079	2,092	2,075	2,103	2,185
(20)		CC	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(21)		CT	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Diesel	1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(23)	Other		1000 kWH	1,692	1,160	1,713	2,156	1,737	865	754	831	725	792	849	839

Schedule 6.1
Energy Sources (GWH)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals											
	Fuel	Type	Units	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		GWH	(2,385)	(2,773)	(2,662)	(2,610)	(2,408)	(2,676)	(2,545)	(2,516)	(2,590)	(2,517)	(2,613)	(2,654)
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	8,774	7,595	8,114	8,032	7,285	6,505	6,045	6,178	6,301	6,061	6,440	6,517
(4)	Residual	Total	GWH	3,044	2,795	1,664	1,897	705	385	424	519	442	507	573	601
(5)		Steam	GWH	3,044	2,795	1,664	1,897	705	385	424	519	442	507	573	601
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	77	89	72	236	250	67	92	113	204	305	354	407
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0	7	8	146	230	258	273
(12)		CT	GWH	77	89	72	236	250	67	85	105	58	74	96	134
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	668	1,333	1,563	1,625	1,213	2,231	3,260	3,339	3,765	4,173	4,085	4,185
(15)		Steam	GWH	668	1,333	1,558	1,597	1,045	380	163	189	130	106	119	103
(16)		CC	GWH	0	0	0	0	0	1,814	3,090	3,142	3,634	4,060	3,967	4,082
(17)		CT	GWH	0	0	5	29	168	36	8	8	1	8	0	0
(18)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Pet Coke	Total	GWH	665	1,584	1,634	1,646	4,543	5,917	5,665	5,644	5,676	5,628	5,705	5,932
(20)		Steam	GWH	665	1,584	1,634	1,646	4,543	5,917	5,665	5,644	5,676	5,628	5,705	5,932
(21)	Other		GWH	625	1,160	1,739	1,679	1,306	860	750	826	721	787	834	833
(22)	Net Energy for Load		GWH	11,468	11,784	12,123	12,505	12,894	13,289	13,692	14,102	14,519	14,945	15,378	15,820

Schedule 6.2
Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals											
	Fuel	Type	Units	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		%	(20.80)	(23.53)	(21.96)	(20.87)	(18.67)	(20.13)	(18.59)	(17.84)	(17.83)	(16.84)	(16.99)	(16.78)
(2)	Nuclear		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(3)	Coal		%	76.51	64.45	66.93	64.23	56.50	48.95	44.15	43.81	43.40	40.56	41.88	41.19
(4)	Residual	Total	%	26.54	23.72	13.72	15.17	5.46	2.90	3.10	3.68	3.05	3.40	3.73	3.80
(5)		Steam	%	26.54	23.72	13.72	15.17	5.46	2.90	3.10	3.68	3.05	3.40	3.73	3.80
(6)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(7)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(8)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(9)	Distillate	Total	%	0.67	0.76	0.60	1.89	1.94	0.51	0.67	0.80	1.40	2.04	2.30	2.57
(10)		Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(11)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.06	1.00	1.54	1.68	1.72
(12)		CT	%	0.67	0.76	0.60	1.89	1.94	0.50	0.62	0.74	0.40	0.50	0.62	0.85
(13)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(14)	Natural Gas	Total	%	5.83	11.31	12.89	13.00	9.40	16.79	23.81	23.68	25.93	27.92	26.57	26.46
(15)		Steam	%	5.83	11.31	12.85	12.77	8.10	2.86	1.19	1.34	0.90	0.71	0.77	0.65
(16)		CC	%	0.00	0.00	0.00	0.00	0.00	13.65	22.57	22.28	25.02	27.17	25.79	25.80
(17)		CT	%	0.00	0.00	0.04	0.23	1.30	0.27	0.06	0.06	0.01	0.05	0.00	0.00
(18)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(19)	Pet Coke	Total	%	5.80	13.44	13.48	13.16	35.24	44.52	41.38	40.02	39.10	37.66	37.10	37.50
(20)		Steam	%	5.80	13.44	13.48	13.16	35.24	44.52	41.38	40.02	39.10	37.66	37.10	37.50
(21)	Other		%	5.45	9.85	14.34	13.43	10.13	6.47	5.48	5.86	4.97	5.26	5.42	5.26
(22)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

Schedule 7
Forecast of Capacity, Demand, and Scheduled Maintenance at Time Of Peak
Summer

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2000	2,707	461	430	0	2,739	2,384	354	15%	0	354	15%
2001	3,023	291	430	0	2,885	2,461	424	17%	0	424	17%
2002	3,237	292	430	0	3,100	2,539	560	22%	0	560	22%
2003	3,395	200	430	0	3,166	2,619	547	21%	0	547	21%
2004	3,395	200	383	0	3,213	2,700	513	19%	0	513	19%
2005	3,395	200	383	0	3,213	2,782	431	15%	0	431	15%
2006	3,635	200	383	0	3,453	2,866	587	20%	0	587	20%
2007	3,635	200	383	0	3,453	2,952	501	17%	0	501	17%
2008	3,635	250	383	0	3,503	3,039	464	15%	0	464	15%
2009	3,793	200	383	0	3,611	3,128	483	15%	0	483	15%

Winter

Year	Existing Capacity	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2000	2,731	552	445	0	2,839	2,464	375	15%	0	375	15%
2001	3,207	303	445	0	3,066	2,548	517	20%	0	517	20%
2002	2,927	550	445	0	3,033	2,634	398	15%	0	398	15%
2003	3,454	200	445	0	3,210	2,722	487	18%	0	487	18%
2004	3,583	200	383	0	3,401	2,812	589	21%	0	589	21%
2005	3,645	200	383	0	3,463	2,903	560	19%	0	560	19%
2006	3,645	200	383	0	3,463	2,996	467	16%	0	467	16%
2007	3,929	200	383	0	3,747	3,091	656	21%	0	656	21%
2008	3,929	200	383	0	3,747	3,188	559	18%	0	559	18%
2009	3,929	250	383	0	3,797	3,286	510	16%	0	510	16%

Schedule 8.0

Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel Type		Fuel Transport		Construction Start Date	Commercial In-Service Date	Expected Retirement/ Shutdown	Gen Max Nameplate kW	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate					Summer MW	Winter MW	Status
Kennedy	10	12-031	ST	NG	FO6	PL	WA			04/01/00	149,600	97	97	M
Kennedy	7	12-031	GT	NG	FO2	PL	TK		06/01/00		195,280	158	191	TS
Brandy Branch	1	Brandy Branch	CT	NG	FO2	PL	TK	10/01/99	01/01/01		195,280	158	191	U
Brandy Branch	2	Brandy Branch	CT	NG	FO2	PL	TK	10/01/99	01/01/01		195,280	158	191	U
Southside	4	12-031	ST	NG	FO6	PL	WA			10/01/01	75,000	67	67	R
Southside	5	12-031	ST	NG	FO6	PL	WA			10/01/01	156,600	142	142	R
Brandy Branch	3	Brandy Branch	GT	NG	FO2	PL	TK	10/01/99	12/01/01		195,280	158	191	U
Northside	2	12-031	FC	PC	Coal	WA	WA	09/01/99	04/01/02		297,000	265	265	RP
Northside	1	12-031	FC	PC	Coal	WA	WA	09/01/99	06/01/02		297,000	265	265	FC
Brandy Branch	4	Brandy Branch	CW	NG	FO2	PL	TK		06/01/03		195,280	158	191	P
Combined Cycle	Unknown	Unknown	CC	NG	FO2	PL	TK		06/02/06			240	284	P
Combustion Turbine	Unknown	Unknown	GT	NG	FO2	PL	TK		06/01/09		195,280	158	191	P

Schedule 9.1
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Kennedy CT 7
(2)	Capacity:	Gas / Oil
(3)	Summer MW	149 MW / 158 MW
(4)	Winter MW	186 MW / 191 MW
(5)	Technology Type:	Simple Cycle Combustion Turbine
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	05/1999
(8)	Commercial In-Service date:	06/2000
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	Diesel Fuel Oil
(12)	Air Pollution Control Strategy:	Low NO_x Burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	5 acres
(15)	Construction Status:	Final Phases
(16)	Certfication Status:	Not Required
(17)	Status with Federal Agencies:	AC Permit Obtained
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	0.84 percent
(20)	Forced Outage Factor (FOF):	1.5 percent
(21)	Equivalent Availability Factor (EAF):	97.66 percent
(22)	Resulting Capacity Factor (%):	10.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	11,120Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	$283
(27)	Direct Construction Cost ($/kW):	Included in total installed cost
(28)	AFUDC Amount ($/kW):	Included in total installed cost
(29)	Escalation ($/kW):	Included in total installed cost
(30)	Fixed O&M ($/kW-yr):	2.47
(31)	Variable O&M ($/MWh):	10.37

Schedule 9.2 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Brandy Branch CTs 1, 2 and 3
(2)	Capacity:	Gas Oil
(3)	Summer MW	149 MW 158 MW
(4)	Winter MW	186 MW 191 MW
(5)	Technology Type:	Simple Cycle Combustion Turbine
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	12/1999
(8)	Commercial In-Service date:	12/2000 Units 1 & 2 12/2001 Unit 3
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	Diesel Fuel Oil
(12)	Air Polluation Control Strategy:	Low NO_x Burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	153 acres
(15)	Construction Status:	Initial Phase
(16)	Certfication Status:	Not Required
(17)	Status with Federal Agencies:	Filed
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	0.84 percent
(20)	Forced Outage Factor (FOF):	1.5 percent
(21)	Equivalent Availability Factor (EAF):	97.66 percent
(22)	Resulting Capacity Factor (%):	5.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	11,120Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	$328
(27)	Direct Construction Cost ($/kW):	Included in total installed cost
(28)	AFUDC Amount ($/kW):	Included in total installed cost
(29)	Escalation ($/kW):	Included in total installed cost
(30)	Fixed O&M ($/kW-yr):	2.47
(31)	Variable O&M ($/MWh):	10.37

Schedule 9.3
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Northside Units 1 and 2
(2)	Net Capacity:	
(3)	Summer MW	265
(4)	Winter MW	265
(5)	Technology Type:	Circulating Fluidized Bed
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	08/1999
(8)	Commercial In-Service date:	04/2002
(9)	Fuel	
(10)	Primary	Petroleum Coke
(11)	Alternate	Coal
(12)	Air Pollution Control Strategy:	CFB with Dry Scrubber, Bag House and SNCR
(13)	Cooling Method:	Once Through Flow
(14)	Total Site Area:	200 acres
(15)	Construction Status:	Active
(16)	Certification Status:	Not Required
(17)	Status with Federal Agencies:	Construction Permit Recieved
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	7.35 percent
(20)	Forced Outage Factor (FOF):	2.5 percent
(21)	Equivalent Availability Factor (EAF):	90.15 percent
(22)	Resulting Capacity Factor (%):	90.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9946 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	$658.0
(28)	AFUDC Amount ($/kW):	Included in direct construction cost
(29)	Escalation ($/kW):	Included in direct construction cost
(30)	Fixed O&M ($/kW-yr):	6.916
(31)	Variable O&M ($/MWh):	1.705

Schedule 10.1 Status Report and Specifications of Proposed Directly Associated Transmission Lines Brandy Branch CTs (Normandy - Brandy Branch – Duval Loop)		
(1)	Point of Origin and Termination	Normandy - Brandy Branch – Duval Loop
(2)	Number of Lines	No New Lines for the First 3 CTs
(3)	Right of Way	Existing ROW
(4)	Line Length	N/A
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	9 months (ISD: January 2001)
(7)	Anticipated Capital Investment	$8,300,000
(8)	Substations	New Brandy Branch Substation
(9)	Participation with Other Utilities	None

Schedule 10.2 Status Report and Specifications of Proposed Directly Associated Transmission Lines Brandy Branch (Brandy Branch – Duval)		
(1)	Point of Origin and Termination	Brandy Branch - Duval
(2)	Number of Lines	One (1) New Line (Increase Reliability)
(3)	Right of Way	Existing ROW
(4)	Line Length	3.1 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	19 Months(ISD: October, 2001)
(7)	Anticipated Capital Investment	$3,000,000
(8)	Substations	Brandy Branch and Duval 230 kV
(9)	Participation with Other Utilities	FPL (at Duval Substation)

Schedule 10.3 Status Report and Specifications of Proposed Directly Associated Transmission Lines Northside (Center Pk-Northside)		
(1)	Point of Origin and Termination	Convert Center Pk-Northside to 230 kV
(2)	Number of Lines	One (1) line
(3)	Right of Way	No new ROW Required
(4)	Line Length	11.03 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	20 Months (ISD: November, 2001)
(7)	Anticipated Capital Investment	$2,000,000
(8)	Substations	Line terminations at Center Pk and Northside Substations
(9)	Participation with Other Utilities	None

Schedule 10.4 Status Report and Specifications of Proposed Directly Associated Transmission Lines Northside (New Center Pk-Greenland)		
(1)	Point of Origin and Termination	New Center Pk-Greenland 230 kV Line
(2)	Number of Lines	One (1) line
(3)	Right of Way	New ROW Required
(4)	Line Length	19.3 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	37 months (ISD: May, 2003)
(7)	Anticipated Capital Investment	$6,000,000
(8)	Substations	Line terminations at Center Pk and Greenland Substations
(9)	Participation with Other Utilities	None

Schedule 10.5 Status Report and Specifications of Proposed Directly Associated Transmission Lines Brandy Branch CC (Normandy-Brandy Branch)		
(1)	Point of Origin and Termination	Normandy-Brandy Branch
(2)	Number of Lines	One (1) New Line
(3)	Right of Way	Existing ROW
(4)	Line Length	9.06 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	Under Evaluation
(7)	Anticipated Capital Investment	
(8)	Substations	Brandy Branch and Normandy 230 kV
(9)	Participation with Other Utilities	None