21 West Church Street
Jacksonville, Florida 32202-3139

06 MAR 31

JEA

March 30, 2006

ELECTRIC
WATER
SEWER

Michael S. Haff
Bureau of Electric Reliability/Conservation
Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

Attached you will find 25 copies of JEA's 2006 Ten Year Site Plan filing. If you have any questions regarding this response or any additional questions, please contact me at (904) 665-7109 or Mary Guyton-Baker at (904) 665-6216.

Thank You,

Don Gilbert

Don Gilbert,
Manager, Electric System Planning

Ten Year Site Plan

JEA®

Building Community®

April 2006

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1.0 Introduction

The objective of JEA's Ten-Year Site Plan is to develop an environmentally sound power supply strategy, which provides reliable electric service at the lowest practical cost. This report represents the 2006 Ten Year Site Plan for JEA covering a planning period from 2006 to 2015.

2.0 Existing Facilities

2.1 Power Supply

Electric System Summary

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

The generating capability of JEA's system currently consists of the Kennedy, Northside, and Brandy Branch 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 3,553 MW in the winter and 3,389 MW in the summer. Details of the existing facilities are displayed in TYSP 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 728 circuit-miles of transmission lines at five voltage levels: 69kV, 138kV, 230kV, and 500kV. JEA's transmission system includes a 230 kV open loop surrounding JEA's service territory. JEA is currently interconnected with Florida Power & Light (FP&L), Seminole Electric Cooperative (SECI), Florida Public Utilities (FPU) and the City of Jacksonville Beach. Interconnections with FP&L are at 230 kV to the Sampson and Duval Substations. The interconnection to SECI is at 230 kV and the interconnection to FPU is at 138 kV

JEA and FP&L jointly own two 500 kV transmission lines that are interconnected with Georgia Integrated Transmission System. JEA, FP&L, Progress Energy and the City of Tallahassee each own transmission interconnections with Georgia Integrated Transmission System. JEA's ownership 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 from JEA. 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 Integrated Transmission System delivers the power from the unit to the jointly owned 500 kV transmission lines.

Purchased Power

Unit Power Sales

Southern Company and JEA entered a Unit Power Sales (UPS) contract in which JEA currently purchases 200 MW of firm capacity and energy from specific Southern Company coal units through May 31, 2010. JEA has the unilateral option, upon three years notice, to cancel 150 MW of the UPS. In this plan, JEA will retain 200 MW of UPS during the contract term and reduce available capacity by 200 MW at the end of the contract term beginning summer 2010.

The Energy Authority

The Energy Authority (TEA), actively trades energy with a large number of counterparties throughout the United States and is generally able to acquire capacity and energy from other market participants when any of TEA's members, including JEA, require additional resources.

TEA generally acquires the necessary short-term purchase for the season of need based on market conditions. TEA identifies a number of potential suppliers within Florida and Georgia. TEA has reserved firm transmission rights across the Georgia ITS to the Florida/Georgia border, therefore capacity from generating units located in Georgia should provide similar levels of reliability to capacity available within Florida. TEA, with input from JEA, selects the best offer. TEA then enters into back to back power purchase agreements with the supplier and with the purchaser, JEA.

TEA's ability to acquire capacity and/or energy and TEA's firm transmission rights across the Georgia ITS gives JEA a degree of assurance that a plan which includes short-term market purchases is viable. Since their inception, TEA has purchased capacity and energy on behalf of JEA for six seasonal periods. Of these six seasons, approximately 65% of the purchases were out of state resources and approximately

35% were Florida resources. In this Ten Year Site Plan, JEA identifies one seasonal need for capacity or energy during the winter 2012 of 70 MW.

Clean Power

As part of JEA's Green Works initiative, JEA has agreed to supply 7.5 percent of its peak demand with renewable resources by 2015. In 2004, JEA issued a Request for Proposal (RFP) for renewable resources. As a result of this RFP, JEA is in negotiation for 22 MW of renewable resources. These resources are included in JEA 2005 TYSP.

Also, JEA is continuing its contract negotiations with Biomass Industries Group, Inc. (BIG). JEA has contracted to purchase 120 MW firm renewable energy from a gasified biomass fueled electric generation plant proposed to be constructed by BIG in South Florida. The proposed facility is to be fueled by an energy crop (bamboo and E-grass) to be grown by BIG.

Cogeneration

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.

	Unit	In-Service	Net Capability[3] – MW	
Cogenerator Name	Type	Date	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 Agreements

Florida Public Utilities Company

JEA also furnishes wholesale power to Florida Public Utilities Company (FPU) for resale in the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU until December 31, 2007. Currently, FPU does not have a contract with JEA to renew this sale. Therefore, starting January 2008, sales to FPU are not included in JEA's load and energy forecast. As of March 14, 2006, FPU has provided written interest to negotiate an extension or new contract with JEA. Sales to FPU in 2005 totaled 496 GWh (3.6 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 autotransformers to provide safe and reliable transmission service under normal and single contingency conditions.
- Plan the transmission system to withstand single contingencies without loss of customer load. (A single contingency is the unexpected failure of any one line, transformer or generator.)
- 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.
- Plan to provide lead time for transmission projects of approximately 3 to 5 years.
- Plan to meet the Florida Reliability Coordinating Council's (FRCC) guidelines on how the Florida electric utilities plan to operate. These guidelines are similar to JEA's transmission planning criteria discussed previously.

- Plan to 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 requirements, capacity benefit margins, and those reliability margins as outlined in industry-standard publications.

- Plan to meet or exceed specific subparts of those transmission system reliability-planning criteria published by the North American Electric Reliability Coordinating Council (NERC), including Planning Criteria Categories A, B, C.2 and C.5. Meet or exceed these criteria generally as they are interpreted by the Florida Reliability Coordinating Council, as updated from time to time.

2.3 Demand Side Management

In 2004, JEA studied numerous DSM measures, evaluated the measures using the Commission approved Florida Integrated Resource 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 were found to be cost-effective for JEA. The inability to find cost-effective DSM measures was primarily due to the low cost of new generation, high efficiency of new generation, low interest rates, and low fuel price projections. In August 2004, the PSC approved JEA's Plan for zero DSM goals for 2005-2014.

JEA agreed to continue several DSM programs, including residential energy audits, commercial energy audits, and community conservation initiatives. With the rising costs of all fuel types, JEA continues to look for cost effective DSM measures.

2.4 Green/Clean Power Programs

In 2001 JEA developed a Green Power Program to encourage the widespread application of renewable energy technology in its service territory. JEA has established two Clean Power Capacity goals. The first, contained in JEA's internal Clean Power Strategic Initiative, calls for a minimum of 4% clean power capacity by 2007. The second, as stated in JEA's Memorandum of Understanding with the American Lung Association and Sierra Club, calls for a minimum of 7.5% clean power capacity by 2015.

As part of the Green Power Program, JEA implemented the solar incentive program in early 2002. Under the terms of the program, JEA provides cash incentives for customers to install solar photovoltaic and solar thermal systems at their homes or business. As of January 2006, JEA has provided incentives to over 800 solar systems installed throughout the community resulting in 9 MWs towards our Clean Power Goals. JEA also owns approximately 223 kw of solar photovoltaic modules throughout the city of Jacksonville including systems at all high schools in the JEA service area and one of the largest photovoltaic systems in the southeast at the Jacksonville International Airport (50 KW).

Also, JEA owns and operates three internal combustion engine generators located at the Girvin Road Landfill. This facility was placed in service in July, 1997 and is fueled by gas produced by the landfill (the gas consists of approximately 52% methane and 48% carbon dioxide and nitrogen). The facility originally had four generators with an aggregate net capacity of 3.0 MW. Since that time, gas generation has declined and one generator has been removed and placed in service at the Buckman Wastewater Treatment facility. JEA also receives approximately 1500 kw of landfill gas from the North Landfill which is pumped to the Northside Generating Station and used to generate power in Unit 3. JEA will continue to monitor and evaluate these and other programs in order to determine the most cost-effective ways of encouraging customers to conserve energy.

In April 2004, JEA received 16 renewable energy proposals in response to a renewable energy RFP issued by JEA in February 2004. The proposals were reviewed for their technical and economic merit. Two proposals were selected for contract negotiations: development of a gas to energy project at the Trailridge Landfill in Baldwin, Florida and utilization of Jacksonville's yard waste as a biomass fuel in an existing Jacksonville boiler. The landfill project will provide a 9.6 MW facility that will utilize the landfill gas generated from the Trailridge Landfill and will recover gas that is currently being flared. When completed, this facility will be one of the largest landfill gas-to-energy projects in the Southeast. The biomass facility is located at a former paper mill in downtown Jacksonville. The existing boiler at the site proposes to burn yard and tree trimming debris from the City of Jacksonville's yard waste collection program. The fuel represents 13 MW of renewable energy. It is JEA's intent to establish long-term, purchased power agreements with these projects.

In 2005, JEA initiated a Green Home and Yard Coalition comprised of various community stakeholders throughout Northeast Florida. This coalition's focus is on promoting "green" building practices in home construction to improve the overall energy and water efficiency and health of the home. The initial goal of this group is to develop a green strategy for Northeast Florida home building.

3.0 Fuel Price Forecast

JEA's fuel price forecast is a major input in the development of JEA's future resource plan. JEA uses a diverse mix of fuels; the forecast includes coal, natural gas, residual fuel oil, diesel fuel, and petroleum coke.

A specific price forecasts for St John's River Power Park (SJRPP) was provided by SJRPP Fuels. Eastern and off-shore coals are the primary fuels burned at SJRPP. In addition, the SJRPP forecast is based on a 28 percent blend of petroleum coke and includes limestone and diesel fuel components. JEA developed its forecast of western coal for Scherer Unit 4 based on existing contracts and non-volatile escalation of spot prices.

The fuel price forecast for JEA's natural gas supply takes into account commodity and transportation components. For natural gas, the transportation portion is based on JEA's purchase of 40,000 mmBtu/day of firm transportation on the Florida Gas Transmission Company (FGT) system under rate schedule FTS-1 and 14,000 mmBtu/day under rate schedule FTS-2. In addition, JEA receives 20,000 mmBtu/day of delivered gas volumes from El Paso Municipal (EPM). The EPM volume will increase to 31,000 mmBtu/day effective June 2005 and to 61,000 mmBtu/day effective June 2006. The EPM volumes are currently supplied via the FGT system.

A blend of residual fuel oil and natural gas is burned in Northside Unit 3. The price forecast for residual fuel oil is based on the allowable sulfur level of 1.8 percent. Forecasts are also provided for high and low sulfur diesel fuel. The 1970's-vintage combustion turbine units at Kennedy and Northside Generating Stations are permitted to burn high sulfur diesel. The new combustion turbine units at Brandy Branch and Kennedy are permitted to burn low sulfur diesel as a backup to natural gas. For operational reasons, all Kennedy combustion turbine units currently burn low sulfur diesel fuel. The Brandy Branch facility use ultra low sulfur diesel as back up fuel.

Northside Units 1 and 2 have been repowered to operate on a blend of 80% petroleum coke and 20% coal. In addition, limestone is blended with the petroleum coke for SO_2 removal. The price forecast for petroleum coke includes limestone and is based on a conservative estimate of the long term petroleum coke market.

4.0 Load and Energy Forecast

JEA's winter and summer hourly net integrated system peak demand for 2005 were 2,794 MW and 2,891 MW respectively. JEA's net energy for load for calendar year 2005 was 13,696 GWH. For the ten year forecasted period, JEA's winter peak demand is expected to increase at an average 2.8 percent per year and the summer peak demand will increase at an average 2.0 percent per year. The net energy for load is forecasted to grow at an average rate of 2.2 percent per year for the ten year period.

JEA's base case forecast of peak demand and energy is based on a trend analysis of weather normalized historical data. JEA's trend analysis methodology has dramatically increased the accuracy of JEA's forecasts. Prior to implementing the trend analysis methodology in 1996, JEA's five-year average absolute error for its one-year-ahead sales forecast was 3.67%. Since implementing the trend analysis methodology JEA's most recent five-year average absolute error has been 0.46%. In addition to achieving this eight-fold improvement in forecast accuracy, JEA has also experienced a twelve-fold decrease in the cycle time to produce the forecast.

Effective January 2008, FPU's wholesale supply contract with JEA ends. At the current time, FPU does not have a contract with JEA to renew this sale. This will result in a decrease in demand and energy which is reflected on the base case forecast of Schedules 2 and 3.

5.0 Facility Requirements

5.1 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, and transmission considerations, JEA has evaluated future supply capacity needs for the electric system. Table 5-1 displays the likely need for capacity when assuming the base case load forecast for JEA's system for a ten-year period beginning in 2006.

5.2 Taylor Energy Center (TEC) Coal-Fired Unit

JEA in conjunction with FMPA, RCID, and the City of Tallahassee are looking at a possible coal plant at a site in Taylor County Florida. We have received alternative power supply proposals which are currently being evaluated. Decisions are forthcoming on accepting the alternative proposals, submitting the request for "need for power", and settling land purchase contracts. The anticipated in service date is scheduled for Summer 2012. For the purposes of this analysis, JEA has included this unit in its capacity mix beginning June 2012.

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

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
2006	3,546	207	376	0	3,378	2,831	547	19%	0
2007	3,586	207	376	0	3,417	2,924	493	17%	0
2008	3,586	229	376	0	3,439	2,921	518	18%	0
2009	3,523	229	376	0	3,376	3,015	361	12%	91
2010	3,516	229	376	0	3,369	3,111	258	8%	208
2011	3,516	22	376	0	3,162	3,207	(45)	-1%	526
2012	3,516	22	376	0	3,162	3,307	(145)	-4%	641
2013	3,516	22	376	0	3,162	3,407	(245)	-7%	756
2014	3,516	22	376	0	3,162	3,510	(348)	-10%	874
2015	3,516	22	376	0	3,162	3,614	(452)	-12%	994

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
2006	3,424	207	383	0	3,248	2,651	597	23%	0
2007	3,433	229	383	0	3,279	2,716	563	21%	0
2008	3,433	229	383	0	3,279	2,698	581	22%	0
2009	3,382	229	383	0	3,228	2,761	467	17%	0
2010	3,375	22	383	0	3,014	2,824	190	7%	234
2011	3,375	22	383	0	3,014	2,888	126	4%	307
2012	3,375	22	383	0	3,014	2,950	64	2%	379
2013	3,375	22	383	0	3,014	3,014	(0)	0%	452
2014	3,375	22	383	0	3,014	3,078	(64)	-2%	526
2015	3,375	22	383	0	3,014	3,158	(144)	-5%	618

Committed Units:

1. 2006 Clean Power Purchases (22 MW).

5.3 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 2009. This need encompasses the inclusion of existing supply resources and transmission system considerations.

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

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 least-cost expansion 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	Season	Expansion Plan
2006	Winter	Brandy Branch Plant Peak Firing Upgrades (17.3 MW) Northside Units 1 & 2 LP Turbine Upgrades (18 MW)
2007	Winter	Purchase Clean Power (22 MW) Kennedy CT 7 Peak Firing Upgrades (4.1 MW)
2008		
2009	Winter	Build 1 - 177 MW 7FA GT Kennedy CT 3 – Reserve Shutdown
2010	Winter	Build 1 - 177 MW 7FA GT
2011	Winter	Build 1 - 177 MW 7FA GT
2012	Winter Summer	Purchase 70 MW Seasonal from TEA Build TEC Pulverized Coal (236 MW)
2013		
2014	Winter	Build 1-248 MW Greenfield CFB
2015		

6.0 Glossary

6.1 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	Under construction, 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

Appendix A

Ten-Year Site Plan

Schedules

Ten-Year Site Plan Schedules

The following Appendix presents the schedules required by the Florida Public Service Commission to be included as part of the Ten-Year Site Plan.

Schedule 1
Existing Generating Facilities
As of January 1, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Commercial	Expected	Gen Max				
Plant	Unit		Unit	Fuel Type		Fuel Transport		In-Service	Retirement	Nameplate	Net MW Capability			
Name	Number	Location	Type	Primary	Alt.	Primary	Alt.	Mo/Yr	Mo/Yr	kW	Summer	Winter	Ownership	Status
Kennedy										372,400	210	254		
	3	12-031	GT	FO2		WA	TK	7/1973	(a)	168,600	51	63	Utility	
	4	12-031	GT	FO2		WA	TK	7/1973		168,600	51	63	Utility	(b)
	5	12-031	GT	FO2		WA	TK	7/1973		168,600	51	63	Utility	(b)
	7	12-031	GT	NG	FO2	PL	WA	6/2000		203,800	159	191	Utility	
Northside										1,158,700	1,285	1,319		
	1	12-031	ST	PC	BIT	WA	RR	2003	(a)	297,500	275	275	Utility	
	2	12-031	ST	PC	BIT	WA	RR	2002	(a)	297,500	275	275	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	(a)	563,700	523	523	Utility	
	3-6	12-031	GT	FO2		WA	TK	1/1975	(a)	248,400	212	246	Utility	
Brandy Branch										676,000	691	759		
	1		GT	NG	FO2	PL	TK	5/2001	(a)	203,800	159	191	Utility	
	2		CT	NG	FO2	PL	TK	5/2001	(a)	203,800	159	191	Utility	
	3		CT	NG	FO2	PL	TK	5/2001	(a)	203,800	159	191	Utility	
	4		CC	NG	FO2	PL	TK	1/2005	(a)	268,400	215	185	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(a)	1.2	1.2	1.2	Utility	
St. Johns River Power Park										1,359,200	1,002	1,020		
	1	12-301	ST	BIT/PC		RR	WA	3/1987	3/2027	679,600	501	510	Joint	(c)
	2	12-301	ST	BIT/PC		RR	WA	5/1988	5/2028	679,600	501	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											**3,389**	**3,553**		

NOTE:
(a) Units expected to be maintained throughout the study period.
(b) Placed in Reserve Shutdown 4/15/05.
(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) Numbers may not add due to rounding.

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)
	Rual and Residential			Commercial			Industrial		
Calendar Year	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
1994	3,909	278,682	14,027	897	29,571	30,334	4,048	2,731	1,482,241
1995	4,137	283,551	14,590	937	29,972	31,263	4,174	2,742	1,522,247
1996	4,391	288,947	15,197	937	30,162	31,066	4,353	2,975	1,463,193
1997	4,165	295,916	14,075	949	30,709	30,903	4,526	3,025	1,496,198
1998	4,643	301,883	15,380	1,035	31,297	33,070	4,835	3,094	1,562,702
1999	4,529	305,917	14,805	1,036	31,873	32,504	5,130	3,203	1,601,623
2000	4,701	312,103	15,062	1,079	32,351	33,353	5,205	3,309	1,572,983
2001	4,884	319,532	15,285	1,104	32,990	33,465	5,411	3,450	1,568,406
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,691
2003	5,226	332,492	15,718	1,184	33,762	35,069	5,605	3,630	1,544,077
2004	5,400	348,320	15,503	1,185	32,123	36,889	5,396	3,638	1,483,233
2005	5,550	358,770	15,469	1,249	33,087	37,738	5,686	3,747	1,517,473
2006	5,716	369,533	15,468	1,286	34,080	37,735	5,857	3,859	1,517,751
2007	5,887	380,619	15,467	1,325	35,102	37,747	6,033	3,975	1,517,736
2008	6,064	392,038	15,468	1,365	36,155	37,754	6,214	4,094	1,517,831
2009	6,246	403,799	15,468	1,406	37,240	37,755	6,400	4,217	1,517,667
2010	6,433	415,913	15,467	1,448	38,357	37,751	6,592	4,344	1,517,495
2011	6,626	428,390	15,467	1,491	39,508	37,739	6,790	4,474	1,517,658
2012	6,825	441,242	15,468	1,536	40,693	37,746	6,994	4,608	1,517,795
2013	7,030	454,479	15,468	1,582	41,914	37,744	7,204	4,746	1,517,910
2014	7,241	468,113	15,468	1,629	43,171	37,734	7,420	4,888	1,518,003
2015	7,458	482,156	15,468	1,678	44,466	37,737	7,643	5,035	1,517,974

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

	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Calendar Year	Street & Highway Lighting GWH	Other Sales to Ultimate Customers GWH	Total Sales to Ultimate Customers GWH	Sales For Resale GWH	Utility Use & Losses GWH	Net Energy For Load GWH	Other Customers (Average No.)	Total No.of Customers
1994	63	0	8,917	304	388	9,609	19	311,003
1995	72	0	9,320	339	667	10,326	21	316,286
1996	70	0	9,751	363	401	10,515	21	322,105
1997	71	0	9,711	383	571	10,665	22	329,672
1998	77	0	10,590	438	442	11,470	21	336,295
1999	86	0	10,781	454	547	11,782	19	341,012
2000	120	0	11,105	482	603	12,190	19	347,782
2001	109	0	11,508	453	361	12,322	22	355,994
2002	112	0	11,856	446	681	12,983	20	363,698
2003	115	0	12,130	453	595	13,178	20	369,904
2004	76	0	12,057	468	718	13,243	27	384,108
2005	111	0	12,596	486	615	13,696	28	395,632
2006	115	0	12,974	500	691	14,165	29	407,501
2007	118	0	13,363	515	563	14,441	30	419,726
2008	122	0	13,765	0	767	14,532	31	432,318
2009	126	0	14,178	0	698	14,876	32	445,288
2010	130	0	14,603	0	655	15,258	33	458,647
2011	134	0	15,041	0	601	15,642	34	472,406
2012	138	0	15,493	0	574	16,067	35	486,578
2013	142	0	15,958	0	461	16,419	36	501,175
2014	146	0	16,436	0	374	16,810	37	516,209
2015	150	0	16,929	0	278	17,207	38	531,695

Schedule 3.1
History and Forecast of Summer Peak Demand
(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Firm Peak Demand	Time Of Peak		Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./Ind.		Date	Hour Ending	Residential	Comm./Ind.
1991	1,756	0	0	0	0	0	0	1,756	7/24/1991	1700	0	0
1992	1,881	0	0	0	0	0	0	1,881	7/9/1992	1700	0	0
1993	1,998	0	0	0	0	0	0	1,998	7/29/1993	1700	0	0
1994	1,918	0	0	0	0	0	0	1,918	7/18/1994	1700	0	0
1995	2,067	0	0	0	0	0	0	2,067	8/14/1995	1700	0	0
1996	2,114	0	0	0	0	0	0	2,114	6/25/1996	1800	0	0
1997	2,131	0	0	0	0	0	0	2,131	7/28/1997	1800	0	0
1998	2,338	0	0	0	0	0	0	2,338	7/1/1998	1800	0	0
1999	2,427	0	0	0	0	0	0	2,427	8/2/1999	1600	0	0
2000	2,380	0	0	0	0	0	0	2,380	7/20/2000	1400	0	0
2001	2,389	0	0	0	0	0	0	2,389	8/8/2001	1800	0	0
2002	2,530	0	0	0	0	0	0	2,530	7/19/2002	1600	0	0
2003	2,485	0	0	0	0	0	0	2,485	7/10/2003	1600	0	0
2004	2,539	0	0	0	0	0	0	2,539	8/2/2004	1600	0	0
2005	2,760	0	0	0	0	0	0	2,891	8/17/2006	1800	0	0
2006	2,826	175	0	0	0	0	0	2,651	---	---	0	0
2007	2,893	177	0	0	0	0	0	2,716	---	---	0	0
2008	2,878	180	0	0	0	0	0	2,698	---	---	0	0
2009	2,944	183	0	0	0	0	0	2,761	---	---	0	0
2010	3,009	185	0	0	0	0	0	2,824	---	---	0	0
2011	3,076	188	0	0	0	0	0	2,888	---	---	0	0
2012	3,141	191	0	0	0	0	0	2,950	---	---	0	0
2013	3,208	194	0	0	0	0	0	3,014	---	---	0	0
2014	3,275	197	0	0	0	0	0	3,078	---	---	0	0
2015	3,358	200	0	0	0	0	0	3,158	---	---	0	0

Schedule 3.2
History and Forecast of Winter Peak Demand
(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Firm Peak Demand	Time Of Peak		Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./Ind.		Date	Hour Ending	Residential	Comm./Ind.
1991	1,725	0	0	0	0	0	0	1,725	2/16/1991	1000	0	0
1992	1,881	0	0	0	0	0	0	1,881	1/17/1992	800	0	0
1993	1,791	0	0	0	0	0	0	1,791	3/15/1993	0800	0	0
1994	1,942	0	0	0	0	0	0	1,942	2/3/1994	0800	0	0
1995	2,190	0	0	0	0	0	0	2,190	2/9/1995	0800	0	0
1996	2,401	0	0	0	0	0	0	2,401	2/5/1996	0800	0	0
1997	2,084	0	0	0	0	0	0	2,084	12/20/1996	0900	0	0
1998	1,975	0	0	0	0	0	0	1,975	12/15/1997	1900	0	0
1999	2,403	0	0	0	0	0	0	2,403	1/6/1999	0800	0	0
2000	2,478	0	0	0	0	0	0	2,478	1/27/2000	0800	0	0
2001	2,666	0	0	0	0	0	0	2,666	1/3/2001	0800	0	0
2002	2,607	0	0	0	0	0	0	2,607	1/4/2002	0800	0	0
2003	3,055	0	0	0	0	0	0	3,055	1/24/2003	0800	0	0
2004	2,668	0	0	0	0	0	0	2,668	1/29/2004	0700	0	0
2005	2,794	0	0	0	0	0	0	2,794	1/24/2005	---	0	0
2006	2,919	0	0	0	0	0	0	2,919	2/14/2006	---	0	0
2007	3,099	175	0	0	0	0	0	2,924	---	---	0	0
2008	3,099	178	0	0	0	0	0	2,921	---	---	0	0
2009	3,195	180	0	0	0	0	0	3,015	---	---	0	0
2010	3,294	183	0	0	0	0	0	3,111	---	---	0	0
2011	3,393	186	0	0	0	0	0	3,207	---	---	0	0
2012	3,496	189	0	0	0	0	0	3,307	---	---	0	0
2013	3,599	192	0	0	0	0	0	3,407	---	---	0	0
2014	3,704	194	0	0	0	0	0	3,510	---	---	0	0
2015	3,811	197	0	0	0	0	0	3,614	---	---	0	0

Schedule 3.3
History and Forecast of Annual Net Energy For Load
(GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Calendar Year	Total Energy For Load	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Energy For Load	Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./ind.		Residential	Comm./Ind.
1991	8,835	0	0	0	0	0	0	8,835	0	0
1992	9,028	0	0	0	0	0	0	9,028	0	0
1993	9,609	0	0	0	0	0	0	9,609	0	0
1994	9,609	0	0	0	0	0	0	9,609	0	0
1995	10,326	0	0	0	0	0	0	10,326	0	0
1996	10,515	0	0	0	0	0	0	10,515	0	0
1997	10,665	0	0	0	0	0	0	10,665	0	0
1998	11,470	0	0	0	0	0	0	11,470	0	0
1999	11,782	0	0	0	0	0	0	11,782	0	0
2000	12,190	0	0	0	0	0	0	12,190	0	0
2001	12,322	0	0	0	0	0	0	12,322	0	0
2002	12,983	0	0	0	0	0	0	12,983	0	0
2003	13,204	0	0	0	0	0	0	13,204	0	0
2004	13,243	0	0	0	0	0	0	13,243	0	0
2005	13,696	0	0	0	0	0	0	13,696	0	0
2006	14,165	0	0	0	0	0	0	14,165	0	0
2007	14,441	0	0	0	0	0	0	14,441	0	0
2008	14,532	0	0	0	0	0	0	14,532	0	0
2009	14,876	0	0	0	0	0	0	14,876	0	0
2010	15,258	0	0	0	0	0	0	15,258	0	0
2011	15,642	0	0	0	0	0	0	15,642	0	0
2012	16,067	0	0	0	0	0	0	16,067	0	0
2013	16,419	0	0	0	0	0	0	16,419	0	0
2014	16,810	0	0	0	0	0	0	16,810	0	0
2015	17,207	0	0	0	0	0	0	17,207	0	0

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 2005		Forecast 2006		Forecast 2007	
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	2,860	1,086	2,831	1,145	2,924	1,175
February	2,272	956	2,571	986	2,655	1,013
March	2,194	1,020	2,177	1,064	2,249	1,093
April	1,847	933	1,888	1,035	1,934	1,063
May	2,417	1,097	2,211	1,171	2,265	1,203
June	2,653	1,260	2,526	1,300	2,588	1,335
July	2,755	1,416	2,651	1,472	2,716	1,511
August	2,815	1,446	2,590	1,431	2,654	1,469
September	2,556	1,275	2,436	1,253	2,496	1,286
October	2,289	1,122	2,368	1,115	2,366	1,110
November	1,990	957	2,111	1,050	2,109	1,045
December	2,453	1,128	2,503	1,145	2,500	1,139
Total		13,696		14,165		14,441

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual										
	Fuel	Type	Units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	NUCLEAR		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	COAL		**1000 TON**	**2,567**	**2,021**	**2,947**	**2,966**	**3,026**	**3,069**	**3,208**	**2,943**	**3,053**	**2,772**	**2,815**
	RESIDUAL													
(3)		STEAM	1000 BBL	1,453	1,181	1,111	1,192	1,151	1,149	1,435	1,129	1,213	848	888
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	**1000 BBL**	**1,453**	**1,181**	**1,111**	**1,192**	**1,151**	**1,149**	**1,435**	**1,129**	**1,213**	**848**	**888**
	DISTILLATE													
(7)		STEAM	1000 BBL	47	37	54	55	56	57	59	54	56	51	52
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	90	25	47	49	42	230	159	104	134	52	112
(10)		TOTAL:	**1000 BBL**	**137**	**63**	**102**	**104**	**98**	**286**	**218**	**158**	**190**	**104**	**164**
	NATURAL GAS													
(12)		STEAM	1000 MCF	1,844	1,421	1,365	1,455	1,415	1,404	1,681	1,373	1,458	1,069	1,132
(13)		CC	1000 MCF	6,140	13,592	11,881	12,867	13,682	17,787	20,209	17,119	17,542	13,548	14,727
(14)		CT/GT	1000 MCF	1,567	409	502	586	689	3,638	3,635	2,611	2,740	1,596	2,139
(15)		TOTAL:	**1000 MCF**	**9,552**	**15,423**	**13,748**	**14,908**	**15,786**	**22,828**	**25,525**	**21,103**	**21,740**	**16,213**	**17,997**
(16)	PETROLEUM COKE		1000 TON	**1,460**	**1,860**	**2,787**	**2,830**	**2,770**	**2,924**	**3,022**	**2,907**	**2,903**	**2,892**	**2,902**
(20)	OTHER (SPECIFY)		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

NOTE:
1. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4 and Northside Coal.

Schedule 6.1
Energy Sources (GWH)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	Type	Units	Actuals 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	**Annual Firm Inter-Region Intchg.**		GWH	1,824	1,489	1,586	1,377	1,596	650	0	1	1	0	0
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**		GWH	5,794	4,536	4,762	4,646	4,886	4,855	5,115	5,064	5,271	4,773	4,834
(4)	**RESIDUAL**	STEAM	GWH	861	662	625	661	642	661	823	628	684	462	493
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL	GWH	861	662	625	661	642	661	823	628	684	462	493
(8)	**DISTILLATE**	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	28	11	23	23	19	108	75	49	64	24	52
(11)		TOTAL	GWH	28	11	23	23	19	108	75	49	64	24	52
(12)	**NATURAL GAS**	STEAM	GWH	169	117	110	117	113	117	145	111	121	82	87
(13)		CC	GWH	951	1,849	1,606	1,763	1,874	2,518	2,875	2,368	2,431	1,816	1,991
(14)		CT	GWH	142	36	45	55	72	414	396	278	312	162	232
(15)		TOTAL	GWH	1,262	2,002	1,761	1,935	2,059	3,049	3,416	2,757	2,864	2,059	2,311
(16)	**NUG**		GWH	0	154	187	187	187	187	187	187	187	187	187
(17)	**HYDRO**		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	**Petroleum Coke**		GWH	3,926	5,311	5,497	5,703	5,488	5,748	6,027	7,381	7,349	9,305	9,330
(19)	**OTHER (SPECIFY)**		GWH	2										
(20)	**NET ENERGY FOR LOAD**		GWH	13,696	14,165	14,441	14,532	14,876	15,258	15,642	16,067	16,419	16,810	17,207

NOTE:

1. Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal.

Schedule 6.2
Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	Type	Units	Actuals 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	Annual Firm Inter-Region Intchg.		%	13.3%	10.5%	11.0%	9.5%	10.7%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	42.3%	32.0%	33.0%	32.0%	32.8%	31.8%	32.7%	31.5%	32.1%	28.4%	28.1%
(4)	RESIDUAL	STEAM	%	6.3%	4.7%	4.3%	4.5%	4.3%	4.3%	5.3%	3.9%	4.2%	2.7%	2.9%
(5)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL	%	6.3%	4.7%	4.3%	4.5%	4.3%	4.3%	5.3%	3.9%	4.2%	2.7%	2.9%
(8)	DISTILLATE	STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	%	0.2%	0.1%	0.2%	0.2%	0.1%	0.7%	0.5%	0.3%	0.4%	0.1%	0.3%
(11)		TOTAL	%	0.2%	0.1%	0.2%	0.2%	0.1%	0.7%	0.5%	0.3%	0.4%	0.1%	0.3%
(12)	NATURAL GAS	STEAM	%	1.2%	0.8%	0.8%	0.8%	0.8%	0.8%	0.9%	0.7%	0.7%	0.5%	0.5%
(13)		CC	%	6.9%	13.1%	11.1%	12.1%	12.6%	16.5%	18.4%	14.7%	14.8%	10.8%	11.6%
(14)		CT	%	1.0%	0.3%	0.3%	0.4%	0.5%	2.7%	2.5%	1.7%	1.9%	1.0%	1.3%
(15)		TOTAL	%	9.2%	14.1%	12.2%	13.3%	13.8%	20.0%	21.8%	17.2%	17.4%	12.3%	13.4%
(16)	NUG		%	0.0%	1.1%	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%	1.1%	1.1%	1.1%
(17)	HYDRO		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	Petroleum Coke		%	28.7%	37.5%	38.1%	39.2%	36.9%	37.7%	38.5%	45.9%	44.8%	55.4%	54.2%
(19)	OTHER (SPECIFY)		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(20)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

NOTE:

1. Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal.

Schedule 7

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

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	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2006	3,553	207	383	0	3,378	2,831	547	19%	0	547	19%
2007	3,593	207	383	0	3,417	2,924	493	17%	0	493	17%
2008	3,593	229	383	0	3,439	2,921	518	18%	0	518	18%
2009	3,721	229	383	0	3,567	3,015	552	18%	0	552	18%
2010	3,905	229	383	0	3,751	3,111	640	21%	0	640	21%
2011	4,096	22	383	0	3,735	3,207	528	16%	0	528	16%
2012	4,096	92	383	0	3,805	3,307	498	15%	0	498	15%
2013	4,332	22	383	0	3,971	3,407	564	17%	0	564	17%
2014	4,582	22	383	0	4,221	3,510	711	20%	0	711	20%
2015	4,582	22	383	0	4,221	3,614	607	17%	0	607	17%

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
2006	3,417	207	376	0	3,248	2,651	597	23%	0	597	23%
2007	3,426	229	376	0	3,279	2,716	563	21%	0	563	21%
2008	3,426	229	376	0	3,279	2,698	581	22%	0	581	22%
2009	3,534	229	376	0	3,387	2,761	626	23%	0	626	23%
2010	3,686	22	376	0	3,332	2,824	508	18%	0	508	18%
2011	3,845	22	376	0	3,491	2,888	603	21%	0	603	21%
2012	4,081	22	376	0	3,727	2,950	777	26%	0	777	26%
2013	4,081	22	376	0	3,727	3,014	713	24%	0	713	24%
2014	4,331	22	376	0	3,977	3,078	899	29%	0	899	29%
2015	4,331	22	376	0	3,977	3,158	819	26%	0	819	26%

Schedule 8

Planned and Prospective Generating Facility and Purchased Power 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/Change 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
Planned and Prospective Generating Facility Changes														
Brandy Branch	4	Brandy Branch	CC	NG	FO2	PL	TK		04/01/06			13.0	13.0	A
Brandy Branch	1	Brandy Branch	GT	NG	FO2	PL	TK		06/01/06			3.8	4.1	A
Northside	1	Northside	ST	PC	BIT	WA	RR		6/2006			8.9	8.9	A
Northside	2	Northside	ST	PC	BIT	WA	RR		12/2006			8.9	8.9	A
Kennedy	7	Kennedy	GT	NG	FO2	PL	TK		6/2007			3.8	4.1	A
Kennedy	3	Kennedy	GT	NG	FO2	PL	TK			01/01/09		51.0	62.7	RS
Planned and Prospective Generating Facility Additions														
CT - 7FA	1	Greenfield	GT	NG	FO2	PL	TK		12/01/08			158.6	191.2	P
CT - 7FA	2	Greenfield	GT	NG	FO2	PL	TK		12/01/09			158.6	191.2	P
CT - 7FA	3	Greenfield	GT	NG	FO2	PL	TK		12/01/10			158.6	191.2	P
PCoal	1	Taylor Energy Center	FC	Bit	Coal	WA	WA		06/01/12			236.0	236.0	P
CFB	4	Greenfield	FC	PC	Coal	WA	WA		12/01/13			248.0	248.0	P
Planned and Prospective Purchased Power Additions														
Trail Ridge									01/01/07	01/01/17		9.1	9.1	P
Jefferson Surfit									01/01/07	01/01/17		13.0	13.0	P
TEA									12/01/11	03/15/12		0.0	70.0	P
UPS										05/31/10		200.0	200.0	R

Schedule 9.0 Status Report and Specifications of Proposed Generating Facilities				
(1)	Plant Name and Unit Number:	Greenfield Units 1-3		
(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:	Unit 1	Unit 2	Unit 3
(7)	Field Construction Start-date:			
(8)	Commercial In-Service date:	12/15/08	12/15/09	12/15/10
(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:			
(15)	Construction Status:	Planned		
(16)	Certfication Status:	Not Required		
(17)	Status with Federal Agencies:	Not Filed		
(18)	Projected Unit Performance Data:			
(19)	Planned Outage Factor (POF):	1.00 percent		
(20)	Forced Outage Factor (FOF):	2.00 percent		
(21)	Equivalent Availability Factor (EAF):	97.00 percent		
(22)	Resulting Capacity Factor (%):	5.0 – 10.0 percent		
(23)	Average Net Operating Heat Rate (ANOHR):	10,816 Btu/kWh		
(24)	Projected Unit Financial Data:			
(25)	Book Life:	30 years		
(26)	Total Installed Cost (In-Service year $/kW):	$ 735.02		
(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):	$ 4.98		
(31)	Variable O&M ($/MWh):	$ 18.78		

Schedule 9.1 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Taylor Energy Center (TEC) Unit 1
(2)	Capacity:	JEA Portion
(3)	Summer MW	236 MW
(4)	Winter MW	236 MW
(5)	Technology Type:	Supercritical Pulverized Coal
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	2008
(8)	Commercial In-Service date:	6/1/2012
(9)	Fuel	
(10)	Primary	Bituminous Coal
(11)	Alternate	N/A
(12)	Air Pollution Control Strategy:	Engineering Review in Progress
(13)	Cooling Method:	Engineering Review in Progress
(14)	Total Site Area:	3,300 Acres
(15)	Construction Status:	Planned
(16)	Certification Status:	FPSC Need Filing Expected Spring/Summer 2006
(17)	Status with Federal Agencies:	Preliminary Review
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	
(20)	Forced Outage Factor (FOF):	
(21)	Equivalent Availability Factor (EAF):	
(22)	Resulting Capacity Factor (%):	
(23)	Average Net Operating Heat Rate (ANOHR):	
(24)	Projected Unit Financial Data:	
(25)	Book Life:	
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	
(31)	Variable O&M ($/MWh):	

Schedule 9.2 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Greenfield Unit 4
(2)	Capacity:	
(3)	Summer MW	248 MW
(4)	Winter MW	248 MW
(5)	Technology Type:	Circulating Fluidized Bed
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	Winter 2014
(9)	Fuel	
(10)	Primary	Petroleum Coke
(11)	Alternate	Bituminous Coal
(12)	Air Pollution Control Strategy:	In Planning Phase
(13)	Cooling Method:	In Planning Phase
(14)	Total Site Area:	
(15)	Construction Status:	In Planning Phase
(16)	Certification Status:	Not Filed
(17)	Status with Federal Agencies:	In Planning Phase
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	1.50 percent
(20)	Forced Outage Factor (FOF):	5.00 percent
(21)	Equivalent Availability Factor (EAF):	93.5 percent
(22)	Resulting Capacity Factor (%):	85.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9,151 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	$2,774
(27)	Direct Construction Cost ($/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 ($/kW-yr):	39.34
(31)	Variable O&M ($/MWh):	6.40

Schedule 10 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	No Updates To Report
(2)	Number of Lines	
(3)	Right of Way	
(4)	Line Length	
(5)	Voltage	
(6)	Anticipated Construction Time	
(7)	Anticipated Capital Investment	
(8)	Substations	
(9)	Participation with Other Utilities	