REPORT
March 29, 2017

21 West Church Street
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March 29, 2017

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E L E C T R I C

W A T E R

S E W E R

Attached you will find 5 hardcopies of JEA's 2017 Ten Year Site Plan. The official e-filing with your office was submitted today. If you have any questions regarding this submittal, please contact me at (904) 665-4048 or fiscml@jea.com.

Thank you,

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Building Community®

TEN YEAR SITE PLAN

April 2017

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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, 2017 to December 31, 2026. 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 the Environmental Protection Agency'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 2017 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. Contractually, the sale would continue until the earlier of the Joint Ownership Agreement expiration in October 2021 or the realization of the sale limit which was expected to occur June 2019. In March 2017, JEA and FPL announced a tentative agreement to decommission SJRPP in January 2018. Definitive agreements related to plant closure are being developed. Final JEA and FPL approval of the agreements are expected later in 2017. For the purpose of this TYSP, JEA reflects a January 2018 decommissioning of SJRPP.

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 Solar Generation

1.1.2.2.1 Jacksonville Solar

In May 2009, JEA entered into a purchase power agreement with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW (AC 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. Jax Solar generated 20,531 MWh in calendar year 2016.

1.1.2.2.2 New Solar Purchase Power Agreements

In 2014, JEA's Board approved a Solar Photovoltaic Initiative that supports up to 38 additional MW (AC). If fully subscribed, this will bring JEA's solar portfolio to 50 MW. The additional energy will be acquired through Purchase Power Agreements.

JEA issued Solar PV RFPs in December 2014 and April 2015 to solicit PPA proposals to satisfy the adopted 2014 Solar Policy. JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements have been finalized for a total of 27 MW. All these solar facilities are expected to be completed and operational by 2018.

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	12	Annual
Montgomery Solar		May 2017	May 2042	7	Annual
Old Plank Road Solar		August 2017	August 2037	3	Annual
Blair Site Solar		December 2017	December 2037	4	Annual
Imeson Solar		December 2017	December 2037	5	Annual
Simmons Road Solar		December 2017	December 2037	2	Annual
Old Kings Solar		December 2017	December 2037	1	Annual
Starratt Solar		December 2017	December 2037	5	Annual

[1] Capacity level may vary over contract term.

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

A purchase power agreement is 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 has furnished wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville, since the 1970s. In September 2006, JEA and FPU entered into a 10 year agreement for JEA to supply FPU all of their system energy requirements. This agreement began January 1, 2008, and is expected to end December 31, 2017. In calendar year 2016, JEA supplied FPU annual peak demand of 82 MW and total energy of 266 GWh, 3.0 percent of JEA's annual peak demand and 2.1 percent of JEA's total system energy requirement. For the purpose of this TYSP, the power sales agreement to FPU ends on December 31, 2017.

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	(a)	563,700	524	524	Utility	
	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	WA	RR	3/1987	1/1/2018	679,600	501	510	Joint	(c)
	2	12-031	ST	BIT	PC	WA	RR	5/1988	1/1/2018	679,600	501	510	Joint	(c)
Scherer														
	4	13-207	ST	BIT		RR		2/1989	(a)	990,000	194	194	Joint	(d)
JEA System Total											**3,769**	**4,110**		(e)

Notes:

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

(b) Generator Max Nameplate is total unit not ownership.

(c) Net capability reflects JEA's 80% ownership of Power Park.

(d) Net capability reflects JEA's 23.64% ownership in Scherer 4.

(e) 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 3,200 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 purchased Cedar Bay and retired the generation in December 2016,
- 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 106 MW of interruptible peak load in both summer and winter, and remains constant throughout the study period. For 2017, the interruptible load represents 3.6 percent of the total peak demand in the winter and 3.8 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 planning the implementation of a Demand Rate Pilot program later this year with the intent of reducing peaks for residential customers. This pilot program is still in development and, as such, impacts are not reflected in Table 3. 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. 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		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Annual	Residential	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
Energy	Commercial	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
(GWh)	***Total***	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**	**26.4**
Summer	Residential	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Peak	Commercial	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
(MW)	***Total***	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
Winter	Residential	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Peak	Commercial	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
(MW)	***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 Assessment Program	Residential Energy Assessment 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 (On Hold)	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

From 1999 - 2014, JEA 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" as a means of providing guidance and recommendations to JEA in the development and implementation of the Clean Power Programs.

Since the conclusion of this program, JEA has continued to make considerable progress related to clean power initiatives. This progress includes installation of clean power systems, unit efficiency improvements, nuclear and solar purchase power agreements, legislative and public education activities, and research 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. JEA issued several Requests for Proposals (RFPs) for solar energy that resulted in new resources for JEA's portfolio. As discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, and landfill gas 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). This net metering policy is capped at 10 MW for total generation, which is expected to be met by summer 2017. JEA is exploring options to create a viable solution for incoming solar customers after that cap has been reached.

JEA signed a purchase power agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 12 MW AC rated solar farm, which began operation in summer 2010 (see Section 1.1.2.2.1 Jacksonville Solar).

JEA issued three Solar PV RFPs between December 2014 and December 2015. JEA received a total of 73 bids and awarded 9 solar projects totaling 36.5 MW with terms between 20 to 30 years. Agreements have been finalized successfully for seven projects for a total of 27 MW. All these solar facilities are expected to be completed and operational by the beginning of 2018. One contract that was awarded was cancelled. JEA is still in contract negotiations on one other 5 MW project. Once signed, 32 of the possible 38 MW will have been subscribed.

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's 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) for 9 net MW of the gas-to-energy facility at the Trail Ridge Landfill in Duval County. In 2011, JEA executed an amendment to the Power Purchase Agreement (Phase Two) to purchase 9 additional MW 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 and NPPD agreed to terminate the contract effective December 31, 2019.

1.4.2.4 Biomass

In 2008, 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 co-fired 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. At that time, JEA 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.

1.4.3 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 with UNF, worked to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, 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 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 provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

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.

In addition to these projects, in 2016 JEA pledged its support to the proposed Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) project, which aims to grow solar capacity in FMEA member utility territories to over 10% by 2024. As proposed, the program will be led by Nhu Energy, Inc. and Florida Municipal Electric Association (FMEA), with partial funding from the DOE. The program will provide an opportunity to research solar and solar + storage opportunities prior to strategically implementing on the grid, taking into account Florida's unique load patterns and power systems.

1.4.3.1 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.

1.4.3.2 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.

1.4.3.3 Energy Storage

JEA continues its efforts to demonstrate its commitment to energy efficiency and environmental improvement by researching energy storage as a means of mitigating excess generation.

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 (Moody) economic parameters for Duval County, JEA's Data Warehouse to determine the total number of Residential Premise ID and CBRE Jacksonville for Commercial and Industrial total inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Fiscal Year 2017 baseline forecast uses 10-years of historical data (2007 to 2016) which captured the pre-2008/09 economic downturn, the 2008/09 economic downturn and the post-recession recovery. Using the shorter periods also allows JEA to capture the more recent trends in customer behavior, energy efficiency and conservation, where 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 analysis of normalized historical seasonal peaks, normalized historical and forecasted residential, commercial and industrial energy for Winter/Summer peak months, heating degree hour for the 72 hours leading to winter peak and cooling degree hours for the 48 hours leading to summer peak. JEA's forecasted Average Annual Growth Rate (AAGR) for total peak demand during the TYSP period is 0.56 percent for summer and 0.62 percent for winter, which reflects the expiration of FPU's wholesale agreement beginning 2018.

2.2 Energy Forecast

JEA begins its forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops its normal weather using 20-year historical (FY95 to FY14) average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. JEA updates its normal weather every 5 years or more frequently, if needed.

The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy, Total Population, Medium Household Income from

Moody's Analytics, total residential Premise ID from JEA's Data Warehouse and JEA's residential electric rate.

The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy, commercial inventory square footages, total population and gross product.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy, total number of industrial employment and total retail sales product for existing industrial account. JEA then layers in the estimated energy for new industrial customers to the forecasted industrial energy.

The lighting energy forecast was developed using the historical actual energy, number of lightings and JEA's estimated High Pressure Sodium (HPS) to Light-Emitting Diode (LED) street light conversion schedule. The LEDs are estimated to use 45% less energy than the HPS street lights. JEA developed the forecasted number of lightings using regression analysis of number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of lights, applied with the conversion of remaining HPS street lights to LED street lights starting and all new lightings to be LED street lights only.

JEA's forecasted AAGR for net energy for load during the TYSP period is 0.69 percent, which reflects the expiration of FPU's wholesale agreement beginning 2018.

Figure 1: Summer Peak Demand History & Forecast

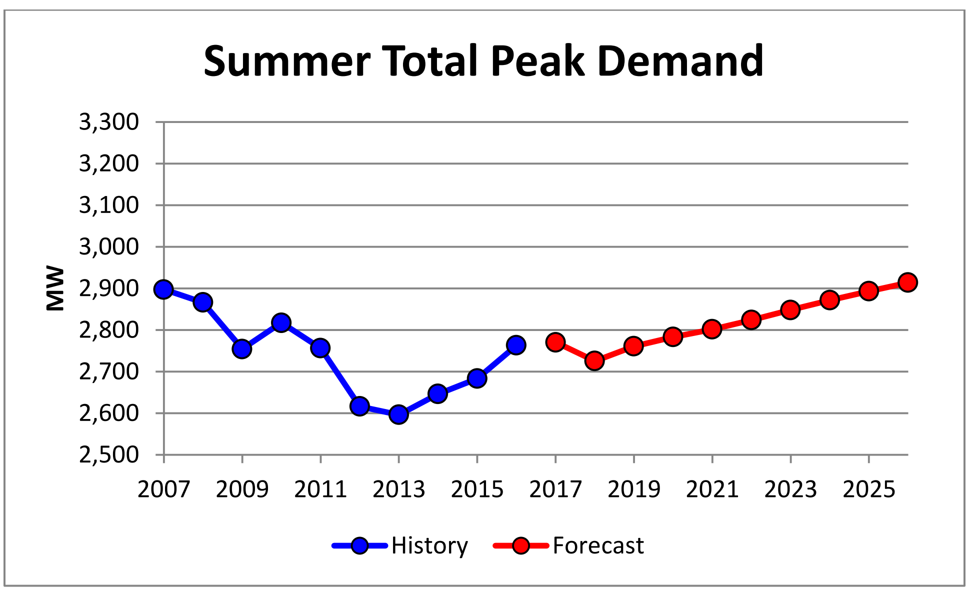


Figure 2: Winter Peak Demand History & Forecast

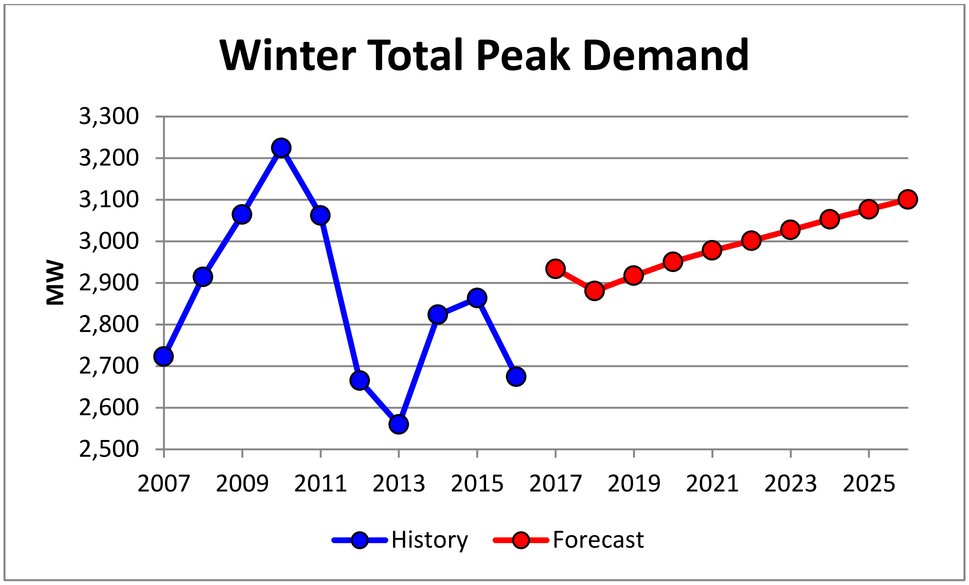
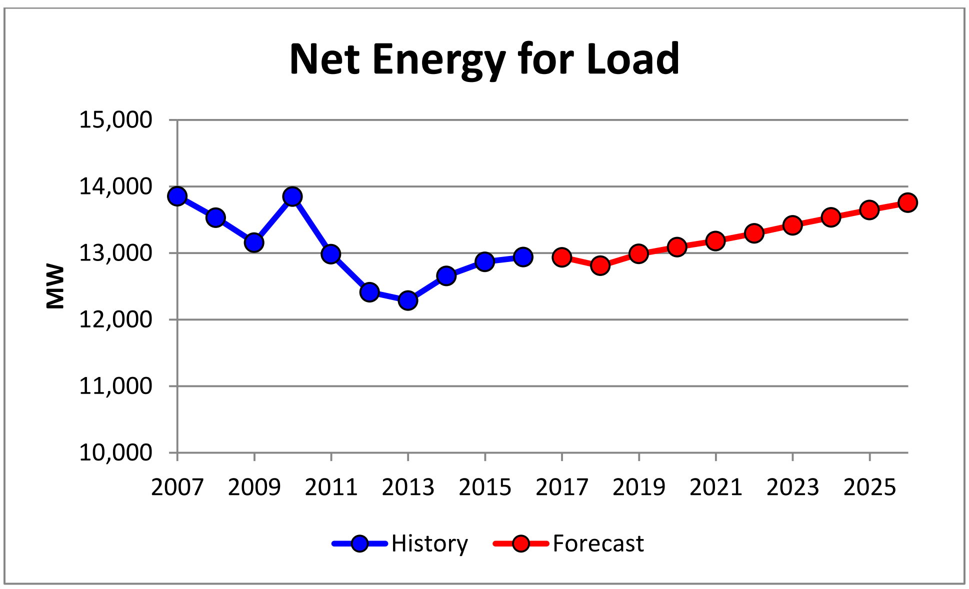


Figure 3: Net Energy for Load History & Forecast



2.3 Plug-in Electric Vehicle Peak Demand and Energy

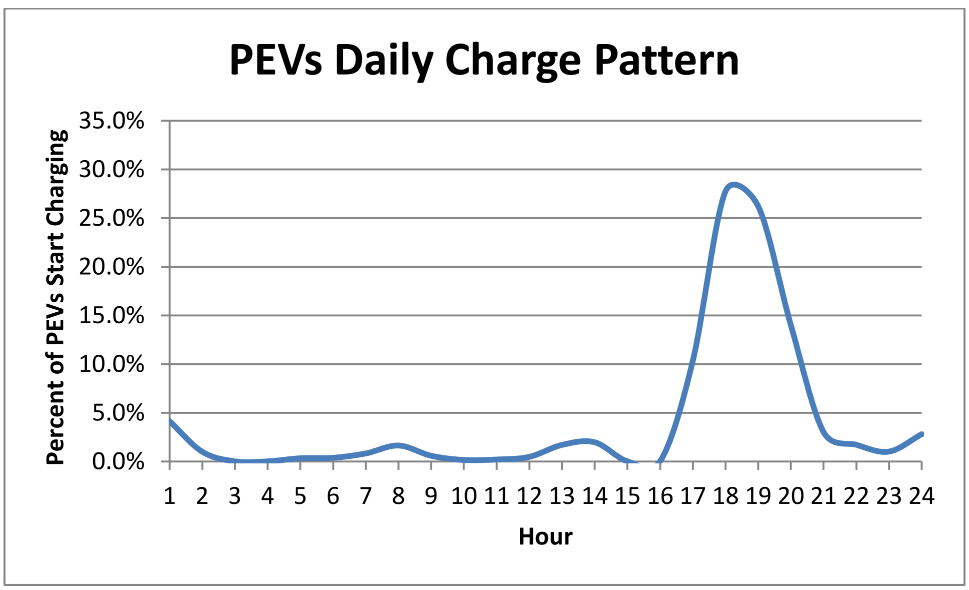
The PEVs demand and energy forecasts are developed using the historical number of PEVs in Duval County obtained from Florida Department of Highway Safety and Motor Vehicles (DHSMV) and the historical number of vehicles in Duval County from the U.S. Census Bureau.

JEA forecasted the numbers of vehicles in Duval County using multiple regression analysis of historical and forecasted Duval Population, Median Household Income and Number of Households from Moody's Analytics. The forecasted number of PEVs is modeled by using multiple regression analysis of the number of vehicles and the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2016 average motor gasoline price.

The usable battery capacity (70% of battery capacity) per vehicle was determined based on the current plug-in vehicle models in Duval County, such as BMW, General Motors' Chevrolet and Cadillac, Honda, Fisker, Ford, Mitsubishi, Nissan, Porsche, Tesla, Toyota and Volvo. The average usable battery capacity per PEV is calculated using the average usable battery capacity of each vehicle brand and then assumes the annual growth of usable battery capacity per PEV by using historical 5 years average growth of 0.64 kWh. Similarly, the peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecast peak capacity per PEV grows by 0.25 kW 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. The baseline forecast assumed that charging will be once per day and uncontrolled charging (PEV start charging immediately upon returning home).

Figure 4: PEVs Daily Charge Pattern



The PEVs peak demand forecast is developed using the on-board charge rate for each model, the PEVs daily charge pattern and the total number of PEVs each year. The PEV energy forecast is developed simply by summing the hourly peak demand for each year. The table below shows the forecasted PEV peak and energy.

JEA's forecasted AAGR for PEV winter and summer coincidental peak demand are 20.9 percent and total energy is 20.9 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)
	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
2007	5,507	358,918	15,591	4,399	42,119	96,392	2,630	222	12,855,251
2008	5,307	365,363	15,072	4,040	44,489	98,887	2,948	225	11,671,666
2009	5,319	365,872	14,506	4,024	45,093	89,591	2,643	231	12,776,809
2010	5,747	368,111	14,448	4,071	45,748	87,957	2,720	226	11,692,820
2011	5,237	369,051	15,572	3,927	46,192	88,137	2,682	223	12,192,004
2012	4,880	369,761	14,163	3,852	46,605	84,255	2,598	215	12,468,380
2013	4,852	372,430	13,102	3,777	47,127	81,735	2,589	218	11,906,357
2014	5,162	377,326	12,860	3,882	47,691	79,204	2,564	219	11,812,944
2015	5,197	383,998	13,443	4,001	49,364	78,642	2,579	215	11,951,824
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,457	202	12,159,793
2017	5,245	403,959	12,985	4,078	52,169	78,162	2,589	203	12,754,418
2018	5,288	411,160	12,860	4,122	53,002	77,772	2,660	205	12,975,390
2019	5,335	418,103	12,761	4,159	53,792	77,309	2,747	206	13,333,739
2020	5,361	424,502	12,629	4,186	54,584	76,689	2,793	207	13,490,579
2021	5,391	430,690	12,516	4,225	55,378	76,286	2,808	207	13,565,925
2022	5,433	437,049	12,431	4,269	56,174	76,003	2,827	207	13,657,004
2023	5,482	443,533	12,360	4,313	56,972	75,707	2,848	207	13,758,683
2024	5,531	449,895	12,295	4,353	57,773	75,353	2,868	207	13,854,672
2025	5,583	455,978	12,244	4,393	58,576	74,998	2,880	207	13,912,789
2026	5,638	461,783	12,209	4,434	59,381	74,666	2,887	207	13,945,961

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)	
2007	113	0	12,649	673	531	13,854	2	401,261
2008	117	0	12,413	619	499	13,531	6	410,083
2009	120	0	12,105	591	458	13,155	5	411,200
2010	122	0	12,660	617	569	13,846	2	414,086
2011	123	0	11,968	589	424	12,980	2	415,468
2012	123	0	11,452	423	537	12,411	2	416,583
2013	122	0	11,340	395	550	12,286	2	419,777
2014	105	0	11,713	472	472	12,656	2	425,238
2015	87	0	11,864	392	612	12,868	2	433,578
2016	77	0	11,949	490	498	12,937	2	450,032
2017	74	0	11,986	381	566	12,933	0	456,331
2018	69	0	12,139	102	566	12,807	0	464,367
2019	67	0	12,308	103	574	12,985	0	472,101
2020	66	0	12,406	103	580	13,089	0	479,293
2021	65	0	12,489	104	586	13,179	0	486,275
2022	67	0	12,596	105	592	13,293	0	493,430
2023	68	0	12,711	106	599	13,415	0	500,712
2024	69	0	12,822	106	605	13,533	0	507,875
2025	70	0	12,926	107	612	13,645	0	514,761
2026	71	0	13,029	108	618	13,755	0	521,371

Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Generation	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
			Residential	Comm/Indu		Residential	Comm/Indu		Month	Day	H.E.	Temp
2007	2,897	0	0	0	0	0	0	2,897	8	7	170	97
2008	2,866	0	0	0	0	0	0	2,866	8	7	1600	96
2009	2,754	0	0	0	0	0	0	2,754	6	22	1600	98
2010	2,817	0	0	0	0	0	0	2,817	6	18	1700	102
2011	2,756	0	0	0	0	0	0	2,756	8	11	1700	98
2012	2,616	0	0	0	0	0	0	2,616	7	25	1700	95
2013	2,596	0	0	0	0	0	0	2,596	8	14	1600	93
2014	2,646	0	0	0	0	0	0	2,646	8	22	1600	99
2015	2,683	0	0	0	0	0	0	2,683	6	17	1600	97
2016	2,763	0	0	0	0	0	0	2,763	7	7	1700	98
2017	2,770	106	0	0	0	4	3	2,658	---	---	---	----
2018	2,725	106	0	0	0	7	5	2,607	---	---	---	----
2019	2,761	106	0	0	0	11	8	2,637	---	---	---	----
2020	2,783	106	0	0	0	14	10	2,653	---	---	---	----
2021	2,801	106	0	0	0	18	13	2,665	---	---	---	----
2022	2,824	106	0	0	0	21	15	2,682	---	---	---	----
2023	2,848	106	0	0	0	25	18	2,700	---	---	---	----
2024	2,871	106	0	0	0	28	20	2,717	---	---	---	----
2025	2,893	106	0	0	0	32	23	2,733	---	---	---	----
2026	2,914	106	0	0	0	35	25	2,748	---	---	---	----

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)	
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Generation	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
			Residential	Comm/Indu		Residential	Comm/Indu		Month	Day	H.E.	Temp
2007	2,722	0	0	0	0	0	0	2,722	1	30	800	28
2008	2,914	0	0	0	0	0	0	2,914	1	3	800	25
2009	3,064	0	0	0	0	0	0	3,064	2	6	800	23
2010	3,224	0	0	0	0	0	0	3,224	1	11	800	20
2011	3,062	0	0	0	0	0	0	3,062	1	14	800	23
2012	2,665	0	0	0	0	0	0	2,665	1	4	800	22
2013	2,559	0	0	0	0	0	0	2,559	2	18	800	24
2014	2,823	0	0	0	0	0	0	2,823	1	7	800	22
2015	2,863	0	0	0	0	0	0	2,863	2	20	800	24
2016	2,674	0	0	0	0	0	0	2,674	1	20	800	28
2017	2,933	106	0	0	0	3	2	2,823	---	---	---	----
2018	2,880	106	0	0	0	6	4	2,765	---	---	---	----
2019	2,917	106	0	0	0	8	6	2,797	---	---	---	----
2020	2,950	106	0	0	0	11	8	2,825	---	---	---	----
2021	2,978	106	0	0	0	14	10	2,848	---	---	---	----
2022	3,001	106	0	0	0	17	11	2,867	---	---	---	----
2023	3,027	106	0	0	0	20	13	2,888	---	---	---	----
2024	3,052	106	0	0	0	22	15	2,909	---	---	---	----
2025	3,076	106	0	0	0	25	17	2,928	---	---	---	----
2026	3,100	106	0	0	0	28	19	2,947	---	---	---	----

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)
Calendar Year	Total Energy for Load	Interruptible Load	Load Management		QF Load Served By QF Generation	Cumulative Conservation		Net Energy for Load	Load Factor
			Residential	Comm/Indu		Residential	Comm/Indu		
2007	13,854	0	0	0	0	0	0	13,854	55%
2008	13,531	0	0	0	0	0	0	13,531	53%
2009	13,155	0	0	0	0	0	0	13,155	49%
2010	13,846	0	0	0	0	0	0	13,846	49%
2011	12,980	0	0	0	0	0	0	12,980	48%
2012	12,411	0	0	0	0	0	0	12,411	53%
2013	12,286	0	0	0	0	0	0	12,286	54%
2014	12,656	0	0	0	0	0	0	12,656	51%
2015	12,868	0	0	0	0	0	0	12,868	51%
2016	12,937	0	0	0	0	0	0	12,937	53%
2017	12,960	0	0	0	0	13	13	12,933	52%
2018	12,860	0	0	0	0	26	27	12,807	53%
2019	13,064	0	0	0	0	39	40	12,985	53%
2020	13,195	0	0	0	0	52	53	13,089	53%
2021	13,311	0	0	0	0	65	66	13,179	53%
2022	13,452	0	0	0	0	79	80	13,293	53%
2023	13,600	0	0	0	0	92	93	13,415	53%
2024	13,744	0	0	0	0	105	106	13,533	53%
2025	13,882	0	0	0	0	118	120	13,645	53%
2026	14,019	0	0	0	0	131	133	13,755	53%

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 2016		Forecast 2017		Forecast 2018		Forecast 2019	
	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	2,674	1,083	2,823	1,053	2,765	1,039	2,797	1,055
February	2,575	951	2,597	913	2,545	901	2,574	915
March	1,928	921	2,009	955	1,968	944	1,991	959
April	2,192	926	2,002	935	1,965	925	1,986	939
May	2,310	1,107	2,417	1,103	2,371	1,091	2,398	1,108
June	2,743	1,268	2,547	1,198	2,498	1,184	2,526	1,202
July	2,763	1,393	2,619	1,303	2,569	1,288	2,598	1,308
August	2,672	1,335	2,658	1,284	2,607	1,270	2,637	1,289
September	2,450	1,180	2,493	1,153	2,446	1,141	2,473	1,159
October	2,137	987	2,298	1,041	2,258	1,036	2,282	1,045
November	1,813	868	2,203	959	2,165	956	2,186	965
December	1,891	918	2,390	1,036	2,349	1,032	2,373	1,041
Annual Peak/Total Energy	2,763	12,937	2,823	12,933	2,765	12,807	2,797	12,985

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 the addition of the purchased power agreement with MEAG for the future Vogtle Units 3 and 4, the retirement of SJRPP Units 1 and 2 in January 2018 and the expiration of FPU's agreement for wholesale power at the end of 2017. With these baseline assumptions, annual and/or seasonal capacity purchases are needed each year of this TYSP period beginning in 2018 (see Table 4).

Table 4a: Resource Needs after Committed Units - Summer

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
2017	3,769	15	376	0	3,408	2,658	750	28%	750	28%
2018	2,767	15	0	0	2,782	2,607	175	7%	175	7%
2019	2,767	106	0	0	2,873	2,637	236	9%	236	9%
2020	2,767	206	0	0	2,973	2,653	320	12%	320	12%
2021	2,767	206	0	0	2,973	2,665	308	12%	308	12%
2022	2,767	206	0	0	2,973	2,682	291	11%	291	11%
2023	2,767	206	0	0	2,973	2,700	273	10%	273	10%
2024	2,767	206	0	0	2,973	2,717	256	9%	256	9%
2025	2,767	206	0	0	2,973	2,733	240	9%	240	9%
2026	2,767	206	0	0	2,973	2,748	225	8%	225	8%

Table 4b: Resource Needs after Committed Units - Winter

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
2016 / 17	4,110	15	383	0	3,743	2,823	920	33%	920	33%
2017 / 18	3,090	15	0	0	3,105	2,765	340	12%	340	12%
2018 / 19	3,090	6	0	0	3,096	2,797	300	11%	300	11%
2019 / 20	3,090	106	0	0	3,196	2,825	371	13%	371	13%
2020 / 21	3,090	206	0	0	3,296	2,848	448	16%	448	16%
2021 / 22	3,090	206	0	0	3,296	2,867	429	15%	429	15%
2022 / 23	3,090	206	0	0	3,296	2,888	408	14%	408	14%
2023 / 24	3,090	206	0	0	3,296	2,909	387	13%	387	13%
2024 / 25	3,090	206	0	0	3,296	2,928	368	13%	368	13%
2025 / 26	3,090	206	0	0	3,296	2,947	349	12%	349	12%

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

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.

To meet these Planning Reserve Policy requirements, JEA will acquire the needed capacity and associated energy as identified in Table 5. The Energy Authority (TEA), JEA's affiliated energy market services company, has negotiated combined cycle capacity and energy pricing with a source to meet JEA's identified annual need in 2018 and 2019. A purchased power agreement will be signed for the annual needs once definitive approvals for SJRPP's decommissioning are acquired.

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. Because JEA's seasonal needs are greater than 3% of firm peak demand, TEA will acquire short-term seasonal market purchases for JEA no later than 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 5: Purchased Power Capacity Need

Year	Summer (MW)	Winter (MW)	Type
2017	-	-	-
2018	225	225	Annual
2019	225	225	Annual
2020	200	55	Seasonal
2021	200	-	Seasonal
2022	200	-	Seasonal
2023	200	25	Seasonal
2024	200	50	Seasonal
2025	200	75	Seasonal
2026	200	100	Seasonal

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, committed unit additions, existing capacity changes and annual and seasonal capacity purchase additions. All these factors considered collectively provide JEA with sufficient capacity to cover customer demand and reserves during this ten year period. Table 6 presents the ten year resource plan which meets JEA's strategic goals. Schedules 5-10 provide further detail on this plan.

Table 6: Resource Plan

Year	Resource Plan[1][2][3]
2017	
2018	SJRPP Sale to FPL Suspended (383 MW)[4] SJRPP Units 1 & 2 Retired (- 1020 MW)[4] Annual Combined Cycle Purchase (225 MW)
2019	Trail Ridge Contract Expires (- 9 MW) Annual Combined Cycle Purchase (225 MW) MEAG Plant Vogtle 3 Purchase (100 MW)[5]
2020	MEAG Plant Vogtle 4 Purchase (100 MW)[5]
2021	
2022	
2023	
2024	
2025	
2026	

Notes:

(1) Cumulative DSM addition of 47 MW Winter and 60 MW Summer at time of peak by 2026.
(2) New Solar addition of 27 MW per signed agreements as of this update.
(3) See Seasonal Purchases in Table 5.
(4) SJRPP sales return and SJRPP Units 1 and 2 retired January 2018.
(5) After accounting for transmission losses, JEA expects to receive 100 MW in June 2019 and 100 MW in June 2020 for a total of 200 MW of net firm capacity from the Vogtle units under construction.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual											
	Fuel	Type	Units	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	**NUCLEAR**														
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL[1]**														
		TOTAL	**1000 TON**	**2,479**	**2,352**	**2,106**	**930**	**983**	**991**	**1,120**	**993**	**899**	**782**	**1,031**	**1,071**
	RESIDUAL														
(3)		STEAM	1000 BBL	10	27	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**	**10**	**27**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	DISTILLATE														
(7)		STEAM	1000 BBL	0	1	2	3	2	3	2	2	3	1	2	3
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	5	6	3	30	22	10	10	31	38	18	28	13
(10)		**TOTAL**	**1000 BBL**	**5**	**8**	**5**	**33**	**24**	**13**	**12**	**33**	**41**	**19**	**30**	**16**
	NATURAL GAS														
(12)		STEAM	1000 MCF	12,104	14,025	14,495	18,065	16,237	19,045	16,530	21,247	18,971	21,265	18,462	19,223
(13)		CC	1000 MCF	26,876	19,754	26,335	25,607	23,475	25,802	25,507	23,582	26,262	26,087	24,842	25,736
(14)		CT/GT	1000 MCF	2,400	4,593	2,776	5,153	4,984	4,542	5,255	6,819	6,864	6,280	7,666	5,248
(15)		**TOTAL**	**1000 MCF**	**41,380**	**38,372**	**43,605**	**48,825**	**44,696**	**49,390**	**47,291**	**51,648**	**52,096**	**53,632**	**50,970**	**50,207**
(16)	**PETROLEUM COKE**														
		TOTAL	**1000 TON**	**584**	**802**	**364**	**398**	**413**	**432**	**413**	**377**	**399**	**433**	**435**	**436**
(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**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
(1)	**Firm Inter-Region Interchange**(1)		GWH	**935**	**1,363**	**0**	**1,777**	**2,269**	**1,590**	**1,909**	**1,945**	**1,997**	**1,969**	**1,981**	**2,062**
(2)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL**(2)		GWH	**5,132**	**4,580**	**4,994**	**2,504**	**2,672**	**2,731**	**2,873**	**2,648**	**2,493**	**2,362**	**2,779**	**2,855**
(4)	**RESIDUAL**	STEAM	GWH	13	16	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)		**TOTAL**		**13**	**16**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(8)	**DISTILLATE**	STEAM	GWH	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		1	2	1	13	9	4	4	13	16	7	12	5
(11)		**TOTAL**		**1**	**2**	**1**	**13**	**9**	**4**	**4**	**13**	**16**	**7**	**12**	**5**
(12)	**NATURAL GAS**	STEAM	GWH	1,011	1,279	1,370	1,725	1,551	1,830	1,574	2,089	1,848	2,077	1,808	1,849
(13)		CC		3,983	2,977	4,141	4,004	3,644	4,039	3,988	3,703	4,122	4,089	3,893	4,030
(14)		CT		215	415	246	465	449	407	475	625	632	574	702	476
(15)		**TOTAL**		**5,209**	**4,672**	**5,757**	**6,194**	**5,643**	**6,276**	**6,037**	**6,417**	**6,602**	**6,740**	**6,404**	**6,355**
(16)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(17)	**RENEWABLES**	HYDRO	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(18)		LANDFILL GAS		81	75	130	123	52	52	52	52	52	52	52	47
(19)		SOLAR		20	24	36	82	82	82	81	81	80	80	79	79
(20)		**TOTAL**		**101**	**99**	**166**	**205**	**133**	**133**	**132**	**132**	**132**	**132**	**131**	**126**
(21)	**PETROLEUM COKE**		GWH	**1,475**	**2,206**	**2,016**	**2,114**	**2,259**	**2,356**	**2,224**	**2,138**	**2,176**	**2,323**	**2,339**	**2,352**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**(3)		GWH	**12,868**	**12,937**	**12,933**	**12,807**	**12,985**	**13,089**	**13,179**	**13,293**	**13,415**	**13,533**	**13,645**	**13,755**

Note: (1) Seasonal and Year-Round PPA starting in 2018 and Nuclear PPA from MEAG commencing in 2019 included in Firm Inter-Regional Interchange.
(2) Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP retires January 2018.
(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	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1)	Firm Inter-Region Interchange		%	7.3	10.5	0.0	13.9	17.5	12.1	14.5	14.6	14.9	14.6	14.5	15.0
(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]		%	39.9	35.4	38.6	19.6	20.6	20.9	21.8	19.9	18.6	17.5	20.4	20.8
(4)	RESIDUAL	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)		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)	DISTILLATE	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	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.0
(11)		TOTAL		0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.0
(12)	NATURAL GAS	STEAM	%	7.9	9.9	10.6	13.5	11.9	14.0	11.9	15.7	13.8	15.3	13.3	13.4
(13)		CC		31.0	23.0	32.0	31.3	28.1	30.9	30.3	27.9	30.7	30.2	28.5	29.3
(14)		CT		1.7	3.2	1.9	3.6	3.5	3.1	3.6	4.7	4.7	4.2	5.1	3.5
(15)		TOTAL		40.5	36.1	44.5	48.4	43.5	47.9	45.8	48.3	49.2	49.8	46.9	46.2
(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		0.6	0.6	1.0	1.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3
(19)		SOLAR		0.2	0.2	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(20)		TOTAL		0.8	0.8	1.3	1.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9
(21)	PETROLEUM COKE		%	11.5	17.1	15.6	16.5	17.4	18.0	16.9	16.1	16.2	17.2	17.1	17.1
(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[2]		%	100	100	100	100	100	100	100	100	100	100	100	100

Note: [1] Nuclear PPA from MEAG commencing in 2019 included in Firm Inter-Regional Interchange.
[2] Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP retires January 2018.
[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
2017	3,769	15	376	0	3,408	2,658	750	28%	0	750	28%
2018	2,767	240	0	0	3,007	2,607	400	15%	0	400	15%
2019	2,767	331	0	0	3,098	2,637	461	18%	0	461	18%
2020	2,767	406	0	0	3,173	2,653	520	20%	0	520	20%
2021	2,767	406	0	0	3,173	2,665	508	19%	0	508	19%
2022	2,767	406	0	0	3,173	2,682	491	18%	0	491	18%
2023	2,767	406	0	0	3,173	2,700	473	18%	0	473	18%
2024	2,767	406	0	0	3,173	2,717	456	17%	0	456	17%
2025	2,767	406	0	0	3,173	2,733	440	16%	0	440	16%
2026	2,767	406	0	0	3,173	2,748	425	15%	0	425	15%

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
2017	4,110	15	383	0	3,743	2,823	920	33%	0	920	33%
2018	3,090	240	0	0	3,330	2,765	565	20%	0	565	20%
2019	3,090	231	0	0	3,321	2,797	525	19%	0	525	19%
2020	3,090	161	0	0	3,251	2,825	426	15%	0	426	15%
2021	3,090	206	0	0	3,296	2,848	448	16%	0	448	16%
2022	3,090	206	0	0	3,296	2,867	429	15%	0	429	15%
2023	3,090	231	0	0	3,321	2,888	433	15%	0	433	15%
2024	3,090	256	0	0	3,346	2,909	437	15%	0	437	15%
2025	3,090	281	0	0	3,371	2,928	443	15%	0	443	15%
2026	3,090	306	0	0	3,396	2,947	449	15%	0	449	15%

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			01/2018	679,600	(501)	(510)	Retired
SJRPP	2	12-031	ST	BIT	PC	RR	WA			01/2018	679,600	(501)	(510)	

Note: Net capability reflects JEA's 80% ownership of Power Park.

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

(2017 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 through 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 2017 (AEO2017). AEO2017 presents projections of energy supply, demand, and prices through 2050. The AEO2017 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 PIRA's long-term projections for PRB coal. The transportation component of the delivered price projection was derived from existing contracts and escalated by an inflation rate of 2.1% thereafter. The inflation rate of 2.1% originates from the AEO2017.

SJRPP currently burns Colombian coal. The commodity price for SJRPP is based on the existing coal supply agreement, which will supply the plant until it is retired at the end of 2017. The current freight rate for 2017 waterborne delivery of Columbian coal was used for the 2017 transportation cost.

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. The projected transportation costs to Northside Generating

Station used the same 2017 freight rates for Colombia coal and escalated it using the AEO2017 inflation rate, with an additional transportation price adder given because of the shallower draft at its offloading facility.

Northside 3 is capable of operating on residual fuel oil as an alternative to natural gas. The projected prices for residual fuel oil are based on the AEO2017 price forecast for residual fuel oil delivered to the Florida Reliability Coordinating Council Region (FRCC).

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 based on PIRA's long-term Henry Hub price forecast and expected variable transportation costs on Florida Gas Transmission.

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 AEO2017 oil growth rate.

JEA has a purchase power agreement with MEAG for 200MW 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 2.1 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.