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JEA

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March 23, 2011

Division of Records and Reporting
Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Attached you will find 25 hardcopies of JEA's 2011 Ten Year Site Plan. If you have any questions regarding this submittal, please contact me at (904) 665-6216.

Thank You,

Mary Guyton Baker

Mary Guyton Baker, PE
Electric System Planning, JEA

COM ___
APA ___
ECR ___
GCL 1
RAD 20
SSC ___
ADM ___
OPC ___
CLK 2

Building Community®

TEN YEAR SITE PLAN

2011

COM ___
APA ___
ECR ___
GCL 2
RAD 21
SSC ___
ADM ___
OPC ___
CLK 1

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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 provides information related to JEA's power supply strategy to adequately meet the forecasted needs of our customers for the planning period from January 1, 2011 to December 31, 2020. This power supply strategy maintains a balance of reliability, environmental stewardship, and cost to the consumers.

1 Description of Existing Facilities

1.1 Power Supply System Description

1.1.1 System Summary

JEA is the eighth 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 approximately 420,000 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 for the winter 2011 was 3,750 MW and 3,754 MW for summer 2011. The summer capacity includes Greenland Energy Center. 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 four plant sites within the City; the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), the Brandy Branch Generating Station (Brandy Branch), and the Greenland Energy Center (GEC). 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); seven dual-fired (gas/diesel) combustion turbine-generator units (Kennedy CT 7 and 8, Brandy Branch CTs 1, 2, and 3, and GEC CTs 1 and 2); 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 forecasted to suspend March 1, 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 has firm transmission service for delivering the energy output from this unit to JEA's system.

1.1.2 Purchased Power

1.1.2.1 Trailridge Landfill

In 2008, JEA entered into a purchase power agreement (PPA) with Landfill Energy Systems (LES) to receive up to 9 MW of firm renewable generation capacity utilizing the methane gas from the Trail Ridge Landfill located in western Duval County. Commercial operating of the LES Trail Ridge Landfill plant began December 6, 2008.

For the purpose of this TYSP, JEA is forecasting additional capacity to be made available under this PPA. Phase II is an additional 9 MW with initial operation in 2011 for a term of 15 years.

1.1.2.2 Jacksonville Solar

In May 2009, JEA entered into a purchase power agreement with Jacksonville Solar, LLC to receive up to 15 MW of as available renewable energy from the Jacksonville Solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100 acre site and is forecasted to generate about 22,340 megawatt-hours (MWh) of electricity per year. The Jacksonville Solar plant began commercial operation at full designed capacity September 30, 2010. For the purpose of this TYSP, it is assumed that the capacity of this variable energy resource is non-firm until valid statistics can be utilized to assign a firm level of contribution to JEA's coincident peak demands.

1.1.2.3 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 and fuel diversification. Meeting this goal will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a 20 year 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. Vogtle Units 3 and 4 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. It has been assumed that 100 MW (net) of capacity is available to JEA beginning January 1, 2016 from Unit 3 and an additional 100 MW (net) is available to JEA beginning January 1, 2017 from Unit 4.

Table 1-1: JEA Purchased Power Schedule

Contract	Contract Start Date	Contract End Date	MW [1]	Product Type
Landfill Energy Systems	Unit 1			
	December 6, 2008	December 6, 2018	9	Annual
	Unit 2			
	December 2011	December 2026	9	Annual
MEAG	Vogtle Unit 3			
	January 2016	December 2036	100	Annual
	Vogtle 4			
	January 2017	December 2037	100	Annual
Jacksonville Solar	September 30, 2010	September 30, 2040	15 [2]	Annual

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

Schedule 1: Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name[a]	Unit Number	Location	Unit Type	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Yr	Mo/Yr	kW	Summer	Winter		
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	
Greenland Energy Center										406,600	284	372		(b)
	1	12-031	GT	NG	FO2	PL	TK	5/2001	(a)	203,800	142	186	Utility	
	2	12-031	CT	NG	FO2	PL	TK	5/2001	(a)	203,800	142	186	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	(c)
	2	12-301	ST	BIT/PC		RR	WA	5/1988	5/2028	679,600	501	510	Joint	(c)
Scherer														
	4	13-207	ST	SUB	BIT	RR	RR	2/1989	2/2029	846,000	194	194	Joint	(d)
JEA System Total											**3,754**	**4,122**		(e)

NOTES:

(a) Units expected to be maintained throughout the study period.
(b) Greenland Energy Center commercial summer 2011.
(c) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(e) Numbers may not add due to rounding.

1.1.2.4 Cogeneration

JEA provides for economic incentives for customers with Cogeneration facilities to help meet the energy needs of JEA's system on as-available, non-firm basis. Since these facilities are considered energy only resources, for the purpose of this TYSP, their capacity is not forecasted to contribute firm capacity to JEA's reserve requirements.

Currently, JEA has contracts with four customer-owned qualifying facilities (QF's), as defined in the Public Utilities Regulatory Policy Act of 1978, having a total installed summer rated capacity of 13 MW and winter rated capacity of 14 MW. 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

<u>Notes</u>:
(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 entered into a 10 year agreement for JEA to supply FPU all of their system energy requirements which began January 1, 2008 and extends through December 31, 2017. For the purpose of this TYSP it is assumed that JEA will continue to serve FPU throughout this TYSP reporting period. Sales to FPU in calendar year 2010 totaled 402 GWh or 2.90% 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

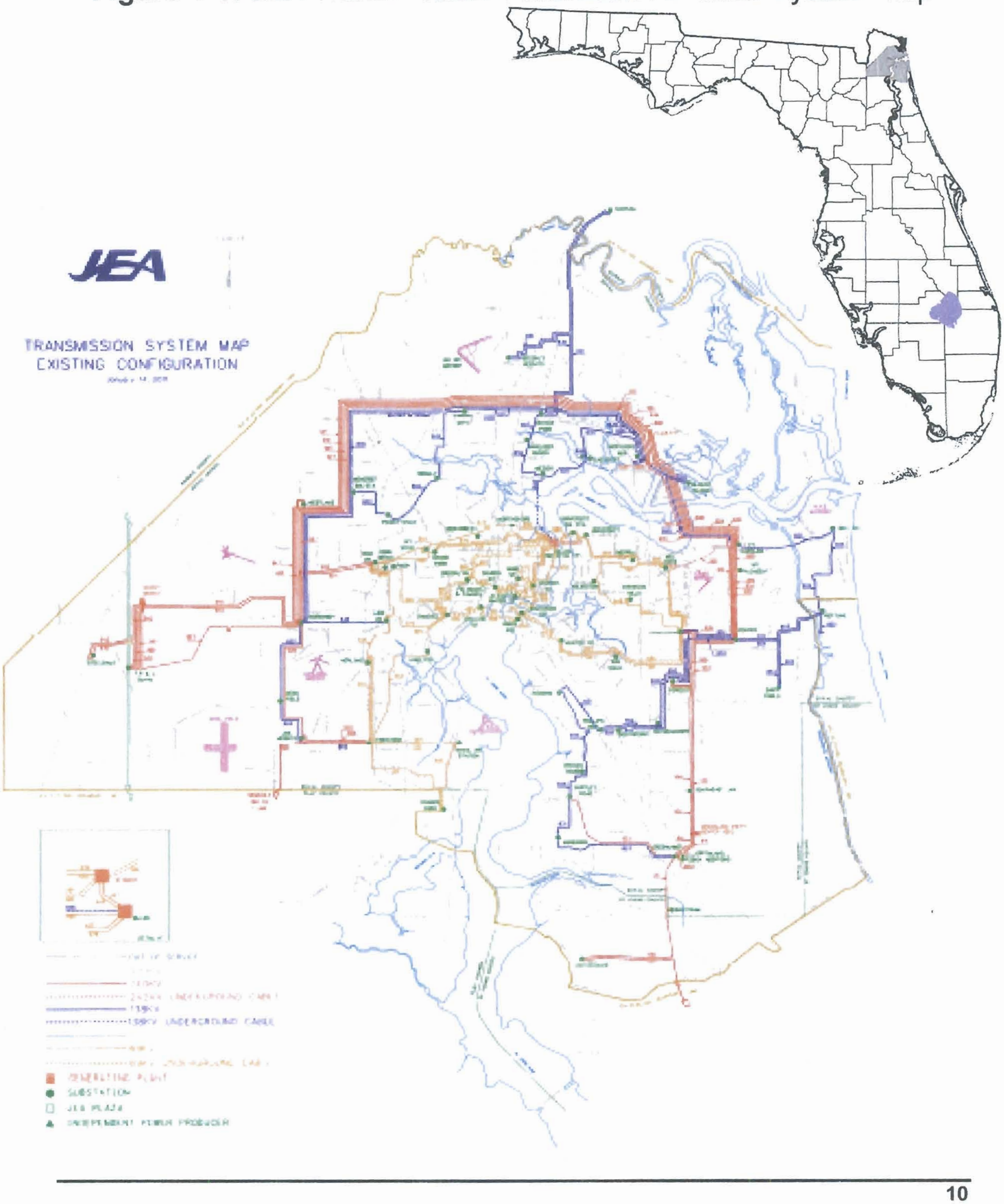
The JEA distribution system operations at three primary voltage levels; 4.16 kV, 13.2 kV, and 26.4 kV. The 26.4 kV system serves approximately 86% of JEA's load, including 75% of the 4.16 kV substations. The current standard is to serve all new distribution loads, except loads in the downtown network, with 26.4 kV systems. Conversion of the aging 4 kV infrastructure continues to be implemented. JEA has approximately 6500 miles of distribution circuits of which more than half is underground.

1.3 Demand Side Management

1.3.1 Interruptible Load

JEA currently offers an Interruptible Service and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to their full nominated load being interrupted during times of system emergencies including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for the Interruptible Service are treated as non-firm resulting in less need for capacity planning reserves to meet peak demands. JEA forecasts 65 MW and 105 MW of interruptible load in the winter and summer, respectively. The interruptible load represents approximately 2.1 percent of the total peak demand in the winter of 2011 and 3.6 percent of the forecasted total peak demand in the summer of 2011. 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 (DSM) Programs

JEA continues to pursue a greater implementation of Demand-side programs where economically beneficial to our customers and to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. Currently, JEA does not have or plan to have any DSM (Load Control) programs for controlling specific customer loads. However, JEA continues to offer economic incentives to customers that choose to participate in energy efficiency (EE) initiatives. JEA recognizes that EE programs will also result in not only decreased energy consumption, but also decreased coincident annual peak demands further reducing JEA's forecasted need for increased planning reserves. JEA's forecast of annual incremental demand and energy reductions due to DSM programs 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

ANNUAL INCREMENTAL		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual Energy (GWh)	Residential	17.7	18.5	18.5	18.5	18.5	15.4	15.2	15.4	15.5	15.7
	Commercial	38.9	40.5	40.5	40.5	40.5	33.7	33.4	33.7	34.1	34.4
	Total	***56.7***	**58.9**	**58.9**	**58.9**	**58.9**	**49.1**	**48.6**	**49.1**	**49.6**	**50.1**
Summer Peak (MW)	Residential	2.7	2.8	2.8	2.8	2.8	2.3	2.3	2.3	2.3	2.4
	Commercial	6.7	6.9	6.9	6.9	6.9	5.8	5.7	5.8	5.8	5.9
	Total	***9.4***	**9.7**	**9.7**	**9.7**	**9.7**	**8.1**	**8.0**	**8.1**	**8.2**	**8.3**
Winter Peak (MW)	Residential	4.0	4.1	4.1	4.1	4.1	3.4	3.4	3.4	3.5	3.5
	Commercial	5.3	5.6	5.6	5.6	5.6	4.6	4.6	4.6	4.7	4.7
	Total	***9.3***	**9.7**	**9.7**	**9.7**	**9.7**	**8.1**	**8.0**	**8.1**	**8.1**	**8.2**

Table 1-4: DSM Programs

Commercial Programs	Residential Programs
Commercial Energy Audit Program	Residential Energy Audit Program
Commercial Energy Efficient Products	Residential Energy Efficient Products
District Chilled Water Program	Green Built Homes of Florida
Commercial Solar Net Metering	Residential Solar Water Heating
Commercial Prescriptive Program	Residential Solar Net Metering
Custom Commercial Program	Neighborhood Efficiency Program
Small Business Direct Install Program	Residential Efficiency Upgrade
Commercial New Construction	

1.4 Clean Power and Renewable Energy

JEA continues to look for opportunities to incorporate clean power and renewable energy that provides economic benefit into JEA's power supply portfolio. To that end, JEA has implemented several clean power and renewable energy initiatives and continues to evaluate potential new initiatives.

1.4.1 Clean Power Program

Since 1999, JEA has worked with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups through routine JEA Clean Power Program meetings, as established in the JEA "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.

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 Request for Proposals (RFPs) for renewable energy resources that have resulted in new resources for JEA's portfolio. As further discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, and landfill and wastewater treatment biogas capacity.

1.4.2.1 Solar and the Solar Incentive

JEA has installed 35 solar PV systems, totaling 222 kW, on 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 which began operation in summer 2010. The facility is located in western Duval County and consists of approximately 200,000 photovoltaic panels on a 100 acre site and is forecasted to 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 2008, JEA entered into a purchase power agreement (PPA) with Landfill Energy Systems (LES) to receive up to 9 MW of firm renewable generation capacity utilizing the methane gas from the Trail Ridge Landfill located in western Duval County. Commercial operating of the LES Trail Ridge Landfill plant began December 6, 2008. 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 (green tags) 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.

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. Even though the price of petroleum coke has been volatile in recent past, petroleum coke prices are still forecasted to be lower than the cost of biomass on an as-fired basis a significant portion of the time. In addition, JEA conducted an analytical evaluation of specific biomass fuel types 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 has evaluated 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. Furthermore, 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 Intracoastal 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 combustion turbine and combined cycle units. Natural gas with its inherent cleaner air emissions compared to No. 6 oil on a fuel basis, and further coupled with the efficiency of a gas-fired combined cycle unit compared to less efficient steam units and combustion turbine units, results in a significant reduction air emissions on a per MWh basis.

The retirement of these units and their replacement with an efficient combined cycle unit 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.

Greenland Energy Center (GEC) Units 1 and 2 are also efficient 7FA simple cycle combustion turbines designed to burn natural gas. The installation of these units further increases the efficiency of JEA's natural gas fueled generating fleet.

2 Forecast of Electric Power Demand, and Energy Consumption

One of the major inputs into Resource Planning is a forecast of demand and energy. The demand and energy forecast is fundamental to the determination of need for new resource capacity.

JEA's forecast methodology utilizes a regression analysis based on seasonal historical data that is weather normalized. The forecasting process involves the collection of historical hourly system load data and daily temperature data. Since the historical system peak typically occurs on non-holiday weekdays, JEA has found that the most accurate historical forecasting method involves removing the data for weekends and holidays from the historical database. To further eliminate historical data that would tend to understate peak demand levels, summer load data is further reduced if a day was a summer rain day and if the 5 p.m. load is lower than the 3 p.m. load. Since JEA's demand peaks in the late afternoon during the summer, the highest value between 2 p.m. and 8 p.m. was identified as the daily peak for the remaining summer days. For winter days, the daily peak occurs early in the morning because of heating requirements. To eliminate historical data that would tend to distort the analysis, daily load data is removed if a cold front moved in and caused the 11 a.m. load to be higher than the load between 1 a.m. and 11 a.m.

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

The results of the summer and winter peak demand forecasts are shown in Table 2-1 and Table 2-2, respectively, 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 summer peak is projected to increase at an average annual growth rate of 1.65%. The average annual increase in summer firm peak demand is 1.44%. During the winter period, the total demand for the winter peak is forecast to increase at an average annual growth rate of 1.90%. The average annual increase in winter firm peak demand is 1.74%.

Table 2-1 indicates that the firm summer peak demand is projected to increase from 2,892 MW in 2011 to 3,290 MW in 2020, and Table 2-2 indicates that the firm winter peak demand is projected to increase from 3,170 MW in 2012 to 3,702 MW in 2021. Figure 2-1 and Figure 2-2 show the historical and forecast summer and winter peaks for JEA.

The energy forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include energy production, JEA territory sales, off-system sales, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature dependent and non-temperature dependent energy requirements over time, then combines these components to derive the system total energy forecast. The temperature dependent energy is modeled as a function of parameter estimates for historical and projected heating degree-days (HDD) and cooling degree-days (CDD). The HDD and CDD parameter estimate projections were based on the historical averages.

The Net Energy for Load (NEL) history and forecast for JEA are shown in Table 2-3. The NEL is forecast to increase at an average annual growth rate of 1.17% during the TYSP period. NEL is forecast to increase from 14,424 GWh in 2011 to 16,009 GWh in 2020. Figure 2-3 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 2-2: Winter Peak Demand History & Forecast

Calendar Year	Total Peak Demand (MW)	DSM (MW)	Non-Firm Demand (MW)	Firm Peak Demand (MW)
2002	2590	0	0	2590
2003	3083	0	0	3083
2004	2668	0	0	2668
2005	2860	0	0	2860
2006	2919	0	0	2919
2007	2722	0	0	2722
2008	2914	0	0	2914
2009	3064	0	0	3064
2010	3224	0	0	3224
2011	3062	0	0	3062
2012	3254	19	65	3170
2013	3320	29	65	3227
2014	3387	38	65	3284
2015	3454	48	65	3341
2016	3521	56	65	3400
2017	3588	64	65	3459
2018	3655	72	65	3518
2019	3722	80	65	3576
2020	3788	89	65	3635
2021	3855	89	65	3702
2002-2011	1.88%			1.88%
2012-2021	1.90%			1.74%

Figure 2-2: Winter Peak Demand History & Forecast

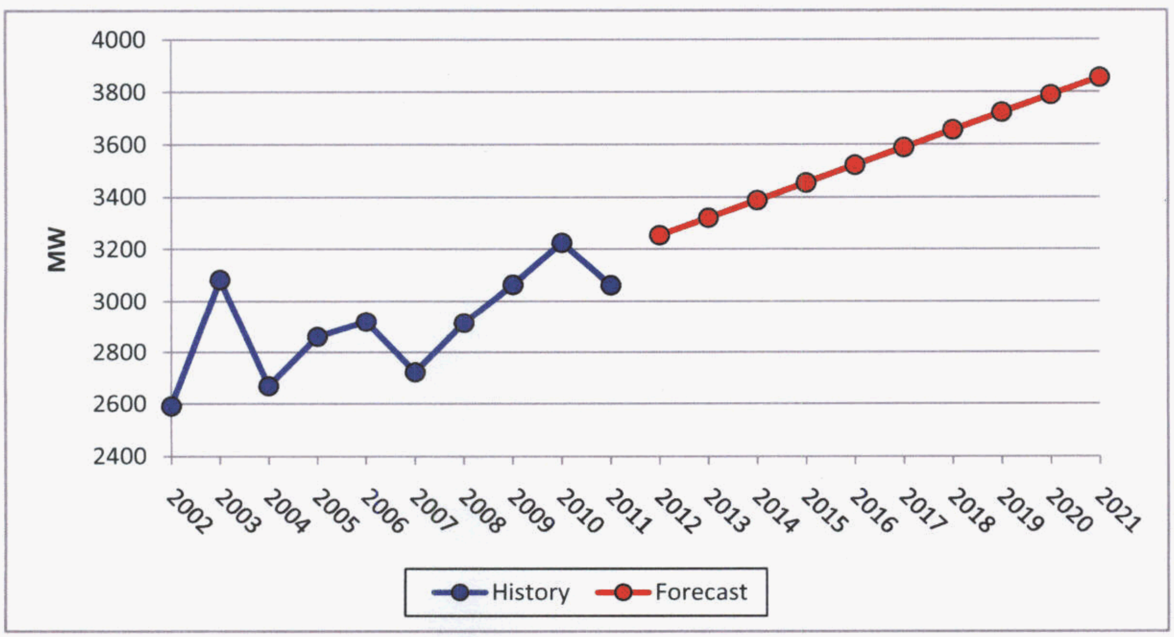


Table 2-3: Net Energy for Load History & Forecast

Calendar Year	Total Energy for Load	DSM	Net Energy for Load	HDD	CDD
	(GWh)			Degree Days	
2001	12340	0	12340	1213	2537
2002	12910	0	12910	1333	2867
2003	13120	0	13120	1432	2616
2004	13349	0	13349	1427	2834
2005	13696	0	13696	1342	2682
2006	13811	0	13811	1170	2742
2007	13854	0	13854	1128	2662
2008	13531	0	13531	1369	2499
2009	13155	0	13155	1347	2799
2010	13842	0	13842	1988	2835
2011	14481	57	14424	1375	2707
2012	14741	116	14625	1375	2707
2013	14932	175	14757	1375	2707
2014	15157	234	14923	1375	2707
2015	15382	292	15090	1375	2707
2016	15644	342	15303	1375	2707
2017	15833	390	15443	1375	2707
2018	16058	439	15619	1375	2707
2019	16283	489	15795	1375	2707
2020	16548	539	16009	1375	2707
2001-2010	1.28%		1.28%		
2011-2020	1.49%		1.17%		

Figure 2-3: Net Energy for Load History & Forecast

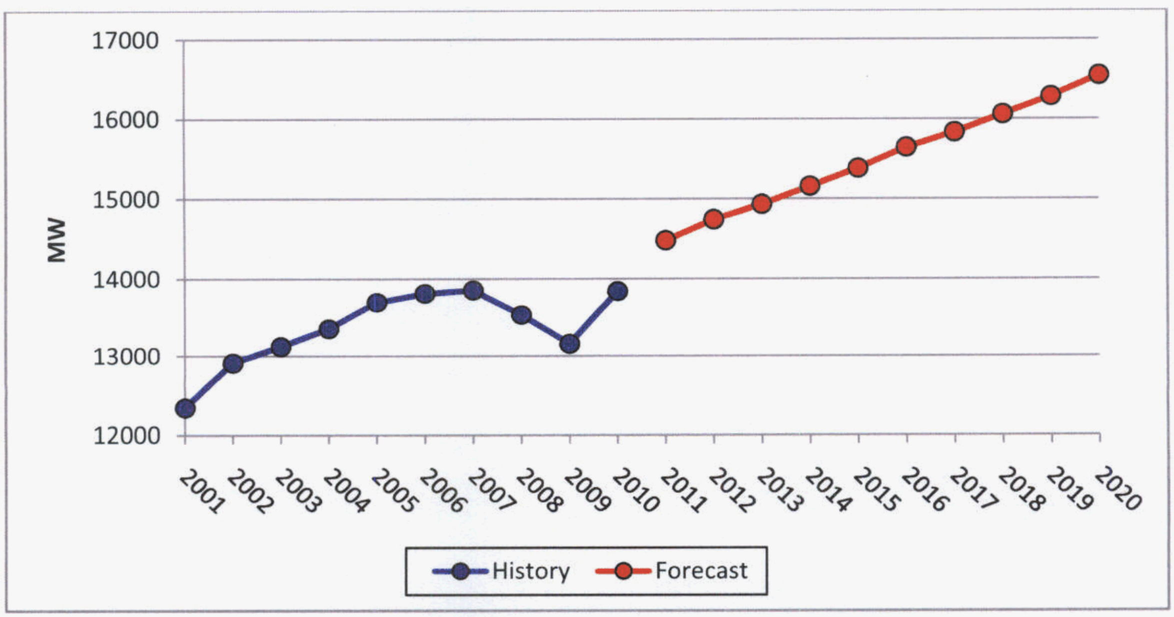
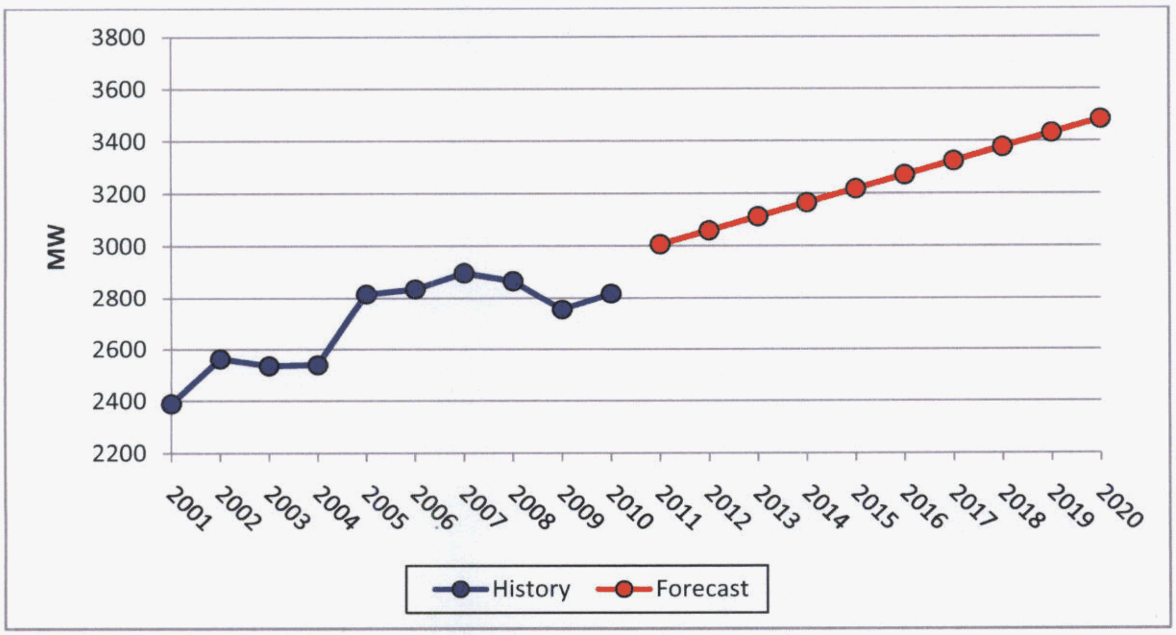


Table 2-1: Summer Peak Demand History & Forecast

Calendar Year	Total Peak Demand (MW)	DSM (MW)	Non-Firm Demand (MW)	Firm Peak Demand (MW)
2001	2389	0	0	2389
2002	2562	0	0	2562
2003	2535	0	0	2535
2004	2539	0	0	2539
2005	2815	0	0	2815
2006	2835	0	0	2835
2007	2897	0	0	2897
2008	2866	0	0	2866
2009	2754	0	0	2754
2010	2817	0	0	2817
2011	3006	9	105	2892
2012	3059	19	105	2935
2013	3112	29	105	2978
2014	3165	39	105	3021
2015	3218	48	105	3065
2016	3271	56	105	3110
2017	3324	64	105	3155
2018	3377	72	105	3200
2019	3431	81	105	3245
2020	3484	89	105	3290
2001-2010	1.85%			1.85%
2011-2020	1.65%			1.44%

Figure 2-1: Summer Peak Demand History & Forecast



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)
Year	Rural and Residential			Commercial			Industrial		
	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
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	5,748	369,050	15,575	1,329	41,693	31,869	5,657	4,722	1,198,052
2011	5,990	383,765	15,608	1,385	43,356	31,935	5,895	4,910	1,200,560
2012	6,073	388,306	15,641	1,404	43,869	32,002	5,977	4,968	1,203,073
2013	6,128	390,989	15,673	1,417	44,172	32,069	6,031	5,002	1,205,591
2014	6,197	394,568	15,706	1,433	44,576	32,136	6,099	5,048	1,208,115
2015	6,266	398,130	15,739	1,448	44,979	32,204	6,167	5,094	1,210,644
2016	6,355	402,910	15,772	1,469	45,519	32,271	6,254	5,155	1,213,179
2017	6,413	405,752	15,805	1,482	45,840	32,339	6,311	5,191	1,215,718
2018	6,486	409,522	15,838	1,499	46,266	32,406	6,383	5,239	1,218,263
2019	6,559	413,261	15,871	1,516	46,688	32,474	6,455	5,287	1,220,814
2020	6,648	429,935	15,905	1,537	47,223	32,542	6,542	5,348	1,223,369

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

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
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	122	0	12,855	343	644	13,842	2	415,467
2011	127	0	13,396	357	671	14,424	2	432,033
2012	129	0	13,583	362	680	14,625	2	437,145
2013	130	0	13,705	365	687	14,757	2	440,165
2014	131	0	13,860	369	694	14,923	2	444,194
2015	133	0	14,014	374	702	15,090	2	448,204
2016	135	0	14,212	379	712	15,303	2	453,586
2017	136	0	14,342	382	718	15,443	2	456,785
2018	137	0	14,506	387	727	15,619	2	461,029
2019	139	0	14,669	391	735	15,795	2	465,239
2020	141	0	14,868	396	745	16,009	2	482,508

Schedule 3.1: History and Forecast of Summer Peak Demand

(MW)													
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
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.
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	2,754	0	0	0	0	0	0	2,754	6	22	1600	0	0
2010	2,817	0	0	0	0	0	0	2,817	6	18	1700	0	0
2011	3,006	105	0	0	0	3	7	2,892	---	---	---	2.68	6.67
2012	3,059	105	0	0	0	5	14	2,935	---	---	---	2.79	6.94
2013	3,112	105	0	0	0	8	21	2,978	---	---	---	2.79	6.94
2014	3,165	105	0	0	0	11	27	3,021	---	---	---	2.79	6.94
2015	3,218	105	0	0	0	14	34	3,065	---	---	---	2.79	6.94
2016	3,271	105	0	0	0	16	40	3,110	---	---	---	2.32	5.78
2017	3,324	105	0	0	0	18	46	3,155	---	---	---	2.30	5.72
2018	3,377	105	0	0	0	21	52	3,200	---	---	---	2.32	5.77
2019	3,431	105	0	0	0	23	58	3,245	---	---	---	2.35	5.83
2020	3,484	105	0	0	0	26	63	3,290	---	---	---	2.37	5.89

Schedule 3.2: History and Forecast of Winter Peak Demand

(MW)												
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
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.
2001/02	2,590	0	0	0	0	0	0	2,590	1	4	0800	0	0
2002/03	3,083	0	0	0	0	0	0	3,083	1	24	0800	0	0
2003/04	2,668	0	0	0	0	0	0	2,668	1	29	0700	0	0
2004/05	2,860	0	0	0	0	0	0	2,860	1	24	0800	0	0
2005/06	2,919	0	0	0	0	0	0	2,919	2	14	0800	0	0
2006/07	2,722	0	0	0	0	0	0	2,722	1	30	0800	0	0
2007/08	2,914	0	0	0	0	0	0	2,914	1	3	0800	0	0
2008/09	3,064	0	0	0	0	0	0	3,064	2	6	0800	0	0
2009/10	3,224	0	0	0	0	0	0	3,224	1	11	0800	0	0
2010/11	3,062	0	0	0	0	0	0	3,062	1	14	0800	0	0
2011/12	3,254	65	0	0	0	8	11	3,170	---	---	---	8.11	10.89
2012/13	3,320	65	0	0	0	12	16	3,227	---	---	---	4.14	5.55
2013/14	3,387	65	0	0	0	16	22	3,284	---	---	---	4.14	5.55
2014/15	3,454	65	0	0	0	21	28	3,341	---	---	---	4.14	5.55
2015/16	3,521	65	0	0	0	24	32	3,400	---	---	---	3.45	4.63
2016/17	3,588	65	0	0	0	27	37	3,459	---	---	---	3.41	4.58
2017/18	3,655	65	0	0	0	31	41	3,518	---	---	---	3.44	4.62
2018/19	3,722	65	0	0	0	34	46	3,576	---	---	---	3.48	4.67
2019/20	3,788	65	0	0	0	38	51	3,635	---	---	---	3.51	4.72
2020/21	3,855	65	0	0	0	38	51	3,702	---	---	---	---	---

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.
2001	12,340	0	0	0	0	0	0	12,340	0	0
2002	12,910	0	0	0	0	0	0	12,910	0	0
2003	13,120	0	0	0	0	0	0	13,120	0	0
2004	13,349	0	0	0	0	0	0	13,349	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	13,531	0	0	0	0	0	0	13,531	0	0
2009	13,155	0	0	0	0	0	0	13,155	0	0
2010	13,842	0	0	0	0	0	0	13,842	0	0
2011	14,481	0	0	0	0	18	39	14,424	17.75	38.93
2012	14,741	0	0	0	0	36	79	14,625	18.46	40.49
2013	14,932	0	0	0	0	55	120	14,757	18.46	40.49
2014	15,157	0	0	0	0	73	160	14,923	18.46	40.49
2015	15,382	0	0	0	0	92	201	15,090	18.46	40.49
2016	15,644	0	0	0	0	107	235	15,303	15.37	33.73
2017	15,833	0	0	0	0	122	268	15,443	15.21	33.38
2018	16,058	0	0	0	0	138	302	15,619	15.37	33.71
2019	16,283	0	0	0	0	153	336	15,795	15.52	34.05
2020	16,548	0	0	0	0	169	370	16,009	15.67	34.39

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)
Month	Actual 2010		Forecast 2011		Forecast 2012	
	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	3,224	1,254	3,062	1,156	3,170	1,168
February	2,667	1,071	2,582	1,005	2,629	1,051
March	2,335	988	2,198	1,074	2,239	1,086
April	2,016	926	2,159	1,041	2,191	1,053
May	2,368	1,189	2,590	1,199	2,629	1,213
June	2,817	1,306	2,728	1,343	2,769	1,360
July	2,749	1,375	2,848	1,518	2,891	1,537
August	2,731	1,379	2,892	1,487	2,935	1,506
September	2,595	1,219	2,669	1,282	2,709	1,297
October	2,199	986	2,498	1,127	2,544	1,140
November	1,785	891	2,428	1,049	2,472	1,061
December	3,053	1,259	2,875	1,142	2,927	1,155
Annual Peak/ Total Energy	3,224	13,842	3,062	14,424	3,170	14,625

3 Forecast of Facilities Requirements

3.1 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, and other planning assumptions (discussed in Section 4.0), 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

Summer – MW									
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin		Capacity Required For 15% Reserves
		Import	Export				Before Maintenance		
2011	3,754	9	376	0	3,388	2,891	496	17%	0
2012	3,754	18	376	0	3,397	2,935	462	16%	0
2013	3,754	18	376	0	3,397	2,978	419	14%	(28)
2014	3,754	18	376	0	3,397	3,021	375	12%	(78)
2015	3,754	18	376	0	3,397	3,065	332	11%	(128)
2016	3,754	118	376	0	3,497	3,110	387	12%	(80)
2017	3,754	218	0	0	3,972	3,155	817	26%	0
2018	3,753	218	0	0	3,971	3,200	771	24%	0
2019	3,753	209	0	0	3,962	3,245	717	22%	0
2020	3,753	209	0	0	3,962	3,290	672	20%	0
Winter – MW									
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin		Capacity Required For 15% Reserves
		Import	Export				Before Maintenance		
2011 / 12	4,122	18	383	0	3,757	3,170	588	19%	0
2012 / 13	4,122	18	383	0	3,757	3,227	530	16%	0
2013 / 14	4,122	18	383	0	3,757	3,284	473	14%	(19)
2014 / 15	4,122	18	383	0	3,757	3,341	416	12%	(85)
2015 / 16	4,122	118	383	0	3,857	3,400	457	13%	(53)
2016 / 17	4,122	218	383	0	3,957	3,459	498	14%	(20)
2017 / 18	4,120	218	0	0	4,338	3,518	821	23%	0
2018 / 19	4,120	209	0	0	4,329	3,576	753	21%	0
2019 / 20	4,120	209	0	0	4,329	3,635	694	19%	0
2020 / 21	4,120	209	0	0	4,329	3,702	628	17%	0

Notes:
Committed Capacity Additions:
a. 9 MW Trailridge II - December 2011
b. Vogtle Units 3 - January 2016
c. Vogtle Units 4 - January 2017

The base capacity plan includes, as committed units, the additions of Trailridge Phase II and the purchased power agreement with MEAG for the future Vogtle Nuclear Units 3 and 4. With JEA's existing and committed capacity, Table 3 shows seasonal needs in 2013 through 2017. The seasonal needs account for 0.5% up to 4.2% of the reserve margin across these 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 establishes a guideline that provides for an allowance to meet the 15% reserve margin with up to 3% of forecasted firm peak demand in any season from purchases acquired in the operating horizon.

JEA's experience with the recent market conditions has proven JEA can acquire in the operating horizon seasonal capacity which is 6% or greater of JEA's firm peak demand. JEA does not forecast these market conditions to necessarily continue over the planning horizon and thus JEA will continue to evaluate, according to JEA's Planning Reserve Policy, the forecasted seasonal reserve margin shortages on an annual basis to determine if in addition to firm market purchases, additional adjustments in JEA owned supply-side or demand side resource alternatives is required. For this report, however, the relatively small short term seasonal needs are planned to be entirely satisfied by market purchases to be made in the operating horizon 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. JEA will engage TEA to meet those needs during those years.

3.2 Resource Plan

The analysis of JEA's electric system needs to develop the resource plan outlined in this TYSP submittal included a review of existing electric supply resources, 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. In addition to cost considerations, environmental impacts, land use, and transmission deliverability considerations were factored into the resource plans. All these factors considered collectively provides a level of assurance that the proposed Resource Plan is holistically beneficial to the community JEA serves. 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
Resource Plan

Year	Season	Resource Plan[1] [2]
2011	Summer	Build 2 - 7FA CTs at GEC (177 MW each)
2012	Winter	Trailridge II Purchase (9 MW)
2013		
2014		
2015		
2016	Winter	MEAG Plant Vogtle Purchase (100 MW) [3]
2017	Winter Summer	MEAG Plant Vogtle Purchase (100 MW) [3] SJRPP Sale to FPL Suspended (383 MW) [4]
2018		Trailridge I Contract Expires (9 MW)
2019		
2020		

Notes:
(1) Seasonal purchases may be required in operating horizon in years 2013-2016.
(2) Cumulative DSM addition of 89 MW Winter and Summer by 2020.
(3) After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from the proposed units.
(4) SJRPP Sales return projected in March 2017.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	**NUCLEAR**		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**[1]		**1000 TON**	**2,847**	**2,301**	**2,271**	**2,380**	**2,292**	**2,505**	**2,269**	**2,691**	**2,965**	**3,124**	**2,992**
	RESIDUAL													
(3)		STEAM	1000 BBL	151	229	182	199	230	201	189	151	115	127	136
(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**	**151**	**229**	**182**	**199**	**230**	**201**	**189**	**151**	**115**	**127**	**136**
	DISTILLATE													
(7)		STEAM	1000 BBL	3	1	1	0	1	0	1	1	1	1	1
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	37	63	44	31	94	31	62	19	13	2	32
(10)		**TOTAL:**	**1000 BBL**	**40**	**64**	**45**	**31**	**95**	**31**	**63**	**20**	**14**	**3**	**33**
	NATURAL GAS													
(12)		STEAM	1000 MCF	6,631	16,246	12,939	14,100	16,253	14,249	13,373	10,740	8,170	9,044	9,667
(13)		CC	1000 MCF	15,698	24,302	26,597	26,058	23,172	27,162	25,739	18,593	17,818	15,518	14,752
(14)		CT/GT	1000 MCF	1,755	6,125	5,984	5,572	8,641	5,770	7,611	4,030	2,420	1,973	4,470
(15)		**TOTAL:**	**1000 MCF**	**24,084**	**46,673**	**45,520**	**45,730**	**48,066**	**47,181**	**46,723**	**33,362**	**28,407**	**26,534**	**28,890**
(16)	**PETROLEUM COKE**		**1000 TON**	**1,123**	**1,225**	**1,321**	**1,339**	**1,383**	**1,280**	**1,262**	**1,310**	**1,323**	**1,369**	**1,417**
(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 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	**Annual Firm Inter-Region Interchange**[1]		GWH	1,606	1,418	7	4	0	24	0	860	1,658	1,596	1,657
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**[2]		GWH	5,598	5,266	5,269	5,362	5,230	5,675	5,150	6,141	6,936	7,276	7,132
(4)	**RESIDUAL**	STEAM	GWH	90	135	105	115	136	115	111	84	59	66	75
(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	90	135	105	115	136	115	111	84	59	66	75
(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	27	19	13	40	13	26	8	5	1	14
(11)		TOTAL	GWH	15	27	19	13	40	13	26	8	5	1	14
(12)	**NATURAL GAS**	STEAM	GWH	592	1,555	1,202	1,319	1,568	1,322	1,272	962	682	760	857
(13)		CC	GWH	2,244	3,578	3,920	3,833	3,410	3,987	3,780	2,682	2,575	2,249	2,155
(14)		CT	GWH	150	550	535	499	784	515	685	362	213	169	400
(15)		TOTAL	GWH	2,986	5,684	5,656	5,651	5,762	5,823	5,736	4,006	3,470	3,177	3,412
(16)	**NUG**		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	**RENEWABLES**	LANDFILL GAS	GWH	75	137	156	156	156	156	156	156	130	77	78
(18)		SOLAR	GWH	12	22	22	21	21	21	21	21	21	21	21
(19)		TOTAL	GWH	87	158	178	177	177	177	177	177	150	98	98
(20)	**PETROLEUM COKE**		GWH	3,649	3,147	3,395	3,439	3,554	3,287	3,243	3,370	3,403	3,520	3,641
(21)	**OTHER (SPECIFY)**													
(22)	**NET ENERGY FOR LOAD**		GWH	13,842	14,424	14,625	14,757	14,923	15,090	15,303	15,443	15,619	15,795	16,009

NOTE:

1. Include 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 2010	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	**Annual Firm Inter-Region Interchange**[1]		%	12.2%	10.2%	0.0%	0.0%	0.0%	0.2%	0.0%	5.6%	10.7%	10.2%	10.5%
(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]		%	40.4%	36.5%	36.0%	36.3%	35.0%	37.6%	33.7%	39.8%	44.4%	46.1%	44.6%
(4)	**RESIDUAL**	Steam	%	0.6%	0.9%	0.7%	0.8%	0.9%	0.8%	0.7%	0.5%	0.4%	0.4%	0.5%
(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	%	0.6%	0.9%	0.7%	0.8%	0.9%	0.8%	0.7%	0.5%	0.4%	0.4%	0.5%
(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%	0.2%	0.1%	0.1%	0.3%	0.1%	0.2%	0.1%	0.0%	0.0%	0.1%
(11)		Total	%	0.1%	0.2%	0.1%	0.1%	0.3%	0.1%	0.2%	0.1%	0.0%	0.0%	0.1%
(12)	**NATURAL GAS**	Steam	%	4.3%	10.8%	8.2%	8.9%	10.5%	8.8%	8.3%	6.2%	4.4%	4.8%	5.4%
(13)		CC	%	16.2%	24.8%	26.8%	26.0%	22.9%	26.4%	24.7%	17.4%	16.5%	14.2%	13.5%
(14)		CT	%	1.1%	3.8%	3.7%	3.4%	5.3%	3.4%	4.5%	2.3%	1.4%	1.1%	2.5%
(15)		Total	%	21.6%	39.4%	38.7%	38.3%	38.6%	38.6%	37.5%	25.9%	22.2%	20.1%	21.3%
(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	%	0.5%	0.9%	1.1%	1.1%	1.0%	1.0%	1.0%	1.0%	0.8%	0.5%	0.5%
(18)		Solar	%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
(19)		Total	%	0.6%	1.1%	1.2%	1.2%	1.2%	1.2%	1.2%	1.1%	1.0%	0.6%	0.6%
(20)	**PETROLEUM COKE**		%	26.4%	21.8%	23.2%	23.3%	23.8%	21.8%	21.2%	21.8%	21.8%	22.3%	22.7%
(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 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

Summer

Year	Installed Capacity MW	Firm Capacity Imports MW	Firm Capacity Exports 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
2011	3,754	9	376	0	3,388	2,891	496	17%	0	496	17%
2012	3,754	18	376	0	3,397	2,935	462	16%	0	462	16%
2013	3,754	48	376	0	3,427	2,978	419	14%	0	449	15%
2014	3,754	98	376	0	3,477	3,021	375	12%	0	455	15%
2015	3,754	148	376	0	3,527	3,065	332	11%	0	462	15%
2016	3,754	198	376	0	3,577	3,110	387	12%	0	467	15%
2017	3,754	218	0	0	3,972	3,155	817	26%	0	817	26%
2018	3,753	218	0	0	3,971	3,200	771	24%	0	771	24%
2019	3,753	209	0	0	3,962	3,245	717	22%	0	717	22%
2020	3,753	209	0	0	3,962	3,290	672	20%	0	672	20%

Winter

Year	Installed Capacity MW	Firm Capacity Imports MW	Firm Capacity Exports 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
2011 / 12	4,122	18	383	0	3,757	3,170	588	19%	0	588	19%
2012 / 13	4,122	18	383	0	3,757	3,227	530	16%	0	530	16%
2013 / 14	4,122	48	383	0	3,787	3,284	473	14%	0	503	15%
2014 / 15	4,122	98	383	0	3,837	3,341	416	12%	0	496	15%
2015 / 16	4,122	168	383	0	3,907	3,400	457	13%	0	507	15%
2016 / 17	4,122	248	383	0	3,987	3,459	498	14%	0	528	15%
2017 / 18	4,120	218	0	0	4,338	3,518	821	23%	0	821	23%
2018 / 19	4,120	209	0	0	4,329	3,576	753	21%	0	753	21%
2019 / 20	4,120	209	0	0	4,329	3,635	694	19%	0	694	19%
2020 / 21	4,120	209	0	0	4,329	3,702	628	17%	0	628	17%

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)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transport		Construction Start Date	Commercial/ Change In-Service Date	Expected Retirement/ Shutdown	Gen Max Nameplate kW	Net Capability		Status
				Primary	Alternate	Primary	Alternate					Summer MW	Winter MW	
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														
None To Report														

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

1.	**Plant Name and Unit Number:**	None to Report
2.	**Capacity:**	
3.	Summer MW	
4.	Winter MW	
5.	**Technology Type:**	
6.	**Anticipated Construction Timing:**	
7.	Field Construction Start-date:	
8.	Commercial In-Service date:	
9.	**Fuel:**	
10.	Primary	
11.	Alternate	
12.	**Air Pollution Control Strategy:**	
13.	**Cooling Method:**	
14.	**Total Site Area:**	
15.	**Construction Status:**	
16.	**Certification Status:**	
17.	**Status with Federal Agencies:**	
18.	**Projected Unit Performance Data:**	
19.	Planned Outage Factor (POF):	
20.	Forced Outage Factor (FOF):	
21.	Equivalent Availability Factor (EAF):	
22.	Resulting Capacity Factor (%):	
23.	Average Net Operating Heat Rate (ANOHR):	
24.	**Projected Unit Financial Data:**	
25.	Book Life:	
26.	Total Installed Cost (In-Service year $/kW):	
27.	Direct Construction Cost ($/kW):	
28.	AFUDC Amount ($/kW):	
29.	Escalation ($/kW):	
30.	Fixed O&M ($/kW-yr):	
31.	Variable O&M ($/MWh):	

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

1.	**Point of Origin and Termination**	
2.	**Number of Lines**	
3.	**Right of Way**	
4.	**Line Length**	
5.	**Voltage**	None To Report
6.	**Anticipated Construction Time**	
7.	**Anticipated Capital Investment**	
8.	**Substations**	
9.	**Participation with Other Utilities**	

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 U.S. Energy Information Administration (EIA) Annual Energy Outlook 2011 Reference Case (AEO2011). AEO2011 presents projections of energy supply, demand, and prices through 2035. The projections presented within AEO2011 are based on results from the EIA's NEMS. NEMS is a computer based, energy-economy modeling system of U.S. energy markets. NEMS 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 AEO2011 and, therefore, focuses on the more prominent aspects of AEO2011 and elaborates on relevant conclusions and projections.

Analyses developed by the EIA are required to be policy-neutral. Therefore, the projections in AEO2011 generally are based on Federal and State laws and regulations in effect on or before November 30, 2010. As stated in AEO2011, 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 AEO2011 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 presented in Table 4-2[2]. The fuel price projections shown in Tables 4-1 and 4-2 are

[1] 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.

[2] Regional fuel price projections, such as those shown in Table 4-2 for FRCC, are available on the EIA Web site as AEO 2011 Supplemental Tables 74.

presented in constant 2009 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. AEO2011 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 AEO2011 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.

4.2 Economic Parameters

This section presents the parameters and methodology used for economic evaluations 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 6.00 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 6.00 percent.

4.2.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 6.00 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 6.00 percent tax exempt municipal bond interest rate, a 1.25 percent bond issuance fee, and an assumed 0.007 percent annual property insurance cost. The resulting 20 year fixed charge rate is 8.899 percent, and the 25 year fixed charge rate is 7.992 percent.

Table 4-1: Annual Energy Outlook 2011 Reference Case Price Projections
Forecast of Central Appalachia and Powder River Basin Coal
Delivered to the Georgia/Florida Region[1]

Year	Central Appalachia (2009 $/mmBtu)	Powder River Basin (2009 $/mmBtu)
2010	4.10	2.14
2011	4.05	2.10
2012	3.96	2.12
2013	3.94	2.14
2014	3.89	2.16
2015	3.97	2.17
2016	3.91	2.20
2017	3.94	2.23
2018	3.92	2.28
2019	3.93	2.31
(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 (2009 $/mmBtu)[2]	Distillate Fuel Oil (2009 $/mmBtu)	Residual Fuel Oil (2009 $/mmBtu)
2010	6.62	15.61	10.63
2011	5.72	16.35	11.27
2012	5.61	15.24	12.22
2013	5.57	15.69	12.53
2014	5.52	16.06	13.03
2015	5.57	16.32	13.45
2016	5.63	17.10	13.88
2017	5.69	17.85	14.25
2018	5.74	18.47	14.69
2019	5.79	19.01	14.98
2020	5.90	19.40	15.28

(1) Based on data presented in Supplemental Table 74 to the AEO2011 Reference Case.

(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.

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 is interconnected to JEA's existing 230 kV transmission circuits. The GEC site is contiguous with the existing transmission circuits: Southeast Jax-Greenland (circuit 922) and Center Park-Greenland 26 kV Additions (circuit 933). Both circuits have been cut-in to the GEC 230 kV switching station via a 0.1 mile transmission line extension per circuit. The CTGs are connected to an 18 kV/230 kV generator step-up (GSU) transformer. The CTGs have generator breakers. The auxiliary power will be derived utilizing the generator terminal voltage (18 kV).

5.3 Site Design

JEA is nearing completion of 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 has been designed to support diesel storage and the units designed to burn diesel fuel as backup. JEA is moving forward to implement this plan.

The GEC site has the capability for future installation of combined cycle and simple cycle units. The site layout and infrastructure supports the future installation of the conversion of GEC CTs 1 and 2 to combined cycle, an identical 2x1 combined cycle power plant, and one additional peaking unit. The ultimate certification capacity for GEC is approximately 1,300 MW. All common equipment and facilities at the site were developed for ultimate build out of the future units; retention pond, the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

5.4 Fuel Supply

The primary fuel for GEC is natural gas. Natural gas is delivered to GEC through the SeaCoast Pipeline and the GEC Lateral. JEA has contracted for firm transportation service on SeaCoast. The initial phase of the SeaCoast pipeline extends from an interconnections with the Southern Natural Gas Cypress pipeline, near Jacksonville, Florida, to an interconnection with the GEC Lateral near Green Cove Springs, Florida. The GEC Lateral extends from the interconnection with SeaCoast GEC plant site.

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 schedule below shows the work completion and projection dates for this project.

Table 5-1: Project Schedule

Key Dates	Dates	
	Completion	Projection
Complete Civil (CT footprint)	01/15/10	
Complete Piping (CT footprint)	02/01/10	
Complete Entrance Road	09/10/10	
Start Construction – EPC	01/28/10	
CT1 & 2 Delivery	06/23 & 06/24/10	
GSU1 & 2 Transformer Delivery	07/22 & 10/20/10	
Aux Transformer 1 & 2 Delivery	08/27/10	
Gas Available	11/18/10	
Substation energized by JEA	11/10/10	
First Fire Unit 1	01/15/11	
Unit 1 Initial Synchronization	01/16/11	
Unit 1 Substantial Completion	02/11/11	
First Fire Unit 2	03/5/11	
Unit 2 Initial Synchronization	03/6/11	
Unit 2 Substantial Completion		03/28/2011
Unit 1 & 2 Released For Operation		06/01/2011