Ten Year Site Plan

April 2004

JEA
Building Community

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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 2004 Ten Year Site Plan for JEA covering a planning period from 2004 to 2013.

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 3,476 MW in the winter and 3,257 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 714 circuit-miles of transmission lines at five voltage levels: 69kV, 138kV, 230kV, and 500kV. JEA's transmission system includes a 230 kV 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 Power Company. JEA, FP&L, Progress Energy and the City of Tallahassee each own transmission interconnections with Georgia Power Company. 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 Power Company 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 southeastern 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. Over the past five years, 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 does not have any short-term, seasonal needs for capacity or energy.

Biomass Industries, Inc.

As part of JEA's Green Works initiative to supply 7.5 percent of its peak demand with renewable resources by 2015, JEA has contracted with Biomass Industries, Inc. (BII). JEA has purchased 70 MW peak and 35 MW off-peak, firm renewable energy from a gasified biomass fueled electric generation plant proposed to be constructed by BII in South Florida. The proposed facility is to be fueled by an energy crop (bamboo and E-grass) to be grown by BII.

The initial term of the purchase is 15 years from the commercial operation date of the facility. The parties, by mutual agreement, have the right to extend the initial contract term for two additional five-year periods, on terms to be agreed upon by the parties. Under the contract, JEA will be obligated to take and pay for energy produced by the facility, up to the limits stated above, and at a fixed price stated in the contract (subject to periodic escalations). The facility currently is scheduled to be in service to meet JEA's internal goal of 130 MW of clean power by summer 2007.

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.

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

Seminole Electric Cooperative Inc.
JEA returned Kennedy Combustion Turbine Unit 4 (GT 4) to service from retirement status in March 1994. Concurrently, JEA sold to SECI priority dispatch rights for one-seventh of the aggregate GT output capacity of JEA's older diesel fueled combustion turbines, which 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 were extended through August 31, 2004.

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. Sales to FPU in 2003 totaled 435 GWh (3.3 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 2000, 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. On February 21, 2001, the PSC approved JEA's Plan for zero DSM goals for 2001-2010.

JEA agreed to continue several DSM programs, including the residential education seminars, residential energy audits, commercial educational programs, commercial energy audits, and community conservation initiatives. As promised in 2001, JEA continued these programs. With the rising costs of all fuel types, JEA continues to look for cost effective DSM measures.

At the Commission's request, JEA is currently re-evaluating its DSM program and requirements. JEA will meet the June 1, 2004 date the Commission has set for submitting the new DSM program.

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 March 2004, JEA has provided incentives to over 600 solar systems installed throughout the community resulting in 4.5 MWs towards our Clean Power Goals. JEA expects demand reduction to total over 9 MWs by 2007. JEA also owns approximately 223 kw of solar photovoltaic modules throughout the city of Jacksonville with approximately 50% of the installations at local public high schools.

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.

On February 6, 2004, JEA issued a Request For Proposals (RFP) for Renewable Energy Generation for 1 to 300 MW. The RFP covers all renewable energy resources that result in energy being delivered to JEA's service territory. More than 80 companies have requested a copy of the RFP. The pre-bid meeting was held on March 3, 2004 and bids are due April 6, 2004.

Through the RFP, JEA will identify potential companies that can provide alternative energy sources such as solar, wind, biomass (grasses, plants, and landfill gas), biogas, and hydropower to meet JEA's Clean Power Capacity Goals over the next decade or longer. It is JEA's intent to establish several long-term, purchased power agreements from this RFP.

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. Sensitivity cases were considered based on high and low fuel price projections and on availability.

Specific price forecasts for St John's River Power Park (SJRPP) and Scherer Unit 4 were provided by SJRPP Fuels and Georgia Power, respectively. Eastern and off-shore coals are the primary fuels burned at SJRPP. In addition, the SJRPP forecast is based on a 16 percent blend of petroleum coke and includes limestone and diesel fuel components. Western coal is burned in Scherer Unit 4.

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 61,000 mmBtu/day to accommodate the completion of the combined cycle conversion at Brandy Branch. 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 will use ultra low sulfur diesel fuel as back up upon completion of the combined cycle unit in 2005.

Northside Units 1 and 2 have been repowered to operate on a blend of petroleum coke and coal. The current petroleum coke blend rate is 80 percent. JEA's goal is to reach a 90 percent blend rate and to eventually begin operating entirely on petroleum coke. 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 2003 were 3055 MW and 2485 MW respectively. JEA's annual net energy for load for calendar year 2003 was 13,178 GWH. JEA's winter peak demand, summer peak demand and net energy for load are growing at approximately 3 percent per year.

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 in appendix A.

5.0 Facility Requirements

5.1 Brandy Branch Combined Cycle Conversion

On February 28, 2001, the Florida Public Service Commission issued an Order Granting Petition For Determination of Need for the Brandy Branch Combined Cycle Conversion. On March 12, 2002, JEA's site certification was approved. The governor's signature and DEP's issuance of the permits for construction followed.

JEA is converting two of the Brandy Branch simple cycle units into a combined cycle unit. The Brandy Branch Plant was designed with future expansion in mind, namely adding the steam turbine unit to the site. This expansion will occur in the northwest quadrant of the current plant, adjacent to the existing combustion turbines.

The conversion is accomplished by adding two heat recovery steam generators (HRSGs) to two of the three existing combustion turbines, one steam turbine generator, and balance of plant equipment. One HRSG will be added to each of the two combustion turbines and the two HRSGs will share the steam turbine generator. This conversion will create a one-block 2 x 1 combined cycle unit. The nominal rating of the steam turbine addition is assumed to be 185 MW. The total capacity of the Brandy Branch power plant, including the remaining simple cycle unit and the combined cycle unit after the conversion, will be 705 MW. The combined cycle unit is currently on schedule for commercial operation starting May 2005.

5.2 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 2004.

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
2004	3,414	207	383	0	3,238	2,722	516	19%	0
2005	3,476	207	383	0	3,301	2,813	488	17%	0
2006	3,666	207	383	0	3,490	2,905	585	20%	0
2007	3,666	207	383	0	3,490	2,998	492	16%	0
2008	3,666	207	383	0	3,490	3,000	491	16%	0
2009	3,666	207	383	0	3,490	3,093	397	13%	67
2010	3,666	207	383	0	3,490	3,188	302	9%	176
2011	3,666	0	383	0	3,283	3,284	(1)	0%	494
2012	3,666	0	383	0	3,283	3,382	(98)	-3%	606
2013	3,666	0	383	0	3,283	3,480	(197)	-6%	719

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
2004	3,205	207	376	0	3,036	2,572	465	18%	0
2005	3,441	207	376	0	3,272	2,640	633	24%	0
2006	3,441	207	376	0	3,272	2,708	564	21%	0
2007	3,441	207	376	0	3,272	2,778	495	18%	0
2008	3,441	207	376	0	3,272	2,758	515	19%	0
2009	3,441	207	376	0	3,272	2,825	447	16%	0
2010	3,441	0	376	0	3,065	2,895	171	6%	263
2011	3,441	0	376	0	3,065	2,964	102	3%	343
2012	3,441	0	376	0	3,065	3,034	31	1%	424
2013	3,441	0	376	0	3,065	3,104	(39)	-1%	504

Committed Units:
1 Brandy Branch CTs 2 & 3 - Outage for conversion starts September 15, - December 15, 2004
2 Brandy Branch Combined Cycle - June 2005.

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 2010. This need encompasses the inclusion of existing supply resources, transmission system considerations, and the Brandy Branch Combined Cycle conversion.

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
2004		
2005	Summer	Convert 2 Brandy Branch CTs to Combined Cycle (Additional 185 Summer/ 190 Winter MWs)
2006		
2007	Winter	Purchase 100 MW Clean Power
2008		
2009		
2010	Winter	Build 2 - 82 MW: 7EA GT Purchase 50 MW Clean Power
2011	Winter	Build 1-250 MW Greenfield CFB
2012	Winter	Purchase 50 MW Clean Power
2013	Winter	Build 1-250 MW Greenfield CFB

6.0 Project Status

6.1 Brandy Branch Combustion Turbines and Combined Cycle Conversion

Site Description

Simple Cycle Plant

JEA's Brandy Branch Generating Station currently consists of three gas/oil fired simple cycle combustion turbine electric generating units. These combustion turbines are GE PG7241 (FA) units with a nominal rating of 173 MW ISO each. The combustion turbines are dual fuel capable and operate with natural gas as the primary fuel and distillate oil as the backup fuel. Construction of the Brandy Branch units began in late 1999 with the completion of the first two units in May 2001 and the third unit in October 2001. The Brandy Branch site is shown on Figure 6-1.

Combined Cycle Conversion

The conversion project consists of converting Brandy Branch CTs 2 and 3 to combined cycle units. A Heat Recovery Steam Generator (HRSG) will be installed on each combustion turbine exhaust that will recover energy to produce steam that in turn will power a new steam turbine generator. The steam turbine, STG 4, will have a nominal output of 185 MW net and a maximum output of 227 MW gross. The combined cycle plant (CT 2, CT 3 and STG 4) will have a net nominal output of 531 MW. Included are all turbine controls, steam condenser, cooling tower, high energy piping, feed water and condensate pumps, related foundations, site improvements, new exhaust stacks, and duct work. To provide the additional service water required for the combined cycle unit, one of the two existing Floridan wells was modified to increase flow capacity, and a third deep well was constructed. As a condition of the Consumptive Use Permit, an upper and lower aquifer monitoring well was installed. Also. wetland soils, vegetation, and hydrology will be monitored for a period of 3 years. The EPC (Engineer, Procure and Construct) contract was awarded on October 4, 2001. Construction broke ground in mid October 2002 and the current commercial date for the CC plant, CT-2, CT-3 and Steam Turbine Generator STG-4, is June 1, 2005.

Water Supply

Service and fire water for use at the generating station is normally supplied from onsite wells. Potable water, construction water, and a backup supply for service water will be provided from the City of Baldwin.

The service water will be demineralized using rental filtration and demineralizer equipment to provide high quality water for NO_x water injection.

Land Use

The plant site is near the City of Baldwin. Baldwin is west of Jacksonville on Highway 301 a short distance north of Interstate 10. The plant site is a short distance north of Highway 90 east of Baldwin. The generation area will consist of the plant buildings, structures, and equipment required for the power plant.

Environmental Features

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

Emissions

The combustion turbines utilize a dry low NO_x combustion system to regulate the distribution of fuel delivered to a multi-nozzle, total premix combustion arrangement. The fuel flow distribution is calculated to maintain unit load and fuel split for optimal combustion turbine emissions. In addition, when operating on distillate oil, demineralized water is injected into the combustion chamber to reduce the firing temperature, which reduces the formation of NO_x. The ratio of the flow rate of demineralized water to No. 2 oil is approximately equal. Selective catalytic reduction (SCR) will be utilized to reduce NO_x emissions for the combined cycle configuration.

Fuel Storage

Natural gas will be the primary fuel for the Brandy Branch plant, with diesel as a backup fuel. Natural gas will be delivered to the site by a pipeline. JEA currently purchases natural gas transportation from Florida Gas Transmission Company (FGT) under FTS-1. FGT operates the 16-inch Jacksonville Lateral to the Brandy Branch area. No. 2 oil will be delivered by truck and stored in the No. 2 oil tank. It is estimated that sufficient distillate oil will be stored on-site for 48 hours of fired operation for each combustion turbine 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 have been obtained for these projects in accordance with regulations. On February 28, 2001, the Florida Public Service Commission issued an Order Granting Petition For Determination of Need for the Brandy Branch Combined Cycle Conversion. On March 12, 2002, JEA's site certification was approved. The governor's signature and DEP's issuance of the permits for construction followed.

6.2 Other Environmental Considerations

Environmental Programs

JEA participates in the American Public Power Association's (APPA) nationwide Tree Power program. In addition, 400,000 trees have been 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.

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	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 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
1993	3,830	270,818	14,143	862	29,378	29,327	3,889	2,670	1,456,427
1994	3,909	278,682	14,027	897	29,571	30,324	4,048	2,731	1,482,265
1995	4,137	283,551	14,589	937	29,972	31,269	4,174	2,742	1,522,385
1996	4,391	288,947	15,195	937	30,162	31,079	4,353	2,975	1,463,160
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	15,284	1,104	32,990	33,476	5,411	3,450	1,568,311
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,570
2003	5,226	332,492	15,718	1,184	33,762	35,062	5,605	3,630	1,544,049
2004	5,398	339,202	15,915	1,223	34,239	35,712	5,790	3,746	1,545,671
2005	5,544	346,048	16,022	1,256	34,723	36,167	5,947	3,865	1,538,510
2006	5,704	353,032	16,158	1,292	35,214	36,693	6,118	3,988	1,534,097
2007	5,865	360,157	16,285	1,329	35,711	37,202	6,291	4,115	1,528,710
2008	6,042	367,426	16,445	1,369	36,216	37,790	6,481	4,246	1,526,250
2009	6,190	374,841	16,514	1,402	36,728	38,175	6,639	4,381	1,515,337
2010	6,353	382,406	16,614	1,439	37,247	38,637	6,814	4,521	1,507,357
2011	6,518	390,124	16,706	1,476	37,773	39,083	6,990	4,665	1,498,619
2012	6,700	397,997	16,833	1,517	38,307	39,614	7,186	4,813	1,492,930
2013	6,823	406,029	16,804	1,543	38,848	39,719	7,382	4,966	1,486,508

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

Calendar Year	(11) Street & Highway Lighting GWH	(12) Other Sales to Ultimate Customers GWH	(13) Total Sales to Ultimate Customers GWH	(14) Sales For Resale GWH	(15) Utility Use & Losses GWH	(16) Net Energy For Load GWH	(17) Other Customers (Average No.)	(18) Total No.of Customers
1989	56	0	7,611	177	678	8,466	0	284,229
1991	58	0	8,124	224	487	8,835	12	293,860
1992	59	0	8,288	309	431	9,028	14	297,973
1993	61	0	8,642	339	628	9,609	17	302,883
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	118	0	12,529	530	615	13,674	20	377,207
2005	122	0	12,869	550	631	14,050	20	384,656
2006	125	0	13,239	571	651	14,461	20	392,254
2007	129	0	13,614	591	668	14,873	20	400,003
2008	132	0	14,024	120	690	14,834	20	407,908
2009	136	0	14,368	127	707	15,202	20	415,970
2010	139	0	14,745	132	726	15,603	20	424,194
2011	143	0	15,127	137	744	16,008	20	432,582
2012	147	0	15,550	140	765	16,455	20	441,137
2013	151	0	15,899	142	782	16,823	20	449,863

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	2,739	168	0	0	0	0	0	2,571	---	---	0	0
2005	2,812	173	0	0	0	0	0	2,639	---	---	0	0
2006	2,886	178	0	0	0	0	0	2,708	---	---	0	0
2007	2,961	183	0	0	0	0	0	2,778	---	---	0	0
2008	2,947	189	0	0	0	0	0	2,758	---	---	0	0
2009	3,021	195	0	0	0	0	0	2,826	---	---	0	0
2010	3,094	200	0	0	0	0	0	2,894	---	---	0	0
2011	3,170	206	0	0	0	0	0	2,964	---	---	0	0
2012	3,246	213	0	0	0	0	0	3,033	---	---	0	0
2013	3,323	219	0	0	0	0	0	3,104	---	---	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	2,976	163	0	0	0	0	0	2,813	---	---	0	0
2005	3,073	168	0	0	0	0	0	2,905	---	---	0	0
2006	3,171	173	0	0	0	0	0	2,998	---	---	0	0
2007	3,179	179	0	0	0	0	0	3,000	---	---	0	0
2008	3,277	184	0	0	0	0	0	3,093	---	---	0	0
2009	3,377	189	0	0	0	0	0	3,188	---	---	0	0
2010	3,479	195	0	0	0	0	0	3,284	---	---	0	0
2011	3,583	201	0	0	0	0	0	3,382	---	---	0	0
2012	3,687	207	0	0	0	0	0	3,480	---	---	0	0
2013	3,794	213	0	0	0	0	0	3,581	---	---	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	13,674	0	0	0	0	0	0	13,674	0	0
2005	14,050	0	0	0	0	0	0	14,050	0	0
2006	14,460	0	0	0	0	0	0	14,460	0	0
2007	14,873	0	0	0	0	0	0	14,873	0	0
2008	14,834	0	0	0	0	0	0	14,834	0	0
2009	15,200	0	0	0	0	0	0	15,200	0	0
2010	15,603	0	0	0	0	0	0	15,603	0	0
2011	16,007	0	0	0	0	0	0	16,007	0	0
2012	16,455	0	0	0	0	0	0	16,455	0	0
2013	16,823	0	0	0	0	0	0	16,823	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 2003		Forecast 2004		Forecast 2005	
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	3,005	1,237	2,722	1,112	2,813	1,142
February	2,171	912	2,472	997	2,554	991
March	1,942	923	2,094	1,021	2,163	1,051
April	1,942	927	1,831	994	1,879	1,023
May	2,329	1,193	2,145	1,108	2,201	1,142
June	2,367	1,203	2,451	1,240	2,515	1,279
July	2,485	1,245	2,571	1,422	2,639	1,467
August	2,430	1,306	2,512	1,368	2,579	1,411
September	2,342	1,166	2,363	1,220	2,426	1,258
October	1,970	1,020	2,278	1,069	2,353	1,100
November	2,017	933	2,031	1,012	2,097	1,041
December	2,274	1,113	2,408	1,114	2,487	1,144
Total		13,178		13,674		14,051

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual										
	Fuel	Type	Units	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	1,887	2,547	2,549	2,495	2,600	2,316	2,397	2,357	2,282	2,224	2,100
	RESIDUAL													
(3)		STEAM	1000 BBL	1,548	1,187	1,378	1,628	1,278	1,277	1,316	1,778	1,512	1,529	1,257
(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	1,548	1,187	1,378	1,628	1,278	1,277	1,316	1,778	1,512	1,529	1,257
	DISTILLATE													
(7)		STEAM	1000 BBL	40	39	39	39	41	42	42	42	39	40	37
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	107	215	150	166	121	112	145	220	164	154	70
(10)		TOTAL:	1000 BBL	146	254	189	205	163	154	186	262	203	193	107
	NATURAL GAS													
(12)		STEAM	1000 MCF	6,083	8,584	2,808	2,629	2,066	2,046	2,109	2,796	2,383	2,411	2,011
(13)		CC	1000 MCF	0	0	10,655	13,072	12,618	12,052	13,293	17,023	13,861	16,609	11,366
(14)		CT/GT	1000 MCF	2,489	5,842	1,477	1,174	887	929	996	2,459	1,676	2,027	1,001
(15)		TOTAL:	1000 MCF	8,572	14,426	14,940	16,874	15,571	15,027	16,398	22,278	17,921	21,047	14,378
(16)	PETROLEUM COKE		1000 TON	1,151	1,323	1,302	1,300	1,510	1,755	1,746	1,747	2,466	2,479	3,170
(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)
				Actuals										
	Fuel	Type	Units	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	**Annual Firm Inter-Region Intchg.**		GWH	1,926	1,375	1,290	1,308	1,254	1,261	1,292	620	101	126	99
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**		GWH	6,304	5,946	5,884	5,797	6,002	5,283	5,415	5,349	5,124	5,036	4,716
(4)	**RESIDUAL**	STEAM	GWH	295	705	816	943	729	737	755	1,057	886	906	734
(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	295	705	816	943	729	737	755	1,057	886	906	734
(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	49	95	67	74	54	49	62	100	70	69	28
(11)		TOTAL	GWH	49	95	67	74	54	49	62	100	70	69	28
(12)	**NATURAL GAS**	STEAM	GWH	1,159	847	256	236	182	184	189	264	222	227	184
(13)		CC	GWH	0	0	1,515	1,912	1,833	1,752	1,940	2,526	2,031	2,444	1,634
(14)		CT	GWH	246	545	126	102	82	87	95	230	157	190	94
(15)		TOTAL	GWH	1,405	1,393	1,897	2,250	2,097	2,023	2,223	3,020	2,410	2,861	1,912
(16)	**NUG**		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	**HYDRO**		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	**Petroleum Coke**		GWH	3,195	4,160	4,095	4,089	4,737	5,481	5,454	5,457	7,418	7,457	9,334
(19)	**OTHER (SPECIFY)**		GWH	4	0	0	0	0	0	0	0	0	0	0
(20)	**NET ENERGY FOR LOAD**		GWH	13,178	13,674	14,051	14,461	14,873	14,834	15,200	15,603	16,008	16,455	16,823

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)
				Actuals										
	Fuel	Type	Units	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Inter-Region Intchg.		%	14.6%	10.1%	9.2%	9.0%	8.4%	8.5%	8.5%	4.0%	0.6%	0.8%	0.6%
(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		%	47.8%	43.5%	41.9%	40.1%	40.4%	35.6%	35.6%	34.3%	32.0%	30.6%	28.0%
(4)	RESIDUAL	STEAM	%	2.2%	5.2%	5.8%	6.5%	4.9%	5.0%	5.0%	6.8%	5.5%	5.5%	4.4%
(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	%	2.2%	5.2%	5.8%	6.5%	4.9%	5.0%	5.0%	6.8%	5.5%	5.5%	4.4%
(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	%	0.4%	0.7%	0.5%	0.5%	0.4%	0.3%	0.4%	0.6%	0.4%	0.4%	0.2%
(11)		TOTAL	%	0.4%	0.7%	0.5%	0.5%	0.4%	0.3%	0.4%	0.6%	0.4%	0.4%	0.2%
(12)	NATURAL GAS	STEAM	%	8.8%	6.2%	1.8%	1.6%	1.2%	1.2%	1.2%	1.7%	1.4%	1.4%	1.1%
(13)		CC	%	0.0%	0.0%	10.8%	13.2%	12.3%	11.8%	12.8%	16.2%	12.7%	14.9%	9.7%
(14)		CT	%	1.9%	4.0%	0.9%	0.7%	0.5%	0.6%	0.6%	1.5%	1.0%	1.2%	0.6%
(15)		TOTAL	%	10.7%	10.2%	13.5%	15.6%	14.1%	13.6%	14.6%	19.4%	15.1%	17.4%	11.4%
(16)	NUG		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(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		%	24.2%	30.4%	29.1%	28.3%	31.8%	36.9%	35.9%	35.0%	46.3%	45.3%	55.5%
(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
2004	3,476	207	445	0	3,238	2,722	516	19%	0	516	19%
2005	3,476	207	383	0	3,301	2,813	488	17%	0	488	17%
2006	3,666	207	383	0	3,490	2,905	585	20%	0	585	20%
2007	3,666	307	383	0	3,590	2,998	592	20%	0	592	20%
2008	3,666	307	383	0	3,590	3,000	591	20%	0	591	20%
2009	3,666	307	383	0	3,590	3,093	497	16%	0	497	16%
2010	3,838	357	383	0	3,812	3,188	624	20%	0	624	20%
2011	4,088	150	383	0	3,855	3,284	571	17%	0	571	17%
2012	4,088	200	383	0	3,905	3,382	524	15%	0	524	15%
2013	4,338	200	383	0	4,155	3,480	675	19%	0	675	19%

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
2004	3,257	207	428	0	3,036	2,572	465	18%	0	465	18%
2005	3,441	207	376	0	3,272	2,640	633	24%	0	633	24%
2006	3,441	207	376	0	3,272	2,708	564	21%	0	564	21%
2007	3,441	307	376	0	3,372	2,778	595	21%	0	595	21%
2008	3,441	307	376	0	3,372	2,758	615	22%	0	615	22%
2009	3,441	307	376	0	3,372	2,825	547	19%	0	547	19%
2010	3,593	150	376	0	3,367	2,895	473	16%	0	473	16%
2011	3,843	150	376	0	3,617	2,964	653	22%	0	653	22%
2012	3,843	200	376	0	3,667	3,034	633	21%	0	633	21%
2013	4,093	200	376	0	3,917	3,104	813	26%	0	813	26%

Committed Units:

1. Brandy Branch CTs 2 & 3 - Outage for conversion starts September 2004.
2. Brandy Branch Combined Cycle - June 2005

Schedule 8														
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
Brandy Branch	4	Brandy Branch	CC	NG	FO2	PL	TK		06/01/05			501	573	U
CT - 7EA	Unknown	Greenfield	GT	NG	FO2	PL	TK		01/01/10			75	86	P
CT - 7EA	Unknown	Greenfield	GT	NG	FO2	PL	TK		01/01/10			75	86	P
CFB	Unknown	Greenfield	FC	PC	Coal	WA	WA		01/01/11			250	250	P
CFB	Unknown	Greenfield	FC	PC	Coal	WA	WA		01/01/13			250	250	P
Planned and Prospective Purchased Power Additions and Changes														
Clean Power									01/01/07			100	100	P
Clean Power									01/01/10			50	50	P
UPS										05/31/10		-200	-200	
Clean Power									01/01/12			50	50	P

Schedule 8 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
Brandy Branch	2	Brandy Branch	GT	NG	FO2	PL	TK		05/01/01	05/01/05		158	191	Conversion
Brandy Branch	3	Brandy Branch	GT	NG	FO2	PL	TK		10/12/01	05/01/05		158	191	Conversion
Brandy Branch	4	Brandy Branch	CC	NG	FO2	PL	TK		06/01/05			501	573	V
CT - 7EA	Unknown	Greenfield	GT	NG	FO2	PL	TK		01/01/10			75	86	P
CT - 7EA	Unknown	Greenfield	GT	NG	FO2	PL	TK		01/01/10			75	86	P
CFB	Unknown	Greenfield	FC	PC	Coal	WA	WA		01/01/11			250	250	P
CFB	Unknown	Greenfield	FC	PC	Coal	WA	WA		01/01/13			250	250	P

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Brandy Branch Combined Cycle
(2)	Net Capacity:	
(3)	Summer MW	502
(4)	Winter MW	572
(5)	Technology Type:	Combined Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	October 15, 2002
(8)	Commercial In-Service date:	May 1, 2005
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Selective catalytic reduction (SCR)
(13)	Cooling Method:	Mechanical Draft Cooling Tower
(14)	Total Site Area:	153 acres
(15)	Construction Status:	Active
(16)	Certification Status:	Site Certification Complete
(17)	Status with Federal Agencies:	All applicable items filed in Site Certification Application
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	3.20 percent
(20)	Forced Outage Factor (FOF):	1.70 percent
(21)	Equivalent Availability Factor (EAF):	95.10 percent
(22)	Resulting Capacity Factor (%):	50.00 percent
(23)	Average Net Operating Heat Rate (ANOHR):	7000 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):	$ 634
(28)	AFUDC Amount ($/kW):	Included in direct construction cost
(29)	Escalation ($/kW):	Included in direct construction cost
(30)	Fixed O&M ($/kW-yr):	1.90
(31)	Variable O&M ($/MWh):	2.18

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	