REPORT
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Building Community®

TEN YEAR SITE PLAN

April 2016

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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, 2016 to December 31, 2025. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

This TYSP does not address any system changes that may be required in order to comply with EPA's Clean Power Plan (CPP) Rule.

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 most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves approximately 450,000 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 2016 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). Northside Unit 3 is planned to be placed into reserve storage April 2017 and retired June 2019.

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 based on realization of the sale limits.

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 20,132 MWh in calendar year 2015.

1.1.2.3 Nuclear Generation

JEA's Board has established targets to acquire 10 percent of JEA's energy requirements from nuclear sources by 2018 and up to 30 percent by 2030. In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships as part of a strategy for greater regulatory and fuel diversification. Meeting these targets 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. This agreement will end December 31, 2017. Calendar year 2015 sales to FPU totaled 332 GWh, 2.6 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	06/01/2019	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 April 2017 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; FPL has purchased Cedar Bay and will retire the generation after winter 2016/2017
- 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 operates 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 109 MW and 110 MW of interruptible peak load in the summer and winter, respectively, and remains constant throughout the study period. For 2016, the interruptible load represents 3.7 percent of the total peak demand in the winter and 3.9 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 is in the planning stage of a Demand Rate Pilot program with the intent of reducing peaks for both residential and small commercial customers. Electrification programs include on-road and off-road vehicles, forklifts, cranes and other industrial process technologies. JEA's forecast of annual incremental demand and energy reductions due to its current DSM energy efficiency programs is shown in Table 2. The Demand Rate Pilot program is in early development, and as such 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 – Energy Efficiency Programs

ANNUAL INCREMENTAL		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy (GWh)	Residential	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
	Commercial	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
	Total	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**
Summer Peak (MW)	Residential	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
	Commercial	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	Total	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
Winter Peak (MW)	Residential	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
	Commercial	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Total	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**

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
Demand Rate Pilot (In Planning)	Electric Vehicles
	Demand Rate Pilot (In Planning)

1.4 Clean Power and Renewable Energy

JEA continues to investigate 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. In 2015, JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20-25 years to various vendors. Agreements have been finalized for five projects for a total of 25.5 MW. JEA is still in contract negotiations over two projects from this RFP for 6 MWs total. Other projects are also under review.

Project	MW_{AC}
Blair Site Solar	4
Imeson Solar Farm	5
Montgomery Solar Farm	7
Old Plank Road Solar Farm	3
Simmons Road Solar	2
Soutel Solar	1
Starratt Solar	5
SunE Solar Farm	4.5

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).

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. With the expansion of JEA's renewable portfolio within the State of Florida, additional landfill gas generation and new solar facilities, JEA exercised its right and sole discretion to terminate this contract pursuant to the Wind Generation Agreement between NPPD and JEA dated October 28, 2004. JEA's formal notice of an April 30, 2017 termination was issued and accepted by NPPD.

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. Currently, no biomass is being co-fired in 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 participated in The Sunshine State Solar Grid Initiative (SUNGRIN) which was a five-year project (2010-2015) 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, was 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 provided 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.

1.4.2.7 Renewable Energy Credits

JEA makes all environmental attributes from renewable facilities available to sell in order to lower rates for our customers. JEA has sold environmental credits for specified periods.

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 removes 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 uses 2006 as the starting point for the forecast model. In 2006, unemployment rate and vacancy rate in Duval County were at their lowest. JEA's 2015 baseline forecast uses 10-years of historical data (2006 to 2015), which captures the time period before, during and after the 2008/09 economic 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, 97°F for the summer peak and 24°F as the normal temperature for the winter peak. JEA develops the seasonal peak forecasts using multiple regression analysis of normalized historical seasonal peaks, residential and C&I historical and forecasted energy for Winter/Summer peak months, last 72 heating degree hours leading to the winter peak and last 48 cooling degree hours leading to the summer peak. JEA's forecasted Average Annual Growth Rate (AAGR) for total peak demand during the TYSP period is 0.41 percent for summer and 0.48 percent for winter, which reflects the expiration of FPU's wholesale agreement beginning 2018.

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, medium household income, disposable income, labor force, unemployment rate for Duval County, residential vacancy rate and residential electric rate. Similarly, the commercial energy forecast was modeled using multiple regression analysis of weather-adjusted historical commercial energy consumption, total number of commercial industries employment, total retail sales, gross product, commercial vacancy rate and commercial electric rates. Industrial energy forecast was modeled using multiple regression analysis of weather-adjusted historical industrial energy consumption, total number of industrial employment, proprietors' profits, total retail sales, gross product, industrial vacancy rates and industrial electric rates. JEA's forecasted AAGR for net energy for load during the TYSP period is 0.35 percent, which reflects the expiration FPU's wholesale agreement beginning 2018.

Figure 1: Summer Peak Demand History & Forecast

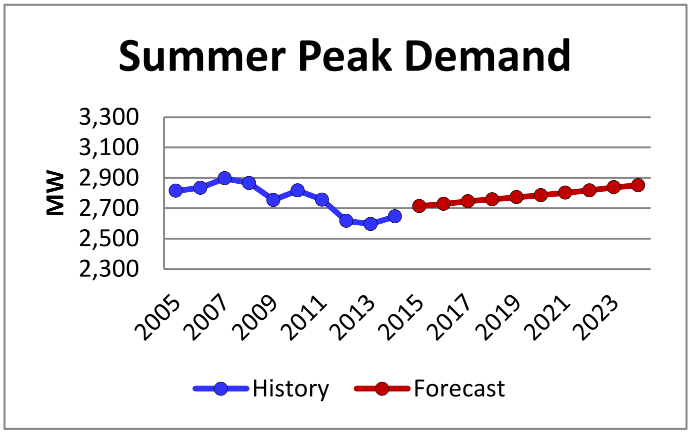


Figure 2: Winter Peak Demand History & Forecast

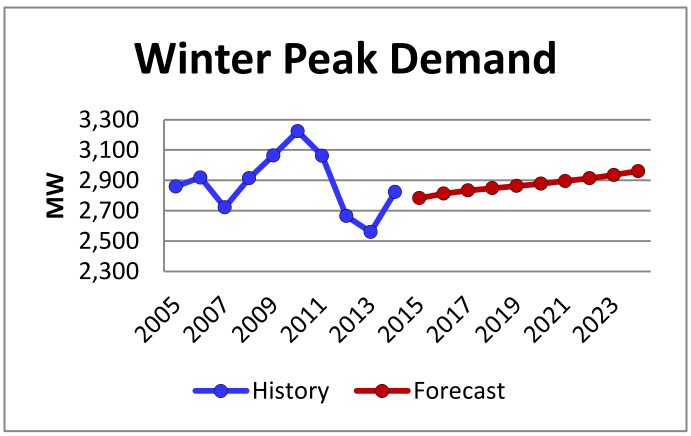
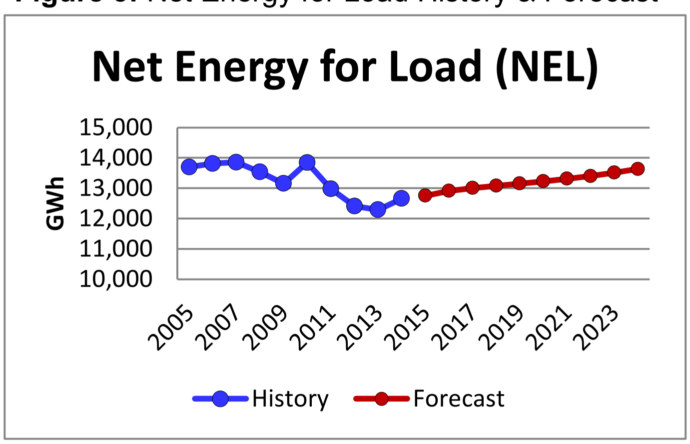


Figure 3: Net Energy for Load History & Forecast

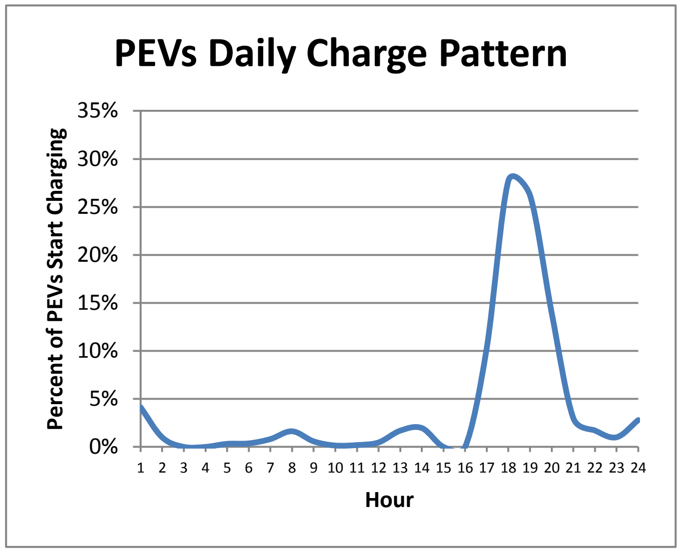


2.3 Plug-in Electric Vehicle Peak Demand and Energy

The PEV demand and energy forecast is developed using the historical number of PEVs in Duval County obtained from Florida Department of Highway Safety and Motor Vehicles (DHSMV) and the 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 historical and forecasted Duval Population, Medium Household Income and Disposable Income from Moody's Analytics. 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) 2015 average motor gasoline price.

The usable battery capacity per vehicle were developed based on the current plug-in vehicle models in Duval County, such as from BMW, General Motors' Chevrolet and Cadillac, Fisker Ford, Mitsubishi, Nissan, Porsche, Tesla and Toyota. The usable battery capacity is calculated using the average of each brand's vehicle. The forecast assumes the usable battery capacity per vehicle grows by 1 kWh per year thereafter. Similarly, the peak capacity is determined based on the average on-board charging rate of each brand's vehicle. The forecasted peak capacity per vehicle grows by 0.35 kW per year.



JEA developed the PEV 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. The baseline forecast assumes that charging will be once per day and uncontrolled charging.

The PEV peak demand forecast is developed using the on-board charge rate for each model, the PEV daily charge pattern and the total number of PEVs each year. Whereas, the PEV energy forecast is the annual summation of hourly demand.

JEA's forecasted AAGR for PEV winter, coincidental peak demand is 27.5 percent and summer, coincidental peak demand is 27.5 percent and total energy is 26.9 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)
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
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	5,197	391,219	13,285	4,001	50,821	78,733	2,579	207	12,438,487
2016	5,202	398,245	13,062	4,020	51,744	77,688	2,619	203	12,903,431
2017	5,231	404,806	12,923	4,053	52,561	77,104	2,658	204	13,029,816
2018	5,281	410,842	12,853	4,090	53,379	76,620	2,685	204	13,161,505
2019	5,324	416,636	12,779	4,123	54,197	76,077	2,691	205	13,127,824
2020	5,376	422,775	12,716	4,152	55,015	75,464	2,692	205	13,132,752
2021	5,432	429,301	12,653	4,176	55,833	74,796	2,685	205	13,096,826
2022	5,485	435,959	12,581	4,193	56,652	74,014	2,668	204	13,076,970
2023	5,538	442,555	12,514	4,206	57,471	73,192	2,650	204	12,991,725
2024	5,594	448,831	12,462	4,221	58,290	72,421	2,634	203	12,977,666
2025	5,650	454,682	12,426	4,236	59,109	71,671	2,619	203	12,902,529

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)	
2006	111	0	12,616	701	494	13,811	2	401,261
2007	113	0	12,649	673	531	13,854	6	410,083
2008	117	0	12,413	619	499	13,531	5	411,200
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	87	0	11,864	392	612	12,868	2	442,249
2016	89	0	11,930	397	555	12,883	2	450,194
2017	89	0	12,031	401	560	12,993	2	457,573
2018	90	0	12,145	111	557	12,813	1	464,426
2019	90	0	12,229	111	561	12,901	1	471,039
2020	90	0	12,310	112	565	12,987	1	477,996
2021	90	0	12,383	113	569	13,065	1	485,340
2022	90	0	12,436	113	573	13,122	1	492,816
2023	90	0	12,485	114	576	13,175	1	500,231
2024	90	0	12,540	114	579	13,233	1	507,325
2025	91	0	12,596	115	583	13,294	1	513,995

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 & Electrification	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
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	1700	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	2,683	0	0	0	0	0	0	0	2,683	6	17	1600	97
2016	2,748	109	5	0	0	0	4	3	2,638	---	---	---	----
2017	2,749	109	8	0	0	0	7	5	2,636	---	---	---	----
2018	2,725	109	11	0	0	0	11	8	2,609	---	---	---	----
2019	2,742	109	13	0	0	0	14	10	2,622	---	---	---	----
2020	2,757	109	14	0	0	0	18	13	2,632	---	---	---	----
2021	2,774	109	15	0	0	0	21	15	2,644	---	---	---	----
2022	2,786	109	16	0	0	0	25	18	2,651	---	---	---	----
2023	2,797	109	17	0	0	0	28	20	2,657	---	---	---	----
2024	2,811	109	18	0	0	0	32	23	2,664	---	---	---	----
2025	2,824	109	19	0	0	0	36	26	2,671	---	---	---	----

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 & Electrification	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
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	2,863	0	0	0	0	0	0	0	2,863	2	20	800	24
2016	2,942	110	3	0	0	0	2	2	2,831	---	---	---	----
2017	2,941	110	6	0	0	0	5	3	2,829	---	---	---	----
2018	2,904	110	7	0	0	0	7	5	2,788	---	---	---	----
2019	2,934	110	8	0	0	0	10	7	2,816	---	---	---	----
2020	2,960	110	9	0	0	0	12	8	2,838	---	---	---	----
2021	2,984	110	10	0	0	0	15	10	2,859	---	---	---	----
2022	3,006	110	10	0	0	0	17	12	2,877	---	---	---	----
2023	3,022	110	11	0	0	0	20	13	2,889	---	---	---	----
2024	3,039	110	11	0	0	0	22	15	2,903	---	---	---	----
2025	3,057	110	11	0	0	0	25	17	2,917	---	---	---	----

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 & Electrification	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy For Load	Load Factor
				Residential	Comm/Ind.		Residential	Comm/Ind.		
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	12,865	0	2	0	0	0	0	0	12,868	51%
2016	12,885	0	24	0	0	0	13	13	12,883	52%
2017	13,005	0	40	0	0	0	26	27	12,993	52%
2018	12,840	0	52	0	0	0	39	40	12,813	52%
2019	12,946	0	61	0	0	0	52	53	12,901	52%
2020	13,051	0	69	0	0	0	66	67	12,987	52%
2021	13,148	0	75	0	0	0	79	80	13,065	52%
2022	13,225	0	81	0	0	0	92	93	13,122	52%
2023	13,299	0	87	0	0	0	105	106	13,175	52%
2024	13,378	0	93	0	0	0	118	120	13,233	52%
2025	13,458	0	100	0	0	0	131	133	13,294	52%

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)
Month	Actual 2014		Actual 2015		Forecast 2016		Forecast 2017	
	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	2,823	1,165	2,554	1,049	2,831	1,053	2,828	1,062
February	2,424	884	2,863	982	2,608	909	2,606	916
March	1,949	917	1,778	942	2,017	952	2,015	960
April	2,164	917	2,094	972	1,991	932	1,989	940
May	2,417	1,066	2,438	1,111	2,401	1,100	2,401	1,108
June	2,521	1,166	2,683	1,231	2,531	1,192	2,529	1,201
July	2,555	1,259	2,648	1,307	2,599	1,297	2,598	1,307
August	2,646	1,289	2,616	1,264	2,638	1,278	2,636	1,288
September	2,411	1,108	2,453	1,123	2,475	1,150	2,475	1,158
October	2,110	988	2,075	990	2,286	1,029	2,313	1,040
November	2,648	935	2,153	946	2,192	956	2,218	966
December	2,148	963	1,806	952	2,378	1,035	2,407	1,046
Annual Peak/Total Energy	2,823	12,656	2,863	12,868	2,831	12,883	2,828	12,993

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 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 April 2017 and retired June 2019 and FPU's agreement for wholesale power expires at the end of 2017. With these baseline assumptions, seasonal capacity purchases are needed for winters 2017 and 2019 and summers of 2016-2018 in amounts less than 35 MW and 100-150 MW, respectively (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) for municipalities in the consideration of need for additional generation additions.

JEA's Planning Reserve Policy establishes a guideline that provides 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. JEA's winter seasonal needs meet this criterion and therefore will be met within the operating horizon in those years. 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.

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
2016	3,769	21	376	0	3,414	2,638	776	29%	776	29%
2017	3,245	28	376	0	2,897	2,636	261	10%	261	10%
2018	3,245	34	376	0	2,903	2,609	294	11%	294	11%
2019	3,245	125	0	0	3,370	2,622	748	29%	748	29%
2020	3,245	225	0	0	3,470	2,632	837	32%	837	32%
2021	3,245	225	0	0	3,470	2,644	826	31%	826	31%
2022	3,245	225	0	0	3,470	2,651	819	31%	819	31%
2023	3,245	225	0	0	3,470	2,657	813	31%	813	31%
2024	3,245	225	0	0	3,470	2,664	805	30%	805	30%
2025	3,245	225	0	0	3,470	2,671	798	30%	798	30%
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
2015 / 16	4,110	15	383	0	3,743	2,831	911	32%	911	32%
2016 / 17	4,110	15	383	0	3,743	2,829	914	32%	914	32%
2017 / 18	3,586	15	383	0	3,219	2,788	431	15%	431	15%
2018 / 19	3,586	6	383	0	3,210	2,816	394	14%	394	14%
2019 / 20	3,586	106	0	0	3,692	2,838	854	30%	854	30%
2020 / 21	3,586	206	0	0	3,792	2,859	933	33%	933	33%
2021 / 22	3,586	206	0	0	3,792	2,877	916	32%	916	32%
2022 / 23	3,586	206	0	0	3,792	2,889	903	31%	903	31%
2023 / 24	3,586	206	0	0	3,792	2,903	890	31%	890	31%
2024 / 25	3,586	206	0	0	3,792	2,917	875	30%	875	30%

Note: Committed Capacity Additions:

- Vogtle Unit 3 – June 2019
- Vogtle Unit 4 – June 2020

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 provide 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 5: Resource Plan

Year	Season	Resource Plan[1][2][3]
2016	Winter	
	Summer	
2017	Summer	Northside Unit 3 Reserve Storage (- 524 MW) TEA Seasonal Purchase (150 MW)
2018	Summer	TEA Seasonal Purchase (100 MW)
2019	Winter	Trail Ridge Contract Expires (- 9 MW)
	Summer	MEAG Plant Vogtle 3 Purchase (100 MW) [4]
		SJRPP Sale to FPL Suspended (383 MW) [5]
		Northside Unit 3 Retired
2020	Summer	MEAG Plant Vogtle 4 Purchase (100 MW) [4]
2021		
2022		
2023		
2024		
2025		

Notes:

(1) Cumulative DSM addition of 42 MW Winter and 62 MW Summer at time of peak by 2025.
(2) PEV addition of 0.75 MW Winter and 3.05 MW Summer by 2025.
(3) New Solar addition of 26 MW per signed agreements as of this update. Fifty percent counted as summer capacity.
(4) 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.
(5) SJRPP sales return based on JEA's forecast estimates.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual											
	Fuel	Type	Units	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1)	**NUCLEAR**														
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**[(1)]														
		TOTAL	**1000 TON**	**3,228**	**2,479**	**2,046**	**2,541**	**3,230**	**3,492**	**2,910**	**2,654**	**2,925**	**2,855**	**3,536**	**3,539**
	RESIDUAL														
(3)		STEAM	1000 BBL	14	10	0	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**	**14**	**10**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	DISTILLATE														
(7)		STEAM	1000 BBL	2	0	1	1	1	1	1	1	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	6	5	5	26	14	16	3	5	12	5	4	0
(10)		**TOTAL**	**1000 BBL**	**8**	**5**	**6**	**27**	**15**	**17**	**4**	**6**	**13**	**7**	**5**	**1**
	NATURAL GAS														
(12)		STEAM	1000 MCF	4,794	12,104	20,640	3,761	60	65	105	88	93	90	69	77
(13)		CC	1000 MCF	24,284	26,876	24,042	26,789	17,848	13,038	23,623	23,881	20,959	22,923	9,888	9,014
(14)		CT/GT	1000 MCF	1,441	2,400	2,097	6,714	5,309	4,895	1,828	2,701	2,669	1,795	2,253	1,748
(15)		**TOTAL**	**1000 MCF**	**30,519**	**41,380**	**46,780**	**37,264**	**23,217**	**17,998**	**25,556**	**26,671**	**23,721**	**24,808**	**12,209**	**10,839**
(16)	**PETROLEUM COKE**														
		TOTAL	**1000 TON**	**492**	**584**	**929**	**887**	**872**	**838**	**663**	**692**	**670**	**668**	**830**	**839**
(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	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1)	**Firm Inter-Region Intchg.**		GWH	**477**	**935**	**0**	**0**	**0**	**488**	**1,323**	**1,665**	**1,665**	**1,665**	**1,610**	**1,606**
(2)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL**(1)		GWH	**7,012**	**5,132**	**4,363**	**5,400**	**7,116**	**7,603**	**6,065**	**5,604**	**6,154**	**6,020**	**7,565**	**7,782**
(4)		STEAM		7	13	0	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	**7**	**13**	**0**	**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		2	1	2	11	6	7	1	2	5	2	2	0
(11)	**DISTILLATE**	**TOTAL**	GWH	**2**	**1**	**2**	**11**	**6**	**7**	**1**	**2**	**5**	**2**	**2**	**0**
(12)		STEAM		346	1,011	2,027	336	0	0	0	0	0	0	0	0
(13)		CC		3,533	3,983	3,604	4,020	2,625	1,936	3,516	3,555	3,118	3,401	1,458	1,334
(14)		CT		114	215	185	613	475	446	165	241	243	158	204	152
(15)	**NATURAL GAS**	**TOTAL**	GWH	**3,993**	**5,209**	**5,815**	**4,970**	**3,101**	**2,382**	**3,681**	**3,796**	**3,361**	**3,559**	**1,663**	**1,486**
(16)	**NUG**		GWH	**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
(18)		**LANDFILL GAS**		69	81	130	130	123	52	52	52	52	52	52	52
(19)		**SOLAR**		21	20	23	51	77	77	76	76	76	75	75	74
(20)		**TOTAL**	GWH	**91**	**101**	**154**	**181**	**200**	**128**	**128**	**128**	**127**	**127**	**127**	**126**
(21)	**Petroleum Coke**		GWH	**1,075**	**1,475**	**2,549**	**2,432**	**2,390**	**2,293**	**1,790**	**1,871**	**1,809**	**1,802**	**2,268**	**2,294**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**(2)		GWH	**12,656**	**12,868**	**12,883**	**12,993**	**12,813**	**12,901**	**12,987**	**13,065**	**13,122**	**13,175**	**13,233**	**13,294**

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**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
(1)	**Firm Inter-Region Intchg.**		%	**3.8**	**7.3**	**0.0**	**0.0**	**0.0**	**3.8**	**10.2**	**12.7**	**12.7**	**12.6**	**12.2**	**12.1**
(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]		%	**55.4**	**39.9**	**33.9**	**41.6**	**55.5**	**58.9**	**46.7**	**42.9**	**46.9**	**45.7**	**57.2**	**58.5**
(4)		STEAM		0.1	0.1	0.0	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**	%	**0.1**	**0.1**	**0.0**	**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	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(11)	**DISTILLATE**	**TOTAL**	%	**0.0**	**0.0**	**0.1**	**0.1**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(12)		STEAM		2.7	7.9	15.7	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		CC		27.9	31.0	28.0	30.9	20.5	15.0	27.1	27.2	23.8	25.8	11.0	10.0
(14)		CT		0.9	1.7	1.4	4.7	3.7	3.5	1.3	1.8	1.9	1.2	1.5	1.1
(15)	**NATURAL GAS**	**TOTAL**	%	**31.5**	**40.5**	**45.1**	**38.2**	**24.2**	**18.5**	**28.3**	**29.1**	**25.6**	**27.0**	**12.6**	**11.2**
(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**		0.5	0.6	1.0	1.0	1.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(19)		**SOLAR**		0.2	0.2	0.2	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(20)		**TOTAL**	%	**0.7**	**0.8**	**1.2**	**1.4**	**1.6**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**0.9**
(21)	**Petroleum Coke**		%	**8.5**	**11.5**	**19.8**	**18.7**	**18.7**	**17.8**	**13.8**	**14.3**	**13.8**	**13.7**	**17.1**	**17.3**
(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 Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2016	3,769	21	376	0	3,414	2,638	776	29%	0	776	29%
2017	3,245	178	376	0	3,047	2,636	411	16%	0	411	16%
2018	3,245	134	376	0	3,003	2,609	394	15%	0	394	15%
2019	3,245	125	0	0	3,370	2,622	748	29%	0	748	29%
2020	3,245	225	0	0	3,470	2,632	837	32%	0	837	32%
2021	3,245	225	0	0	3,470	2,644	826	31%	0	826	31%
2022	3,245	225	0	0	3,470	2,651	819	31%	0	819	31%
2023	3,245	225	0	0	3,470	2,657	813	31%	0	813	31%
2024	3,245	225	0	0	3,470	2,664	805	30%	0	805	30%
2025	3,245	225	0	0	3,470	2,671	798	30%	0	798	30%

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

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2016	4,110	15	383	0	3,743	2,831	911	32%	0	911	32%
2017	4,110	15	383	0	3,743	2,829	914	32%	0	914	32%
2018	3,586	15	383	0	3,219	2,788	431	15%	0	431	15%
2019	3,586	36	383	0	3,240	2,816	424	15%	0	424	15%
2020	3,586	106	0	0	3,692	2,838	854	30%	0	854	30%
2021	3,586	206	0	0	3,792	2,859	933	33%	0	933	33%
2022	3,586	206	0	0	3,792	2,877	916	32%	0	916	32%
2023	3,586	206	0	0	3,792	2,889	903	31%	0	903	31%
2024	3,586	206	0	0	3,792	2,903	890	31%	0	890	31%
2025	3,586	206	0	0	3,792	2,917	875	30%	0	875	30%

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					Summer	Winter	
											kW	MW	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			04/2017	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 2016 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.

The fuel price projections for natural gas, coal, and petroleum coke 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 fuel price projections for diesel fuel used in this TYSP were developed based on those included in the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2015 (AEO2015). AEO2015 presents projections of energy supply, demand, and prices through 2040. The AEO2015 projections are based on results from the EIA's National Energy Modeling System (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 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. Projections of the commodity price for PRB coal are based on current contracted prices and PIRA's long-term projections 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 coals. For the purposes of this study, it has been assumed that 100 percent Colombian coal will be burned by the SJRPP units beginning in 2017. 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 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.

Northside Units 1 and 2 currently burn a blend of petroleum coke and coal. These units are projected to burn 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 petroleum coke to coal price ratio 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 price projection reflects delivery to a Florida city gate is based on PIRA's long-term Henry Hub price forecast and expected variable transportation costs on Florida Gas Transmission.

Northside 3 is capable of operating on residual fuel oil as an alternative to natural gas. On March 31, 2017, Northside 3 is planned to go into reserve storage. 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 AEO2015 oil growth rate.

JEA has executed a power purchase agreement with MEAG for power and capacity 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.