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JEA

March 30, 2015

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

Attached you will find 5 hardcopies of JEA's 2015 Ten Year Site Plan and a disk containing an electronic version of the TYSP Schedules in excel format and the report in Adobe Reader format. If you have any questions regarding this submittal, please contact me at (904) 665-6216 or guytml@JEA.com.

Thank You,

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Building Community®

TEN YEAR SITE PLAN

April 2015

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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, 2015 to December 31, 2024. 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 seventh largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves approximately 425,000 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 projected net capability of JEA's generation system for 2015 is 4,110 MW for winter and 3,769 MW for summer. Details of the existing facilities are displayed in TYSP Schedule 1.

1.1.1.1 The JEA Electric System

The JEA Electric System consists of generating facilities located on four plant sites within the City of Jacksonville (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); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, and Brandy Branch GT1, CT2, and CT3); two natural gas-fired combustion turbine-generator units (GEC GT1 and GT2); four diesel-fired combustion turbine-generator units (Northside GTs 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 Florida Power and Light (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, Florida. 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 Florida Power and Light (FPL) 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 October 2021 or the realization of the sale limits. For the purposes of this Ten Year Site Plan, the 37.5 percent sale to FPL is forecasted to suspend June 2019.

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 FPL 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 Trail Ridge Landfill

In 2006, JEA entered into a purchase power agreement (PPA) with Trail Ridge Energy, LLC (TRE) to receive up to 9 net MW of firm renewable generation capacity utilizing the methane gas from the City's Trail Ridge landfill located in western Duval County (the "Phase One Purchase"). The TRE gas-to-energy facility began commercial operation December 6, 2008 for a ten year term ending December 2018.

JEA and TRE executed an amendment to this purchase power agreement on March 9, 2011 to include additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) has developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began February 2015.

1.1.2.2 Jacksonville Solar

In May 2009, JEA entered into a purchase power agreement with Jacksonville Solar, LLC (Jax Solar) to receive up to 15 MW (DC rating) of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100 acre site and was forecasted to produce an average of 22,340 megawatt-hours (MWh) of electricity per year. The Jacksonville Solar plant began commercial operation at full designed capacity September 30, 2010. Statistics show that approximately half of Jax Solar's capacity (6 MW – AC rating) can be utilized as a firm contribution to meet JEA's coincident Summer peak demand. Jax Solar generated 21,177 MWh in calendar year 2014.

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. These two new nuclear units are under construction at the existing Plant Vogtle location in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity from these units. After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from these units. The current schedule makes available to JEA 100 net MW of capacity beginning June 1, 2019 from Unit 3 and an additional 100 net MW beginning June 1, 2020 from Unit 4. Table 1 lists JEA's current purchased power contracts.

Table 1: JEA Purchased Power Schedule

Contract		Start Date	End Date	MW [1]	Product Type
LES Trail Ridge	I	December 6, 2008	December 5, 2018	9	Annual
	II	February 1, 2014	November 30, 2026	6	Annual
MEAG Plant Vogtle	Unit 3	June 1, 2019	June 1, 2039	100	Annual
	Unit 4	June 1, 2020	June 1, 2040	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.

1.1.2.4 Cogeneration

Cogeneration facilities help meet the energy needs of JEA's system on an as-available, non-firm basis. Since these facilities are considered energy only resources, they are not forecasted to contribute firm capacity to JEA's reserve margin requirements.

Currently, JEA has contracts with one customer-owned qualifying facility (QF), as defined in the Public Utilities Regulatory Policy Act of 1978. Anheuser Busch has a total installed summer rated capacity of 8 MW and winter rated capacity of 9 MW.

In 2014, JEA established a Distributed Generation (DG) Policy which provides requirements for customer-owned electric generators connecting to the JEA electric grid. This policy is applicable to all nonrenewable customer-owned generation, and to all renewable customer-owned generation that does not qualify under the JEA Net Metering Policy. All systems under this policy will fall into one of the following gross power rating categories:

- DG-1 – Nonrenewable < 50 kW
- DG-2 – Nonrenewable 50 kW ≤ DG ≤ 2 MW
- DG-3D – All over 2 MW with distribution level connection to JEA
- DG-3T – All DG over 2 MW with transmission level connection to JEA

Purchase power agreements are required to connect to JEA under this policy and pricing is based on the category of subscription which is also defined in this policy.

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. Calendar year 2014 sales to FPU totaled 339 GWh, 2.7 percent of JEA's total system energy requirement.

Schedule 1: Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate (b)	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	(a)	203,800	150	191	Utility	
	8	12-031	GT	NG	FO2	PL	WA	6/2009	(a)	203,800	150	191	Utility	
Northside										1,512,100	1,322	1,356		
	1	12-031	ST	PC	BIT	WA	RR	5/2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	4/2003	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	01/01/2016	563,700	524	524	Utility	(c)
	33-36	12-031	GT	FO2		WA	TK	1/1975	(a)	248,400	212	246	Utility	
Brandy Branch										879,800	651	786		
	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	186	Utility	
	3	12-031	CT	NG	FO2	PL	TK	10/2001	(a)	203,800	150	186	Utility	
	4	12-031	CA	WH				1/2005	(a)	268,400	201	223	Utility	
Greenland Energy Center										406,600	300	372		
	1	12-031	GT	NG		PL		6/2011	(a)	203,800	150	186	Utility	
	2	12-031	GT	NG		PL		6/2011	(a)	203,800	150	186	Utility	
St. Johns River Power Park										1,359,200	1,002	1,020		
	1	12-031	ST	BIT	PC	RR	WA	3/1987	(a)	679,600	501	510	Joint	(d)
	2	12-031	ST	BIT	PC	RR	WA	5/1988	(a)	679,600	501	510	Joint	(d)
Scherer														
	4	13-207	ST	BIT		RR		2/1989	(a)	990,000	194	194	Joint	(e)
JEA System Total											**3,769**	**4,110**		(f)

Notes:

(a) Units expected to be maintained throughout the TYSP period.
(b) Generator Max Nameplate is total unit not ownership.
(c) Scheduled for reserve storage, winter 2016, and then retirement June 2019.
(d) Net capability reflects JEA's 80% ownership of Power Park.
(e) Net capability reflects JEA's 23.64% ownership in Scherer 4.
(f) Numbers may not add due to rounding.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

The JEA transmission system consists of 745 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

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, Duke Energy Florida, and the City of Tallahassee each own transmission interconnections with the Georgia ITS. JEA's import entitlement over these transmission lines is 1,228 MW out of 3,700 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 four 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at FPL's Sampson substation (FPL metered tie-line) in St. Johns County, one 230 kV tie-line terminating at Seminole Electric Cooperative Incorporated's (SECI) Black Creek substation in Clay County, one 138 kV tie-line connecting Cedar Bay, an IPP located within JEA's bulk electric system, and one 138 kV interconnection with Beaches Energy Services' at JEA's Neptune Substation. This tie-line is owned and operated by Beaches Energy.

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. In compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, JEA continually assesses 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. FRCC's published Regional Transmission Planning Process facilitates coordinated planning by all transmission providers, owners, and stakeholders within 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 for: (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 the obligation to serve 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 the 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 percent of JEA's load, including 75 percent 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. JEA has approximately 6600 miles of distribution circuits of which more than half is underground.

1.3 Demand Side Management

1.3.1 Interruptible Load

JEA currently offers Interruptible 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 interruption of their full nominated load 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 Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 119 MW and 108 MW of interruptible peak load in the summer and winter, respectively, and remains constant throughout the study period. For 2015, the interruptible load represents 3.9 percent of the total peak demand in the winter and 4.4 percent of the forecasted total peak demand in the summer.

1.3.2 Demand-Side Management Programs

JEA continues to pursue a greater implementation of demand-side management programs where economically beneficial and to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's demand-side management programs focus on improving the efficiency of customer end uses as well as improving the system load factor. To encourage efficient customer usage, JEA offers customers both education and economic incentives on more efficient end use technologies. For load factor improvement, JEA has just begun the implementation of a valley filling electrification program and is planning for a peak reducing Direct Load Control (DLC) program. Electrification technologies include on-road and off-road vehicles, forklifts, cranes and other industrial process equipment. JEA's forecast of annual incremental demand and energy reductions due to its current DSM programs are shown in the Table 2. DLC programs are in early development, and as such their impacts are not reflected in Table 2. JEA's current and planned DSM programs are summarized by commercial and residential programs in Table 3.

Table 2: DSM Portfolio

ANNUAL INCREMENTAL		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Annual Energy (GWh)	Residential	17.7	15.1	14.2	14.0	14.0	14.0	14.0	14.0	14.0	14.0
	Commercial	18.0	15.3	14.5	14.2	14.2	14.2	14.2	14.2	14.2	14.2
	Total	**35.7**	**30.5**	**28.7**	**28.2**	**28.2**	**28.2**	**28.2**	**28.2**	**28.2**	**28.2**
Summer Peak (MW)	Residential	4.2	3.7	3.5	3.4	3.4	3.4	3.4	3.4	3.4	3.4
	Commercial	2.9	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Total	**7.2**	**6.2**	**5.9**	**5.8**	**5.8**	**5.8**	**5.8**	**5.8**	**5.8**	**5.8**
Winter Peak (MW)	Residential	3.3	2.9	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
	Commercial	2.2	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
	Total	**5.5**	**4.8**	**4.5**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**

Table 3: DSM Programs

Commercial Programs	Residential Programs
Commercial Energy Audit Program	Residential Energy Audit Program
Commercial Energy Efficient Products	Residential Energy Efficient Products
Commercial Prescriptive Program	Residential New Build
Custom Commercial Program	Residential Solar Water Heating
Commercial Solar Net Metering	Residential Solar Net Metering
Small Business Direct Install Program	Neighborhood Efficiency Program
Off-Road Electrification	Residential Efficiency Upgrade
Direct Load Control (Planned)	Electric Vehicles
	Direct Load Control (Planned)

1.4 Clean Power and Renewable Energy

JEA continues to look for economic opportunities to incorporate clean power and renewable energy 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 Clean Power Program meetings, as established in JEA's "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 (including nuclear power), 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 Requests 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. 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.

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 as the Tier 1 & 2 Net Metering policy in 2009, to include all customer-owned renewable generation systems up to and equal to 100 kW. In 2011, JEA established the Tier 3 Net Metering Policy for customer-owned renewable generation systems greater than 100 kW up to 2 MW. The 2014 updated policy defines Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as greater than 100 kW – 2 MW. All customer-owned generation in excess of 2 MW is addressed in JEA's Distributed Generation Policy (see Section 1.1.2.4 Cogeneration).

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 (see Section 1.1.2.2 Jacksonville Solar).

In 2014, JEA's Board approved a Solar Photovoltaic Policy that supports up to 38 additional MW (AC) by the end of calendar year 2016. When fully subscribed, this will bring JEA's solar portfolio to 50 MW. The additional energy will be acquired through Purchase Power Agreements. In December 2014, JEA issued a Solar PV Request for Proposal (RFP) and received bids in February 2015. These bids are currently under evaluation.

1.4.2.2 Landfill Gas and Biogas

JEA owned three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and has been 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 and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and Girvin was decommissioned in 2014.

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 three anaerobic digesters and one sludge dryer to produce a pelletized fertilizer product. The methane gas from the digesters can be used as a fuel for the sludge dryer and for the on-site 800 kW generator.

JEA signed a Power Purchase Agreement with Trail Ridge Energy, LLC (TRE) in 2006 (Phase One) and executed an amendment to the Power Purchase Agreement in 2011 (Phase Two) to purchase 9 net MW each phase from a gas-to-energy facility. LES has developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began February 2015 (see Section 1.1.2.1 Trail Ridge Landfill).

JEA also has the ability to receive up to 1,500 kW of landfill gas from the North Landfill, which can be piped to the Northside Generating Station 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, in 2004 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 and 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 have been eligible for the federal tax credits afforded to developers. The co-firing alternative for Northside 1 and 2 considered 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. 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.

In 2011, JEA commenced co-firing biomass in the Northside Units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. Northside 1 and 2 produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. JEA has received bids from local sources to provide sized biomass for potential use for Northside Units 1 and 2.

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 large-scale power generating technologies. 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. In the past, 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.
  In addition,
- 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.
- Through Florida State University (FSU), JEA is participating in The Sunshine State Solar Grid Initiative (SUNGRIN) which is a five-year project funded under the DOE Solar Energy Technologies Program (SETP), Systems Integration (SI) Subprogram, High Penetration Solar Deployment Projects. The goal of the SUNGRIN project, which started in Spring 2010, is to gain significant insight into effects of high-penetration levels of solar PV systems in the power grid, through simulation-assisted research and development involving a technically varied and geographically dispersed set of real-world test cases within the Florida grid. JEA provides FSU with data from the output of Jacksonville Solar project.

1.4.2.6 Generation Efficiency and New Natural Gas Generation

In 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 more efficient natural gas fired combustion turbines and combined cycle units. The retirement of units and their replacement with an efficient combined cycle unit and efficient simple cycle combustion turbines at Brandy Branch, Kennedy, and Greenland Energy Center significantly reduces CO_2 emissions.

2 Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peaks demand, net energy for load (NEL), interruptible customer demand, demand-side management (DSM), and the impact of plug-in electric vehicles (PEVs). JEA subtracts from the total load forecast all seasonal, coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

JEA uses National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for the weather parameters, Moody's Analytics' economic parameters for Duval County, JEA's existing and new applications for residential meters to determine Residential vacancy rates and CBRE Jacksonville for Commercial and Industrial (C&I) vacancy rates. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA used 2006 as the starting point for the forecast model. In 2006, the unemployment and vacancy rates in Duval County were at their lowest. JEA's 2015 baseline forecast uses 9-years of historical data (2006 to 2014), which captured the pre-2008/09 economic downturn, the 2008/09 economic downturn, and the post-recession. JEA uses shorter periods to capture more of the recent trends in customer behavior, energy efficiency and conservation. These trends are captured in the actual data and used to forecast projections.

2.1 Peak Demand Forecast

JEA normalizes its historical seasonal peaks using historical maximum and minimum temperatures, 24°F as the normal temperature for the Winter peak and 97°F for the Summer peak. JEA then develops the seasonal peak forecasts using multiple regression analyses of normalized historical seasonal peaks, residential and C&I historical and forecasted energy for Winter/Summer peak months, heating degree hour for the 72 hours leading up to the winter peak and cooling degree hour for the 48 hours leading up to the summer peak. Overall, JEA's forecasted Average Annual Growth Rate (AAGR) for total peak demand during the TYSP period is 0.55 percent for summer and 0.69 percent for winter.

2.2 Energy Forecast

JEA develops its energy forecast using 20-year historical average heating and cooling degree days. The residential energy forecast was modeled using multiple regression analysis of weather-adjusted historical residential energy consumption per residential customer, population, medium household income, disposable income, gross product, unemployment rate for Duval County, residential vacancy rate and residential electric rate. Similarly, the C&I energy forecast was modeled using multiple regression analysis of weather-adjusted historical C&I energy consumption, proprietors profits, income earnings, total retail sales, C&I vacancy rate and C&I electric rates. Overall, JEA's forecasted AAGR for total energy during the TYSP period is 0.74 percent.

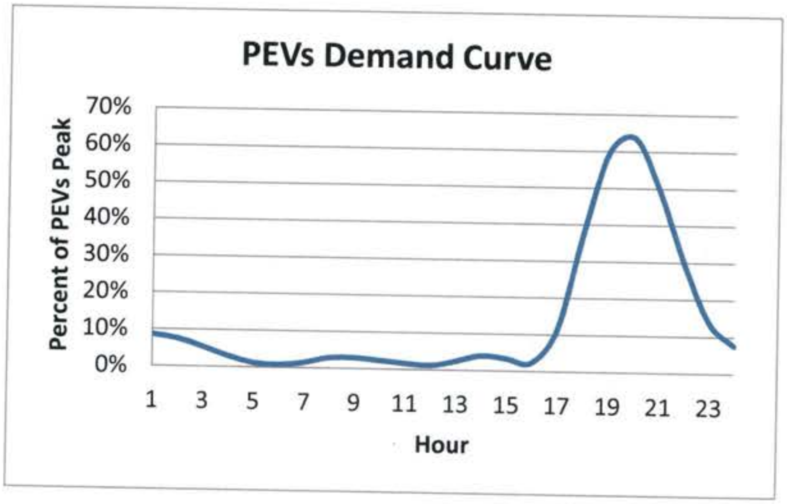
2.3 Plug-in Electric Vehicle Peak Demand and Energy

PEVs demand and energy forecast are developed using historical number of PEVs in Duval County obtained from Florida Department of Highway Safety and Motor Vehicles (DHSMV) and historical number of vehicles in Duval County from the U.S. Census Bureau.

JEA forecasted the numbers of vehicles in Duval County using regression analysis of population and disposable income. The forecasted number of PEVs is modeled by using regression analysis of the number of vehicles and the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 motor gasoline price.

The forecasted demand and average usable battery capacity per vehicle were developed using the upcoming plug-in vehicle model roll-outs from BMW, General Motors' Chevrolet and Cadillac, Ford, Nissan, Tesla and Toyota, and grew the demand and capacity by 0.34 kW and 1 kWh, respectively, per year.

JEA developed the PEVs daily charge pattern based on the U.S. Census 2013 American Community Survey (ACS-13) for time of arrival to work and travel time to work for Duval County and the on-board charge rate for each model. The baseline forecast assumed that charging will be once per day and uncontrolled charging.



JEA's forecasted AAGR for PEVs Winter coincidental peak demand is 33.4 percent, Summer coincidental peak demand is 52.3 percent and total energy is 33.5 percent during the TYSP period.

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		
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
2005	5,576	351,705	15,853	3,911	39,225	99,696	2,915	217	13,411,955
2006	5,596	358,918	15,591	4,060	42,119	96,392	2,849	222	12,855,251
2007	5,507	365,363	15,072	4,399	44,489	98,887	2,630	225	11,671,666
2008	5,307	365,872	14,506	4,040	45,093	89,591	2,948	231	12,776,809
2009	5,319	368,111	14,448	4,024	45,748	87,957	2,643	226	11,692,820
2010	5,747	369,051	15,572	4,071	46,192	88,137	2,720	223	12,192,004
2011	5,237	369,761	14,163	3,927	46,605	84,255	2,682	215	12,468,380
2012	4,880	372,430	13,102	3,852	47,127	81,735	2,598	218	11,906,357
2013	4,852	377,326	12,860	3,777	47,691	79,204	2,589	219	11,812,944
2014	5,162	383,998	13,443	3,882	49,364	78,642	2,564	215	11,951,824
2015	5,105	390,376	13,078	3,953	50,290	78,607	2,576	216	11,927,459
2016	5,152	397,057	12,975	3,996	50,917	78,484	2,607	219	11,902,786
2017	5,145	403,655	12,747	4,034	51,476	78,368	2,634	222	11,863,328
2018	5,154	409,756	12,577	4,053	51,963	77,990	2,648	224	11,820,992
2019	5,182	415,662	12,467	4,057	52,413	77,400	2,653	226	11,738,257
2020	5,215	421,331	12,378	4,063	52,841	76,887	2,659	228	11,662,254
2021	5,260	426,984	12,319	4,065	53,262	76,326	2,663	230	11,577,432
2022	5,307	432,669	12,267	4,069	53,676	75,800	2,667	232	11,496,620
2023	5,360	438,312	12,229	4,082	54,087	75,479	2,678	234	11,446,193
2024	5,414	443,879	12,196	4,100	54,499	75,233	2,692	236	11,407,499

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

Year	(11) Street & Highway Lighting	(12) Other Sales to Ultimate Customers	(13) Total Sales to Ultimate Customers	(14) Sales For Resale	(15) Utility Use & Losses	(16) Net Energy For Load	(17) Other Customers	(18) Total Number of Customers
	GWH	GWH	GWH	GWH	GWH	GWH	(Avg. Number)	
2005	108	0	12,509	659	528	13,696	2	391,150
2006	111	0	12,616	701	494	13,811	6	401,265
2007	113	0	12,649	673	531	13,854	5	410,082
2008	117	0	12,413	619	499	13,531	2	411,197
2009	120	0	12,105	591	458	13,155	2	414,086
2010	122	0	12,660	617	569	13,846	2	415,468
2011	123	0	11,968	500	512	12,980	2	416,583
2012	123	0	11,452	423	537	12,411	2	419,777
2013	122	0	11,340	395	550	12,286	2	425,238
2014	105	0	11,713	472	472	12,656	2	433,578
2015	112	0	11,747	440	531	12,718	2	440,884
2016	112	0	11,867	444	536	12,848	2	448,195
2017	113	0	11,926	448	540	12,914	2	455,355
2018	113	0	11,967	452	544	12,963	2	461,945
2019	114	0	12,005	455	549	13,009	2	468,303
2020	114	0	12,051	457	554	13,062	2	474,402
2021	114	0	12,102	459	560	13,121	2	480,478
2022	115	0	12,158	461	567	13,186	2	486,579
2023	115	0	12,236	464	574	13,274	2	492,635
2024	115	0	12,321	466	583	13,371	2	498,616

Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	
Calendar Year	Total Demand	Interruptible Load	PEV	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
				Residential	Comm/Ind.		Residential	Comm/Ind.		Month	Day	H.E.	Temp
2005	2,815	0	0	0	0	0	0	0	2,815	8	17	1800	96
2006	2,835	0	0	0	0	0	0	0	2,835	8	4	1700	97
2007	2,897	0	0	0	0	0	0	0	2,897	8	7	170	97
2008	2,866	0	0	0	0	0	0	0	2,866	8	7	1600	96
2009	2,754	0	0	0	0	0	0	0	2,754	6	22	1600	98
2010	2,817	0	0	0	0	0	0	0	2,817	6	18	1700	102
2011	2,756	0	0	0	0	0	0	0	2,756	8	11	1700	98
2012	2,616	0	0	0	0	0	0	0	2,616	7	25	1700	95
2013	2,596	0	0	0	0	0	0	0	2,596	8	14	1600	93
2014	2,646	0	0	0	0	0	0	0	2,646	8	22	1600	99
2015	2,714	119	0	0	0	0	4	3	2,588	---	---	---	----
2016	2,728	119	0	0	0	0	8	6	2,596	---	---	---	----
2017	2,746	119	1	0	0	0	11	8	2,608	---	---	---	----
2018	2,759	119	1	0	0	0	15	10	2,615	---	---	---	----
2019	2,772	119	1	0	0	0	18	13	2,623	---	---	---	----
2020	2,786	119	1	0	0	0	22	15	2,631	---	---	---	----
2021	2,802	119	2	0	0	0	25	18	2,642	---	---	---	----
2022	2,818	119	2	0	0	0	28	20	2,653	---	---	---	----
2023	2,838	119	3	0	0	0	32	22	2,667	---	---	---	----
2024	2,851	119	11	0	0	0	35	25	2,682	---	---	---	----

Note: All projections coincident at time of peak.

Schedule 3.2: History and Forecast of Winter Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	
Calendar Year	Total Demand	Interruptible Load	PEV	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
				Residential	Comm/Ind.		Residential	Comm/Ind.		Month	Day	H.E.	Temp
2005	2,860	0	0	0	0	0	0	0	2,860	1	24	800	23
2006	2,919	0	0	0	0	0	0	0	2,919	2	14	800	26
2007	2,722	0	0	0	0	0	0	0	2,722	1	30	800	28
2008	2,914	0	0	0	0	0	0	0	2,914	1	3	800	25
2009	3,064	0	0	0	0	0	0	0	3,064	2	6	800	23
2010	3,224	0	0	0	0	0	0	0	3,224	1	11	800	20
2011	3,062	0	0	0	0	0	0	0	3,062	1	14	800	23
2012	2,665	0	0	0	0	0	0	0	2,665	1	4	800	22
2013	2,559	0	0	0	0	0	0	0	2,559	2	18	800	24
2014	2,823	0	0	0	0	0	0	0	2,823	1	7	800	22
2015	2,783	108	0	0	0	0	3	2	2,669	---	---	---	----
2016	2,812	108	0	0	0	0	6	4	2,693	---	---	---	----
2017	2,833	108	0	0	0	0	9	6	2,710	---	---	---	----
2018	2,848	108	0	0	0	0	12	8	2,720	---	---	---	----
2019	2,863	108	0	0	0	0	14	10	2,731	---	---	---	----
2020	2,878	108	0	0	0	0	17	11	2,742	---	---	---	----
2021	2,896	108	0	0	0	0	20	13	2,755	---	---	---	----
2022	2,914	108	1	0	0	0	22	15	2,769	---	---	---	----
2023	2,936	108	1	0	0	0	25	17	2,786	---	---	---	----
2024	2,961	108	1	0	0	0	28	19	2,807	---	---	---	----

Note: All projections coincident at time of peak.

Schedule 3.3: History and Forecast of Annual Net Energy For Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Calendar Year	Total Energy For Load	Interruptible Load	PEV	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy For Load	Load Factor
				Residential	Comm/Ind.		Residential	Comm/Ind.		
2005	13,696	0	0	0	0	0	0	0	13,696	55%
2006	13,811	0	0	0	0	0	0	0	13,811	54%
2007	13,854	0	0	0	0	0	0	0	13,854	55%
2008	13,531	0	0	0	0	0	0	0	13,531	53%
2009	13,155	0	0	0	0	0	0	0	13,155	49%
2010	13,846	0	0	0	0	0	0	0	13,846	49%
2011	12,980	0	0	0	0	0	0	0	12,980	48%
2012	12,411	0	0	0	0	0	0	0	12,411	53%
2013	12,285	0	1	0	0	0	0	0	12,286	54%
2014	12,654	0	2	0	0	0	0	0	12,656	51%
2015	12,751	0	2	0	0	0	18	18	12,718	54%
2016	12,910	0	4	0	0	0	33	33	12,848	54%
2017	13,004	0	5	0	0	0	47	48	12,914	54%
2018	13,079	0	8	0	0	0	61	62	12,963	54%
2019	13,151	0	10	0	0	0	75	76	13,009	54%
2020	13,228	0	14	0	0	0	89	90	13,062	54%
2021	13,312	0	17	0	0	0	103	105	13,121	54%
2022	13,400	0	22	0	0	0	117	119	13,186	54%
2023	13,511	0	27	0	0	0	131	133	13,274	54%
2024	13,631	0	33	0	0	0	145	147	13,371	54%

Note: All projections are coincident at time of peak.

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

(1)	(2)	(3)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 2013		Actual 2014		Forecast 2015		Forecast 2016	
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)	Peak Demand (MW)	Net Energy For load (GWH)
January	2,126	944	2,823	1,165	2,669	1,048	2,693	1,061
February	2,559	879	2,424	884	2,424	892	2,446	902
March	2,447	969	1,949	917	1,910	938	1,925	949
April	1,951	902	2,164	917	1,974	934	1,982	945
May	2,139	1,017	2,417	1,066	2,379	1,076	2,386	1,088
June	2,567	1,182	2,521	1,166	2,506	1,189	2,515	1,202
July	2,479	1,204	2,555	1,259	2,548	1,262	2,558	1,276
August	2,596	1,265	2,646	1,289	2,588	1,297	2,596	1,311
September	2,500	1,122	2,411	1,108	2,450	1,137	2,458	1,150
October	2,106	987	2,110	988	2,187	1,019	2,199	1,024
November	1,965	882	2,648	935	2,097	893	2,110	899
December	1,997	933	2,148	963	2,276	1,034	2,290	1,040
Annual Peak/Total Energy	2,596	12,286	2,823	12,656	2,669	12,718	2,693	12,848

Figure 1: Summer Peak Demand History & Forecast

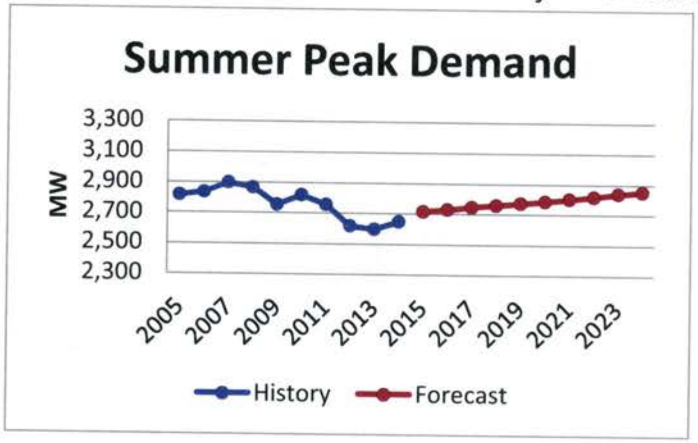


Figure 2: Winter Peak Demand History & Forecast

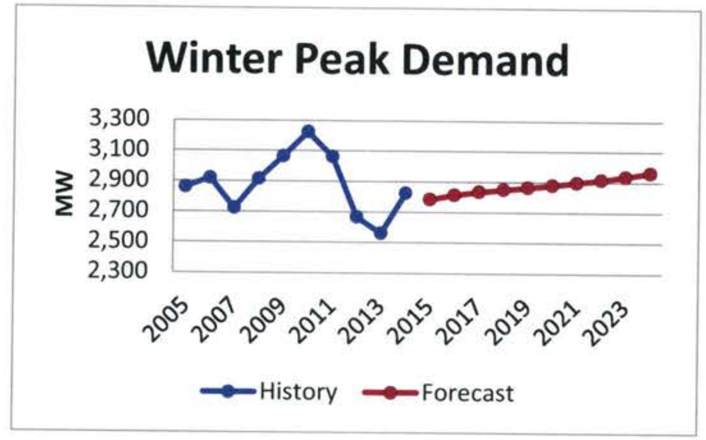
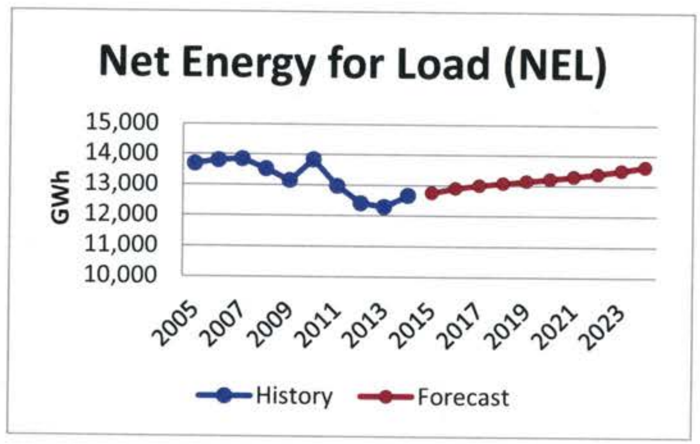


Figure 3: Net Energy for Load History & Forecast



3 Forecast of Facilities Requirements

3.1 Future Resource Needs

JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources, as well as other planning assumptions. The base capacity plan includes as committed units the addition of the purchased power agreement with MEAG for the future Vogtle Nuclear Units 3 and 4 and the return of the SJRPP capacity and energy sale from FPL. Additionally, Northside Unit 3 is currently planned to be placed in reserve storage January 2016 and retired June 2019. With these baseline assumptions, seasonal capacity purchases are needed for the summers of 2016-2018 (see Table 4).

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 percent 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 percent reserve margin with up to 3 percent of forecasted firm peak demand in any season from purchases acquired in the operating horizon. The Energy Authority (TEA), JEA's affiliated energy market services company, typically acquires short-term seasonal market purchases for JEA the season prior to the need. 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 its members require additional resources.

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA included a review of existing electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and fuel availability, and committed unit additions and capacity changes. All these factors considered collectively provided JEA with sufficient capacity to cover customer demand and reserves during this ten year period. Table 5 presents the ten year resource plan which meets JEA's strategic goals. Schedules 5-10 provide further detail on this plan.

Table 4: Resource Needs after Committed Units

Summer										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2015	3,769	21	376	0	3,414	2,588	827	32%	827	32%
2016	3,245	21	376	0	2,890	2,596	295	11%	295	11%
2017	3,245	21	376	0	2,890	2,608	282	11%	282	11%
2018	3,245	21	376	0	2,890	2,615	275	11%	275	11%
2019	3,245	112	0	0	3,357	2,623	734	28%	734	28%
2020	3,245	212	0	0	3,457	2,631	826	31%	826	31%
2021	3,245	212	0	0	3,457	2,642	815	31%	815	31%
2022	3,245	212	0	0	3,457	2,653	804	30%	804	30%
2023	3,245	212	0	0	3,457	2,667	790	30%	790	30%
2024	3,245	212	0	0	3,457	2,682	775	29%	775	29%
Winter										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2014 / 15	4,110	15	383	0	3,743	2,669	1,074	40%	1,074	40%
2015 / 16	3,586	15	383	0	3,219	2,693	526	20%	526	20%
2016 / 17	3,586	15	383	0	3,219	2,710	509	19%	509	19%
2017 / 18	3,586	15	383	0	3,219	2,720	498	18%	498	18%
2018 / 19	3,586	6	383	0	3,210	2,731	479	18%	479	18%
2019 / 20	3,586	106	0	0	3,692	2,742	951	35%	951	35%
2020 / 21	3,586	206	0	0	3,792	2,755	1,037	38%	1,037	38%
2021 / 22	3,586	206	0	0	3,792	2,769	1,024	37%	1,024	37%
2022 / 23	3,586	206	0	1	3,792	2,786	1,006	36%	1,006	36%
2023 / 24	3,586	206	0	2	3,792	2,807	985	35%	985	35%

Note: Committed Capacity Additions:
- Vogtle Unit 3 – June 2019
- Vogtle Unit 4 – June 2020

Table 5: Resource Plan

Year	Season	Resource Plan[(1)] [(2)]
2015	Winter	Trail Ridge II Purchase (6 MW)
2016	Winter	Northside Unit 3 Reserve Storage (- 524 MW)
	Summer	TEA Seasonal Purchase (100 MW)
2017	Summer	TEA Seasonal Purchase (110 MW)
2018	Summer	TEA Seasonal Purchase (125 MW)
2019	Winter	Trail Ridge Contract Expires (- 9 MW)
	Summer	MEAG Plant Vogtle 3 Purchase (100 MW) [(3)]
		SJRPP Sale to FPL Suspended (383 MW) [(4)]
		Northside Unit 3 Retired
2020	Summer	MEAG Plant Vogtle 4 Purchase (100 MW) [(3)]
2021		
2022		
2023		
2024		

Notes:

(1) Cumulative DSM addition of 46 MW Winter and 60 MW Summer at time of peak by 2024.

(2) PEV addition of 0.79 MW Winter and 10.57 MW Summer by 2024.

(3) After accounting for transmission losses, JEA expects to receive 100 MW June 2019 and 100 MW June 2020 for a total of 200 MW of net firm capacity from the Vogtle units under construction.

(4) SJRPP sales return based on JEA's forecast estimates.

Schedule 5: Fuel Requirements

	(1) Fuel	(2) Type	(3) Units	(4) Actual 2013	(5) Actual 2014	(6) 2015	(7) 2016	(8) 2017	(9) 2018	(10) 2019	(11) 2020	(12) 2021	(13) 2022	(14) 2023	(15) 2024
(1)	**NUCLEAR**	**TOTAL**	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL[1]**	**TOTAL**	**1000 TON**	**2,710**	**3,228**	**2,235**	**2,875**	**2,830**	**2,921**	**3,247**	**2,045**	**1,941**	**1,754**	**1,992**	**2,006**
(3)	**RESIDUAL**	STEAM	1000 BBL	0	14	114	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	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	0
(6)		**TOTAL**	**1000 BBL**	**0**	**14**	**114**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(7)	**DISTILLATE**	STEAM	1000 BBL	1	2	1	1	1	2	1	2	1	2	1	1
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	8	6	3	57	60	30	8	18	1	5	1	5
(10)		**TOTAL**	**1000 BBL**	**9**	**8**	**4**	**58**	**62**	**33**	**9**	**20**	**2**	**7**	**2**	**6**
(12)	**NATURAL GAS**	STEAM	1000 MCF	4,842	4,794	13,346	70	63	67	73	74	66	65	43	69
(13)		CC	1000 MCF	23,002	24,284	28,080	23,778	25,811	25,107	22,273	20,845	6,808	8,139	6,768	7,008
(14)		CT/GT	1000 MCF	1,894	1,441	2,342	10,447	8,568	7,596	4,425	3,565	826	1,593	879	1,113
(15)		**TOTAL**	**1000 MCF**	**29,738**	**30,519**	**43,768**	**34,295**	**34,442**	**32,770**	**26,771**	**24,484**	**7,700**	**9,796**	**7,689**	**8,190**
(16)	**PETROLEUM COKE**	**TOTAL**	**1000 TON**	**761**	**492**	**731**	**730**	**767**	**761**	**715**	**657**	**731**	**735**	**767**	**743**
(17)	**OTHER (SPECIFY)**	**TOTAL**	**TRILLION BTU**	**0**	**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)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual											
	Fuel	Type	Units	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	**Firm Inter-Region Intchg.**		GWH	**841**	**477**	**0**	**0**	**0**	**0**	**488**	**1,323**	**1,665**	**1,665**	**1,665**	**1,610**
(2)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL**[1]		GWH	**5,376**	**7,012**	**4,607**	**5,914**	**5,749**	**6,058**	**6,558**	**6,241**	**8,086**	**7,872**	**8,148**	**8,301**
(4)		STEAM		0	7	66	0	0	0	0	0	0	0	0	0
(5)		CC		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
(7)	**RESIDUAL**	**TOTAL**	GWH	**0**	**7**	**66**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(8)		STEAM		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
(10)		CT		3	2	1	24	26	13	3	8	1	2	0	2
(11)	**DISTILLATE**	**TOTAL**	GWH	**3**	**2**	**1**	**24**	**26**	**13**	**3**	**8**	**1**	**2**	**0**	**2**
(12)		STEAM		383	346	1,244	0	0	0	0	0	0	0	0	0
(13)		CC		3,357	3,533	4,214	3,564	3,864	3,756	3,314	3,096	1,000	1,197	988	1,031
(14)		CT		150	114	210	970	796	699	407	328	72	142	75	97
(15)	**NATURAL GAS**	**TOTAL**	GWH	**3,890**	**3,993**	**5,668**	**4,535**	**4,659**	**4,455**	**3,720**	**3,424**	**1,071**	**1,339**	**1,063**	**1,128**
(16)	**NUG**		GWH		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(17)	**RENEWABLES**	**HYDRO**		0	0	0	0	0	0	0	0	0	0	0	0
(18)		**LANDFILL GAS**		71	69	126	130	130	104	52	52	52	52	52	52
(19)		**SOLAR**		21	21	21	21	21	20	20	20	20	20	20	20
(20)		**TOTAL**	GWH	**92**	**91**	**146**	**151**	**151**	**124**	**72**	**72**	**72**	**72**	**72**	**72**
(21)	**Petroleum Coke**		GWH	**2,084**	**1,075**	**2,230**	**2,224**	**2,330**	**2,313**	**2,168**	**1,995**	**2,227**	**2,237**	**2,327**	**2,258**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**[2]		GWH	**12,286**	**12,656**	**12,718**	**12,848**	**12,914**	**12,963**	**13,009**	**13,062**	**13,121**	**13,186**	**13,274**	**13,371**

Note: [1] Nuclear PPA from MEAG beginning 2019 included in Firm Inter-Regional Interchange.
[2] Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.
[3] May not add due to rounding

Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual											
	Fuel	**Type**	**Units**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
(1)	**Firm Inter-Region Intchg.**		%	**6.8**	**3.8**	**0.0**	**0.0**	**0.0**	**0.0**	**3.8**	**10.1**	**12.7**	**12.6**	**12.5**	**12.0**
(2)	**NUCLEAR**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(3)	**COAL**[1]		%	**43.8**	**55.4**	**36.2**	**46.0**	**44.5**	**46.7**	**50.4**	**47.8**	**61.6**	**59.7**	**61.4**	**62.1**
(4)		STEAM		0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		CC		0.0	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	0.0
(7)	**RESIDUAL**	**TOTAL**	%	**0.0**	**0.1**	**0.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(8)		STEAM		0.0	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	0.0
(10)		CT		0.0	0.0	0.0	0.2	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0
(11)	**DISTILLATE**	**TOTAL**	%	**0.0**	**0.0**	**0.0**	**0.2**	**0.2**	**0.1**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
(12)		STEAM		3.1	2.7	9.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		CC		27.3	27.9	33.1	27.7	29.9	29.0	25.5	23.7	7.6	9.1	7.4	7.7
(14)		CT		1.2	0.9	1.6	7.6	6.2	5.4	3.1	2.5	0.5	1.1	0.6	0.7
(15)	**NATURAL GAS**	**TOTAL**	%	**31.7**	**31.5**	**44.6**	**35.3**	**36.1**	**34.4**	**28.6**	**26.2**	**8.2**	**10.2**	**8.0**	**8.4**
(16)	**NUG**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(17)	**RENEWABLES**	**HYDRO**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(18)		**LANDFILL GAS**		0.6	0.5	1.0	1.0	1.0	0.8	0.4	0.4	0.4	0.4	0.4	0.4
(19)		**SOLAR**		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
(20)		**TOTAL**	%	**0.7**	**0.7**	**1.2**	**1.2**	**1.2**	**1.0**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**
(21)	**Petroleum Coke**		%	**17.0**	**8.5**	**17.5**	**17.3**	**18.0**	**17.8**	**16.7**	**15.3**	**17.0**	**17.0**	**17.5**	**16.9**
(22)	**OTHER (SPECIFY)**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(23)	**NET ENERGY FOR LOAD**		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Note: [1] Nuclear PPA with MEAG beginning 2019 included in Firm Inter-Regional Interchange.
[2] Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.
[3] May not add due to rounding.

Schedule 7.1: Summer Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2015	3,769	21	376	0	3,414	2,588	827	32%	0	827	32%
2016	3,245	121	376	0	2,990	2,596	395	15%	0	395	15%
2017	3,245	131	376	0	3,000	2,608	392	15%	0	392	15%
2018	3,245	146	376	0	3,015	2,615	400	15%	0	400	15%
2019	3,245	112	0	0	3,357	2,623	734	28%	0	734	28%
2020	3,245	212	0	0	3,457	2,631	826	31%	0	826	31%
2021	3,245	212	0	0	3,457	2,642	815	31%	0	815	31%
2022	3,245	212	0	0	3,457	2,653	804	30%	0	804	30%
2023	3,245	212	0	0	3,457	2,667	790	30%	0	790	30%
2024	3,245	212	0	0	3,457	2,682	775	29%	0	775	29%

Schedule 7.2: Winter Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2015	4,110	15	383	0	3,743	2,669	1,074	40%	0	1,074	40%
2016	3,586	15	383	0	3,219	2,693	526	20%	0	526	20%
2017	3,586	15	383	0	3,219	2,710	509	19%	0	509	19%
2018	3,586	15	383	0	3,219	2,720	498	18%	0	498	18%
2019	3,586	6	383	0	3,210	2,731	479	18%	0	479	18%
2020	3,586	106	0	0	3,692	2,742	951	35%	0	951	35%
2021	3,586	206	0	0	3,792	2,755	1,037	38%	0	1,037	38%
2022	3,586	206	0	0	3,792	2,769	1,024	37%	0	1,024	37%
2023	3,586	206	0	0	3,792	2,786	1,006	36%	0	1,006	36%
2024	3,586	206	0	0	3,792	2,807	985	35%	0	985	35%

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/ In-Service or Change Date	Expected Retirement/ Shutdown Date	Gen Max Nameplate	Net Capability		Status
				Primary	Alternate	Primary	Alternate				kW	Summer MW	Winter MW	
SJRPP	1	12-031	ST	BIT	PC	RR	WA		06/2019	(a)	679,600	188	191	Sale To FPL Ends
SJRPP	2	12-031	ST	BIT	PC	RR	WA		06/2019	(a)	679,600	188	191	
Northside	3	12-031	ST	NG	FO6	PL	WA			01/2016	563,700	- 524	- 524	Reserve Storage
Northside	3	12-031	ST	NG	FO6	PL	WA			06/2019	563,700	0	0	Retired

Notes:
(a) Units expected to be maintained throughout the TYSP period.

Schedule 9: Status Report and Specifications of Proposed Generating Facilities 2015 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**	None To Report
2	**Number of Lines**	
3	**Right of Way**	
4	**Line Length**	
5	**Voltage**	
6	**Anticipated Construction Time**	
7	**Anticipated Capital Investment**	
8	**Substations**	
9	**Participation with Other Utilities**	

4 Other Planning Assumptions and Information

4.1 Fuel Price Forecast

JEA uses a diverse mix of fuels in its generating units. The fuel price projections include natural gas, coal, petroleum coke, uranium, residual fuel oil and diesel fuel.

JEA typically uses the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) for fuel price projections. With the delay in the 2015 AEO release, the fuel price projections for natural gas, coal, petroleum coke and diesel fuel used in this forecast were developed based on long-term price forecasts from PIRA Energy Group. PIRA is an international consulting firm that specializes in global energy market research and intelligence. PIRA provides long-term price projections for fuels, power, freight and emissions in its Energy Price Portal though 2035.

The price projections for emissions allowances are derived from JD Energy's most recent outlook. JD Energy is an independent energy and environmental price forecasting firm. JD Energy uses a proprietary Generation and Emissions Modeling System (GEMS) methodology that integrates independent macroeconomic, energy and emissions pricing projections to deliver forecasts and perspectives on the outlook for fuel, power and emissions markets.

Scherer 4 burns Powder River Basin (PRB) coal. The commodity price projection for PRB coal was developed by escalating current contract prices by the PIRA forecasted growth rate for PRB coal. The transportation component of the delivered price projection was derived from existing contracts.

SJRPP currently burns a blend of Illinois Basin (IB) and Colombian coal. For the purposes of this study, it has been assumed that 100 percent Colombian coal will be burned by the SJRPP units beginning in 2016. Projections of the commodity price for Colombian coal are based on current contracted prices and PIRA's long-term projections for Colombian coal. Current freight rates for 2015 and 2016 waterborne delivery of Colombian coal were escalated using the assumed inflation rate to project transportation costs beyond 2016. SJRPP has the ability to burn up to 30 percent petroleum coke, but there are currently no plans to reintroduce petroleum coke at SJRPP at this time.

Northside units 1 and 2 currently burn a blend of petroleum coke and coal. These units are projected to burn on average 60 percent petroleum coke and 40 percent coal during the forecast period. The Northside coal and petroleum coke price projections are based on PIRA's long-term Colombian coal forecast with a three year historical ratio of petroleum coke to coal applied to derive the petroleum coke price. As with the transportation projections for SJRPP, the same methodology was used to project transportation costs to Northside Generating Station with additional price consideration given to the shallower draft available at its offloading facility.

JEA currently operates eight units utilizing natural gas as a primary fuel. These units are GEC GT1 and GT2, Brandy Branch GT1, CT2 and CT3, Northside 3, and Kennedy GT7 and GT8. The natural gas prices reflect delivery to a Florida city gate. The natural gas price projections are based on PIRA's long-term Henry Hub forecast for natural gas and include consideration of variable transportation costs on Florida Gas Transmission pipeline.

Northside 3 is capable of operating on residual fuel oil as an alternative to natural gas. On December 2015, Northside 3 is planned to go into reserve shutdown. For 2015, the projected price for residual fuel oil is based on current market prices.

The 1970's-vintage combustion turbine units at Northside Generating Station (GT3, GT4, GT5, and GT6) burn diesel fuel as the primary fuel type. Five JEA units utilize diesel fuel as an alternative to natural gas: Kennedy GT7 and GT8 and Brandy Branch GT1, CT2, and CT3. GEC GT1 and GEC GT2 are capable of using diesel fuel as a backup fuel. Projections for the price of diesel fuel are based on current ultra-low sulfur diesel pricing and PIRA's forecasted oil growth rate.

JEA has a twenty year PPA for output from Vogtle Units 3 and 4 currently under construction in Georgia with planned in-service dates of 2019 and 2020. The fuel price forecast accounts for the costs of mine-mouth uranium, enrichment and fabrication.

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 resource 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 4.50 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 4.50 percent.

4.2.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.50 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 4.50 percent tax exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.50 percent annual property insurance cost. The resulting 20 year fixed charge rate is 8.265 percent and the 25 year fixed charge rate is 7.312 percent.

5 Environmental and Land Use Information

JEA does not have any capacity build projects underway or planned for the term of this Ten Year Site Plan. Therefore, there are no potential sites in which to report environmental and land use information.