Building Community®

TEN YEAR SITE PLAN

April 2020

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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
DFO	No. 2 Fuel Oil
RFO	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, 2020 to December 31, 2029. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

1. Description of Existing Facilities

1.1 Power Supply System Description

1.1.1 System Summary

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 450,000 customers.

As of January 1, 2020, JEA consists of two financially separate entities: the JEA Electric System; and the Robert W. Scherer bulk power system. The total projected net capability of JEA's generation system is 3,145 MW for winter and 2,854 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 (CFB) steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); seven dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2 and Brandy Branch GT1, CT2, and CT3); 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).

During the spring of 2019, JEA upgraded Brandy Branch units CT2 and CT3. The upgrade involved the addition of General Electric's Advanced Gas Path (AGP) and 7FA.05 compressor modifications to the existing Brandy Branch CT2 and CT3 7FA.03 units. Refer to Schedule 1 for summer and Winter Net Capability updates.

1.1.1.2 Robert W. Scherer Bulk Power System

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. Scherer Unit 4 is one of four coal-fired steam units located at the 12,000-acre site near the Ocmulgee River approximately three miles east of Forsyth, Georgia. JEA and FPL purchased an undivided interest of this unit from Georgia Power Company. JEA has 23.6 percent (200 net MW) and FPL 76.4 percent ownership interest in Unit 4.

In addition to the purchase of undivided ownership interests in Scherer Unit 4, under the Scherer Unit 4 Purchase Agreement, JEA and FPL also purchased proportionate undivided ownership interests in (i) certain common facilities shared by Units 3 and 4 at Plant Scherer, (ii) certain common facilities shared by Units 1, 2, 3 and 4 at Plant Scherer and (iii) an associated coal stockpile. Under a separate agreement, JEA also purchased a proportionate undivided ownership interest in substation and switchyard facilities. 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 purchase energy and environmental attributes from 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 facility was one of the largest landfill gas-to-energy facilities in the Southeast when it began commercial operation December 6, 2008.

JEA and TRE executed an amendment to this purchase power agreement on March 9, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) 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. These landfill gas projects generated 87,561 MWh calendar year 2019.

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 12 MW_{AC} 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 18,314 MWh calendar year 2019.

1.1.2.3 Solar Purchase Power Agreements

In 2014, JEA's Board approved a Solar Photovoltaic Initiative that supports up to 38 additional MW_{AC}. JEA issued a Solar PV Request For Proposals (RFPs) December 2014 and April 2015 to solicit PPA proposals to satisfy the adopted 2014 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 were finalized for a total of 27 MW. The last of these seven projects was completed December 2019.

In October 2017, the JEA Board approved a further solar expansion consisting of five-50 MW_{AC} solar facilities to be constructed on JEA-owned property. These projects, totaling 250 MW_{AC}, are structured as PPAs. A Request for Qualifications to select the vendors was issued and a vendor short list was announced November 2017. The RFP for the facilities was released to the short listed vendors on January 2, 2018. JEA received and evaluated 50 proposals that conformed to the requirements of the RFP. JEA awarded the contracts to EDF Renewables Distributed Solutions on April 26, 2018. JEA negotiated and executed the contracts with EDF the first quarter 2019. JEA will purchase the produced energy and the associated environmental attributes from each facility. Beaver Street Solar Center, Cecil Commerce Solar Center, Deep Creek Solar Center, Forest Trail Solar Center, and Westlake Solar Center are tentatively scheduled for completion by the end of 2022.

1.1.2.4 Nuclear Generation

JEA's Board had established targets to acquire 10 percent of JEA's energy requirements from nuclear sources by 2018 and up to 30 percent by 2030. 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. October 2017, the JEA Board modified this goal by adopting an Energy Mix Policy, which allows the 30 percent target to be met by any carbon-free or carbon-neutral generation. Meeting these targets will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a 20-year 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 November 2021 from Unit 3 and an additional 100 net MW beginning November 2022 from Unit 4. Table 1 lists JEA's current purchased power contracts.

1.1.2.5 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.

Table 1: JEA Purchased Power Schedule

Contract		Start Date	End Date	MW_{AC}	Product Type
LES Trail Ridge	I	12/06/08	12/31/26	9	Annual
	II	02/01/14	12/31/26	6	Annual
MEAG Plant Vogtle	Unit 3	11/01/21	11/01/41	100	Annual
	Unit 4	11/01/22	11/01/42	100	Annual
Jacksonville Solar		09/30/10	09/30/40	12	Annual
NW Jacksonville Solar		05/30/17	05/30/42	7	Annual
Old Plank Road Solar		10/13/17	10/13/37	3	Annual
Starratt Solar		12/20/17	12/20/37	5	Annual
Simmons Road Solar		01/17/18	01/17/38	2	Annual
Blair Site Solar		01/23/18	01/23/38	4	Annual
Old Kings Solar		10/15/18	10/15/38	1	Annual
SunPort Solar		12/04/19	12/04/39	5	Annual
Cecil Commerce Solar(1)		05/19/21	05/19/46	50	Annual
Westlake Solar(1)		07/07/21	07/07/46	50	Annual
Deep Creek Solar (1)		08/03/21	08/03/46	50	Annual
Beaver Street Solar(1)		10/08/21	10/08/46	50	Annual
Forest Trail Solar (1)		12/01/21	12/01/46	50	Annual

(1) Dates are tentative.

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/Year	Mo/Year	kW	Summer	Winter		
Kennedy										407,600	300	382		
	7	12-031	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	150	191	Utility	
	8	12-031	GT	NG	DFO	PL	WA	06/2009	(a)	203,800	150	191	Utility	
Northside										1,512,100	1,310	1,356		
	1	12-031	ST	PC	BIT	WA	RR	05/2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	04/2003	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	RFO	PL	WA	07/1977	(a)	563,700	524	524	Utility	
	33-36	12-031	GT	DFO		WA,TK		01/1975	(a)	248,400	200	246	Utility	
Brandy Branch										879,800	746	826		
	1	12-031	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	150	191	Utility	
	2	12-031	CT	NG		PL	TK	05/2001	(a)	203,800	190	209	Utility	
	3	12-031	CT	NG		PL	TK	10/2001	(a)	203,800	190	209	Utility	
	4	12-031	CA	WH				01/2005	(a)	268,400	216	216	Utility	
Greenland Energy Center										407,600	300	382		
	1	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	203,800	150	191	Utility	
	2	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	203,800	150	191	Utility	
Scherer														
	4	13-207	ST	BIT		RR		02/1989	(a)	990,000	198	198	Joint	(c)
JEA System Total											**2,854**	**3,145**		(d)

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 23.64% ownership in Scherer 4.
(d) Numbers may not add due to rounding.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

JEA's transmission system consists of 744 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, completing the path from FPL's Duval substation (west of JEA's system) to the north to interconnect with 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 capacity is 1,228 MW over the 500 kV transmission lines through Duval substation.

The 230 kV and 138 kV transmission systems provide 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; covering the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates a total of four 230 kV transmission interconnections at FPL's Duval substation in Duval County. JEA has one 230 kV transmission interconnection which terminates at Beaches Energy Services' Sampson substation (FPL metered) in St. Johns County. JEA's ownership of this interconnection ends at State Road 210 which is located just north of the Sampson substation. JEA has one 230 kV transmission interconnection terminating at Seminole Electric Cooperative Incorporated's (SECI) Black Creek substation in Clay County. JEA's ownership of this interconnection ends at the Duval County – Clay County line.

JEA's one 138 kV tie-line, owned by Beaches Energy Services, terminates at JEA's Neptune substation. The 138 kV circuit breaker at Neptune substation is owned and maintained by JEA, and the 138 kV transmission line fed by the circuit breaker is owned and operated by Beaches Energy Services. JEA owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to JEA's Nassau substation. This substation serves as a 138 kV transmission interconnection point for FPL's O'Neil substation and Florida Public Utilities Company's (FPU) Step Down substation. JEA's ownership of these two 138 kV interconnections end at the first transmission structure outside of the Nassau substation.

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.

Since FRCC region became FL-Peninsula sub-region of SERC from July 2019, JEA is following additional guidelines and actively participating in the SERC activities towards the reliability and security of the bulk electric 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, 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 Technical Subcommittee 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

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.

The following two existing transmission service contracts expired or are set to expire in this Ten Year Site Plan period:

- The contract for the delivery of backup, non-firm, as-available service to Beaches Energy Services expired at the end of November 2019.
- FPL purchased Cedar Bay plant and retired the generation December 2016. The transmission service for the delivery of Cedar Bay generation has been converted to JEA's Open Access Transmission service, and will remain with FPL through 2024.

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 4.16 kV system serves a permanently defined area in older residential neighborhoods. The 13 kV system serves a permanently defined area in the urban downtown area. These two distribution systems serve any new customers that are located within their defined areas, but there are no plans to expand these two systems beyond their present boundaries. The 26.4 kV system serves approximately 88 percent of JEA's load, including 75 percent of the 4.16 kV substations. The current standard is to expand the 26.4 kV system as required to serve all new distribution loads, except loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,000 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 100 MW of interruptible peak load for the summer and 102 MW for the winter which remain constant throughout the study period. For 2020, the interruptible load represents 3.8 percent of the forecasted total peak demand in the winter and 3.6 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 continues to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's demand-side management programs focus on improving the efficiency of customer end uses as well as improving the system load factor. To encourage efficient customer usage, JEA offers customers both education and economic incentives on more efficient end use technologies. For load factor improvement, JEA has implemented a Demand Rate Pilot program with the intent of reducing peaks for residential customers.

Electrification programs include on-road and off-road vehicles, floor scrubbers, 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. Final results from the Demand Rate Pilot program have not yet been determined, and as such impacts are not reflected. 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		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Annual	Residential	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Energy	Commercial	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
(GWh)	***Total***	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**
Summer	Residential	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Peak	Commercial	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
(MW)	***Total***	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**
Winter	Residential	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Peak	Commercial	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
(MW)	***Total***	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**

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
	Electric Vehicles
	Demand Rate Pilot

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

As established in JEA's "Clean Power Action Plan" and through routine Clean Power Program meetings from 1999-2014, JEA worked with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups 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, 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 early 2002. This program provided 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. The policy has since evolved with several revisions:

- 2009: Tier 1 & 2 Net Metering policy launched to include all customer-owned renewable generation systems less than or equal to 100 kW
- 2011: Tier 3 Net Metering policy established for customer-owned renewable generation systems greater than 100 kW up to 2 MW

- 2014: Policy updated to define Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as 100 kW – 2 MW. This policy was capped at 10 MW for total generation. All customer-owned generation in excess of 2 MW would be addressed in JEA's Distributed Generation Policy.
- 2017: In October, the JEA Board approved the consolidation of the Net Metering and Distributed Generation Policies into a single, comprehensive Distributed Generation Policy.
- 2018: Effective April 1, the comprehensive Distributed Generation (DG) Policy qualified renewable and non-renewable customer-owned generation systems under the following ranges:
    - DG-1 – Less than or equal to 2 MW
    - DG-2D – Over 2 MW with distribution level connection
    - DG-2T – Over 2 MW with transmission level connection

  This DG policy acts in concert with the JEA Battery Incentive Program (see Section 1.4.3.3 Energy Storage) and allows existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years.

JEA signed a purchase power agreement with Jacksonville Solar, LLC May 2009 to provide energy from a 12 MW_{AC} rated solar farm, which began operation summer 2010 (see Section 1.1.2.3 Jacksonville Solar).

In December 2014, a Solar Policy was approved by the JEA Board, setting forth the goal of an additional 38 MW of solar photovoltaic (PV) power via power purchase contracts by the end of 2016. JEA issued three Solar PV RFPs and received a total of 73 bids. In 2015, JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20 to 25 years to various vendors. The PPA, 5 MW on U.S. Navy owned land, awarded to Hecate Energy, LLC in 2016 was cancelled because JEA and the Navy were unable to reach an agreement on the land lease. A 4.5 MW award to SunEdison Utility Solutions, LLC was cancelled due to failure of the contractor to secure site control. The following are the seven PPAs that were finalized for a total of 27 MW in JEA's service territory of which JEA pays for the energy and has rights to the associated environmental attributes produced by the facilities:

- Northwest Jacksonville Solar Partners, LLC: 7 MW_{AC} / 25-year PPA. The NW Jax facility consists of 28,000 single-axis tracking photovoltaic panels on a vendor-leased site, owned by American Electric Power (AEP). The facility became operational on May 30, 2017.
- Old Plank Road Solar Farm, LLC: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility consists of 12,800 single-axis tracking photovoltaic panels on a vendor-leased 40-acre site, owned by Southeast Solar Farm Fund, a partnership between PEC Velo & Cox Communications. The site attained commercial operation on October 13, 2017.

- C2 Starratt Solar, LLC: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility, on a vendor-leased site, is owned by C2 Starratt Solar, LLC and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20, 2017.
- Inman Solar Holdings 2, LLC: 2 MW_{AC} /20-year PPA. The Simmons Solar facility, on a vendor-leased site, is owned by Inman Solar Holdings 2, LLC and was constructed by Inman Solar, Inc. The site attained commercial operation on January 17, 2018.
- Hecate Energy Blair Road, LLC: 4 MW_{AC} / 20-year PPA. The Blair Road facility, on a vendor-leased site, is owned by Hecate Energy Blair Road, LLC and was constructed by Hecate Energy, LLC. The site attained commercial operation on January 23, 2018.
- JAX Solar Developers, a wholly-owned subsidiary of Mirasol Fafco Solar, Inc.: 1 MW_{AC} / 20-year PPA. The Old Kings Rd Solar facility is owned by EcoPower Development, LLC and was constructed by Mirasol Fafco Solar, Inc. The site attained commercial operation on October 15, 2018.
- Imeson Solar, LLC: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The primary function of the BESS is to smooth the solar generation. It is the first utility scale solar plus storage facility interconnected to the JEA grid. The site, labeled SunPort Solar, was constructed by 174 Power Global and attained commercial operation on December 4, 2019.

In October 2017, the JEA Board approved a further solar expansion consisting of five-50 MW_{AC} solar facilities to be constructed on JEA-owned property. These projects, totaling 250 MW_{AC}, are structured as PPAs. A Request for Qualifications (RFQ) to select the vendors was issued and a vendor short list was announced November 2017. The RFP for the facilities was released to the short listed vendors on January 2, 2018. JEA received and evaluated 50 proposals that conformed to the requirements of the RFP. JEA awarded the contracts to EDF Renewables Distributed Solutions April 2018 and executed the contracts the 1st quarter of 2019. JEA will purchase the produced energy, as well as the associated environmental attributes from each facility. Beaver Street Solar Center, Cecil Commerce Solar Center, Deep Creek Solar Center, Forest Trail Solar Center, and Westlake Solar Center contractually have until the end of 2022 to be completed.

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 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, methane 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.

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 the digester heaters.

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 the 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 allowed JEA to receive environmental credits (green tags) associated with this green power project. Under the wind generation agreement, JEA purchased 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD bought back the energy at specified on and off peak charges.

JEA sold environmental credits for specified periods from this project thereby reducing but not eliminating JEA's net cost for this resource. With the expansion of JEA's renewable portfolio within the State of Florida, which includes 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 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 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 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 the Jacksonville Solar project.

In 2016, JEA pledged its support to the proposed 3-year Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) project. The program is led by Nhu Energy, Inc. and Florida Municipal Electric Association (FMEA) with partial funding from the DOE. FAASSTeR seeks to grow solar capacity in FMEA member utilities to over 10% by 2024, and provide increased value in terms of cost of service, electric infrastructure reliability, security, and resilience, and environmental and broader economic benefits. With assistance from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL), studies on cost and performance of solar and solar plus storage applications were conducted. The program recently opted for a no-cost extension to continue research efforts through June 2020. During this extension, Nhu Energy, Inc. will continue to provide technical assistance on various solar and solar plus storage applications.

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 reduced CO2 emissions.

During the spring of 2019, JEA upgraded Brandy Branch units CT2 and CT3. The upgrade involved the addition of General Electric's Advanced Gas Path (AGP) and 7FA.05 compressor modifications to the existing Brandy Branch CT2 and CT3 7FA.03 units. These upgrades improved the efficiency of the Brandy Branch units CT2 and CT3 taking it from approximately 48% to 53% on an ISO basis.

1.4.3.2 Renewable Energy Credits

JEA makes all environmental attributes from renewable facilities available to sell in order to lower rates for JEA customers. JEA has sold environmental credits for specified periods. In 2019, JEA certified approximately 20,000 Solar RECs under the Green-e certification structure and tracked and delivered approximately 46,000 landfill gas RECs through the North America Renewables (NAR) registry.

1.4.3.3 Energy Storage

JEA continues its efforts to demonstrate its commitment to energy efficiency and environmental improvement by researching energy storage applications and methods to efficiently incorporate storage technologies into the JEA system.

JEA welcomed the first utility-scale battery energy storage system to its grid with the addition of the SunPort Solar facility's 4 MWh battery. The storage system levels the solar PV output.

JEA's residential Battery Incentive Program enacted April 1, 2018 has continued to provide financial incentive towards the cost of an energy storage system, subject to lawfully appropriated funds. The Program, used in concert with the 2018 Distributed Generation Policy, is intended to assist customers in being efficient energy users. Customers who elect to collect the rebate are able to offset electricity consumption from JEA, up to the limits of their storage devices. Funds allotted to each customer under the Program is subject to review and change to optimize adoption. Since its inception, 49 residential storage systems have been installed and more than 30 applications are pending approval.

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 accounts and CBRE Jacksonville for Industrial total inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Fiscal Year 2020 baseline forecast uses 10-years of historical data. Using the shorter period 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 historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 24°F as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA 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 degrees for the 72 hours leading to winter peak and cooling degrees 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 0.38 percent for summer and 0.59 percent for winter.

2.2 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical 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, Median Household Income, Total Housing Starts from Moody's Analytics, JEA's total residential accounts 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 footage, total commercial employment, gross product and JEA's commercial electric rate.

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

The lighting energy forecast was developed using the historical actual energy, number of luminaries 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 luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries, applied with the remaining HPS to LED street light conversions with all new street light additions as LED only.

JEA's forecasted AAGR for net energy for load during the TYSP period is 0.63 percent.

Figure 1: Summer Peak Demand History & Forecast

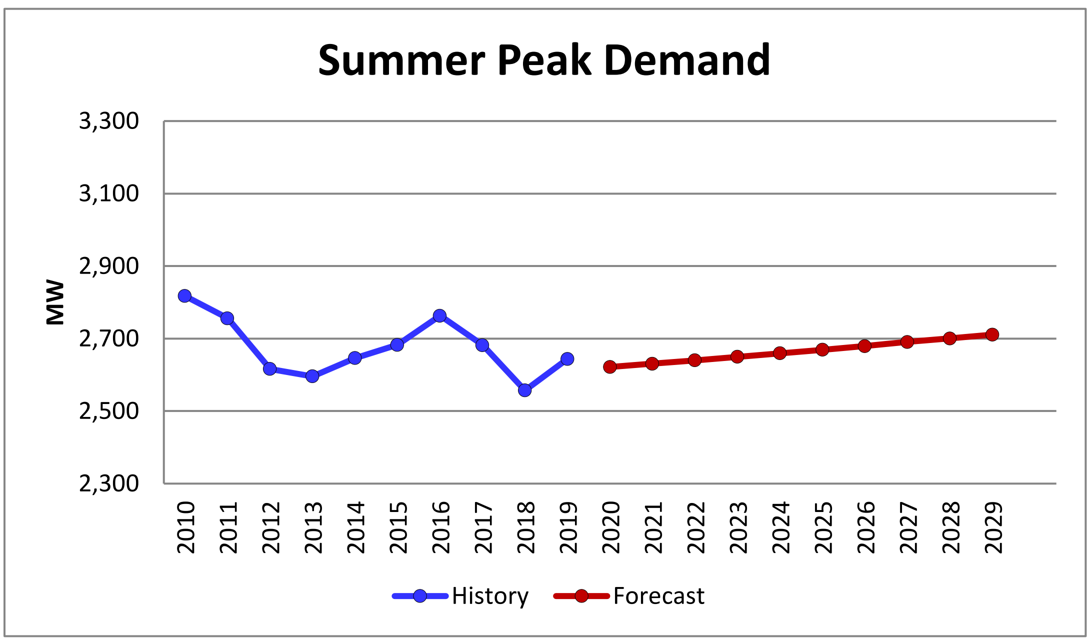


Figure 2: Winter Peak Demand History & Forecast

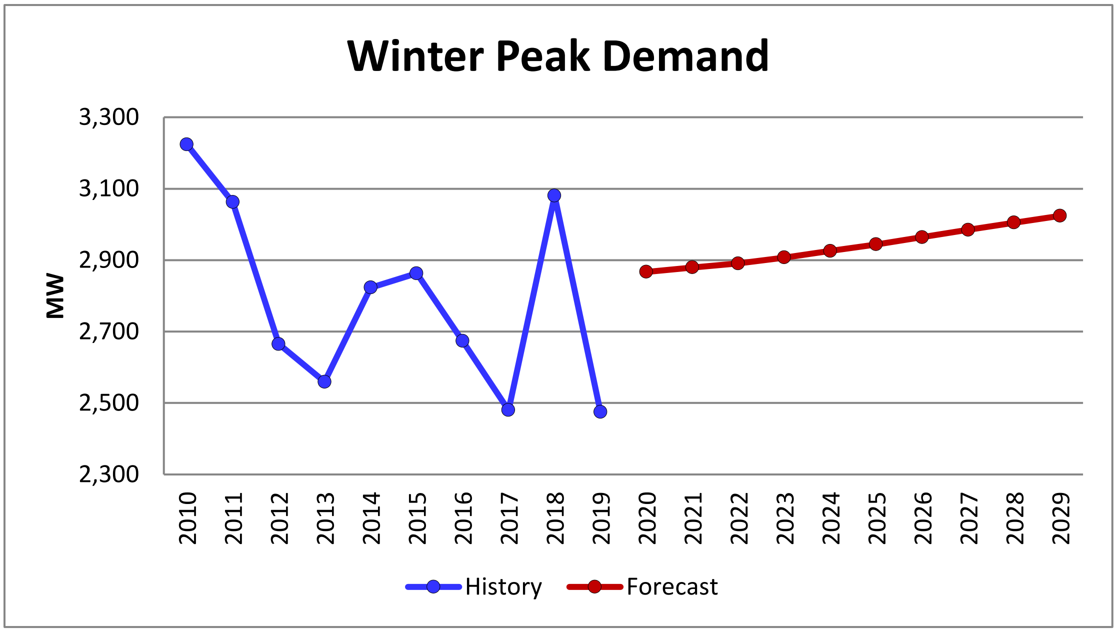
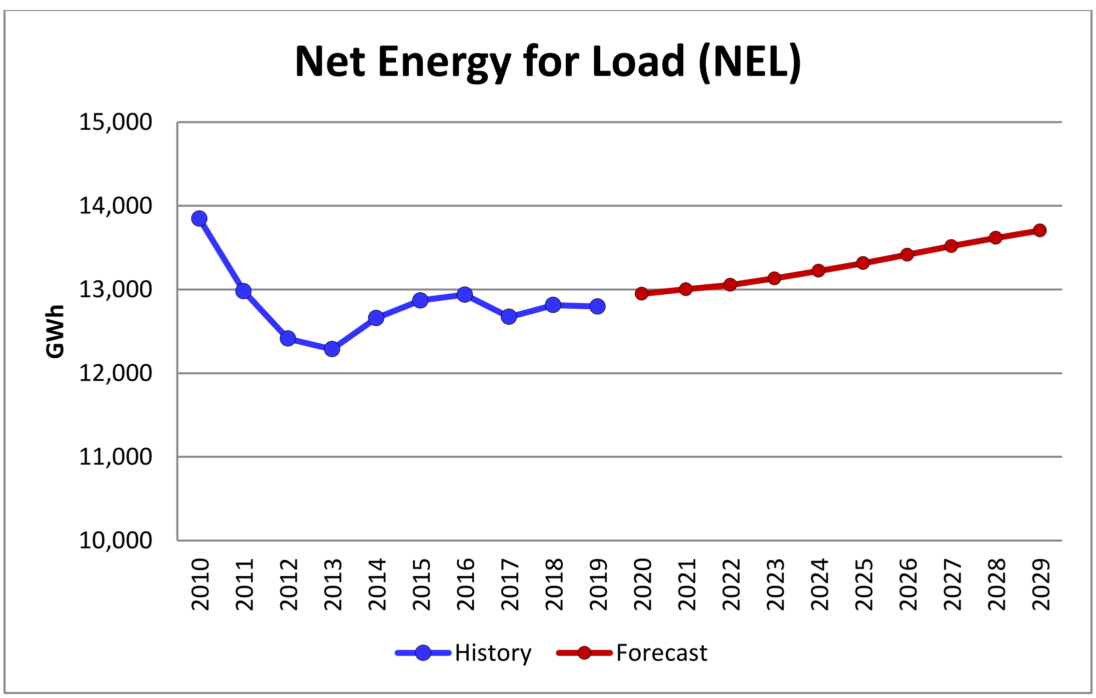


Figure 3: Net Energy for Load History & Forecast



2.3 Plug-in Electric Vehicle Peak Demand and Energy

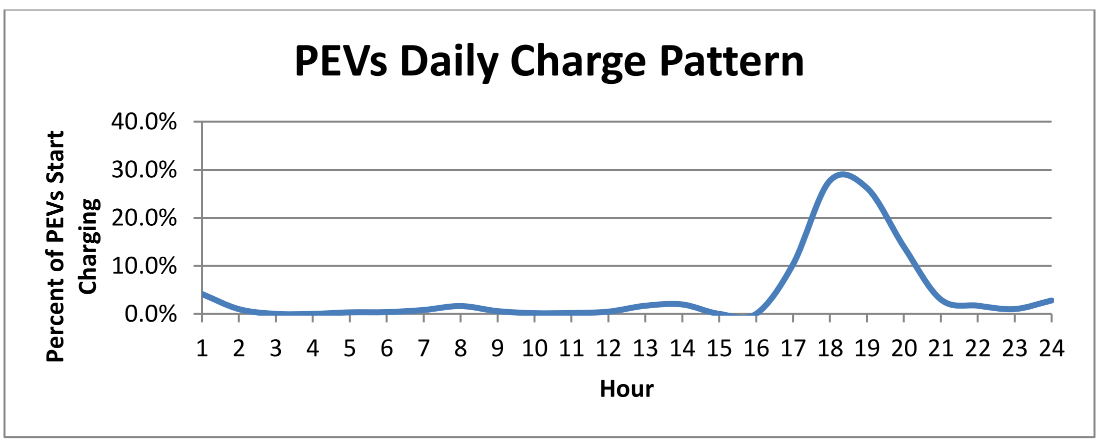
The PEVs demand and energy forecasts are developed using the historical number of PEVs in Duval County obtained from the Florida Department of Highway Safety and Motor Vehicles (DHSMV) and the historical number of vehicles in Duval County from the U.S. Census Bureau.

JEA forecasted the number 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 using multiple regression analysis of the number of vehicles and the average motor gasoline price from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO).

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 0.08 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 0.03 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 every two days and uncontrolled; charging starts immediately upon arriving 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.

JEA's forecasted AAGRs for PEV winter and summer coincidental peak demand and total energy are approximately 13 percent during the TYSP period.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Class

Year	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	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
2010	5,747	369,051	15,572	4,071	46,192	88,137	2,720	223	12,192,753
2011	5,237	369,761	14,163	3,927	46,605	84,255	2,682	215	12,469,585
2012	4,880	372,430	13,102	3,852	47,127	81,735	2,598	218	11,908,327
2013	4,852	377,326	12,860	3,777	47,691	79,204	2,589	219	11,812,928
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	5,351	398,387	13,431	4,064	51,441	78,994	2,457	202	12,159,793
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,532	202	12,510,027
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,524	196	12,853,285
2019	5,479	420,831	13,019	4,060	53,153	76,389	2,733	194	14,085,278
2020	5,576	429,768	12,975	4,029	53,993	74,626	2,712	191	14,197,111
2021	5,594	436,345	12,820	4,051	54,560	74,255	2,779	191	14,547,180
2022	5,617	443,763	12,657	4,076	55,110	73,969	2,794	191	14,626,109
2023	5,665	451,212	12,555	4,096	55,644	73,617	2,801	191	14,664,783
2024	5,719	458,504	12,473	4,116	56,167	73,274	2,815	191	14,739,844
2025	5,771	465,513	12,398	4,133	56,677	72,929	2,835	191	14,841,936
2026	5,833	472,150	12,354	4,152	57,175	72,611	2,858	191	14,963,495
2027	5,894	478,408	12,320	4,170	57,660	72,324	2,882	191	15,091,142
2028	5,943	484,196	12,274	4,190	58,134	72,067	2,908	191	15,227,151
2029	5,982	489,750	12,214	4,213	58,597	71,896	2,941	191	15,396,936

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

Year	(10) Street & Highway Lighting	(11) Other Sales to Ultimate Customers	(12) Total Sales to Ultimate Customers	(13) Sales For Resale	(14) Utility Use & Losses	(15) Net Energy For Load	(16) Other Customers	(17) Total Number of Customers
	GWH	GWH	GWH	GWH	GWH	GWH	Average Number	
2010	122	0	12,660	617	569	13,846	2	415,468
2011	123	0	11,968	589	424	12,980	2	416,583
2012	123	0	11,452	585	374	12,411	2	419,777
2013	122	0	11,340	395	550	12,286	2	425,238
2014	105	0	11,713	472	473	12,658	2	433,578
2015	87	0	11,864	392	612	12,868	2	442,249
2016	77	0	11,949	490	498	12,937	2	450,032
2017	63	0	11,805	288	578	12,672	2	456,981
2018	59	0	12,085	82	646	12,813	0	464,793
2019	57	0	12,328	58	411	12,797	0	474,178
2020	52	0	12,369	36	542	12,948	0	483,952
2021	51	0	12,475	36	491	13,002	0	491,095
2022	52	0	12,539	37	478	13,053	0	499,064
2023	53	0	12,615	37	481	13,133	0	507,047
2024	54	0	12,703	37	482	13,222	0	514,861
2025	55	0	12,794	38	481	13,313	0	522,380
2026	55	0	12,897	38	479	13,415	0	529,516
2027	56	0	13,002	39	477	13,518	0	536,260
2028	56	0	13,097	39	479	13,615	0	542,521
2029	57	0	13,192	39	473	13,704	0	548,538

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/Ind.		Residential	Comm/Ind.		Month	Day	H.E.	Temp
2010	2,817	0	0	0	0	0	0	2,817	6	22	1600	98
2011	2,756	0	0	0	0	0	0	2,756	6	18	1700	102
2012	2,616	0	0	0	0	0	0	2,616	8	11	1700	98
2013	2,596	0	0	0	0	0	0	2,596	7	25	1700	95
2014	2,646	0	0	0	0	0	0	2,646	8	14	1600	93
2015	2,683	0	0	0	0	0	0	2,683	8	22	1600	99
2016	2,763	0	0	0	0	0	0	2,763	6	17	1600	97
2017	2,682	0	0	0	0	0	0	2,682	7	7	1700	98
2018	2,557	0	0	0	0	0	0	2,557	8	16	1700	96
2019	2,644	0	0	0	0	0	0	2,644	8	14	1600	94
2020	2,623	100	0	0	0	3	2	2,518	---	---	---	----
2021	2,633	100	0	0	0	8	5	2,520	---	---	---	----
2022	2,642	100	0	0	0	11	7	2,524	---	---	---	----
2023	2,652	100	0	0	0	16	11	2,526	---	---	---	----
2024	2,662	100	0	0	0	17	11	2,534	---	---	---	----
2025	2,672	100	0	0	0	19	13	2,540	---	---	---	----
2026	2,682	100	0	0	0	22	15	2,545	---	---	---	----
2027	2,694	100	0	0	0	30	20	2,544	---	---	---	----
2028	2,704	100	0	0	0	31	21	2,552	---	---	---	----
2029	2,715	100	0	0	0	39	26	2,551	---	---	---	----

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/Ind.		Residential	Comm/Ind.		Month	Day	H.E.	Temp
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	2,480	0	0	0	0	0	0	2,480	1	9	800	30
2018	3,080	0	0	0	0	0	0	3,080	1	8	800	26
2019	2,475	0	0	0	0	0	0	2,475	1	31	800	34
2020	2,862	102	0	0	0	2	1	2,756	---	---	---	----
2021	2,875	102	0	0	0	4	3	2,766	---	---	---	----
2022	2,886	102	0	0	0	6	4	2,774	---	---	---	----
2023	2,902	102	0	0	0	9	6	2,785	---	---	---	----
2024	2,921	102	0	0	0	10	7	2,802	---	---	---	----
2025	2,939	102	0	0	0	13	9	2,815	---	---	---	----
2026	2,959	102	0	0	0	15	10	2,833	---	---	---	----
2027	2,980	102	0	0	0	16	11	2,851	---	---	---	----
2028	3,000	102	0	0	0	18	12	2,868	---	---	---	----
2029	3,019	102	0	0	0	20	14	2,883	---	---	---	----

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/Ind.		Residential	Comm/Ind.		
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	12,658	0	0	0	0	0	0	12,658	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	12,672	0	0	0	0	0	0	12,672	53%
2018	12,813	0	0	0	0	0	0	12,813	54%
2019	12,797	0	0	0	0	0	0	12,797	55%
2020	12,987	0	0	0	0	20	20	12,948	53%
2021	13,064	0	0	0	0	31	31	13,002	54%
2022	13,149	0	0	0	0	48	48	13,053	54%
2023	13,263	0	0	0	0	65	65	13,133	54%
2024	13,388	0	0	0	0	83	83	13,222	54%
2025	13,513	0	0	0	0	100	100	13,313	54%
2026	13,649	0	0	0	0	117	117	13,415	54%
2027	13,787	0	0	0	0	135	135	13,518	54%
2028	13,920	0	0	0	0	152	152	13,615	54%
2029	14,043	0	0	0	0	169	169	13,704	54%

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 2019		Forecast 2020		Forecast 2021		Forecast 2022	
	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	2,475	1,029	2,764	1,086	2,773	1,091	2,781	1,095
February	1,936	821	2,507	937	2,516	941	2,523	944
March	2,120	905	1,952	952	1,959	956	1,964	959
April	1,969	937	1,878	941	1,880	945	1,883	948
May	2,584	1,187	2,254	1,102	2,256	1,107	2,259	1,110
June	2,643	1,232	2,373	1,216	2,375	1,221	2,379	1,226
July	2,643	1,276	2,478	1,322	2,480	1,327	2,484	1,332
August	2,644	1,305	2,516	1,292	2,518	1,298	2,522	1,302
September	2,556	1,201	2,488	1,148	2,493	1,153	2,498	1,157
October	2,256	1,095	2,214	1,016	2,220	1,019	2,229	1,025
November	1,834	885	2,125	936	2,131	939	2,139	944
December	2,098	924	2,301	1,001	2,307	1,004	2,316	1,010
Annual Peak and Total Energy	2,644	12,797	2,764	12,948	2,773	13,002	2,781	13,053

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

3.1.1 Integrated Resource Planning Study

JEA initiated an Integrated Resource Planning (IRP) study the Spring of 2018. This 2019 IRP was developed to study JEA's electric system over the 2020 through 2050 period and assist JEA in determining the most cost-effective type of generation to provide firm power in the 2025 to 2030 timeframe with the potential retirement due to 316(b) compliance of JEA's Northside 3 as the primary driver for projected capacity requirements.

A scenario approach was utilized which allowed simultaneous consideration of variations to several inputs. Scenarios were developed to address uncertainties related to:

- Projected load growth (both peak demand and annual energy requirements)
- Penetration of plug-in electric vehicles and increased electrification
- Net metering, energy efficiency, energy conservation, and direct load control
- Future environmental regulations and clean energy standards
- Estimated capital costs for new generating units
- Projected natural gas prices
- Potential future solid-fuel unit retirements

A wide range of natural gas and solar photovoltaic (PV) technologies were considered as potential supply-side options for evaluation. The natural gas options represent various technologies including reciprocating engines, aeroderivatives, and combustion turbines in different simple cycle and combined cycle configurations. Solar PV technologies included utility scale PV with and without battery storage, and reflected projected continuation of decreases in equipment and construction costs.

The economic evaluations performed included an initial screening of the supply-side options as well as detailed generation expansion and production cost modeling. The initial screening, performed as a levelized cost of energy (LCOE) analysis, was utilized to evaluate the various supply-side options and screen out options that were not economic for consideration in the generation expansion planning and subsequent production cost modeling.

Regardless of the scenario or sensitivity evaluated, the expansion plan that includes retirement of Northside 3 and a new 7HA.02 1x1 combined cycle is the least cost expansion plan on a cumulative present worth cost (CPWC) basis. When comparing expansion plans including continued operation of Northside 3, retirement of Northside 3, and conversion of the Greenland Energy Center simple cycle units to combined cycle, the CPWCs of expansion plans within each scenario and sensitivity are within approximately 1 percent to 3 percent of one another. The differentials in CPWC are small for expansion plans that included replacement of Northside 3 with either a new 1x1 combined cycle or conversion of one or both of the existing Greenland Energy Center simple cycle units to combined cycle.

Because the need for additional capacity is fueled by the retirement of Northside Unit 3, JEA is preparing for a comprehensive condition assessment on Northside 3 to determine the unit's safety and reliability in the near term and determine the capital investment needed to comply with applicable regulations including and other than 316(b). Since JEA has not made a definitive decision on the future of this Unit, Northside 3 is included as a capacity resource for the term of this Ten Year Site Plan period. The 2019 IRP is in final review and will be available under a separate cover.

3.1.2 Capacity 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 in Table 4 includes the addition of the purchased power agreement with MEAG for Vogtle Units 3 and 4 in 2021 and 2022.

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
2020	2,853	15	0	0	2,869	2,514	354	0	354	14%
2021	2,853	15	0	0	2,869	2,510	358	0	358	14%
2022	2,853	115	0	0	2,969	2,508	460	0	460	18%
2023	2,853	215	0	0	3,069	2,504	565	0	565	23%
2024	2,853	215	0	0	3,069	2,506	563	0	563	22%
2025	2,853	215	0	0	3,069	2,506	562	0	562	22%
2026	2,853	215	0	0	3,069	2,504	564	0	564	23%
2027	2,853	200	0	0	3,053	2,495	558	0	558	22%
2028	2,853	200	0	0	3,053	2,497	556	0	556	22%
2029	2,853	200	0	0	3,053	2,489	564	0	564	23%

Note: Committed capacity additions include Vogtle Units 3 & 4 November 2021 & 2022, respectively.

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
2019/20	3,145	15	0	0	3,160	2,763	396	14%	396	14%
2020/21	3,145	15	0	0	3,160	2,773	387	14%	387	14%
2021/22	3,145	115	0	0	3,260	2,781	479	17%	479	17%
2022/23	3,145	215	0	0	3,360	2,792	568	20%	568	20%
2023/24	3,145	215	0	0	3,360	2,809	551	20%	551	20%
2024/25	3,145	215	0	0	3,360	2,822	538	19%	538	19%
2025/26	3,145	215	0	0	3,360	2,840	520	18%	520	18%
2026/27	3,145	215	0	0	3,360	2,858	502	18%	502	18%
2027/28	3,145	200	0	0	3,345	2,875	470	16%	470	16%
2028/29	3,145	200	0	0	3,345	2,890	455	16%	455	16%

Note: Committed capacity additions include Vogtle Units 3 & 4 November 2021 & 2022, respectively.

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 4, for those years where the reserve margin is below 15 percent. 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. Where 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.

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 5 presents the ten-year resource plan, which meets JEA's strategic goals. TYSP Schedules 5-10 provide further detail on this plan.

Table 5: Resource Plan

Year	Description
2020	TEA Purchase (25 MW Summer)
2021	MEAG Plant Vogtle 3 Purchase (100 MW) (1)
	TEA Purchase (25 MW Winter/50 MW Summer)
2022	MEAG Plant Vogtle 4 Purchase (100 MW) (1)
2023	
2024	
2025	
2026	
2027	Trail Ridge Contract Expires (-15 MW)
2028	
2029	

Notes:

(1) After accounting for transmission losses, JEA expects to receive 100 MW November 2021 and 100 MW November 2022 for a total of 200 MW of net firm capacity from the Vogtle units under construction.

(3) PEV addition of 0.80 MW Winter and 4.12 MW Summer by 2029.

(4) Cumulative DSM addition of 34 MW Winter and 65 MW Summer at time of peak by 2029.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual										
	Fuel	Type	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
(1)	NUCLEAR													
		TOTAL	TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL													
		TOTAL	1000 TON	1,654	1,767	1,953	1,654	1,672	1,618	1,997	2,003	2,149	2,087	2,205
	RESIDUAL													
(3)		STEAM	1000 BBL	2	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
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL	1000 BBL	2	0	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	0.4	3.4	6.1	5.2	3.1	7.5	2.2	4.3	4.0	4.3	4.0
(8)		CC	1000 BBL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)		CT/GT	1000 BBL	6.2	10.8	15.9	6.6	4.6	2.1	0.3	4.1	4.0	9.2	2.7
(10)		TOTAL	1000 BBL	7	14	22	12	8	10	3	8	8	14	7
	NATURAL GAS													
(12)		STEAM	1000 MCF	19,104	27,399	22,400	21,549	19,824	19,172	13,298	12,698	13,296	12,076	12,410
(13)		CC	1000 MCF	23,490	30,476	29,590	29,710	28,032	29,690	28,865	28,984	27,992	29,448	29,198
(14)		CT/GT	1000 MCF	8,416	6,601	7,164	4,666	3,381	3,418	3,144	3,514	4,826	5,364	3,633
(15)		TOTAL	1000 MCF	51,010	64,475	59,154	55,924	51,237	52,280	45,306	45,196	46,114	46,888	45,241
(16)	OTHER (SPECIFY)													
		TOTAL	TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0

Note: Coal includes JEA's share of Scherer 4 and Northside Coal and Petroleum Coke.

Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
(1)	**Firm Inter-Region Intchg.** [(a)]		GWH	**3,050**	**66**	**211**	**982**	**1,676**	**1,622**	**1,619**	**1,681**	**1,622**	**1,628**	**1,679**
(2)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL**[(b)]		GWH	**3,287**	**4,275**	**4,589**	**3,843**	**3,842**	**3,773**	**4,640**	**4,697**	**4,955**	**4,881**	**5,121**
(4)		STEAM		0.987	0	0	0	0	0	0	0	0	0	0
(5)		CC		0	0	0	0	0	0	0	0	0	0	0
(6)		CT		0	0	0	0	0	0	0	0	0	0	0
(7)	**RESIDUAL**	**TOTAL**	GWH	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(8)		STEAM		0	0	0	0	0	0	0	0	0	0	0
(9)		CC		0	0	0	0	0	0	0	0	0	0	0
(10)		CT		1.891	5	7	3	2	1	0	2	2	4	1
(11)	**DISTILLATE**	**TOTAL**	GWH	**2**	**5**	**7**	**3**	**2**	**1**	**0**	**2**	**2**	**4**	**1**
(12)		STEAM		1,881	2,771	2,262	2,131	1,934	1,866	1,286	1,214	1,269	1,146	1,166
(13)		CC		3,610	4,956	4,809	4,814	4,528	4,810	4,651	4,674	4,519	4,763	4,716
(14)		CT		822	664	721	469	341	343	313	347	483	527	358
(15)	**NATURAL GAS**	**TOTAL**	GWH	**6,312**	**8,391**	**7,792**	**7,413**	**6,803**	**7,018**	**6,250**	**6,234**	**6,270**	**6,436**	**6,240**
(16)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(17)	**RENEWABLES**	**HYDRO**		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(18)		**LANDFILL GAS**		87.56	130.30	130.00	130.00	130.00	130.30	130.00	130.00	0.00	0.00	0.00
(19)		**SOLAR**		58.36	81.70	273.10	682.20	679.60	678.50	673.80	671.00	668.60	667.30	662.90
(20)		**TOTAL**		**146**	**212**	**403**	**812**	**810**	**809**	**804**	**801**	**669**	**667**	**663**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**[(c)]		GWH	**12,798**	**12,948**	**13,002**	**13,053**	**13,133**	**13,222**	**13,313**	**13,415**	**13,518**	**13,615**	**13,704**

Note:

[(a)] Firm Inter-Regional Interchange includes Seasonal and Annual PPAs starting 2018 and Nuclear PPA from MEAG starting 2021.
[(b)] Coal includes JEA's share of Scherer 4, and Northside Coal and Petroleum Coke.
[(c)] 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)
	Fuel	**Type**	**Units**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
(1)	**Firm Inter-Region Intchg.** [(a)]		%	**23.8**	**0.5**	**1.6**	**7.5**	**12.8**	**12.3**	**12.2**	**12.5**	**12.0**	**12.0**	**12.3**
(2)	**NUCLEAR**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(3)	**COAL** [(b)]		%	**25.7**	**33.0**	**35.3**	**29.4**	**29.3**	**28.5**	**34.9**	**35.0**	**36.7**	**35.8**	**37.4**
(4)	**RESIDUAL**	STEAM		0.01	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
(6)		CT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		**TOTAL**	%	**0.0**	**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
(9)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CT		0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		**TOTAL**	%	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(12)	**NATURAL GAS**	STEAM		14.7	21.4	17.4	16.3	14.7	14.1	9.7	9.0	9.4	8.4	8.5
(13)		CC		28.2	38.3	37.0	36.9	34.5	36.4	34.9	34.8	33.4	35.0	34.4
(14)		CT		6.4	5.1	5.5	3.6	2.6	2.6	2.3	2.6	3.6	3.9	2.6
(15)		**TOTAL**	%	**49.3**	**64.8**	**59.9**	**56.8**	**51.8**	**53.1**	**46.9**	**46.5**	**46.4**	**47.3**	**45.5**
(16)	**NUG**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(17)	**RENEWABLES**	**HYDRO**		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**		0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0
(19)		**SOLAR**		0.5	0.6	2.1	5.2	5.2	5.1	5.1	5.0	4.9	4.9	4.8
(20)		**TOTAL**	%	**1.1**	**1.6**	**3.1**	**6.2**	**6.2**	**6.1**	**6.0**	**6.0**	**4.9**	**4.9**	**4.8**
(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**
(23)	**NET ENERGY FOR LOAD** [(c)]		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Note:

[(a)] Nuclear PPA with MEAG beginning 2021 is included in Firm Inter-Regional Interchange.

[(b)] Coal includes JEA's share of Scherer 4, and Northside Coal and Petroleum Coke.

[(c)] 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
2020	2,853	40	0	0	2,894	2,516	378	0	0	378	15%
2021	2,853	40	0	0	2,894	2,512	382	0	0	382	15%
2022	2,853	115	0	0	2,969	2,510	459	0	0	459	18%
2023	2,853	215	0	0	3,069	2,505	563	0	0	563	22%
2024	2,853	215	0	0	3,069	2,507	561	0	0	561	22%
2025	2,853	215	0	0	3,069	2,507	561	0	0	561	22%
2026	2,853	215	0	0	3,069	2,506	563	0	0	563	22%
2027	2,853	200	0	0	3,053	2,497	557	0	0	557	22%
2028	2,853	200	0	0	3,053	2,499	555	0	0	555	22%
2029	2,853	200	0	0	3,053	2,491	563	0	0	563	23%

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
2020	3,145	40	0	0	3,185	2,764	421	0	0	421	15%
2021	3,145	65	0	0	3,210	2,773	437	0	0	437	16%
2022	3,145	115	0	0	3,260	2,781	479	0	0	479	17%
2023	3,145	215	0	0	3,360	2,792	568	0	0	568	20%
2024	3,145	215	0	0	3,360	2,809	550	0	0	550	20%
2025	3,145	215	0	0	3,360	2,823	537	0	0	537	19%
2026	3,145	215	0	0	3,360	2,840	520	0	0	520	18%
2027	3,145	215	0	0	3,360	2,859	501	0	0	501	18%
2028	3,145	200	0	0	3,345	2,875	469	0	0	469	16%
2029	3,145	200	0	0	3,345	2,891	454	0	0	454	16%

Schedule 8: Planned and Prospective Generating Facility Additions and Changes

Planned and Prospective Generating Facility and Purchased Power 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	
NONE TO REPORT														

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

(2020 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 and diesel fuel.

The fuel price projections used in this forecast were developed based on long-term price forecasts from the Annual Energy Outlook 2020 (AEO2020) issued by the U.S. Energy Information Administration (EIA). The AEO2020 presents projections of energy supply, demand, and prices through 2050. AEO2020 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, cost and performance characteristics of energy technologies, and demographics.

Scherer 4 burns Powder River Basin (PRB) coal. Projections of the commodity price for PRB coal are based on existing coal contracts through 2022 and then escalated using AEO2020 projections for Wyoming PRB coal. The transportation component of the delivered price projection was derived from existing contracts and escalated by an inflation rate of 1.9% thereafter. The inflation rate of 1.9% originates from the AEO2020.

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 price projections are based on 1/29/20 settle prices of short-term NYMEX API2 Argus-McCloskey coal futures and then escalated using AEO2020 projections for Interior coal. Freight rates for waterborne delivery of Colombian coal were based on the historical average over the last five years and escalated using the AEO2020 inflation rate to project transportation costs beyond 2020. A ratio of historical delivered petroleum coke and coal prices over the past year was applied to the delivered Northside coal price projections to derive the projected petroleum coke price.

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 was based on the 1/29/20 settle prices of short-term NYMEX natural gas strip and then escalated using AEO2020 Henry Hub price forecast. The transportation costs are a combination of historical Florida city gate market costs on Florida Gas Transmission and local distribution fees.

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, GEC GT1 and GT2, and Brandy Branch GT1. Projections for the price of diesel fuel are based on 1/29/20 settle prices of short-term NYMEX ultra-low sulfur diesel futures pricing and then escalated using AEO2020 projections for ultra-low sulfur diesel.

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 2021 and 2022. 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 1.9 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.