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Attached you will find 25 hardcopies of JEA's 2010 Ten Year Site Plan. If you have any questions regarding this submittal, please contact me at (904) 665-6216.

Thank You,

Mary Guyton Baker, PE
Electric System Planning, JEA

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Ten Year Site Plan

April 2010

JEA®

Building Community®

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List of Abbreviations

Type of Generation Units

CA	Combined Cycle - Steam Turbine Portion, Waste Heat Boiler (only)
CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
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
WH	Waste Heat

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Introduction

The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.

The Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. This TYSP reports the environmentally sound, power supply strategy, which provides reliable electric service at the lowest practical cost to JEA's customers. The report covers a planning period from January 1, 2009 to December 31, 2018.

1 Description of Existing Facilities

1.1 Power Supply System Description

1.1.1 System Summary

JEA is the seventh largest municipally owned electric utility in the United States in terms of number of customers. 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 and serves more than 417,000 customers.

JEA consists of three financially separate entities: the JEA Electric System, the St. Johns River Power Park bulk power system, and the Robert W. Scherer bulk power system. The total net capability of JEA's generation system is 3,750 MW in the winter and 3,470 MW in the summer. Details of the existing facilities are displayed in TYSP Schedule 1.

1.1.1.1 The Electric System

The Electric System consists of generating facilities located on three plant sites within the City; the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), and the Brandy Branch Generating Station (Brandy Branch). Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy CT 7 and 8, Brandy Branch CTs 1, 2, and 3); four diesel-fired combustion turbine-generator units (Northside CTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4).

1.1.1.2 The Bulk Power Systems

1.1.1.2.1 St. John's River Power Park

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 in Jacksonville, FL. Unit 1 began commercial operation in March 1987 and Unit 2 followed in May 1988. The two units have operated efficiently since commercial operation.

Although JEA is the majority owner of SJRPP, both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, JEA has agreed to sell, and FPL has agreed to purchase, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. This sale will continue until the earlier of the Joint Ownership Agreement expiration in 2022 or the realization of the sale limits. For the purposes of this Ten Year Site Plan, the 37.5% sale to FP&L is suspended as of March 2017.

1.1.1.2.2 Robert W. Scherer Generating Station

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA and FP&L have purchased an undivided interest of this unit from Georgia Power Company. JEA has a 23.6 percent ownership interest in Unit 4 (200 net MW) and proportionate ownership interests in associated common facilities and the associated coal stockpile. JEA purchased 150 megawatts of Scherer Unit 4 in July 1991, and purchased an additional 50 megawatts in June 1995. Georgia ITS delivers the power from the unit to the jointly owned 500 kV transmission lines.

1.1.2 Purchased Power

1.1.2.1 Southern Company 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. These capacity obligations are firm and subject only to the availability of Miller Units 1 through 4 and Scherer Unit 3. The capacity and energy are priced based on the specific cost of these units. In addition, JEA occasionally purchases economy interchange power from Southern Company over and above the UPS. JEA plans to continue to maintain the transmission rights for this capacity after the expiration of the UPS Purchase.

1.1.2.2 Constellation Energy Commodities Group, Inc

Constellation Energy Commodities Group, Inc (Constellation) and JEA entered into a power purchase and sale agreement in October 2006. The purchase power agreement entitles JEA to 75 MW, 150 MW, and 150 MW of peaking capacity and energy for the three consecutive winter seasons 2007/08 through 2009/10. The contract states that Constellation will deliver the firm energy to the Georgia side of the Florida /Georgia ITS.

1.1.2.3 Trailridge Landfill

In 2004, JEA issued a Request for Proposal (RFP) for renewable resources. As a result of this RFP, JEA has under contract 9.6 MW of renewable resources. The contract is for landfill gas generation from Trailridge landfill located in west of Duval County.

As an addendum to this agreement, JEA is completing negotiations for Phase II of the Trailridge Landfill Gas Project. Phase II is an additional 6 MW with initial operation in 2011 for a term of 15 years. These resources are included in this TYSP.

1.1.2.4 Jacksonville Solar

JEA signed a purchase power agreement with Jacksonville Solar, LLC to provide energy from a 15.0 MW solar farm scheduled to commence operation in 2010. The facility will be located in western Duval County and will consist of approximately 200,000 photovoltaic panels on a 100 acre site and will generate about 22,340 megawatt-hours (MWh) of electricity per year. This resource is included in this TYSP.

1.1.2.5 Nuclear Generation

In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships with the goal of providing 10 percent of JEA's power from nuclear sources. Adding power from nuclear sources to JEA's portfolio is part of a strategy for greater regulatory diversification and fuel diversification. Meeting this goal will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a purchase power agreement (PPA) with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4, which are proposed new nuclear units to be constructed at the existing Plant Vogtle located in Burke County, GA. Under this PPA, JEA will be entitled to a total of 206 MW of firm capacity from the proposed units. After accounting for transmission losses, JEA's is anticipating to receive a total of 200 MW of net firm capacity from the proposed units. For purposes of the analyses, it has been assumed that 100 MW (net) of capacity is available to JEA beginning January 1, 2016 from Vogtle Unit 3, and an additional 100 MW (net) is available to JEA beginning January 1, 2017 from Vogtle Unit 4.

Table 1-1: JEA Purchased Power Schedule

Contract	Contract Start Date	Contract End Date	MW [1]	Product Type
Southern Company	January 1980	May 31, 2010	207	Annual
Constellation	December 2007	March 15, 2010	150	Winter Only
Landfill Energy Systems	Unit 1			
	December 2008	January 2019	9.6	Annual
	Unit 2			
	June 2011	June 2026	6	Annual
MEAG	Vogtle Unit 3			
	January 2016	December 2036	100	Annual
	Vogtle 4			
	January 2017	December 2037	100	Annual
Jacksonville Solar	Summer 2010	Summer 2040	15 [2]	Annual

1 Capacity level may vary over contract term.
2 Direct Current (DC) rating.

Schedule 1: Existing Generating Facilities
As of December 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant	Unit		Unit	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net MW Capability			
Name	Number	Location	Type	Primary	Alt.	Primary	Alt.	Mo/Yr	Mo/Yr	kW	Summer	Winter	Ownership	Status
Kennedy										407,600	300	382		
	7	12-031	GT	NG	FO2	PL	WA	6/2000		203,800	150	191	Utility	
	8	12-031	GT	NG	FO2	PL	WA	6/2009		203,800	150	191	Utility	
Northside										1,263,700	1,322	1,356		
	1	12-031	ST	PC	BIT	WA	RR	2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	2002	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	(a)	563,700	524	524	Utility	
	3-6	12-031	GT	FO2		WA	TK	1/1975	(a)	248,400	212	246	Utility	
Brandy Branch										676,000	651	796		
	1	12-031	GT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	2	12-031	CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	3	12-031	CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	4	12-031	CA	WH				1/2005	(a)	268,400	201	223	Utility	
Girvin Landfill	1-2	12-031	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	12-031	ST	BIT/PC		RR	WA	3/1987	3/2027	679,600	501	510	Joint	(b)
	2	12-301	ST	BIT/PC		RR	WA	5/1988	5/2028	679,600	501	510	Joint	(b)
Scherer	4	13-207	ST	SUB	BIT	RR	RR	2/1989	2/2029	846,000	194	194	Joint	(c)
JEA System Total											**3,470**	**3,750**		

NOTES:
(a) Units expected to be maintained throughout the study period.
(b) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(c) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(d) Numbers may not add due to rounding.

1.1.2.6 Cogeneration

JEA encourages 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 13 MW and winter peak capacity of 14 MW. JEA purchases energy from these QF's on as-available, non-firm basis. Table 1-2 lists JEA customers having Qualifying Facilities located within JEA's service territory.

Table 1-2: JEA Service Territory Qualifying Facilities

Cogenerator Name	Unit Type	In-Service Date	Net Capability[1] – MW	
			Summer	Winter
Anheuser Busch	COG[2]	Apr-88	8	9
Baptist Hospital	COG	Oct-82	3	3
Ring Power Landfill	SPP[3]	Apr-92	1	1
St Vincent's Hospital	COG	Dec-91	1	1
Total			13	14

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

1.1.3 Power Sales Agreements

1.1.3.1 Florida Public Utilities Company

JEA furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. In September 2006, JEA and FPU signed a 10 year renewal agreement which began January 1, 2008 and extends through December 31, 2017. In this report, it is assumed that JEA will serve FPU throughout this TYSP reporting period. Sales to FPU in calendar year 2009 totaled 406 GWh or 3.09% of JEA's total system energy requirement.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

The JEA transmission system consists of 728 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV (Figure 1-1).

The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Progress Energy Florida and the City of Tallahassee each also own transmission interconnections with the Georgia ITS. JEA's import entitlement over these transmission lines is 1,228 MW out of 3,600 MW.

The 230 kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates three 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at Beaches Energy's Sampson substation (FPL metered tie-line) in St. Johns County, one 230 kV tie-line terminating at Seminole Electric Cooperative's Black Creek substation in Clay County, and one 138 kV tie-line terminating at Beaches Energy's Penman Road substation.

JEA also owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to the Nassau substation, where JEA delivers wholesale power to FPU for resale within the City of Fernandina Beach, Nassau County, Florida.

1.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually assesses, in compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, the needs and options for increasing the capability of the transmission system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC'S published Regional Transmission Planning Process which facilitates coordinated planning by all transmission providers, owners, and stakeholders with the FRCC Region. FRCC's members include investor owned utilities, municipal utilities, a federal power agency, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Working Group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

1.2.3 Transmission Service Requirements

In addition to JEA's obligation to serve JEA's native retail territorial load, JEA also has contractual obligations to provide transmission service for:

- the delivery of FPL's share of SJRPP energy output from the plant to FPL's interconnections
- the delivery of Cedar Bay's energy output from the plant to FPL's interconnections
- the delivery of backup, non-firm, as available tie capability for Beaches Energy System

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

1.2.4 Distribution

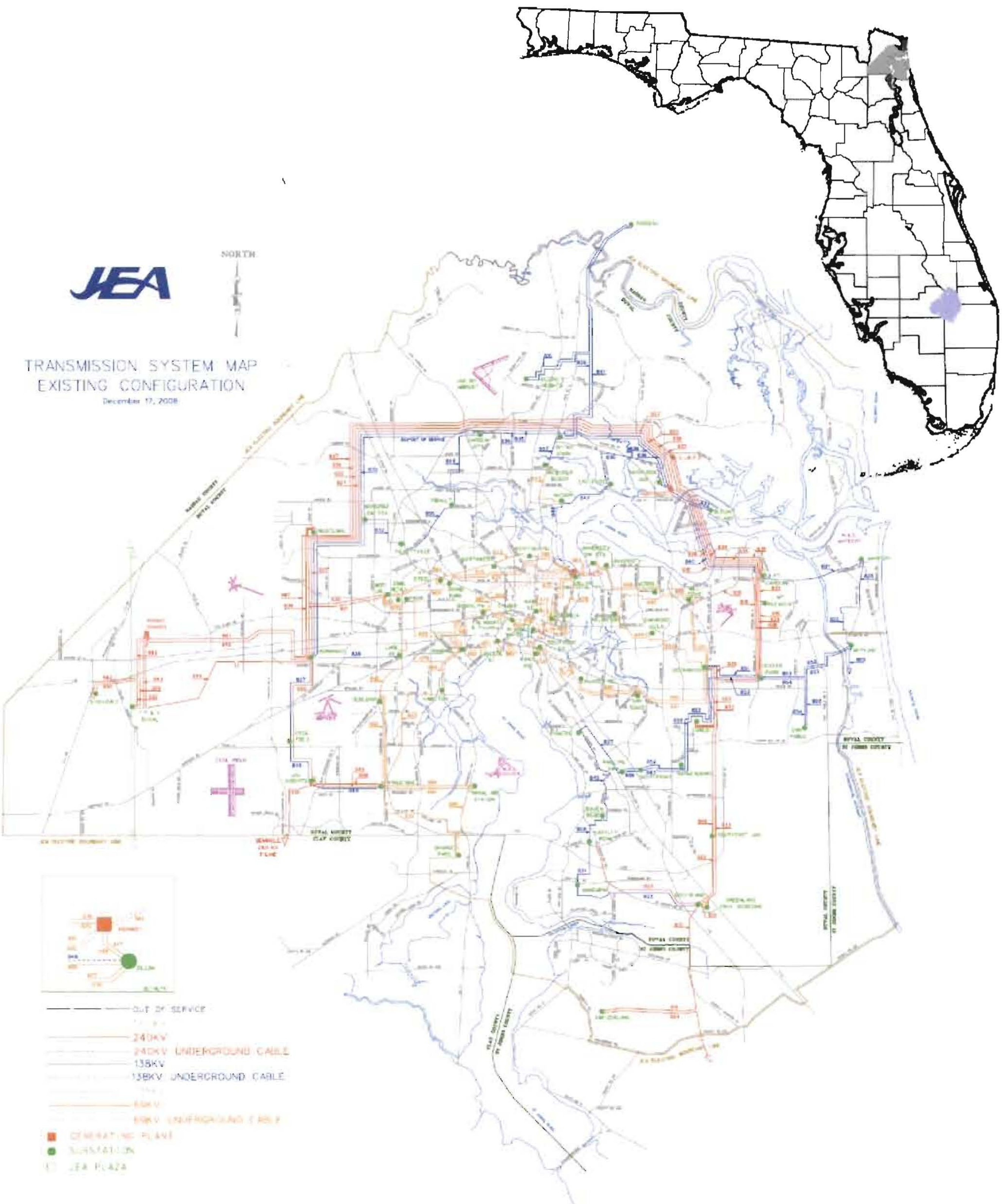
The JEA distribution system operations at three primary voltage levels; 4.16 kV, 13.2 kV, and 26.4 kV. The 26.4 kV system serves approximately 86% of JEA's load, including 75% of the 4.16 kV substations. The current standard is to serve all new distribution loads, except loads in the downtown network, with 26.4 kV systems. Conversion of the aging 4 kV infrastructure continues to be implemented. JEA has approximately 6200 miles of distribution circuits of which more than half is underground.

1.3 Demand Side Management

1.3.1 Interruptible Load

Interruptible load is non-firm load that can be shed during times of system emergencies including supply shortages. This contractual arrangement results in less need for capacity reserves to meet peak demands. JEA forecasts 87 MW and 123 MW of interruptible load in the winter and summer, respectively. The interruptible load represents approximately 4.44 percent of the total peak demand in the winter of 2010 and 2.85 percent of the forecasted total peak demand in the summer of 2010. JEA forecasts that its interruptible load will remain constant throughout the forecast period.

Figure 1-1: JEA Transmission/Generation Facilities System Map



1.3.2 Demand Side Management

JEA is currently restructuring its DSM portfolio; two RFP's are being deployed for expanded residential and commercial programs. The current estimate for annual incremental demand and energy over the next ten year period is shown in the Table 1-3. JEA's planned DSM programs are summarized by commercial and residential programs in Table 1-4.

Table 1-3: DSM Portfolio

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Annual Energy (GWh)	14.33	28.66	28.66	28.66	28.66	28.66	28.66	28.66	28.66	28.66
Summer Peak (MW)	2.88	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76	5.76
Winter Peak (MW)		4.20	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80

Table 1-4: DSM Programs

Commercial Programs	Residential Programs
Prescriptive	ENERGY STAR Products
Custom Commercial	Neighborhood Energy Efficiency
Small Business Direct Install	Residential Existing Homes
Commercial New Construction	Solar Water Hearter Incentives
	Home Energy Report Card
	Green Built Homes of Florida

1.4 Clean Power and Renewable Energy

JEA recognizes the importance of integrating renewable energy into its power supply portfolio. To that end, JEA has pursued several clean power initiatives and is in the process of evaluating potential new renewable energy resources. The remainder of this section discusses JEA's Clean Power Program, JEA's existing renewable energy resources, and potential new renewable energy resources being evaluated by JEA.

1.4.1 Clean Power Program

Since 1999, JEA has worked closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled "Clean Power Action Plan." The "Clean Power Action Plan" has an Advisory Panel which is comprised of participants from the Jacksonville community. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Current members of the Advisory Panel include the Sierra Club, ALA, and the City of Jacksonville Environmental Protection Board.

JEA has made considerable progress related to clean power initiatives. This progress includes installation of clean power systems, unit efficiency improvements, commitment to purchase power agreements, legislative and public education activities, and research into and development of clean power technologies.

1.4.2 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. In addition, JEA has issued several RFPs for renewable energy resources. As further discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, landfill and wastewater treatment biogas capacity, and wind capacity.

1.4.2.1 Solar and the Solar Incentive

JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program continues to provide rebates for the installation of solar thermal systems. As a result of a solar thermal and PV economic benefit analysis, cash incentives to install solar PV were discontinued in 2005.

In addition to the solar thermal system incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems, which was revised in 2009 to include all customer-owned renewable generation systems up to and equal to 100 kW.

JEA signed a purchase power agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 15.0 MW DC rated solar farm scheduled to commence operation in 2010. The facility will be located in western Duval County and will consist of approximately 200,000 photovoltaic panels on a 100 acre site and will generate about 22,340 megawatt-hours (MWh) of electricity per year.

1.4.2.2 Landfill Gas and Biogas

JEA owns three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined to 1.2 MW, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The JEA Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using two anaerobic digesters and a sludge dryer to produce a fertilizer pellet product. The methane gas from the digesters is used, as a fuel, for the sludge dryer and for the on-site 800 kW generator. In addition, JEA is conducting an analytical evaluation of the bio-solids to determine the possibility of conducting a co-firing test in Northside 1 or 2.

JEA has under contract 9.6 MW of energy produced from Landfill Energy System's Trail Ridge landfill gas-to-energy facility which is located in west Duval County. JEA also receives approximately 1,500 kW of landfill gas from the North Landfill, which is piped to the Northside Generating Station and is used to generate power at Northside Unit 3.

1.4.2.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA purchases 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD buys back the energy at specified on/off peak charges. JEA retains the rights to the environmental credits (green tags).

1.4.2.4 Biomass

In a continuing effort to obtain cost effective biomass generation, JEA completed a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not be eligible for the federal tax credits afforded to developers, but would take advantage of JEA's low cost tax exempt financing. The co-firing alternative for Northside 1 and 2 must consider potential reliability issues associated with both of those units. Also, the price of petroleum coke is extremely volatile, but is expected to be lower than the cost of biomass on an as-fired basis a significant portion of the time. In addition, JEA is conducting an analytical evaluation of a specific biomass fuel type to determine the possibility of conducting a co-firing test in Northside 1 or 2. JEA has received unsolicited as well as solicited offers for biomass and other renewable generation. JEA evaluates the feasible offers, but has been unable to successfully execute a contract for cost-effective biomass generation. One notable example is the 70 MW biomass project burning E-grass that JEA executed in 2002 with Biomass Investment Group (BIG). Even though JEA executed the purchase power agreement, BIG never implemented the project and subsequently, the contract expired. Also, an unsolicited offer was received from ADAGE for energy from a proposed 50MW facility. An exclusive letter of intent between JEA and ADAGE for 50MW of biomass power expired on Dec. 31, 2009. JEA and ADAGE did not enter into a purchase power agreement.

1.4.2.5 Research Efforts

Many of Florida's renewable resources such as offshore wind, tidal, and energy crops require additional research and development before they can be implemented as a large-scale technology. JEA's renewable energy research efforts have focused on the development of these technologies through a partnership with the University of North Florida's (UNF) Engineering Department. UNF and JEA have worked on the following projects:

- JEA has worked with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, has evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF has evaluated the tidal hydro-electric potential for North Florida, particularly in the Intercoastal Waterway, where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA has also provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

1.4.2.6 Generation Efficiency and New Natural Gas Generation

Since the late 1990's JEA began to modernize its natural gas/oil fleet of generating units by replacing inefficient steam units and inefficient combustion turbine units with efficient combined cycle units and efficient combustion turbine units. Natural gas emits approximately 70 percent of the CO_2 emitted by No. 6 oil on a fuel basis. This program, coupled with the much greater efficiency of a combined cycle unit compared to No. 6 oil steam units and inefficient combustion turbine units results, in significant reduction of CO_2 on a per MWh basis.

1.4.2.7 Prior and Ongoing Projects

As a result of its fleet efficiency improvement efforts, JEA has retired the following units:

Kennedy Steam Unit 8	43 MW Summer	Natural Gas/No. 6.
Kennedy Steam Unit 9	43 MW Summer	Natural Gas/No. 6.
Kennedy Steam Unit 10	97 MW Summer	Natural Gas/No. 6.
Kennedy Combustion Turbine Unit 3	51 MW Summer	No. 2 Oil
Kennedy Combustion Turbine Unit 4	51 MW Summer	No. 2 Oil
Kennedy Combustion Turbine Unit 5	51 MW Summer	No. 2 Oil
Southside Steam Unit 4	67 MW Summer	Natural Gas/No. 6.
Southside Steam Unit 5	142 MW Summer	Natural Gas/No. 6.

The retirement of these units and their replacement with an efficient combined cycle and efficient simple cycle combustion turbines significantly reduces CO_2 emissions. JEA's replacement units include Brandy Branch Unit 1, Kennedy CT Unit 7, and Kennedy CT Unit 8 (7FA simple cycle combustion turbine units) and Brandy Branch Combined Cycle, a 2x1 7FA combined cycle unit. These units all burn natural gas as the primary fuel with ultra low sulfur diesel as a back-up fuel.

JEA is in the construction process of Greenland Energy Center (GEC) Units 1 and 2 which will also be efficient 7FA simple cycle combustion turbines designed to burn natural gas. The installation of these units will further increase the efficiency of JEA's natural gas fueled generating fleet.

2 Forecast of Electric Power Demand, and Energy Consumption

A greater uncertainty in forecasting short-term demand growth, and to a lesser degree long-term demand growth, has emerged due to the global financial crisis and the resulting downturn in consumer demands. JEA's service territory has a diverse mix of industrial customers including a significant military presence. This diverse mix of customers tends to moderate the long term impact of economic downturns. In addition, the Jacksonville Port Authority is expanding their cargo processing capability with two new port terminal additions and the Navy is adding a nuclear carrier to Mayport. Both of these industrial and military additions will lead to job development and community growth.

It is too soon to determine how the current global and local economic environments will translate into an impact on JEA's long-term growth outlook. However, in response to the forecasted impact on the short-term outlook, JEA has adopted a complementary forecast methodology that better reflects recent history and short-term growth expectations.

The 2010 Demand and Energy forecast takes into account these fundamental changes by applying recent historical annual growth trends. This is accomplished by utilizing historical average annual growth rates (AAGR) and applying the AAGR to the next subsequent forecast year.

For example, the actual AAGR from 2008 to 2009 for the winter peak demand is applied to the actual 2009 weather normalized integrated hourly winter demand results in the 2010 forecasted weather normalized integrated hourly winter demand. For the same season, the AAGR from 2007 to 2008 when applied to the forecasted 2010 weather normalized integrated hourly winter demand results in the 2011 forecasted weather normalized integrated hourly winter demand. The weather normalized integrated hourly summer peak demand forecast uses a similar method. The summer peak demand forecast method assumes no load growth the first year and maintains the subsequent years' historical AAGR. This method continues for the 10 year historical period to produce a 10 year forecast period such that the most recent history is reflected in the nearest future, but the overall historical trend is eventually reflected in the overall 10 year forecast for both demand and energy.

This method puts additional weighting on recent historical demand growth rates and maintains a 10 year historical demand growth rate trend when compared to JEA's other forecast methodologies. JEA continues to monitor customer consumption patterns and will adjust the forecast methods periodically as new trends are observed.

JEA uses 97° F (summer) and 25° F (winter) as weather normalization temperatures. The winter seasonal extreme for a year is the lowest temperature during the months of December, January, and February. The summer seasonal extreme is the highest temperature during the months of July, August, and September.

The results of the summer and winter peak demand forecasts are shown in Table 2-1 for total demand, non-firm demand, and firm demand levels. The summer and winter interruptible load is held constant throughout the study period. During the TYSP forecast period, the growth rate of the total demand for the winter peak is projected to increase at an average annual growth rate of 2.52%. The average annual increase in winter firm peak demand is 2.50%. During the summer period, the total demand for the summer peak is forecast to increase at an average annual growth rate of 2.53%. The average annual increase in summer firm peak demand is 2.46%.

Table 2-1 indicates that the firm winter peak demand is projected to increase from 2,969 MW in 2010 to 3,706 MW in 2019, and the firm summer peak demand is projected to increase from 2,645 MW in 2010 to 3,292 MW in 2019. Figure 2-1 shows the historical and forecast summer and winter peaks for JEA.

The Net Energy for Load (NEL) history and forecast for JEA are shown in Table 2-2. The NEL is forecast to increase at an average annual growth rate of 1.88% during the TYSP period. NEL is forecast to increase from 13,269 GWh in 2010 to 15,692 GWh in 2019. Figure 2-2 shows the historical and forecast NEL for JEA. Historical and forecast winter peak demand, summer peak demand, and net energy for load are shown several ways and in greater detail in Schedules 2 through 4.

Table 2-1: Seasonal Peak Demand History & Forecast

Year	Total Peak Demand Winter (MW)	Total Peak Demand Summer (MW)	DSM Winter (MW)	DSM Summer (MW)	Non-Firm Demand Winter (MW)	Non-Firm Demand Summer (MW)	Firm Peak Demand Winter (MW)	Firm Peak Demand Summer (MW)
2000	2,478	2,380	0	0	0	0	2,478	2,380
2001	2,666	2,389	0	0	0	0	2,666	2,389
2002	2,590	2,562	0	0	0	0	2,590	2,562
2003	3,083	2,535	0	0	0	0	3,083	2,535
2004	2,668	2,539	0	0	0	0	2,668	2,539
2005	2,860	2,815	0	0	0	0	2,860	2,815
2006	2,919	2,835	0	0	0	0	2,919	2,835
2007	2,722	2,897	0	0	0	0	2,722	2,897
2008	2,914	2,866	0	0	0	0	2,914	2,866
2009	3,064	2,735	0	0	0	0	3,064	2,735
2010	3,054	2,770	0	3	87	123	2,967	2,645
2011	3,099	2,823	4	9	87	123	3,008	2,691
2012	3,154	2,882	7	14	87	123	3,060	2,745
2013	3,219	2,948	10	20	87	123	3,122	2,805
2014	3,294	3,020	13	26	87	123	3,194	2,871
2015	3,379	3,098	15	32	87	123	3,276	2,944
2016	3,474	3,183	18	37	87	123	3,369	3,022
2017	3,579	3,273	21	43	87	123	3,471	3,106
2018	3,694	3,368	24	49	87	123	3,584	3,196
2019	3,820	3,470	27	55	87	123	3,706	3,292
Average Annual Growth Rate								
2000 - 2009	2.39%	1.56%					2.39%	1.56%
2010 - 2019	2.52%	2.53%					2.50%	2.46%
2000 - 2019	2.30%	2.00%					2.14%	1.72%

*** Historical values are actual not normalized. Winter 2010 actual peak demand experienced by JEA is 3,224 MW on January 11th.**

Figure 2-1: Historical and Forecast Summer and Winter Peaks

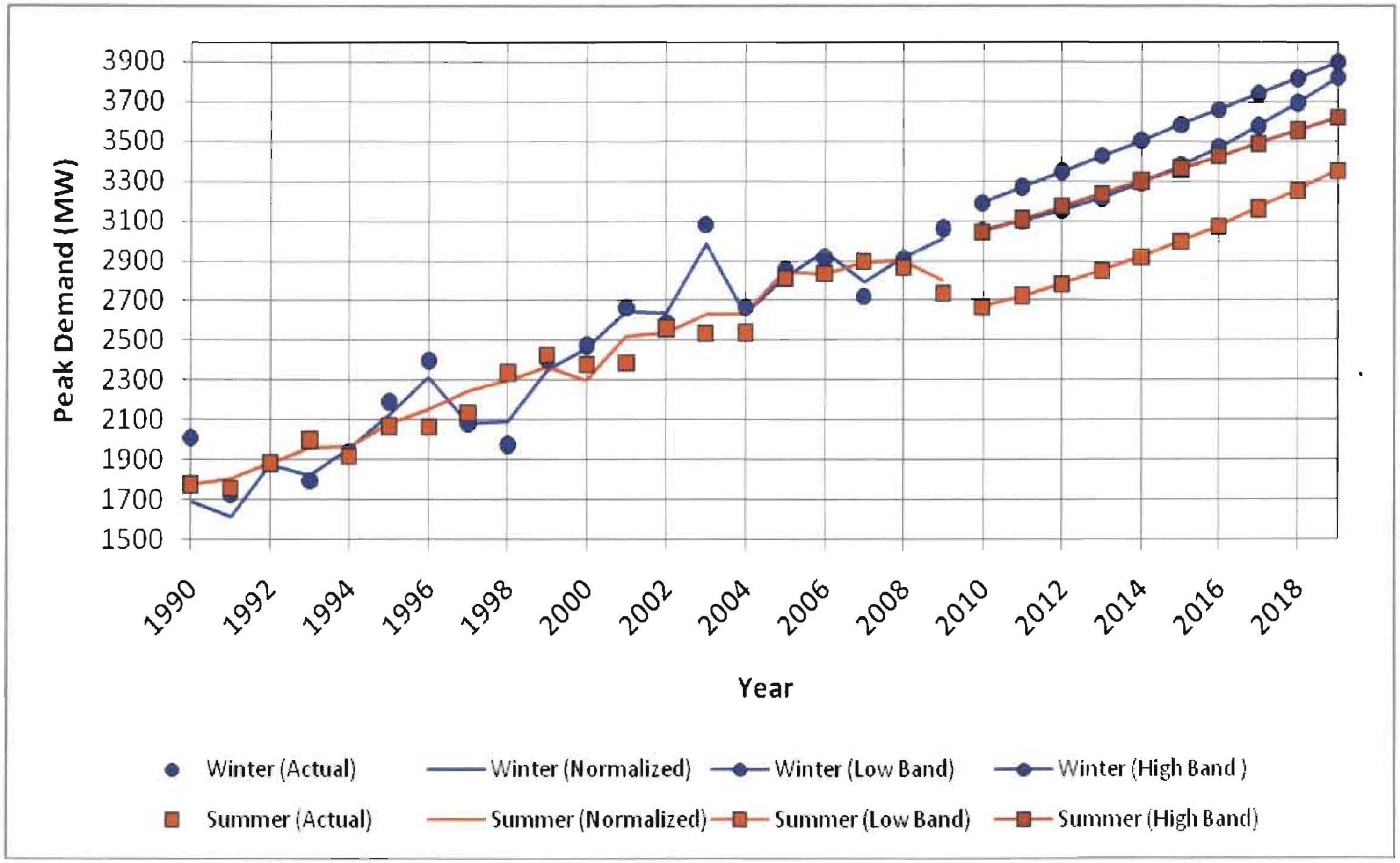
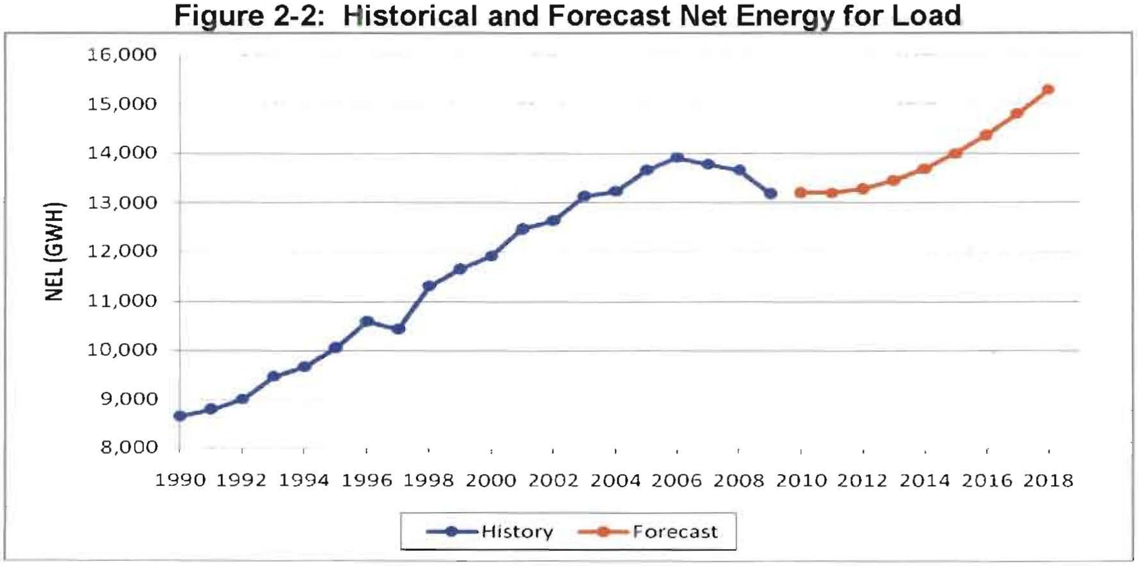


Table 2-2: Net Energy for Load History & Forecast

Calendar Year	Total Energy for Load	DSM	Net Energy For Load	HDD	CDD
	(GWh)			Days	
2000	12,190		12,190	1,478	2,456
2001	12,322		12,322	1,213	2,537
2002	12,983		12,983	1,333	2,867
2003	13,204		13,204	1,432	2,616
2004	13,243		13,243	1,427	2,834
2005	13,696		13,696	1342	2682
2006	13,811		13,811	1170	2742
2007	13,854		13,854	1,128	2,662
2008	13,530		13,530	1,369	2,499
2009	13,155		13,155	1,347	2,799
2010	13,283	14	13,269	1,324	2,669
2011	13,174	43	13,131	1,324	2,669
2012	13,279	72	13,207	1,324	2,669
2013	13,545	100	13,445	1,324	2,669
2014	13,717	129	13,588	1,324	2,669
2015	14,263	158	14,105	1,324	2,669
2016	14,471	186	14,285	1,324	2,669
2017	15,091	215	14,876	1,324	2,669
2018	15,436	244	15,192	1,324	2,669
2019	15,964	272	15,692	1,324	2,669

2000 - 2009	0.85%		0.85%		
2010 - 2019	2.06%		1.88%		
2000 - 2019	1.43%		1.34%		

Figure 2-2: Historical and Forecast Net Energy for Load



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)
	Rural and Residential			Commercial			Industrial		
Calendar Year	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer
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	5,637	357,232	15,780	1,289	37,136	34,704	5,658	4,206	1,345,307
2007	5,478	364,284	15,039	1,328	39,919	33,279	5,832	4,521	1,290,035
2008	5,364	365,632	14,670	1,357	40,608	33,417	5,777	4,599	1,256,240
2009	5,300	367,864	14,408	1,303	41,150	31,660	5,546	4,660	1,190,207
2010	5,346	372,883	14,337	1,314	41,711	31,504	5,595	4,724	1,184,352
2011	5,291	370,835	14,267	1,300	41,482	31,349	5,536	4,698	1,178,525
2012	5,321	371,172	14,337	1,308	41,520	31,503	5,569	4,702	1,184,323
2013	5,417	375,987	14,407	1,332	42,059	31,658	5,669	4,763	1,190,150
2014	5,475	378,131	14,478	1,346	42,298	31,814	5,729	4,790	1,196,005
2015	5,683	390,619	14,549	1,397	43,695	31,971	5,947	4,948	1,201,889
2016	5,756	393,650	14,621	1,415	44,034	32,128	6,023	4,987	1,207,802
2017	5,994	407,921	14,693	1,473	45,631	32,286	6,272	5,168	1,213,745
2018	6,121	414,579	14,765	1,505	46,375	32,445	6,406	5,252	1,219,716
2019	6,323	426,106	14,838	1,554	47,665	32,605	6,616	5,398	1,225,717

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 (Avg. Number)	(18) Total Number of Customers
2000	120	0	11,105	482	603	12,190	2	347,782
2001	109	0	11,508	453	361	12,322	2	355,994
2002	112	0	11,856	446	681	12,983	2	363,698
2003	115	0	12,130	453	595	13,178	2	369,904
2004	76	0	12,057	468	718	13,243	2	384,108
2005	111	0	12,596	486	615	13,696	2	395,606
2006	110	0	12,694	522	595	13,811	7	398,581
2007	113	0	12,751	624	479	13,854	5	408,729
2008	117	0	12,615	451	464	13,530	3	414,418
2009	120	0	12,270	479	406	13,155	3	413,677
2010	121	0	12,376	483	410	13,269	3	419,321
2011	120	0	12,247	478	405	13,131	3	417,018
2012	121	0	12,319	481	408	13,207	3	417,397
2013	123	0	12,540	490	415	13,445	3	422,811
2014	124	0	12,674	495	419	13,588	3	425,222
2015	129	0	13,157	514	435	14,106	3	439,266
2016	131	0	13,324	520	441	14,285	3	442,675
2017	136	0	13,875	542	459	14,876	3	458,722
2018	139	0	14,171	553	469	15,193	3	466,209
2019	143	0	14,636	571	484	15,692	4	479,173

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	Interr. Load	Load Management		QF Load Served By QF Gen.	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			Incremental Conservation Since 1980	
			Resid	Comm/Ind		Residential	Comm./ind.		Month	Day	H.E.	Resid.	Comm/Ind
2000	2,380	0	0	0	0	0	0	2,380	7	20	1400	0	0
2001	2,389	0	0	0	0	0	0	2,389	8	8	1800	0	0
2002	2,562	0	0	0	0	0	0	2,562	7	19	1600	0	0
2003	2,535	0	0	0	0	0	0	2,535	7	10	1600	0	0
2004	2,539	0	0	0	0	0	0	2,539	8	2	1700	0	0
2005	2,815	0	0	0	0	0	0	2,815	8	17	1800	0	0
2006	2,835	0	0	0	0	0	0	2,835	8	4	1700	0	0
2007	2,897	0	0	0	0	0	0	2,897	8	7	1700	0	0
2008	2,866	0	0	0	0	0	0	2,866	8	7	1600	0	0
2009	2,735	0	0	0	0	0	0	2,735	8	12	1600	0	0
2010	2,770	123	0	0	0	2	1	2,645	---	---	---	1.61	1.27
2011	2,823	123	0	0	0	5	4	2,691	---	---	---	3.22	2.54
2012	2,882	123	0	0	0	8	6	2,745	---	---	---	3.22	2.54
2013	2,948	123	0	0	0	11	9	2,805	---	---	---	3.22	2.54
2014	3,020	123	0	0	0	15	11	2,871	---	---	---	3.22	2.54
2015	3,098	123	0	0	0	18	14	2,944	---	---	---	3.22	2.54
2016	3,183	123	0	0	0	21	16	3,022	---	---	---	3.22	2.54
2017	3,273	123	0	0	0	24	19	3,106	---	---	---	3.22	2.54
2018	3,368	123	0	0	0	27	22	3,196	---	---	---	3.22	2.54
2019	3,470	123	0	0	0	31	24	3,292	---	---	---	3.22	2.54

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 Gen.	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			Incremental Conservation Since 1980	
			Residential	Comm/Ind		Residential	Comm/Ind		Month	Day	H.E.	Residential	Comm/Ind
2000	2,478	0	0	0	0	0	0	2,478	1	27	0800	0	0
2001	2,666	0	0	0	0	0	0	2,666	1	3	0800	0	0
2002	2,590	0	0	0	0	0	0	2,590	1	4	0800	0	0
2003	3,083	0	0	0	0	0	0	3,083	1	24	0800	0	0
2004	2,668	0	0	0	0	0	0	2,668	1	29	0700	0	0
2005	2,860	0	0	0	0	0	0	2,860	1	24	0800	0	0
2006	2,919	0	0	0	0	0	0	2,919	2	14	0800	0	0
2007	2,722	0	0	0	0	0	0	2,722	1	30	0800	0	0
2008	2,914	0	0	0	0	0	0	2,914	1	3	0800	0	0
2009	3,064	0	0	0	0	0	0	3,043	2	6	0800	0	0
2010	3,224	0	0	0	0	0	0	3,224	1	11	0800	0	0
2011	3,099	87	0	0	0	2	2	3,008	---	---	---	2.47	1.73
2012	3,154	87	0	0	0	4	3	3,060	---	---	---	1.65	1.15
2013	3,219	87	0	0	0	6	4	3,122	---	---	---	1.65	1.15
2014	3,294	87	0	0	0	7	5	3,194	---	---	---	1.65	1.15
2015	3,379	87	0	0	0	9	6	3,276	---	---	---	1.65	1.15
2016	3,474	87	0	0	0	11	7	3,369	---	---	---	1.65	1.15
2017	3,579	87	0	0	0	12	9	3,471	---	---	---	1.65	1.15
2018	3,694	87	0	0	0	14	10	3,584	---	---	---	1.65	1.15
2019	3,820	87	0	0	0	16	11	3,706	---	---	---	1.65	1.15

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	Cumulative Conservation		Net Energy For Load	Incremental Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./Ind.		Residential	Comm./Ind.
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	13,811	0	0	0	0	0	0	13,811	0	0
2007	13,854	0	0	0	0	0	0	13,854	0	0
2008	13,530	0	0	0	0	0	0	13,530	0	0
2009	13,155	0	0	0	0	0	0	13,155	0	0
2010	13,283	0	0	0	0	7	7	13,269	7.29	7.04
2011	13,174	0	0	0	0	22	21	13,131	14.57	14.09
2012	13,279	0	0	0	0	36	35	13,207	14.57	14.09
2013	13,545	0	0	0	0	51	49	13,445	14.57	14.09
2014	13,717	0	0	0	0	66	63	13,588	14.57	14.09
2015	14,263	0	0	0	0	80	77	14,105	14.57	14.09
2016	14,471	0	0	0	0	95	92	14,285	14.57	14.09
2017	15,091	0	0	0	0	109	106	14,876	14.57	14.09
2018	15,436	0	0	0	0	124	120	15,192	14.57	14.09
2019	15,964	0	0	0	0	138	134	15,692	14.57	14.09

Schedule 4: Previous Year Actual and Two Year Forecast of Peak Demand and Net Energy for Load By Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 2009		Forecast 2010		Forecast 2011	
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	3,060	1,106	2,967	1,104	3,008	1,166
February	3,064	985	2,461	996	2,496	974
March	2,476	948	2,095	948	2,125	945
April	2,048	929	1,974	940	2,009	952
May	2,451	1,131	2,369	1,117	2,411	1,170
June	2,754	1,288	2,494	1,287	2,539	1,300
July	2,628	1,292	2,603	1,308	2,650	1,337
August	2,735	1,292	2,644	1,292	2,691	1,161
September	2,417	1,185	2,441	1,164	2,484	1,050
October	2,423	1,094	2,402	1,167	2,444	1,137
November	1,710	883	2,305	951	2,345	1,003
December	2,151	1,022	2,730	995	2,777	936
Annual Peak and NEL	3,064	13,155	2,967	13,269	3,008	13,131

3 Forecast of Facilities Requirements

3.1 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 3 displays the likely need for capacity when assuming the base case load forecast, installation of committed units, and existing unit changes in capacity for JEA's system for the term of this TYSP.

Table 3-1: Resource Needs After Committed Units

Winter - MW (1)									
Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Capacity Required For 15% Reserves
2010	3,750	367	383	0	3,734	2,967	766	26%	0
2011	3,750	10	383	0	3,377	3,008	369	12%	(82)
2012	4,126	16	383	0	3,759	3,060	699	23%	0
2013	4,126	16	383	0	3,759	3,122	637	20%	0
2014	4,126	16	383	0	3,759	3,194	564	18%	0
2015	4,126	16	383	0	3,759	3,276	482	15%	(9)
2016	4,126	116	383	0	3,859	3,369	490	15%	(15)
2017	4,126	216	383	0	3,959	3,471	488	14%	(33)
2018	4,126	216	0	0	4,341	3,584	758	21%	0
2019	4,126	206	0	0	4,332	3,706	625	17%	0

Summer - MW									
Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Capacity Required For 15% Reserves
2010	3,470	10	376	0	3,104	2,645	459	17%	0
2011	3,754	16	376	0	3,394	2,691	702	26%	0
2012	3,754	16	376	0	3,394	2,745	649	24%	0
2013	3,754	16	376	0	3,394	2,805	589	21%	0
2014	3,754	16	376	0	3,394	2,871	522	18%	0
2015	3,754	16	376	0	3,394	2,944	450	15%	0
2016	3,754	116	376	0	3,494	3,022	472	16%	0
2017	3,754	216	0	0	3,969	3,106	863	28%	0
2018	3,753	216	0	0	3,968	3,196	772	24%	0
2019	3,753	206	0	0	3,959	3,292	667	20%	0

Notes:

1. Winter 2010 is actual normalized peak.
2. Committed Capacity Additions: 6 MW Trailridge II, GEC CTs, and Vogtle Units 3 & 4.
3. UPS Purchase expires summer 2010.

The base capacity plan includes, as committed units, the additions of Trailridge Phase II, 2 7FA CTs at Greenland Energy Center (GEC), and the nuclear purchased power agreement with MEAG for Vogtle Units 3 and 4. Although the Jacksonville Solar project provides energy to serve JEA's load, it is not a contributor to firm capacity at the time of JEA's peak demand. With JEA's existing and committed capacity, Table 3 shows small winter seasonal needs in 2011, 2015, 2016, and 2017. The seasonal needs account for less than three percent of the reserve margin in 2011 and less than one-half of one percent in the remaining years.

JEA's Planning Reserve Policy defines the planning reserve requirements that are used to develop the resource portfolio through the Integrated Resource Planning process. These guidelines set forth the planning criteria relative to the planning reserve levels and the constraints of the resource portfolio.

JEA's system capacity is planned with a targeted 15% generation reserve level for forecasted wholesale and retail firm customer coincident one hour peak demand for both winter and summer seasons. This reserve level has been determined to be adequate to meet and exceed the industry standard Loss of Load Probability of 0.1 days per year. This level has been used by the Florida Public Service Commission (FPSC) in the consideration of need for additional generation additions.

JEA's Planning Reserve Policy limits the level of market dependency to meet the 15% reserve margin to no more than 3% of Forecasted Firm Demand in any season. This assumes that JEA can obtain within the operating horizon, resources capable of supplying up to 3% (90 MW for a 3,000 MW firm demand level) of JEA's Firm Demand. In accordance with JEA's Planning Reserve Policy, the seasonal needs identified in Table 3 are sufficiently low enough to consider it minimum risk to obtain market capacity utilizing the extensive resources of The Energy Authority (TEA), JEA's affiliated energy market services company.

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 among 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 levels of reliability similar 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, in this case, 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. In the Ten Year Site Plan, JEA identifies areas of seasonal needs in Table 3 which JEA will engage TEA to meet those needs during those seasons.

3.2 Projects In Progress

Greenland Energy Center

Greenland Energy Center (GEC) is a new greenfield site in southeast Jacksonville. JEA is proceeding with the installation of two combustion turbine units at this site. These units are natural gas-fired simple-cycle GE frame 7FA combustion turbine units, with site and units capable of future fuel storage additions to support diesel as backup fuel. The scheduled commercial operation date for these units is June 2011. For further discussion on GEC, refer to Chapter 5 of this document.

The conversion of GEC CTs 1 and 2 to combined cycle was originally initiated to replace capacity and energy that JEA planned to receive as its share in the suspended Taylor Energy Center (TEC) Supercritical Pulverized Coal Unit. Replacing JEA's share of Taylor Energy Center capacity with capacity and energy from the Greenland combined cycle would have reduced JEA's CO_2 emissions by over 1 million tons per year from what otherwise would have been produced with TEC.

JEA's 2008 TYSP filled the summer 2012 capacity shortfall with GEC CC. Changes in the economy and changes in customer demand and energy consumption resulted in a decline in future forecasts of demand and energy and subsequently a decline in the need for firm, annual capacity. By October 2008, the conversion date changed to June 2013 and in February 2009, the FPSC issued a Need for Power Certificate giving approval to the conversion for that date. With these continual changes, JEA's need for annual capacity has continued to move further into the future. GEC's combined cycle conversion is currently forecast for 2020.

An earlier commercial operation date may be identified as dictated by updated forecasts of the suspension of SJRPP sales to FPL (383 MW) and any final greenhouse gas regulation affecting the economic need for fuel efficiencies afforded by the GEC CC heat recovery steam generation. The sale suspension, although energy limited, is determined by and dependent upon FPL's utilization of the resource. At current levels of consumption, JEA forecasts FPL will reach the energy limit March 2017. The ultimate suspension date of the SJRPP sale to FPL is 2022, if FPL does not reach the energy off-take limit earlier. A forecast of a suspension date after 2018 would produce a forecasted reserve margin where additional capacity afforded by the GEC CC addition would be required.

Potential climate change legislation could affect JEA's need for fuel efficiency and reduce CO_2 emissions. Any legislation currently in discussion such as HR2454 or any future mandates that would encourage greater utilization of natural gas could require an earlier commercial date for GEC CC, regardless of a capacity need, driven solely by JEA's need for fuel efficiency and reduced CO_2 emissions.

Although the commercial date has been delayed, the GEC conversion project, when implemented, will allow JEA's generating unit efficiency improvement to increase. The conversion will allow the output of the combined cycle unit to increase over 60 percent without any increase in CO_2 emissions. The installation of the combined cycle conversion of the Greenland combustion turbines along with the Brandy Branch combined cycle unit will allow JEA to generate a large amount of energy with natural gas with its attendant lower CO_2 emissions per unit of electrical output.

3.3 Resource Plan

The analysis of JEA's electric system to determine the current plan included a review of existing electric supply resources including renewable energy, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and fuel 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. The base case peak demand indicates a need for additional capacity to meet system reserve requirements beginning summer 2011. This need encompasses the inclusion of existing supply resources, but not the committed units.

In addition to cost considerations, environmental, land use, and transmission deliverability considerations were factored into the resource plans. This ensured that the plans selected were holistically beneficial.

Based on modeling of the JEA system, forecast of demand and energy, forecast of fuel prices and availability, and environmental considerations, Table 3-2 presents the least-cost expansion plan which meets JEA's strategic goals. Schedules 5-10 provides further detail on this plan.

Table 3-2
Reference Plan

Year	Season	Expansion Plan
2010	Winter	Constellation Purchase (150 MW - Seasonal)
	Summer	Southern - UPS Contract Expires (207 MW) Solar Purchase (15 MW – DC rating)
2011	Winter Summer	Seasonal Market Purchase (90 MW) Build 2 - 7FA CTs at GEC (177 MW each) Trailridge II Purchase (6 MW)
2012		
2013		
2014		
2015	Winter	Seasonal Market Purchase (25 MW)
2016	Winter	Seasonal Market Purchase (25 MW) MEAG Plant Vogtle Purchase (100 MW)
2017	Winter Summer	Seasonal Market Purchase (50 MW) MEAG Plant Vogtle Purchase (100 MW) SJRPP Sale to FPL Suspended (383 MW)
2018		Trailridge I Contract Expires (9.6 MW)
2019		

- Cumulative DSM addition of 25 MW Winter and 52 MW Summer by 2019

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual										
	Fuel	Type	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	**NUCLEAR**		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**[1]		**1000 TON**	**2,918**	**2,471**	**2,718**	**2,554**	**2,717**	**2,586**	**2,701**	**2,628**	**3,092**	**3,152**	**3,259**
	RESIDUAL													
(3)		STEAM	1000 BBL	66	106	157	152	149	159	131	153	103	104	108
(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**	**66**	**106**	**157**	**152**	**149**	**159**	**131**	**153**	**103**	**104**	**108**
	DISTILLATE													
(7)		STEAM	1000 BBL	9	4	3	4	4	3	2	3	3	10	10
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	39	27	11	6	1	2	14	7	2	5	1
(10)		**TOTAL:**	**1000 BBL**	**48**	**32**	**14**	**10**	**6**	**6**	**16**	**11**	**5**	**15**	**12**
	NATURAL GAS													
(12)		STEAM	1000 MCF	7,920	7,508	11,086	10,795	10,560	11,246	9,305	10,829	7,350	7,373	7,651
(13)		CC	1000 MCF	11,372	12,715	9,856	15,046	12,971	14,239	16,362	13,679	6,724	8,096	8,662
(14)		CT/GT	1000 MCF	1,462	2,446	2,154	2,288	2,321	3,390	5,167	3,206	1,696	1,852	2,506
(15)		**TOTAL:**	**1000 MCF**	**20,754**	**22,669**	**23,097**	**28,129**	**25,851**	**28,875**	**30,834**	**27,714**	**15,770**	**17,321**	**18,819**
(16)	**PETROLEUM COKE**		**1000 TON**	**1,033**	**1,487**	**1,486**	**1,344**	**1,462**	**1,469**	**1,480**	**1,420**	**1,400**	**1,379**	**1,407**
(17)	**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	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	**Annual Firm Inter-Region Interchange**[1]		GWH	1,606	612	14	0	0	1	3	863	1,721	1,654	1,715
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**[2]		GWH	6,019	5,935	6,407	6,188	6,437	6,185	6,410	6,317	7,582	7,863	8,094
(4)	**RESIDUAL**	STEAM	GWH	38	59	88	85	83	89	75	85	54	53	57
(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	38	59	88	85	83	89	75	85	54	53	57
(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	15	11	5	3	1	1	6	3	1	2	1
(11)		TOTAL	GWH	15	11	5	3	1	1	6	3	1	2	1
(12)	**NATURAL GAS**	STEAM	GWH	699	673	1,011	978	950	1,021	860	981	617	607	650
(13)		CC	GWH	1,577	1,708	1,324	2,029	1,735	1,941	2,224	1,836	875	1,061	1,148
(14)		CT	GWH	127	200	168	179	178	269	420	252	129	138	190
(15)		TOTAL	GWH	2,403	2,582	2,504	3,185	2,862	3,231	3,503	3,068	1,621	1,806	1,988
(16)	**NUG**		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	**RENEWABLES**	LANDFILL GAS	GWH	75	78	117	130	130	130	130	130	130	104	52
(18)		SOLAR	GWH	0	10	22	22	21	21	21	21	21	21	21
(19)		TOTAL	GWH	75	89	139	152	151	151	151	151	151	125	72
(20)	**PETROLEUM COKE**		GWH	2,999	3,982	3,975	3,594	3,911	3,931	3,958	3,798	3,747	3,690	3,766
(21)	**OTHER (SPECIFY)**		GWH											
(22)	**NET ENERGY FOR LOAD**		GWH	13,155	13,269	13,131	13,207	13,445	13,588	14,105	14,285	14,876	15,192	15,692

NOTE:

1. Include UPS from Southern Company through May 2010 and purchased power from MEAG's future shares of Vogtle Units 3 & 4 starting 2016.
2. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4, and Northside Coal. SJRPP sales suspension is assumed to be 3/2017.

Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	Type	Units	**Actual** 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	**Annual Firm Inter-Region Interchange**[1]		%	12.2%	4.6%	0.1%	0.0%	0.0%	0.0%	0.0%	6.0%	11.6%	10.9%	10.9%
(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**[2]		%	45.8%	44.7%	48.8%	46.9%	47.9%	45.5%	45.4%	44.2%	51.0%	51.8%	51.6%
(4)	**RESIDUAL**	Steam	%	0.3%	0.4%	0.7%	0.6%	0.6%	0.7%	0.5%	0.6%	0.4%	0.3%	0.4%
(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	%	0.3%	0.4%	0.7%	0.6%	0.6%	0.7%	0.5%	0.6%	0.4%	0.3%	0.4%
(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	%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		Total	%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)	**NATURAL GAS**	Steam	%	5.3%	5.1%	7.7%	7.4%	7.1%	7.5%	6.1%	6.9%	4.1%	4.0%	4.1%
(13)		CC	%	12.0%	12.9%	10.1%	15.4%	12.9%	14.3%	15.8%	12.9%	5.9%	7.0%	7.3%
(14)		CT	%	1.0%	1.5%	1.3%	1.4%	1.3%	2.0%	3.0%	1.8%	0.9%	0.9%	1.2%
(15)		Total	%	18.3%	19.5%	19.1%	24.1%	21.3%	23.8%	24.8%	21.5%	10.9%	11.9%	12.7%
(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)	**RENEWABLES**	Landfill Gas	%	0.6%	0.6%	0.9%	1.0%	1.0%	1.0%	0.9%	0.9%	0.9%	0.7%	0.3%
(18)		Solar	%	0.0%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%
(19)		Total	%	0.6%	0.7%	1.1%	1.2%	1.1%	1.1%	1.1%	1.1%	1.0%	0.8%	0.5%
(20)	**PETROLEUM COKE**		%	22.8%	30.0%	30.3%	27.2%	29.1%	28.9%	28.1%	26.6%	25.2%	24.3%	24.0%
(21)	**OTHER (SPECIFY)**		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(22)	**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. Include UPS from Southern Company through May 2010 and purchased power from MEAG's future shares of Vogtle Units 3 & 4 starting 2016.
2. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4, and Northside Coal. SJRPP sales suspension is assumed to be 3/2017.

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

Winter											
		Firm Capacity					Reserve Margin Before Maintenance			Reserve Margin After Maintenance	
Year	Installed Capacity MW	Purchases MW	Sales MW	QF MW	Available Capacity MW	Firm Peak Demand MW	MW	Percent	Scheduled Maintenance MW	MW	Percent
2010	3,750	367	383	0	3,734	3,109	625	20%	0	625	20%
2011	3,750	100	383	0	3,467	3,008	459	15%	0	459	15%
2012	4,126	16	383	0	3,759	3,060	699	23%	0	699	23%
2013	4,126	16	383	0	3,759	3,122	637	20%	0	637	20%
2014	4,126	16	383	0	3,759	3,194	564	18%	0	564	18%
2015	4,126	41	383	0	3,784	3,276	507	15%	0	507	15%
2016	4,126	141	383	0	3,884	3,369	515	15%	0	515	15%
2017	4,126	266	383	0	4,009	3,471	538	15%	0	538	15%
2018	4,126	216	0	0	4,341	3,584	758	21%	0	758	21%
2019	4,126	206	0	0	4,332	3,706	625	17%	0	625	17%
Summer											
		Firm Capacity					Reserve Margin Before Maintenance			Reserve Margin After Maintenance	
Year	Installed Capacity MW	Purchases MW	Sales MW	QF MW	Available Capacity MW	Firm Peak Demand MW	MW	Percent	Scheduled Maintenance MW	MW	Percent
2010	3,470	10	376	0	3,104	2,645	459	17%	0	459	17%
2011	3,754	16	376	0	3,394	2,691	702	26%	0	702	26%
2012	3,754	16	376	0	3,394	2,745	649	24%	0	649	24%
2013	3,754	16	376	0	3,394	2,805	589	21%	0	589	21%
2014	3,754	16	376	0	3,394	2,871	522	18%	0	522	18%
2015	3,754	16	376	0	3,394	2,944	450	15%	0	450	15%
2016	3,754	116	376	0	3,494	3,022	472	16%	0	472	16%
2017	3,754	216	0	0	3,969	3,106	863	28%	0	863	28%
2018	3,753	216	0	0	3,968	3,196	772	24%	0	772	24%
2019	3,753	206	0	0	3,959	3,292	667	20%	0	667	20%

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						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Construction Start Date	Commercial/ Change In-Service Date	Expected Retirement/ Shutdown	Gen Max Nameplate kW	Summer MW	Winter MW	Status
Planned and Prospective Generating Facility Changes														
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		03/01/17			186	189	Sale To FPL Ends
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		03/01/17			186	189	
Planned and Prospective Generating Facility Additions														
Greenland Energy Center	1	GEC	CT	NG		PL			06/01/11			142	188	U
	2	GEC	CT	NG		PL			06/01/11			142	188	U
Planned and Prospective Purchased Power Changes and Additions														
Constellation									12/15/09	03/15/10		0	150	Under Contract
Southern Company		Miller 1-4 Scherer 3								06/01/10		(207)	(207)	Contract Ends
Jacksonville Solar									07/01/10	07/01/35		0	0	Energy Only
TEA									12/15/10	03/15/11		0	90	Planned
Trailridge II									06/01/11	06/01/26		6	6	Under Contract
TEA									12/15/14	03/15/15		0	25	Planned
TEA									12/15/15	03/15/16		0	25	Planned
MEAG	3	Plant Vogtle							01/01/16	01/01/36		100	100	Under Contract
TEA									12/15/16	03/15/17		0	50	Planned
MEAG	4	Plant Vogtle							01/01/17	01/01/37		100	100	Under Contract

Schedule 9: Status Report and Specifications of Proposed Generating Facilities 2010 Dollars

1.	**Plant Name and Unit Number:**	Greenland Energy Center CT Units 1 & 2
2.	**Capacity:**	
3.	Summer MW	142 MW
4.	Winter MW	188 MW
5.	**Technology Type:**	Simple Cycle Combustion Turbine
6.	**Anticipated Construction Timing:**	
7.	Field Construction Start-date:	09/08/09
8.	Commercial In-Service date:	06/01/11
9.	**Fuel:**	
10.	Primary	Natural Gas
11.	Alternate	
12.	**Air Pollution Control Strategy:**	Low NO_x Burners
13.	**Cooling Method:**	N/A
14.	**Total Site Area:**	
15.	**Construction Status:**	Site prep. underway, equipment on order
16.	**Certification Status:**	Not Required
17.	**Status with Federal Agencies:**	Not Filed
18.	**Projected Unit Performance Data:**	
19.	Planned Outage Factor (POF):	3.00%
20.	Forced Outage Factor (FOF):	2.00%
21.	Equivalent Availability Factor (EAF):	95.00%
22.	Resulting Capacity Factor (%):	5.0 %
23.	Average Net Operating Heat Rate (ANOHR):	10,800 Btu/kWh
24.	**Projected Unit Financial Data:**	
25.	Book Life:	20 years
26.	Total Installed Cost (In-Service year $/kW):	$615.95
27.	Direct Construction Cost ($/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):	$8.84
31.	Variable O&M ($/MWh):	$16.36

Schedule 10: Status Report and Specification of Proposed Directly Associated Transmission Lines

1.	**Point of Origin and Termination**	GEC and GEC Switching Station
2.	**Number of Lines**	Two
3.	**Right of Way**	Existing
4.	**Line Length**	0.2 circuit miles
5.	**Voltage**	230 kV
6.	**Anticipated Construction Time**	Approximately 1 Month
7.	**Anticipated Capital Investment**	Approximately $1.5 Million
8.	**Substations**	GEC Switching Station
9.	**Participation with Other Utilities**	No

4 Other Planning Assumptions and Information

4.1 Fuel Price Forecast

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

The fuel price projections for natural gas, fuel oil, and coal used in this TYSP were developed based on those included in the US EIA Updated Annual Energy Outlook 2009 Reference Case with American Recovery and Reinvestment Act (AEO2009-ARRA). At the time of JEA's assessment, the AEO 2010 forecast was not yet published. AEO2009-ARRA presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2009-ARRA are based on results from the EIA's NEMS. NEMS is a computer based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented within this section is intended to be an overview of the AEO2009 and, therefore, focuses on the more prominent aspects of AEO2009-ARRA and elaborates on relevant conclusions and projections.

Analyses developed by the EIA are required to be policy-neutral. Therefore, the projections in AEO2009-ARRA generally are based on Federal and State laws and regulations in effect on or before March 31, 2009. As stated in AEO2009-ARRA, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

The AEO2009-ARRA forecasted prices for Central Appalachia (CAPP) and Powder River Basin (PRB) coal delivered to the Georgia/Florida region are presented in Table 4-1[1]. Forecasts of prices for natural gas and fuel oil delivered to the FRCC region are

[1] Supplemental Table 69 to the AEO2009-ARRA, referenced previously, only presents forecasts of prices for coal delivered to the FRCC region on a composite basis (i.e., a single coal price forecast, with no differentiation between coal type/production regions). EIA was able to provide forecast prices for coal delivered to the Georgia/Florida region from various coal production regions upon request. These projections are factored into the overall modeling and analysis used to generate the coal price projections shown in Supplemental Table 69 to the AEO2009-ARRA.

presented in Table 4-2[2]. The fuel price projections shown in Tables 4-1 and 4-2 are presented in constant 2007 dollars per mmBtu. For the economic analysis, the fuel price projections were converted to nominal dollars per mmBtu by applying a 2.5 percent general inflation rate.

Table 4-1 only presents forecasted prices for coal delivered to the Georgia/Florida region from the CAPP and PRB coal production region. For planning purposes, JEA assumes that PRB coal will continue to be burned in the existing Scherer plant, while CAPP coal is assumed to be burned in the existing SJRPP and Northside units.

Although SJRPP and Northside have historically utilized coal from international sources (including Latin America), the characteristics of CAPP coal are relatively comparable to the characteristics of the Latin American coal that has been used in the SJRPP and Northside units. AEO2009-ARRA does not include projections of the price of international coal for delivery to the United States. Given the similarities in coal characteristics and the capability of the SJRPP and Northside units to burn CAPP coal, consideration of CAPP coal is appropriate for the comparative economic analyses presented throughout this Application.

The natural gas prices in table 4-2 are the AEO2009-ARRA projections for delivered natural gas to the FRCC region and do not include any usage charges or any other costs for firm or interruptible intrastate natural gas transportation.

A blend of 1.8 percent sulfur residual fuel oil and natural gas is burned in Northside Unit 3. The 1970's-vintage combustion turbine units at Northside Generating Station are permitted to burn high sulfur diesel. The combustion turbine units at Brandy Branch and Kennedy generation stations are permitted to burn low sulfur diesel as a backup to natural gas.

[2] Regional fuel price projections, such as those shown in Table 4-2 for FRCC, are not included in the AEO2009-ARRA report itself, but are available on the EIA Web site as *Supplemental Tables* (http://www.eia.doe.gov/oiaf/aeo/supplement/stimulus/suparra.htm). The FRCC fuel price projections corresponding to the AEO2009-ARRA, from which the data in Table 4-1 were extracted, are presented in Supplemental Table 69.

Table 4-1: Annual Energy Outlook 2009 Reference Case Price Projections
Forecast of High Sulfur Eastern Interior and
Low Sulfur Powder River Basin Coal Delivered to the Georgia/Florida Region(1)

Year	Central Appalachia (2007 $/mmBtu)	Powder River Basin (2007 $/mmBtu)
2009	3.35	2.24
2010	3.05	2.11
2011	3.04	2.17
2012	2.95	2.17
2013	2.96	2.25
2014	2.96	2.31
2015	3.00	2.33
2016	2.99	2.37
2017	2.90	2.42
2018	2.86	2.46
2019	2.84	2.48

(1) Based on data received directly from the EIA.

Table 4-2: Annual Energy Outlook 2009 Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary[1]

Year	Natural Gas (2007 $/mmBtu) [2]	Distillate Fuel Oil (2007 $/mmBtu) [3]	Residual Fuel Oil (2007 $/mmBtu) [3]
2009	4.99	12.10	6.22
2010	5.61	16.14	11.56
2011	6.32	17.54	12.28
2012	6.99	18.35	12.68
2013	6.81	17.94	12.88
2014	7.05	18.15	13.13
2015	7.24	17.83	13.76
2016	7.44	18.70	14.54
2017	7.57	19.47	15.24
2018	7.74	20.20	15.94
2019	7.98	20.58	16.29

(1) Based on data presented in Supplemental Table 79 to the Updated AEO2009 Reference Case with ARRA.

(2) Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the State. These costs are accounted for in the economic analysis.

(3) In 2010-2014, the current NYMEX curve prices substituted for the AEO's residual and diesel oil prices. In this short term, the EIA Updated Reference Case clearly reflects the market prices from the time in which it was created.

4.2 Economic Parameters

This section presents the economic parameters and methodology used to evaluate the economics of GEC as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the TYSP period.

4.2.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

4.2.2 Municipal Bond Interest Rate

JEA performs sensitivity assessments of project cost to test the robustness of JEA's reference plan. Project cost includes forecast of direct cost of construction, indirect cost, and financing cost. Financing cost includes the forecast of long term tax exempt municipal bond rates, issuance cost, and insurance cost. For JEA's plan development, the long term tax exempt municipal bond rate is assumed to be 5.25 percent. This rate is based on JEA's judgment and expectation that the long term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 5.25 percent.

4.2.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 5.25 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR (LFCR) that has the same present value as the year-by-year fixed charge rate.

Different generating technologies are assumed to have different economic lives and therefore different financing terms. Simple cycle combustion turbines are assumed to have a 20 year financing term; while natural gas fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different LFCRs were developed.

All LFCR calculations assume the 5.25 percent tax exempt municipal bond interest rate, a 1.25 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.25 percent. The resulting 20 year fixed charge rate is 9.075 percent, and the 25 year fixed charge rate is 8.034 percent.

JEA has not incurred additional expenses specifically due to the financial situations of its underwriters. However, in general, JEA's costs to the underwriters are increasing.

5 Greenland Energy Center

5.1 Description

The Greenland Energy Center (GEC) is located in Duval County; south of J. Turner Butler Boulevard, east of Interstate 95, and north of St. Johns County. Currently, JEA has no generation stations east of the St. Johns River where JEA's territory has experienced the most growth. This location provides increased system reliability, increased power quality, increased grid efficiency, and economic integration into the existing transmission system.

5.2 Transmission Interconnection

GEC will be interconnected to JEA's existing 230 kV transmission circuits. The GEC site is contiguous with the existing transmission circuits: Southeast-Greenland circuit 922 and Center Park-Greenland circuit 933. Both circuits will be cut-in to the future Greenland Energy Center 230 kV switching station via 0.1 mile transmission line extension per circuit. The CTGs will connect to an 18 kV/230 kV generator step-up (GSU) transformer. The CTGs will have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each unit's 18 kV power.

5.3 Site Design

JEA is proceeding with the installation of two combustion turbine units, GEC CTs 1 and 2, at this site. The scheduled commercial operation date for these units is June 2011. The units are natural gas-fired simple-cycle GE frame 7FA combustion turbine units. The site will be designed to support diesel storage and the units designed to burn diesel fuel as backup. However, at this time JEA has elected not to implement this backup fuel option.

The GEC site will have the capability for future installation of combined cycle and simple cycle units. The site layout and infrastructure will support the future installation of the conversion of GEC CTs 1 and 2 to combined cycle, an identical 2x1 combined cycle power plant, and future peaking unit capacity. The ultimate certification capacity for GEC is approximately 1,300 MW.

It is anticipated that the site will be cleared and developed, including the storm water detention pond, for ultimate build out of future units during the construction of the initial simple cycle combustion turbines at GEC. It is also anticipated that most offsite facilities will be sized for ultimate build out including the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

5.4 Fuel Supply

The primary fuel for GEC will be natural gas. Natural gas will be delivered to the GEC site through the SeaCoast Pipeline and a GEC lateral utilizing firm transportation service from SeaCoast. The natural gas will be regulated, metered, and conditioned onsite. The initial phase of the SeaCoast pipeline will extend from interconnections with FGT and SNG Cypress Lateral, near Jacksonville, Florida, to the interconnection between the SeaCoast Pipeline and PGS located in Clay County, Florida. The lateral will extend from the SeaCoast–PGS interconnection to the inlet of the meter located at GEC. SeaCoast's interconnection with both FGT and SNG will allow JEA to utilize a diverse natural gas supply portfolio. It is anticipated that adequate natural gas pressure will be available with no need for the addition of gas compressors.

5.5 Schedule

Construction officially began on the GEC site in September 2009 with the removal of trees and the establishment of project management offices. The Engineering, Procurement and Construction Contractor was mobilized in February 2010. The combustion turbines and generators for both units are scheduled to be set in place in July 2010. Backfeed of both units is schedule before the end of calendar year 2010. First fire in Unit 1 is scheduled for January 2011 with Unit 2 following approximately 8 weeks later. Both units are scheduled to go on line in the spring of 2011 and be released for commercial operation on June 1, 2011.

At the end of January 2010, Engineering was 60% complete and procurement was 78% complete. The CTs have completed fabrication and are in storage in Newport News, Virginia. As of March 2010, the site preparation construction was 72% complete with ongoing work on temporary facilities, civil, storm water management, and underground utilities and the transformers are through the design stage and in fabrication.