Building Community®

TEN-YEAR SITE PLAN

April 2022

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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, 2022 to December 31, 2031. 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.

JEA consists of one financial entity: the JEA Electric System. The total projected net capability of JEA's generation system is 2,952 MW for winter and 2,799 MW for summer. The Robert W. Scherer bulk power system agreement ended on January 1st, 2022. 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 Florida Power & Light (FPL) purchased an undivided interest of this unit from Georgia Power Company in 1991. JEA has a 23.6 percent (200 net MW) and FPL has a 76.4 percent ownership interest in Unit 4.

In addition to the purchase of undivided ownership interests in Scherer Unit 4, 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 the Scherer Unit 4 Purchase Agreement. 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.

On June 26, 2020, the Board adopted Resolution 2020-06, which delegated authority to the Interim Managing Director and Chief Executive Officer to enter into a Cooperation Agreement with FPL ("FPL Cooperation Agreement") for the closure of Plant Scherer Unit 4 on or before January 1, 2022 with the capacity and energy to be replaced by a 20-year power purchase agreement (PPA) between JEA and FPL for a natural gas-fired system product with a solar conversion option. The FPL Cooperation Agreement was executed on August 25, 2020 and calls for the parties to cooperate in good faith in a joint effort to consummate the retirement of Plant Scherer Unit 4 and enter into the FPL PPA. On November 24, 2020, JEA executed a retirement agreement with FPL, setting forth the terms and conditions of the Plant Scherer Unit 4 closure as of January 1, 2022.

JEA and FPL closed Plant Scherer Unit 4 on January 1, 2022.

1.1.2 Power Purchases

1.1.2.1 Trail Ridge Landfill

In 2006, JEA entered into a 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 on December 6, 2008.

JEA and TRE executed an amendment to this PPA 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 in February 2015. These landfill gas projects generated 85,218 MWh during calendar year 2021.

1.1.2.2 Jacksonville Solar

In May 2009, JEA entered into a PPA 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 on September 30, 2010. The facility generated 16,125 MWh during calendar year 2021 and was recently acquired by Rev Renewables, LLC, an LS Power company.

1.1.2.3 Solar Power Purchase 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 (RFP) in 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 in 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 (RFQ) to select the vendors was issued and a vendor short list was announced in 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 in the first quarter of 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 were originally planned to be completed by the end of 2022, however, due to the impacts caused by the COVID-19 pandemic, construction of the facilities has been delayed and the final completion date is undetermined.

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 carbon-neutral sources 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. In 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 projected commercial operation dates for 100 net MW of capacity from Vogtle Unit 3 is Q1 2023, and an additional 100 net MW from Vogtle Unit 4 is Q4 2023. However, for planning purposes, to ensure JEA plans for sufficient supply resources and capacity, JEA assumes Vogtle Unit 3 and Unit 4 commercial operation dates to be Q3 2023 and Q3 2024, respectively.

1.1.2.5 Florida Power & Light Power Purchase Agreement

On August 25, 2020, JEA and FPL executed a Cooperation Agreement for the retirement of Plant Scherer Unit 4 with the capacity and energy to be replaced by a 20-year 200 MW PPA between JEA and FPL for a natural gas-fired system product beginning January 1, 2022, with a solar conversion option on or after the 10th anniversary from the PPA start date.

1.1.2.6 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 Power Purchase 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(1)**	Q3 2023	Q3 2043	100	Annual
	Unit 4(1)	Q3 2024	Q3 2044	100	Annual
FPL PPA		01/01/22	01/01/42	200	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

(1) After accounting for transmission losses, JEA expects to receive 100 MW from Vogtle Unit 3 and 100 MW from Vogtle Unit 4. Start dates reflected are for JEA's planning purposes, not the current projected start dates for Vogtle Unit 3 and Unit 4.

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	357	382		
	7	12-031	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	179	191	Utility	
	8	12-031	GT	NG	DFO	PL	WA	06/2009	(a)	203,800	179	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	774	831		
	1	12-031	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	179	191	Utility	
	2	12-031	CT	NG		PL	TK	05/2001	(a)	203,800	190	212	Utility	
	3	12-031	CT	NG		PL	TK	10/2001	(a)	203,800	190	212	Utility	
	4	12-031	CA	WH				01/2005	(a)	268,400	216	216	Utility	
Greenland Energy Center										407,600	357	382		
	1	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	203,800	179	191	Utility	
	2	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	203,800	179	191	Utility	
JEA System Total											**2,799**	**2,952**		(c)

Notes:

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

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

(c) Numbers may not add due to rounding.

Schedule 1.1: Retired 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		
Scherer														
	4	13-207	ST	BIT		RR		02/1989	01/2022	990,000	198	198	Joint	(a)
JEA System Total											**198**	**198**		

Notes:

(a) Net capability reflects JEA's 23.64% ownership in Scherer 4. Scherer 4 retired January 1, 2022.

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 (located in the westerly portion 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 has a 138 kV tie with Beaches Energy Services at JEA's Neptune substation. 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 the FRCC region became the FL-Peninsula sub-region of SERC in July 2019, JEA has been 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 existing transmission service contract is set to expire in the future during this Ten-Year Site Plan period:

- FPL purchased Cedar Bay plant and retired the generation in 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 90 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 7,200 miles of distribution circuits of which more than half is underground.

1.3 Demand-Side Management (DSM)

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 110 MW of interruptible peak load for the summer and 100 MW for the winter which remain constant throughout the study period. For 2022, the interruptible load represents 3.5 percent of the forecasted total peak demand in the winter and 4.1 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.

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. 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		2021	2022	2023	2024	2026	2026	2027	2028	2029	2030
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 Prescriptive Program	Residential Energy Efficiency Products
Commercial Custom Program	Residential Solar Water Heating
Small Business Direct Install Program	Neighborhood Energy Efficiency Program
Commercial Solar Net Metering	Residential Energy Upgrades
Commercial Prescriptive Lighting	Residential Solar Net Metering
Electrification Rebates Program	

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 PPAs, 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 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 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 (DG) Policy.
- 2017: In October, the JEA Board approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1, the comprehensive 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 PPA 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 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 now owned by EDPR DR (acquired 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 RFQ to select the vendors was issued and a vendor short list was announced in 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 in April 2018 and executed the contracts in 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 originally planned to be completed by the end of 2022, however, due to the impacts caused by the COVID-19 pandemic, construction of the facilities has been delayed and the final completion date is undetermined.

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 was 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 the remaining Girvin landfill generation facilities were 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 PPA with 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 PPA (Phase Two) to purchase 9 additional MW from a gas-to-energy facility. LES 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 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 and 2.

In 2011, JEA co-fired biomass in 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.

In 2021, JEA began co-firing up to 10% of biomass (approximately up to 240 Tons per Day) in Northside Unit 2 due to the high price of petcoke. In early 2022, JEA submitted a request for permit modification with the Florida Department of Environment Protection (FDEP) to burn more biomass in Northside Units 1 and 2. If approved, the modification will allow biomass firing up to 1000 tons per day.

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 and 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 Department of Energy (DOE) Solar Energy Technologies Program, Systems Integration 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 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, resilience, and environmental and broader economic benefits. With assistance from the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory, studies on cost and performance of solar and solar plus storage applications were conducted. The program recently concluded after a no-cost extension, where Nhu Energy, Inc. provided technical assistance on various solar and solar plus storage applications, including proper storage sizing for solar ramp rate mitigation. The study results will aid JEA in making informed decisions regarding its generation strategy.

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 GEC 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 them from approximately 48% to 53% on an ISO basis.

1.4.3.2 Renewable Energy Credits (REC)

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 2021, JEA certified approximately 17,000 Solar RECs under the Green-e certification structure and tracked approximately 80,000 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 is undertaking an Integrated Resource Plan (IRP), scoped to include supply-side and demand-side strategies and recommendations on existing resources and future resource additions/replacements, including battery energy storage and other storage technologies. For more information on JEA's IRP, see Section 3.1.1.

JEA's residential Battery Incentive Program enacted on 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 DG 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, over 370 residential storage systems have been installed.

1.4.3.4 Potential Hydrokinetic Project for the St. John's River

JEA is working with several parties regarding a potential Hydrokinetic Project for the St. John's River at The City's St. John's Marina. Hydrokinetic Energy Corp is working on a low velocity hydro turbine prototype (in Key West) and is looking to possibly partner with The City and JEA with the St. John's Marina project. Hydrokinetic is working with other parties to possibly make this a DOE project. The current proposal contains four 9kW turbines at the marina. The output of the turbines is variable depending on flow velocity of the river.

2. Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peak demands, net energy for load (NEL), interruptible customer demand, 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, University of Florida's Bureau of Economic and Business Research (BEBR), JEA's Data Warehouse to determine the total number of Residential accounts and CBRE Jacksonville for Commercial total inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Calendar Year 2022 baseline forecast uses 10 years of historical data. Using the shorter period allows JEA to capture the more recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections.

2.1 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, median household income, disposable income, total housing starts from Moody's Analytics, total population from BEBR, 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, total commercial employment, commercial inventory square footage, and gross domestic product from Moody's Analytics.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy, total industrial employment, gross domestic product from Moody's Analytics and JEA's Industrial accounts.

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) streetlight conversion schedule. The LEDs are estimated to use 45% less energy than the HPS streetlights. 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 streetlight conversions with all new streetlight additions as LED only.

JEA's forecasted AAGR for net energy for load during the TYSP period is 0.75 percent.

2.2 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 25°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 normalized historical and forecasted residential, commercial, and industrial energy for winter/summer peak months, and the average load factor based on historical peaks and net energy for winter/summer peak months. JEA's forecasted Average Annual Growth Rate (AAGR) for total peak demand during the TYSP period is 0.73 percent for summer and 0.66 percent for winter.

2.3 Plug-in Electric Vehicles 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 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, disposable income from Moody's Analytics, the average motor gasoline price from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO), and JEA's electric rates.

The usable battery capacity (85% of battery capacity) per vehicle was determined based on the current plug-in vehicle models in Duval County, such as Audi, BMW, General Motors' Chevrolet and Cadillac, Honda, Karma, Ford, Mercedes, Mitsubishi, Nissan, Porsche, Tesla, Toyota, Volkswagen 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 the historical 5-year average annual growth rate of 0.01 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 0.01 kW per year.

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

JEA forecasts AAGRs for PEVs winter and summer coincidental peak demand of 24 percent and 28 percent, respectively, and total energy of 24 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)
	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
2012	4,880	372,430	13,102	3,852	47,127	81,735	2,809	218	12,875,696
2013	4,852	377,326	12,860	3,777	47,691	79,204	2,804	219	12,795,722
2014	5,162	383,998	13,443	3,882	49,364	78,642	2,785	215	12,984,365
2015	5,197	391,219	13,285	4,001	50,821	78,733	2,806	207	13,531,924
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,692	202	13,322,934
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,777	202	13,717,349
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,765	196	14,081,384
2019	5,479	420,831	13,019	4,060	53,153	76,389	2,733	194	14,085,278
2020	5,679	429,575	13,220	3,886	53,701	72,363	2,698	196	13,759,522
2021	5,551	438,470	12,660	3,848	54,374	70,767	2,612	196	13,348,772
2022	5,648	446,885	12,640	3,968	71,974	55,132	2,661	197	13,507,944
2023	5,743	455,085	12,620	3,978	71,183	55,885	2,664	199	13,388,581
2024	5,822	462,483	12,589	3,987	70,400	56,635	2,673	200	13,363,515
2025	5,892	469,456	12,551	3,996	69,633	57,384	2,681	200	13,404,069
2026	5,952	475,784	12,510	4,004	68,879	58,130	2,690	200	13,450,239
2027	6,003	481,526	12,467	4,012	68,137	58,875	2,698	200	13,489,867
2028	6,050	486,785	12,429	4,019	67,420	59,617	2,706	200	13,527,995
2029	6,095	491,661	12,397	4,028	66,729	60,357	2,716	201	13,512,583
2030	6,138	496,231	12,369	4,036	66,055	61,095	2,724	201	13,550,251
2031	6,180	500,573	12,345	4,044	65,402	61,831	2,731	201	13,587,754

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)	
2012	123	0	11,663	423	325	12,411	2	419,777
2013	122	0	11,556	395	335	12,286	2	425,238
2014	105	0	11,934	472	252	12,658	2	433,578
2015	87	0	12,091	392	385	12,868	2	442,249
2016	77	0	12,184	490	263	12,937	2	450,033
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,793
2019	57	0	12,328	58	411	12,797	0	474,178
2020	56	0	12,319	7	414	12,740	0	483,471
2021	55	0	12,066	25	449	12,540	0	493,039
2022	55	0	12,333	23	481	12,837	0	519,056
2023	56	0	12,442	36	496	12,974	0	526,467
2024	57	0	12,539	36	514	13,090	0	533,083
2025	58	0	12,627	37	534	13,197	0	539,290
2026	59	0	12,705	37	555	13,297	0	544,863
2027	59	0	12,772	37	577	13,386	0	549,863
2028	60	0	12,835	38	601	13,473	0	554,405
2029	61	0	12,899	38	625	13,563	0	558,591
2030	61	0	12,958	38	651	13,647	0	562,487
2031	62	0	13,016	38	679	13,734	0	566,176

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
2012	2,556	0	0	0	0	0	0	2,556	7	25	1700	86
2013	2,524	0	0	0	0	0	0	2,524	8	14	1600	91
2014	2,591	0	0	0	0	0	0	2,591	8	22	1600	98
2015	2,618	0	0	0	0	0	0	2,618	6	17	1600	95
2016	2,689	0	0	0	0	0	0	2,689	7	7	1700	98
2017	2,631	0	0	0	0	0	0	2,631	8	16	1700	95
2018	2,495	0	0	0	0	0	0	2,495	8	8	1500	90
2019	2,591	0	0	0	0	0	0	2,591	8	14	1600	94
2020	2,582	0	0	0	0	0	0	2,582	6	29	1800	93
2021	2,511	0	0	0	0	0	0	2,511	7	22	1700	83
2022	2,705	110	0	0	0	5	3	2,587	---	---	---	----
2023	2,732	110	0	0	0	9	6	2,606	---	---	---	----
2024	2,757	110	0	0	0	14	10	2,624	---	---	---	----
2025	2,781	110	0	0	0	19	13	2,639	---	---	---	----
2026	2,801	110	0	0	0	24	16	2,652	---	---	---	----
2027	2,820	110	0	0	0	28	19	2,663	---	---	---	----
2028	2,839	110	0	0	0	33	22	2,674	---	---	---	----
2029	2,852	110	0	0	0	37	25	2,682	---	---	---	----
2030	2,870	110	0	0	0	42	28	2,693	---	---	---	----
2031	2,890	110	0	0	0	46	31	2,706	---	---	---	----

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
2012	2,587	0	0	0	0	0	0	2,587	1	4	800	24
2013	2,529	0	0	0	0	0	0	2,529	2	18	800	29
2014	2,754	0	0	0	0	0	0	2,754	1	7	800	22
2015	2,791	0	0	0	0	0	0	2,791	2	20	800	26
2016	2,600	0	0	0	0	0	0	2,600	1	20	800	30
2017	2,635	0	0	0	0	0	0	2,635	1	9	800	32
2018	3,007	0	0	0	0	0	0	3,007	1	8	800	26
2019	2,410	0	0	0	0	0	0	2,410	1	31	800	34
2020	2,445	0	0	0	0	0	0	2,445	1	22	800	33
2021	2,532	0	0	0	0	0	0	2,532	2	4	800	30
2022	2,834	100	0	0	0	4	2	2,728	---	---	---	----
2023	2,861	100	0	0	0	7	5	2,748	---	---	---	----
2024	2,884	100	0	0	0	11	7	2,766	---	---	---	----
2025	2,905	100	0	0	0	15	10	2,781	---	---	---	----
2026	2,925	100	0	0	0	19	12	2,795	---	---	---	----
2027	2,943	100	0	0	0	22	14	2,806	---	---	---	----
2028	2,959	100	0	0	0	26	17	2,816	---	---	---	----
2029	2,975	100	0	0	0	30	19	2,827	---	---	---	----
2030	2,991	100	0	0	0	33	22	2,836	---	---	---	----
2031	3,006	100	0	0	0	37	24	2,845	---	---	---	----

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.		
2012	12,411	0	0	0	0	0	0	12,411	55%
2013	12,286	0	0	0	0	0	0	12,286	55%
2014	12,658	0	0	0	0	0	0	12,658	52%
2015	12,868	0	0	0	0	0	0	12,868	53%
2016	12,937	0	0	0	0	0	0	12,937	57%
2017	12,672	0	0	0	0	0	0	12,672	55%
2018	12,813	0	0	0	0	0	0	12,813	49%
2019	12,797	0	0	0	0	0	0	12,797	61%
2020	12,740	0	0	0	0	0	0	12,740	59%
2021	12,540	0	0	0	0	0	0	12,540	57%
2022	12,871	0	0	0	0	17	17	12,837	54%
2023	13,043	0	0	0	0	34	35	12,974	54%
2024	13,194	0	0	0	0	52	52	13,090	54%
2025	13,335	0	0	0	0	69	70	13,197	54%
2026	13,470	0	0	0	0	86	87	13,297	54%
2027	13,594	0	0	0	0	103	104	13,386	54%
2028	13,716	0	0	0	0	120	122	13,473	55%
2029	13,839	0	0	0	0	138	139	13,563	55%
2030	13,959	0	0	0	0	155	157	13,647	55%
2031	14,080	0	0	0	0	172	174	13,734	55%

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

(1)	(2)	(3)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual	**2021**	**Forecast**	**2022**	**Forecast**	**2023**	**Forecast**	**2024**
Month	Firm Peak Demand (MW)	Net Energy For load (GWH)	Firm Peak Demand (MW)	Net Energy For load (GWH)	Firm Peak Demand (MW)	Net Energy For load (GWH)	Firm Peak Demand (MW)	Net Energy For load (GWH)
January	2,362	1,008	2,728	1,081	2,748	1,095	2,766	1,105
February	2,532	879	2,405	934	2,428	946	2,449	955
March	2,003	942	1,949	940	1,968	942	1,985	953
April	2,052	904	2,073	929	2,095	936	2,115	946
May	2,372	1,071	2,339	1,079	2,363	1,089	2,386	1,101
June	2,432	1,152	2,547	1,211	2,573	1,222	2,598	1,235
July	2,511	1,260	2,552	1,316	2,579	1,331	2,604	1,341
August	2,498	1,300	2,587	1,294	2,606	1,307	2,624	1,318
September	2,305	1,151	2,452	1,138	2,477	1,151	2,501	1,159
October	2,136	1,048	2,165	1,006	2,186	1,016	2,205	1,027
November	1,859	901	1,947	919	1,966	932	1,983	940
December	1,803	925	2,312	990	2,335	1,006	2,355	1,011
Annual Peak/Total Energy	2,532	12,540	2,728	12,837	2,748	12,974	2,766	13,090

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

3.1.1 Integrated Resource Planning (IRP) Study

JEA's new IRP is underway, with an expected completion in early calendar year 2023. This IRP continues to use a multi-scenario approach to better accommodate different potential futures. The primary variables and considerations that define these different potential futures include the following:

- Environmental Legislative and Regulatory Action
    - Cost for emissions of CO_2
    - Specific goals or targets for % of energy from non-emitting sources
    - Specific CO_2 emissions limitations
    - Mandated retirement of solid fuel and/or natural gas fired generation
    - Conventional pollutant regulations
    - 316(b) Regulations
- Load Growth Forecasts
    - Energy
    - Peak Demand
    - Demand-Side Management and Energy Efficiency
    - Plug-In Electric Vehicles
    - Electrification
    - Customer Sited Generation
- Fuel Costs
- Cost of New Generation
- Continued Potential to Operate Existing Generating Units
- Other Considerations
    - Affordability
    - Reliability
    - Environmental Justice
    - Economic Development
    - CO_2 Emissions Reductions

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 reflects the addition of the PPA with MEAG for Vogtle Units 3 and 4 in 2023 and 2024, respectively, and the planned retirement of Scherer Unit 4 and replacement with a 200 MW PPA with FPL on January 1, 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
2022	2,799	215	0	0	3,014	2,587	427	17%	427	17%
2023	2,799	215	0	0	3,014	2,606	408	16%	408	16%
2024	2,799	315	0	0	3,114	2,624	491	19%	491	19%
2025	2,799	415	0	0	3,214	2,639	575	22%	575	22%
2026	2,799	415	0	0	3,214	2,652	562	21%	562	21%
2027	2,799	400	0	0	3,199	2,663	536	20%	536	20%
2028	2,799	400	0	0	3,199	2,674	525	20%	525	20%
2029	2,799	400	0	0	3,199	2,682	517	19%	517	19%
2030	2,799	400	0	0	3,199	2,693	506	19%	506	19%
2031	2,799	400	0	0	3,199	2,706	493	18%	493	18%

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
2021/22	2,952	215	0	0	3,167	2,728	440	16%	440	16%
2022/23	2,952	215	0	0	3,167	2,748	419	15%	419	15%
2023/24	2,952	315	0	0	3,267	2,766	501	18%	501	18%
2024/25	2,952	415	0	0	3,367	2,781	587	21%	587	21%
2025/26	2,952	415	0	0	3,367	2,795	573	20%	573	20%
2026/27	2,952	400	0	0	3,352	2,806	546	19%	546	19%
2027/28	2,952	400	0	0	3,352	2,816	536	19%	536	19%
2028/29	2,952	400	0	0	3,352	2,827	526	19%	526	19%
2029/30	2,952	400	0	0	3,352	2,836	516	18%	516	18%
2030/31	2,952	400	0	0	3,352	2,845	507	18%	507	18%

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 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 of 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	Resource Plan
2022	Scherer 4 Retires (-198 MW)(1) FPL Purchase (200 MW)(2)
2023	MEAG Plant Vogtle 3 Purchase (100 MW)(3)
2024	MEAG Plant Vogtle 4 Purchase (100 MW)(3)
2025	
2026	Trail Ridge Contract Expires (-15 MW)(4)
2027	
2028	
2029	
2030	
2031	

Notes:

(1) Scherer Unit 4 retires January 1, 2022

(2) 30-year power purchase agreement (PPA) with FPL starting on January 1, 2022

(3) After accounting for transmission losses, JEA expects to receive 100 MW from Vogtle Unit 3 and 100 MW from Vogtle Unit 4. The start dates reflected are for JEA's planning purposes, not the current projected start dates for Vogtle Unit 3 and Unit 4

(4) Trail Ridge contract ends December 31, 2026

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual											
	Fuel	**Type**	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
(1)	**NUCLEAR**														
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**														
		TOTAL	**1000 TON**	**1,405**	**1,486**	**615**	**652**	**547**	**434**	**542**	**734**	**643**	**717**	**796**	**927**
	RESIDUAL														
(3)		STEAM	1000 BBL	2	18	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**	**2**	**18**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	DISTILLATE														
(7)		STEAM	1000 BBL	0.5	0.6	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	10	14	77	45	43	31	56	48	59	40	45	64
(10)		**TOTAL**	**1000 BBL**	**10**	**15**	**77**	**45**	**43**	**31**	**56**	**48**	**59**	**40**	**45**	**64**
	NATURAL GAS														
(12)		STEAM	1000 MCF	23,396	18,288	22,294	28,509	24,460	24,262	22,243	25,418	23,827	22,725	22,040	19,755
(13)		CC	1000 MCF	32,398	31,314	29,517	30,049	31,256	30,673	30,544	26,828	30,360	31,189	30,494	28,873
(14)		CT/GT	1000 MCF	9,317	11,442	9,920	9,913	10,276	9,214	10,113	9,511	8,380	7,668	8,495	9,772
(15)		**TOTAL**	**1000 MCF**	**65,111**	**61,045**	**61,731**	**68,471**	**65,992**	**64,150**	**62,900**	**61,757**	**62,566**	**61,582**	**61,029**	**58,400**
(17)	**OTHER (SPECIFY)**														
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Note: Coal includes 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 2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
(1)	**Firm Inter-Region Intchg.[a]**		GWH	**1,943**	**2,843**	**2,183**	**2,813**	**3,470**	**3,389**	**3,394**	**3,451**	**3,396**	**3,355**	**3,437**
(2)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL[b]**		GWH	**2,742**	**1,729**	**1,803**	**1,505**	**1,198**	**1,499**	**2,032**	**1,784**	**1,988**	**2,208**	**2,570**
(4)	**RESIDUAL**	STEAM	GWH	10	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)		**TOTAL**		**10**	**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
(9)		CC		0	0	0	0	0	0	0	0	0	0	0
(10)		CT		6	33	19	18	13	24	21	25	17	19	28
(11)		**TOTAL**		**6**	**33**	**19**	**18**	**13**	**24**	**21**	**25**	**17**	**19**	**28**
(12)	**NATURAL GAS**	STEAM	GWH	1,740	2,256	2,889	2,460	2,424	2,228	2,567	2,387	2,275	2,209	1,985
(13)		CC		4,819	4,770	4,866	5,056	4,960	4,935	4,335	4,907	5,037	4,925	4,656
(14)		CT		1,114	991	999	1,024	919	1,008	954	836	766	849	975
(15)		**TOTAL**		**7,673**	**8,017**	**8,755**	**8,540**	**8,303**	**8,171**	**7,855**	**8,130**	**8,079**	**7,983**	**7,617**
(16)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(17)	**RENEWABLES**	**HYDRO**		0	0	0	0	0	0	0	0	0	0	0
(18)		**LANDFILL GAS**		85	129	129	129	129	129	0	0	0	0	0
(19)		**SOLAR**		81	86	85	85	84	84	83	83	83	82	82
(20)		**TOTAL**		**166**	**215**	**214**	**214**	**213**	**213**	**83**	**83**	**83**	**82**	**82**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD[c]**		GWH	**12,540**	**12,837**	**12,974**	**13,090**	**13,197**	**13,296**	**13,386**	**13,473**	**13,562**	**13,647**	**13,733**

Note:

[a] Nuclear PPA with MEAG starting in 2023 is included in Firm Inter-Regional Interchange
[b] Coal includes 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**	**Actual 2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
(1)	**Firm Inter-Region Intchg.[a]**		%	**15.5**	**22.1**	**16.8**	**21.5**	**26.3**	**25.5**	**25.4**	**25.6**	**25.0**	**24.6**	**25.0**
(2)	**NUCLEAR**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(3)	**COAL[b]**		%	**21.9**	**13.5**	**13.9**	**11.5**	**9.1**	**11.3**	**15.2**	**13.2**	**14.7**	**16.2**	**18.7**
(4)	**RESIDUAL**	STEAM	%	0.08	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**		**0.1**	**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
(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	0.3	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.2
(11)		**TOTAL**		**0.0**	**0.3**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.2**
(12)	**NATURAL GAS**	STEAM	%	13.9	17.6	22.3	18.8	18.4	16.8	19.2	17.7	16.8	16.2	14.5
(13)		CC		38.4	37.2	37.5	38.6	37.6	37.1	32.4	36.4	37.1	36.1	33.9
(14)		CT		8.9	7.7	7.7	7.8	7.0	7.6	7.1	6.2	5.7	6.2	7.1
(15)		**TOTAL**		**61.2**	**62.5**	**67.5**	**65.2**	**62.9**	**61.5**	**58.7**	**60.3**	**59.6**	**58.5**	**55.5**
(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**		0.680	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0
(19)		**SOLAR**		0.643	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(20)		**TOTAL**		**1.3**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
(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 starting in 2023 is included in Firm Inter-Regional Interchange

(b) Coal includes 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
2022	2,799	215	0	0	3,014	2,587	427	17%	0	427	17%
2023	2,799	215	0	0	3,014	2,606	408	16%	0	408	16%
2024	2,799	315	0	0	3,114	2,624	491	19%	0	491	19%
2025	2,799	415	0	0	3,214	2,639	575	22%	0	575	22%
2026	2,799	415	0	0	3,214	2,652	562	21%	0	562	21%
2027	2,799	400	0	0	3,199	2,663	536	20%	0	536	20%
2028	2,799	400	0	0	3,199	2,674	525	20%	0	525	20%
2029	2,799	400	0	0	3,199	2,682	517	19%	0	517	19%
2030	2,799	400	0	0	3,199	2,693	506	19%	0	506	19%
2031	2,799	400	0	0	3,199	2,706	493	18%	0	493	18%

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
2022	2,952	215	0	0	3,167	2,728	440	16%	0	440	16%
2023	2,952	215	0	0	3,167	2,748	419	15%	0	419	15%
2024	2,952	315	0	0	3,267	2,766	501	18%	0	501	18%
2025	2,952	415	0	0	3,367	2,781	587	21%	0	587	21%
2026	2,952	415	0	0	3,367	2,795	573	20%	0	573	20%
2027	2,952	400	0	0	3,352	2,806	546	19%	0	546	19%
2028	2,952	400	0	0	3,352	2,816	536	19%	0	536	19%
2029	2,952	400	0	0	3,352	2,827	526	19%	0	526	19%
2030	2,952	400	0	0	3,352	2,836	516	18%	0	516	18%
2031	2,952	400	0	0	3,352	2,845	507	18%	0	507	18%

Schedule 8: Planned and Prospective Generating Facility Additions and Changes

<table>
<tr><th colspan="15">Planned and Prospective Generating Facility and Purchased Power Additions and Changes</th></tr>
<tr><td>(1)</td><td>(2)</td><td>(3)</td><td>(4)</td><td>(5)</td><td>(6)</td><td>(7)</td><td>(8)</td><td>(9)</td><td>(10)</td><td>(11)</td><td>(12)</td><td>(13)</td><td>(14)</td><td>(15)</td></tr>
<tr><td rowspan="3">Plant Name</td><td rowspan="3">Unit No.</td><td rowspan="3">Location</td><td rowspan="3">Unit Type</td><td colspan="2">Fuel Type</td><td colspan="2">Fuel Transport</td><td rowspan="3">Construction Start Date</td><td rowspan="3">Commercial/ In-Service or Change Date</td><td rowspan="3">Expected Retirement/ Shutdown Date</td><td rowspan="2">Gen Max Nameplate</td><td colspan="2">Net Capability</td><td rowspan="3">Status</td></tr>
<tr><td rowspan="2">Primary</td><td rowspan="2">Alternate</td><td rowspan="2">Primary</td><td rowspan="2">Alternate</td><td>Summer</td><td>Winter</td></tr>
<tr><td>kW</td><td>MW</td><td>MW</td></tr>
<tr><td colspan="15">NONE TO REPORT</td></tr>
</table>

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

(2021 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

The fuel price projections used in this forecast were developed based on long-term price forecasts from the Annual Energy Outlook 2021 (AEO2021) issued by the EIA. The Annual Energy Outlook 2022 was not released in time to be used. The AEO2021 presents projections of energy supply, demand, and prices through 2050. AEO2021 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 retired at the end of calendar year 2021 and was replaced by a PPA with FPL that provides 200 MW of natural gas combined cycle power. The natural gas price projection was based on the 2/2/22 settle prices of short-term NYMEX natural gas strip and then escalated using the AEO2021 Henry Hub price forecast. The transportation costs are based on the PPA contract terms and the total cost is escalated by an inflation rate of 3 percent thereafter.

Northside Units 1 and 2 currently burn a blend of petroleum coke, coal, biomass, and natural gas. These units are projected to burn 57 percent petroleum coke, 29 percent coal, 5 percent biomass, and 10 percent natural gas by MMBtu during the forecast period. The Northside coal price projections are based on 2/2/22 settle prices of short-term NYMEX API2 Argus-McCloskey coal futures and then escalated using AEO2021 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 a 3 percent inflation rate to project transportation costs beyond 2021. 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 2/2/22 settle prices of short-term NYMEX natural gas strip and then escalated using the AEO2021 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 (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 2/2/22 settle prices of short-term NYMEX ultra-low sulfur diesel futures pricing and then escalated using AEO2021 projections for ultra-low sulfur diesel.

JEA has a PPA with MEAG for 200 MW from Vogtle Units 3 and 4 currently under construction in Georgia with in-service dates expected in 2023 and 2024. 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 non-fuel 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 FCR.

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 FCR is 8.265 percent and the 25-year FCR 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.