JEA®

Building Community®

TEN-YEAR SITE PLAN

April 2026

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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.

This Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. The 2026 TYSP provides information related to JEA's power supply strategy to adequately meet the forecasted needs of its customers for the planning period from January 1st, 2026 through December 31st, 2035. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

1. Description of Existing Facilities and Resources

1.1 Power Supply System Description

1.1.1 JEA Electric System

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 510,000 customers.

1.1.1.1 Existing Generation 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 multifuel-fired (coal/petroleum coke/natural gas/biomass) 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); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2, and Brandy Branch GT1); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle system that comprises two gas-fired combustion turbine-generator units and one combined cycle heat recovery steam generator unit (Brandy Branch CT2 and CT3, and Brandy Branch steam Unit 4). Details of the existing facilities are displayed in Schedule 1.

Schedule 1: Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	FYI	(12)	(13)	(14)	(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate (b)	Gen Max Turbine	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Year	Mo/Year	kW	kW	Summer	Winter		
Kennedy										427,800	346,400	357	382		
	7	Jacksonville, FL	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	173,200	179	191	Utility	OP
	8	Jacksonville, FL	GT	NG	DFO	PL	WA	06/2009	(a)	224,000	173,200	179	191	Utility	OP
Northside										1,601,856	1,407,100	1,310	1,356		
	1	Jacksonville, FL	ST	PC	BIT	WA		05/2003	(a)	350,000	297,500	293	293	Utility	OP
	2	Jacksonville, FL	ST	PC	BIT	WA		04/2003	(a)	350,000	297,500	293	293	Utility	OP
	3	Jacksonville, FL	ST	NG	RFO	PL	WA	07/1977	01/2035	626,300	563,700	524	524	Utility	OP
	33-36	Jacksonville, FL	GT	DFO		TK		01/1975	(a)	275,556	248,400	200	246	Utility	OP
Brandy Branch										946,200	745,100	758	831		
	1	Jacksonville, FL	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	173,200	179	191	Utility	OP
	2	Jacksonville, FL	CT	NG		PL		05/2001	(a)	237,000	173,200	190	212	Utility	OP
	3	Jacksonville, FL	CT	NG		PL		10/2001	(a)	237,000	173,200	190	212	Utility	OP
	4	Jacksonville, FL	CA	WH				01/2005	(a)	268,400	225,500	200	216	Utility	OP
Greenland Energy Center										448,000	346,400	357	382		
	1	Jacksonville, FL	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	OP
	2	Jacksonville, FL	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	OP
JEA System Total												**2,782**	**2,952**		

Notes:

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

(b) Numbers may not add to JEA System Total add due to rounding.

1.1.2 Power Purchases

1.1.2.1 FPL Natural Gas Power Purchase Agreement

On August 25, 2020, JEA and Florida Power & Light (FPL) executed a Cooperation Agreement for the retirement of Plant Scherer Unit 4 with the firm capacity and energy to be replaced by a 20-year 200 MW power purchase agreement (PPA) between JEA and FPL for a natural gas-fired system product beginning January 1st, 2022, with a solar conversion option on or after the 10th anniversary from the PPA start date. An increase of up to 100 MW in capacity and transmission service for the Cooperation Agreement was approved by the JEA Board to help meet JEA's growing demand. The agreement is in final negotiations for an 80 MW increase in capacity, starting June 1, 2026.

1.1.3 Clean Energy Power Purchases

1.1.3.1 Trail Ridge Landfill Power Purchase Agreement

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 6th, 2008.

JEA and TRE executed an amendment to this PPA on March 9th, 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. The contract for Trail Ridge Phase One and Phase Two will expire in December 2026.

1.1.3.2 Jacksonville Solar Power Purchase Agreement

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. The Jacksonville Solar plant began commercial operation at full designed capacity on September 30th, 2010. The facility was acquired by Rev Renewables, LLC, an LS Power company, on June 15th, 2021. The contract for Jax Solar will expire in September 2040.

1.1.3.3 Small Utility-Scale Solar Power Purchase Agreements

JEA issued two Solar Photovoltaic (PV) Request for Proposals (RFP), one in December 2014 and another in April 2015, and awarded a total of 31.5 MW_{AC} 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_{AC}. The last of these seven projects was completed in December 2019.

The following are the seven PPAs that are installed within 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 OnSite Partners, LLC (formerly American Electric Power OnSite Partners). The facility became operational on May 30th, 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 13th, 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 20th, 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 17th, 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 23rd, 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 15th, 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 4th, 2019.

1.1.3.4 FPL Solar Power Purchase Agreements

On January 24th, 2023, JEA entered into a five-year agreement with The Energy Authority (TEA) to purchase 150 MW_{AC} of electric energy and capacity resources and renewable attributes (solar) from Florida Power & Light. The contract will expire in April 2028.

1.1.3.5 Planned Solar Power Purchase Agreements

JEA sought bids for the development of approximately 300 MW_{AC} of solar or solar plus energy storage system on JEA-owned parcels. The solicitation, released on January 31st, 2023 and facilitated through TEA, sourced full attribute solar, or solar plus storage resource solutions formatted in multiple blocks, not to exceed 74.9 MW_{AC} each. Fifteen companies responded to the solicitation, providing an array of options. Responses were evaluated in a two-phase process, narrowing those fifteen respondents down to a shortlist of five, before award. On November 7th, 2023, JEA Board of Directors approved the award of four facilities, totaling 280 MW_{AC} of solar and energy storage systems, to Florida Renewable Partners (FRP). Contracts for four facilities were originally in negotiations, and due to costly wetland impacts at the proposed Peterson Solar Energy Center, the scope was narrowed to the following: Forest Trail Solar Energy Center, 50 MW_{AC}; Caldwell Solar Energy Center, 74.9 MW_{AC}, and Miller Solar Energy Center, 74.9 MW_{AC}, with the Caldwell and Miller Solar Energy Centers each paired with a 50 MW, 4-hour battery energy storage system. As the projects phased through development, the evolving macroeconomic climate for renewables resulted in the termination of the Caldwell Solar Energy Center and battery energy storage system as of November 13, 2025. The project scope has now been optimized to a total of two renewable energy facilities: Miller Solar Energy Center, 74.9 MW_{AC}, paired with 50 MW, 4-hour battery energy storage system, and Forest Trail Solar Center, 50 MW_{AC}. JEA and FRP have executed power purchase agreements, lease option contracts, and energy storage agreements for the projects. Both facilities are expected to be commissioned by December 31st, 2026.

JEA entered into a 20-year solar agreement with the Florida Municipal Power Agency (FMPA) to purchase approximately 150 MW_{AC} from two facilities located in Florida. The projects were scheduled to commission in December 2026, but were delayed to October 2028, due to longer network upgrade timelines and other nationwide challenges with solar project development. Resultantly, in June 2025, the FMPA Board of Directors approved the termination of the solar agreement and JEA was released of its obligations.

Many factors have negatively impacted the economics of new solar development, including the elimination of subsidies on utility-scale solar projects. In addition, several planned solar projects in which JEA intended to participate were cancelled; transmission/interconnection equipment supply chain issues persist and continue to impact project costs and schedule; and finding appropriately sized, environmentally suitable land to support utility-scale solar in Duval County is prohibitively expensive such that extensive transmission upgrades would be necessary to import solar power to JEA's system. JEA will continue to evaluate cost-effective solar as part of its resource planning process.

1.1.3.6 MEAG Nuclear Power Purchase Agreement

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 located at the existing Plant Vogtle in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity.

Vogtle Units 3 and 4 were commissioned on July 31st, 2023 and April 29th, 2024, respectively. Each unit is supplying approximately 103 MW of net firm capacity to JEA.

In February 2026, the JEA Board approved sale of up to 206 MW of Vogtle capacity and energy to Dalton Utilities and Santee Cooper from 2027 – 2032. To support the sale commitments, JEA will be purchasing 150 MW of firm capacity, energy, and transmission, with an option for an additional 50 MW to serve native load. This agreement, noted as the “TEA Backfill Purchase” in Table 5 (see Section 3.2 herein), is in final negotiations.

1.1.4 Cogeneration

Cogeneration facilities help meet the energy needs of JEA’s system on an as-available, non-firm basis. Since these facilities are considered energy only resources, they are not forecasted to contribute towards 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 1a: JEA Existing Power Purchase Agreement 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**	07/31/2023	07/31/2043	103	Annual
	Unit 4	04/29/2024	04/29/2044	103	Annual
FPL PPA		01/01/22	01/01/42	200	Annual
FPL Solar PPA		04/01/23	04/01/28	150	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
Forest Trail Solar PPA		12/31/26	12/31/61	50	Annual
Miller Solar PPA		12/31/26	12/31/61	74.9	Annual

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.

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 94 percent of JEA's distribution load, including 57 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 smaller loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,607 miles of distribution circuits of which approximately 59.2 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

On April 25th, 2023, JEA's Board of Directors approved clean energy goals. JEA has incorporated a significant amount of clean energy into its power supply portfolio, including numerous solar power purchase agreements, and continues to explore opportunities to incorporate additional clean energy while ensuring alignment with system reliability, affordability, and adaptability. Given regulatory changes and other factors affecting practicality and affordability, as well as unprecedented load growth, JEA continues to evaluate the current cost and practical ability to meet the aspirational clean energy goals and will utilize information from its next Integrated Resource Plan to inform leadership decisions moving forward. As such, JEA is not incorporating assumptions relative to its aspirational clean energy goals in this Ten-Year Site Plan.

1.3.2 Renewable Energy

1.3.2.1 JEA Distributed Energy

JEA has Solar PV systems installed at various customer sites in the community such as the Chamber of Commerce, Jacksonville University, a fire station and multiple Duval County public school locations that are approximately 100kW in total. However, all of these systems are at end of life and next step options are being evaluated.

In 2009 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 of Directors approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1st, 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 allowed existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years. When JEA enacted the DG Policy on April 1st, 2018, JEA rolled out a residential Battery Incentive Program pilot. The pilot, subject to lawfully appropriated funds, provided financial incentive towards the cost of an energy storage system. Used in concert with the 2018 DG Policy, the pilot was intended to assist customers in being efficient energy users. Customers who elected to collect the rebate were able to offset electricity consumption from JEA up to the limits of their storage devices. Funds allotted to each customer under the pilot were subject to review and change to optimize adoption. Between the inception of the pilot and July 2022 when the pilot ended, over 700 residential storage systems have been installed.

1.3.2.2 Renewable Energy Credits (REC)

JEA has acquired environmental attributes through its series of renewable PPAs and made those available to sell in order to lower rates for JEA customers. JEA had sold these environmental credits for specified periods. To maximize our clean energy efforts, a portion of those attributes have been inventoried. In 2025, JEA certified over 150,000 Solar RECs under the Green-e® Energy certification structure and tracked over 300,000 landfill gas RECs through the North America Renewables (NAR) registry.

1.3.2.3 SolarSmart and SolarMax

Since 2017, JEA has offered residential and small/mid-sized commercial customers the opportunity to contribute towards funding solar adoption by purchasing renewable energy through its SolarSmart program. Participants pay a premium on their electric bill for solar energy. Customers can select any percentage (1% to 100%) of their energy to come from solar resources. The renewable energy is produced by six small utility-scale solar facilities inside JEA's service territory that were installed between 2017 and 2019. JEA removes RECs from inventory on behalf of the SolarSmart customers.

In addition, SolarMax was a rate offering for JEA's largest commercial and industrial customers with a minimum consumption of 7 million kWh. The rate was designed around JEA solar farms which are not yet operational and are currently being fulfilled via solar PPAs and associated RECs. The rate allowed large business customers to choose to have up to 100 percent of their energy needs met by solar power, with the SolarMax rate replacing their fuel charge. JEA then retires the RECs commensurate with their consumption in NAR. Companies selected either a five or ten-year contract term. The program is currently closed to new customers as JEA fulfills the contractual obligations of the current customers, while continuing to explore other innovative programs to offer.

1.3.2.4 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.

1.3.2.4 Biomass

In 2008, to obtain cost-effective biomass generation, JEA completed a detailed feasibility study of building stand-alone biomass units. However, the JEA self-build project would not have been eligible for the federal tax credits afforded to developers, so JEA proceeded with completing a feasibility study of co-firing biomass in Northside units 1 and 2. The co-firing of biomass in Northside 1 and 2 was found to be more cost-effective, but there were concerns with potential operational reliability issues caused by the biomass. Therefore, JEA conducted an analytical evaluation of the specific biomass fuel types to be used, and the percent of biomass co-firing that would be applied, in order to ensure reliable operation of these units could be maintained while co-firing biomass.

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. They 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 continued use.

In 2021, JEA began co-firing up to 10 percent biomass (approximately up to 240 tons per day) in Northside Unit 2 due to the high price of petroleum coke. In early 2022, JEA submitted a request and was granted an air construction permit with the Florida Department of Environment Protection (FDEP), to burn up to 1,000 tons per day of biomass in Northside units 1 and 2. JEA continues to co-fire biomass when available and economically beneficial.

1.3.3 Clean Energy Research Efforts

1.3.3.1 Collaboration with University of North Florida

JEA's clean energy research efforts have focused on the development of clean energy 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.
- JEA, Miller Electric, and UNF have joined forces under the DOE-backed "Emerge" initiative to train the next generation of energy professionals. Through hands-on training, industry certifications, and expert mentorship, EMERGE equips participants with cutting-edge skills in renewable energy and microgrid technologies. This program is shaping the “Technician of the Future,” preparing a workforce capable of building and maintaining resilient, sustainable energy systems to meet the demands of an evolving grid.
- On November 28th, 2023, JEA and UNF commemorated the grand opening of the JEA Sustainable Solutions Lab, a collaboration with UNF’s College of Computing, Engineering and Construction, that allows undergraduate and graduate students to research clean energy technologies. JEA has committed to contributing $100,000 per year, for five years, for a total contribution of $500,000. The lab will serve as a hub for research to develop sustainable solutions for JEA and a variety of industries.

1.3.3.2 Energy Storage

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

JEA welcomed the first utility-scale BESS to its grid with the addition of the SunPort Solar facility's 4 MWh battery; the storage system levels the solar PV output. The Florida Renewable Partner projects will also host 50 MW of BESS alongside the 75 MW_{AC} Miller solar facility. JEA will continue to evaluate the integration of additional storage resources as future studies are conducted.

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

JEA's Calendar Year 2026 baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the most 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 sales, total population, number of households, median household income and 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 sales, total commercial employment and gross domestic product from Moody's Analytics, JEA's total commercial accounts, and commercial inventory square footage from the CBRE Jacksonville Office Figures Q3 2025 Report.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy sales, gross domestic product, total industrial employment, and total proprietors' profits from Moody's Analytics, and JEA's total industrial accounts. The first 7 years of the forecast also incorporate confirmed new development projects and their expected demand, as well as increase consumption from existing industrial customers due to expansion.

The lighting energy forecast was developed using the historical actual energy and number of luminaries. 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.

JEA's forecasted Compounding Annual Growth Rate (CAGR) for net energy for load during the TYSP period is 1.43 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 CAGR for net firm peak demand during the TYSP period is 1.32 percent for summer and 1.36 percent for winter.

2.3 Demand-Side Management (DSM)

2.3.1 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 120 MW of interruptible peak load for the summer and 107 MW for the winter which remain constant throughout the study period. For 2026, the interruptible load represents 3.7 percent of the forecasted total peak demand in the summer and 3.4 percent of the forecasted total peak demand in the winter.

2.3.2 Demand-Side Management Programs

JEA continues to offer DSM programs as included in JEA's 2025 Demand-Side Management Plan (approved by the Florida Public Service Commission in April 2025) that contribute to meeting JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals, as well as additional programs that are economically beneficial. JEA's programs focus on improving the efficiency of customer end use equipment, as well as, improving the system load factor through behavioral education and technology incentives.

JEA's forecast of annual incremental demand and energy reductions associated with its current DSM programs is shown in Table 2. JEA's current and planned DSM programs are summarized by commercial/industrial and residential programs in Table 3.

Table 2: DSM Portfolio – Energy Efficiency Programs

ANNUAL INCREMENTAL		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy (GWh)	Residential	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04
	Commercial/ Industrial	11.36	11.36	11.36	11.36	11.36	11.36	11.36	11.36	11.36	11.36
	Total	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**
Summer Peak (MW)	Residential	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
	Commercial/ Industrial	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08
	Total	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**
Winter Peak (MW)	Residential	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28
	Commercial/ Industrial	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
	Total	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**

Table 3: DSM Programs

Commercial/Industrial Programs	Residential Programs
Commercial/Industrial Energy Assessment Program	Residential Energy Assessment Program
Commercial/Industrial Prescriptive & Prescriptive Lighting Program	Residential Home Efficiency Upgrades Program
Commercial/Industrial Custom Program	Residential Energy Efficient Products Program
Small Business Program	Residential Neighborhood Energy Efficiency (NEE) Program

2.4 Customer-Sited Renewables

A customer-sited renewables analysis on rooftop solar PV and battery storage installation was conducted by Resource Innovations group for JEA.

The customer-sited solar PV analysis accounted for available roof space (including pitched versus flat roofs, other roof equipment, etc.), PV power density, hourly generation shapes, and AC/DC ratios, among other factors. These technical potential calculations were supplemented by forecasting market adoption of solar PV systems. A rigorous hourly economic analysis calculated the point at which it is cost-effective for customers to install a system as a function of $/kW and other costs using the extensive sensitivity analysis capabilities of the modeling software.

The battery storage analysis focused primarily on potential for paired solar and energy storage systems. The modeling software accounted for the complex economics of a storage technology, which can shift load to reduce energy charges (e.g., through on/off peak period arbitration) or reduce peak demand charges, by utilizing an hourly battery storage dispatch optimization module. This analysis simulates the hourly dispatch of solar-paired storage systems, accounting for electric rate structure, system characteristics, customer load profile, and solar PV generation profile.

The potential peak demand and energy reductions associated with the customer-sited renewable analysis are reflected in JEA's 2026 TYSP forecast. JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds the different sources of additional demand, to derive a firm load forecast.

2.5 Plug-in Electric Vehicles Peak Demand and Energy

The forecasts of demand and energy associated with PEVs 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 percent of battery capacity) per vehicle was determined based on the current plug-in electric vehicle models in Duval County. 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 of 0.001 kWh. Similarly, the peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecasted 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 Average Annual Growth Rate (AAGR) for PEVs summer and winter coincidental peak demand of 41.18 percent and 35.39 percent, respectively, and total energy of 34.86 percent during the TYSP period.

2.6 Electrification

JEA's electrification load forecast has been updated to reflect the most current approved program goals and actual performance for the Electrification Rebate Program (ERP) and Fleet Electrification Program (FEP). The forecast aligns with updated annual targets through fiscal year 2027 for FEP and fiscal year 2028 for ERP, with the final year levels extended through the remainder of the planning horizon.

ERP goals were developed using a balanced approach informed by both the ICF (2019) and EPRI (2025) market potential studies, reflecting updated assessments of convertible load and evolving market conditions. Recent program performance has met or exceeded established goals, and the revised forecast incorporates these realized results.

The ERP contract was renewed in 2026, supporting continued program implementation through fiscal year 2028. Beyond the current contract term, the forecast assumes continued program activity at levels generally consistent with recent performance. However, consistent with market potential analyses, electrification opportunities are expected to diminish around 2030 as market saturation increases, potentially resulting in a gradual moderation of incremental load growth in the outer years of the planning period.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Rural and Residential			Commercial			Industrial		
Calendar 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
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	5,723	447,308	12,795	4,005	55,082	72,717	2,708	199	13,641,119
2023	5,658	458,764	12,334	3,968	55,946	70,922	2,614	199	13,151,607
2024	6,022	470,564	12,797	4,104	56,724	72,359	2,691	203	13,254,576
2025	6,081	479,288	12,641	4,194	57,376	73,096	2,648	198	13,389,674
2026	6,075	485,840	12,504	4,022	58,168	69,136	2,754	211	13,054,071
2027	6,174	492,159	12,546	4,027	58,935	68,335	3,033	215	14,107,857
2028	6,262	498,274	12,568	4,035	59,713	67,577	3,285	219	15,001,436
2029	6,351	504,171	12,597	4,046	60,504	66,865	3,357	222	15,120,763
2030	6,441	509,869	12,633	4,057	61,311	66,176	3,427	224	15,297,656
2031	6,531	515,323	12,674	4,070	62,134	65,498	3,475	227	15,307,034
2032	6,620	520,487	12,719	4,082	62,969	64,829	3,526	230	15,329,031
2033	6,707	525,330	12,766	4,097	63,813	64,196	3,544	233	15,209,228
2034	6,794	529,885	12,822	4,109	64,666	63,548	3,567	236	15,114,511
2035	6,892	534,234	12,901	4,122	65,527	62,901	3,600	240	14,999,094

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

Calendar 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)	
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	12,491	30	408	12,930	0	502,588
2023	55	0	12,295	63	376	12,733	0	514,909
2024	56	0	12,873	60	321	13,255	0	527,491
2025	57	0	12,980	69	431	13,479	0	536,862
2026	57	0	12,908	0	479	13,386	0	544,219
2027	58	0	13,293	0	493	13,785	0	551,309
2028	58	0	13,641	0	506	14,147	0	558,206
2029	59	0	13,812	0	512	14,324	0	564,897
2030	59	0	13,984	0	518	14,503	0	571,404
2031	59	0	14,135	0	524	14,659	0	577,684
2032	60	0	14,288	0	530	14,817	0	583,686
2033	60	0	14,407	0	534	14,941	0	589,376
2034	61	0	14,531	0	539	15,070	0	594,787
2035	61	0	14,675	0	544	15,219	0	600,001

Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Net Demand (MW)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand (MW)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2016	2,689	0	0	0	0	0	0	2,689
2017	2,631	0	0	0	0	0	0	2,631
2018	2,495	0	0	0	0	0	0	2,495
2019	2,591	0	0	0	0	0	0	2,591
2020	2,582	0	0	0	0	0	0	2,582
2021	2,511	0	0	0	0	0	0	2,511
2022	2,728	0	0	0	0	0	0	2,728
2023	2,753	0	0	0	0	0	0	2,753
2024	2,675	0	0	0	0	0	0	2,675
2025	2,849	0	0	0	0	0	0	2,849
2026	2,896	120	0	0	0	2	2	2,772
2027	2,978	120	0	0	0	4	4	2,850
2028	3,066	124	0	0	0	6	6	2,930
2029	3,100	124	0	0	0	8	7	2,961
2030	3,140	124	0	0	0	10	9	2,997
2031	3,170	124	0	0	0	12	11	3,023
2032	3,201	124	0	0	0	13	12	3,052
2033	3,227	124	0	0	0	17	16	3,070
2034	3,251	124	0	0	0	18	17	3,092
2035	3,282	124	0	0	0	20	19	3,119

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)
Calendar Year	Total Net Demand (MW)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand (MW)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2015/16	2,600	0	0	0	0	0	0	2,600
2016/17	2,433	0	0	0	0	0	0	2,433
2017/18	3,011	0	0	0	0	0	0	3,011
2018/19	2,410	0	0	0	0	0	0	2,410
2019/20	2,445	0	0	0	0	0	0	2,445
2020/21	2,532	0	0	0	0	0	0	2,532
2021/22	2,599	0	0	0	0	0	0	2,599
2022/23	2,326	0	0	0	0	0	0	2,326
2023/24	2,416	0	0	0	0	0	0	2,416
2024/25	2,913	0	0	0	0	0	0	2,913
2025/26	3,012	107	0	0	0	3	1	2,901
2026/27	3,103	107	0	0	0	6	2	2,988
2027/28	3,200	111	0	0	0	9	3	3,077
2028/29	3,238	111	0	0	0	10	3	3,114
2029/30	3,279	111	0	0	0	16	5	3,147
2030/31	3,309	111	0	0	0	14	4	3,180
2031/32	3,346	111	0	0	0	19	6	3,210
2032/33	3,370	111	0	0	0	25	8	3,226
2033/34	3,393	111	0	0	0	23	7	3,252
2034/35	3,420	111	0	0	0	26	8	3,275

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)
Calendar Year	Total Energy for Load (GWH)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy for Load (GWH)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2016	12,937	0	0	0	0	0	0	12,937
2017	12,672	0	0	0	0	0	0	12,672
2018	12,813	0	0	0	0	0	0	12,813
2019	12,797	0	0	0	0	0	0	12,797
2020	12,740	0	0	0	0	0	0	12,740
2021	12,540	0	0	0	0	0	0	12,540
2022	12,930	0	0	0	0	0	0	12,930
2023	12,733	0	0	0	0	0	0	12,733
2024	13,255	0	0	0	0	0	0	13,255
2025	13,479	0	0	0	0	0	0	13,479
2026	13,409	0	0	0	0	12	11	13,386
2027	13,831	0	0	0	0	24	22	13,785
2028	14,216	0	0	0	0	36	33	14,147
2029	14,416	0	0	0	0	48	44	14,324
2030	14,618	0	0	0	0	60	55	14,503
2031	14,797	0	0	0	0	72	66	14,659
2032	14,978	0	0	0	0	84	77	14,817
2033	15,125	0	0	0	0	96	88	14,941
2034	15,277	0	0	0	0	108	99	15,070
2035	15,449	0	0	0	0	120	110	15,219

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	**Actual 2025**		**Forecast 2026**		**Forecast 2027**		**Forecast 2028**	
	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	2,913	1,254	2,901	1,077	2,988	1,110	3,077	1,144
February	2,336	881	2,439	935	2,515	964	2,595	994
March	1,826	923	2,291	979	2,362	1,009	2,438	1,041
April	2,171	1,029	2,217	966	2,281	996	2,350	1,027
May	2,601	1,226	2,551	1,123	2,624	1,157	2,703	1,192
June	2,597	1,284	2,723	1,257	2,799	1,292	2,877	1,331
July	2,849	1,407	2,767	1,359	2,844	1,397	2,924	1,438
August	2,767	1,351	2,772	1,342	2,850	1,379	2,930	1,420
September	2,406	1,174	2,646	1,205	2,722	1,240	2,804	1,277
October	1,998	1,022	2,507	1,098	2,584	1,133	2,667	1,147
November	2,155	927	2,219	993	2,288	1,024	2,361	1,037
December	2,220	1,002	2,467	1,051	2,543	1,085	2,625	1,098
Annual Peak/ Total Energy	2,913	13,479	2,901	13,386	2,988	13,785	3,077	14,147

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**NUCLEAR**													
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**[(a)]													
		TOTAL	**1000 TON**	**574**	**312**	**433**	**755**	**902**	**1,146**	**591**	**612**	**637**	**595**	**504**
	RESIDUAL													
(3)		STEAM	1000 BBL	7	15	0	5	0	0	31	7	34	100	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**	**7**	**15**	**0**	**5**	**0**	**0**	**31**	**7**	**34**	**100**	**0**
	DISTILLATE													
(7)		STEAM	1000 BBL	0	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
(9)		CT/GT	1000 BBL	36	4	7	17	4	18	2	2	6	14	0
(10)		**TOTAL**	**1000 BBL**	**36**	**4**	**7**	**17**	**4**	**18**	**2**	**2**	**6**	**14**	**0**
	NATURAL GAS													
(11)		STEAM	1000 MCF	15,741	19,502	22,746	18,647	14,530	12,390	77	81	85	93	72
(12)		CC	1000 MCF	31,237	29,572	27,273	29,249	28,365	27,395	55,677	55,686	54,388	55,399	56,112
(13)		CT/GT	1000 MCF	14,270	17,083	18,376	12,397	8,914	7,985	5,747	6,193	9,131	9,382	13,030
(14)		**TOTAL**	**1000 MCF**	**61,249**	**66,156**	**68,395**	**60,294**	**51,809**	**47,769**	**61,500**	**61,960**	**63,604**	**64,874**	**69,214**
(15)	**OTHER (BIOMASS)**													
		TOTAL	**1000 TON**	**28**	**123**	**171**	**298**	**356**	**452**	**233**	**241**	**251**	**235**	**199**

Note:

(a) 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 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**Firm Inter-Region Interchange**		GWH	**2,521**	**1,769**	**3,069**	**3,383**	**3,484**	**3,106**	**1,967**	**1,961**	**1,214**	**1,279**	**1,014**
(2)	**Firm Inter-Region Interchange - Nuclear**		GWH	**1,613**	**1,693**	**0**	**0**	**614**	**818**	**828**	**885**	**1,634**	**1,634**	**1,765**
(3)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(4)	**COAL[a]**		GWH	**1,334**	**868**	**1,219**	**2,135**	**2,559**	**3,278**	**1,666**	**1,724**	**1,789**	**1,678**	**1,413**
(5)	**RESIDUAL**	STEAM	GWH	4	1	0	0	0	0	2	1	3	9	0
(6)		CC		0	0	0	0	0	0	0	0	0	0	0
(7)		CT		0	0	0	0	0	0	0	0	0	0	0
(8)		**TOTAL**		**4**	**1**	**0**	**0**	**0**	**0**	**2**	**1**	**3**	**9**	**0**
(9)	**DISTILLATE**	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CC		0	0	0	0	0	0	0	0	0	1	0
(11)		CT		16	1	2	6	1	6	1	1	1	3	0
(12)		**TOTAL**		**16**	**1**	**2**	**6**	**1**	**6**	**1**	**1**	**1**	**4**	**0**
(13)	**NATURAL GAS**	STEAM	GWH	1,482	2,023	2,379	1,934	1,491	1,246	0	0	0	0	0
(14)		CC		4,646	4,775	4,412	4,723	4,568	4,405	9,041	9,041	8,815	8,983	9,106
(15)		CT		1,300	1,509	1,733	1,150	816	737	510	551	826	846	1,327
(16)		**TOTAL**		**7,427**	**8,307**	**8,524**	**7,807**	**6,874**	**6,388**	**9,550**	**9,592**	**9,641**	**9,828**	**10,433**
(17)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(18)	**RENEWABLES**	LANDFILL GAS	GWH	50	129	0	0	0	0	0	0	0	0	0
(19)		SOLAR		462	453	749	444	352	350	350	349	344	342	340
(20)		SOLARSMART/SOLARMAX[b]		24	24	24	24	24	24	24	24	24	24	24
(21)		**TOTAL**		**536**	**606**	**773**	**468**	**376**	**373**	**373**	**373**	**368**	**366**	**364**
(22)	**OTHER (BIOMASS)**		GWH	**28**	**141**	**198**	**348**	**417**	**534**	**271**	**281**	**291**	**273**	**230**
(23)	**NET ENERGY FOR LOAD[c]**		GWH	**13,479**	**13,386**	**13,785**	**14,147**	**14,324**	**14,503**	**14,659**	**14,817**	**14,941**	**15,070**	**15,219**

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.
(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.
(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 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**Firm Inter-Region Interchange**		%	**18.7**	**13.2**	**22.3**	**23.9**	**24.3**	**21.4**	**13.4**	**13.2**	**8.1**	**8.5**	**6.7**
(2)	**Firm Inter-Region Interchange - Nuclear**		%	**12.0**	**12.6**	**0.0**	**0.0**	**4.3**	**5.6**	**5.6**	**6.0**	**10.9**	**10.8**	**11.6**
(3)	**NUCLEAR**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(4)	**COAL[(a)]**		%	**9.9**	**6.5**	**8.8**	**15.1**	**17.9**	**22.6**	**11.4**	**11.6**	**12.0**	**11.1**	**9.3**
(5)	**RESIDUAL**	STEAM	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
(6)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		**TOTAL**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**
(9)	**DISTILLATE**	STEAM	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CT		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		**TOTAL**		**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(13)	**NATURAL GAS**	STEAM	%	11.0	15.1	17.3	13.7	10.4	8.6	0.0	0.0	0.0	0.0	0.0
(14)		CC		34.5	35.7	32.0	33.4	31.9	30.4	61.7	61.0	59.0	59.6	59.8
(15)		CT		9.6	11.3	12.6	8.1	5.7	5.1	3.5	3.7	5.5	5.6	8.7
(16)		**TOTAL**		**55.1**	**62.1**	**61.8**	**55.2**	**48.0**	**44.0**	**65.1**	**64.7**	**64.5**	**65.2**	**68.5**
(17)	**NUG**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(18)	**RENEWABLES**	LANDFILL GAS	%	0.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)		SOLAR		3.4	3.4	5.4	3.1	2.5	2.4	2.4	2.4	2.3	2.3	2.2
(20)		SOLARSMART/SOLARMAX[(b)]		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(21)		**TOTAL**		**4.0**	**4.5**	**5.6**	**3.3**	**2.6**	**2.6**	**2.5**	**2.5**	**2.5**	**2.4**	**2.4**
(22)	**OTHER (BIOMASS)**		%	**0.2**	**1.1**	**1.4**	**2.5**	**2.9**	**3.7**	**1.8**	**1.9**	**1.9**	**1.8**	**1.5**
(23)	**NET ENERGY FOR LOAD**		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Notes:
(a) Coal includes Northside Coal and Petroleum Coke.
(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

JEA's system capacity is planned with a targeted 15 percent generation reserve margin above forecasted firm customers coincident one-hour peak demand, for both winter and summer seasons. The reserve margin has been used by the FPSC for municipalities in the consideration of need for additional generation resources.

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.

3.1.1 Resource Planning

JEA utilizes its Integrated Resource Planning (IRP) process to evaluate and inform long-term resource decisions, including scenarios and sensitivities to consider environmental legislative and regulatory action, load growth forecasts, fuel costs, costs of new generation, continued operation of existing generating units, and other factors. JEA has used the IRP process for decades, with the most recent IRP conducted in 2023 and another planned in the 2026/2027 timeframe. The assumptions and information utilized in JEA's IRPs, however, are continually updated to fully inform JEA leadership decisions relative to resource additions. For example, given EPA's repeal of the 2009 Endangerment Finding and the proposed repeal of the GHG regulations for electrical generating units, for purposes of this TYSP, JEA is assuming that the GHG Rule is not in effect moving forward. In addition, as explained in Section 1.3.1, JEA is not incorporating its aspirational clean energy goals at this time.

The resource expansion plan included in this TYSP is representative of what is presently indicated considering the most common/frequent near-term resource additions identified across multiple scenarios and sensitivities. It should be noted that all aspects of the resource expansion plan presented in this TYSP, i.e., schedule and content, are subject to change. JEA will continue to evaluate its resource plan, including continued operation of existing resources and new resource additions, as part of its ongoing resource planning activities.

The addition of a 1x1 advanced-class combined cycle combustion turbine (CCCT) configuration in the 2031 timeframe is part of the least-cost resource plan across all of JEA's current modeled scenarios and sensitivities. JEA anticipates moving forward with seeking a Determination of Need from the Florida Public Service Commission and certification under Florida's Electrical Power Plant Siting Act (PPSA), section 403.501, et. seq., in the second quarter of 2026. Upon commercial operation of the new CCCT unit, Northside Unit 3 will be placed in limited use status and operated at or below 8% annual capacity factor, serving as a back-up resource during peak demand periods, system emergencies, or unexpected equipment outages. Maintaining Northside Unit 3 in limited use is necessary based on increased demand and to ensure reliable service during periods of extreme weather and/or when other generating units or purchased power are unavailable.

3.1.2 JEA Planning Reserve Policy

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 the forecasted firm peak demand in any season from purchases acquired in the operating horizon. If up to 3 percent of firm peak demand in any season is needed, The Energy Authority (TEA), JEA's affiliated energy market services company, 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.

Based on consideration of generating resources and the load forecast reflected in this TYSP, JEA anticipates coordinating with TEA to acquire short-term winter and summer seasonal market purchases to maintain JEA's 15 percent reserve margin for years 2027 through 2031. These purchases will account for up to 3 percent of respective forecasted firm winter and summer peak demand. Please refer to Table 5 for more information related to the projected timing and magnitude of these short-term seasonal purchases, which are referred to as "TEA Backfill Purchases."

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA conducted a comprehensive evaluation of existing electric supply resources, customer energy requirements and peak demand forecasts, fuel price and availability projections, committed unit additions, existing capacity changes, and annual and seasonal capacity purchase additions. Tables 4a and 4b identify the specific years in which resource needs arise across the 2026 through 2035 planning period. Table 5 and TYSP Schedules 8 and 9 present additional information related to the ten-year resource addition plan designed to address those identified needs. TYSP Schedules 7.1 and 7.2 reflect the combined effect of incorporating those resource additions, demonstrating that JEA meets or exceeds the minimum 15% reserve margin requirement throughout the planning period.

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
2026	2,782	601	0	0	3,383	2,772	611	22%	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	522	18%
2028	2,782	703	-206	0	3,279	2,930	349	12%	349	12%
2029	2,782	753	-129	0	3,406	2,961	445	15%	445	15%
2030	2,782	753	-103	0	3,432	2,997	435	15%	435	15%
2031	2,782	753	-103	0	3,432	3,023	409	14%	409	14%
2032	2,782	753	-103	0	3,432	3,052	380	12%	380	12%
2033	2,782	553	0	0	3,335	3,070	265	9%	265	9%
2034	2,782	553	0	0	3,335	3,092	243	8%	243	8%
2035	2,258	553	0	0	2,811	3,119	-308	-10%	-308	-10%

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
2025/26	2,952	471	0	0	3,423	2,901	522	18%	522	18%
2026/27	2,952	661	-206	0	3,407	2,988	419	14%	419	14%
2027/28	2,952	686	-206	0	3,432	3,077	355	12%	355	12%
2028/29	2,952	736	-129	0	3,559	3,114	445	14%	445	14%
2029/30	2,952	736	-103	0	3,585	3,147	438	14%	438	14%
2030/31	2,952	736	-103	0	3,585	3,180	405	13%	405	13%
2031/32	2,952	736	-103	0	3,585	3,210	375	12%	375	12%
2032/33	2,952	536	0	0	3,488	3,226	262	8%	262	8%
2033/34	2,952	536	0	0	3,488	3,252	236	7%	236	7%
2034/35	2,428	536	0	0	2,964	3,275	-311	-9%	-311	-9%

Table 5: Resource Plan

Year [1]	**Resource Plan**
2026	Trail Ridge Contract Expires (-15 MW)[2] Forest Trail Solar Energy Center PPA (50 MW_{AC})[3] Miller Solar Energy Center PPA (~75 MW_{AC})[3] Miller Battery Energy Storage (50 MW_{AC})[3] FMPA Winter PPA (50 MW Winter)
2027	Vogtle 3 & 4 Sale (-206 MW) FPL PPA (+80 MW) TEA Backfill Purchase (150 MW) TEA Purchase (29 MW Winter) FMPA Winter PPA (125 MW Winter)
2028	FPL Solar PPA (-150 MW) Vogtle 3 & 4 Sale (-206 MW) TEA Purchase (91 MW Summer, 107 MW Winter)
2029	Vogtle 3 & 4 Sale (-129 MW) TEA Backfill Purchase (200 MW) TEA Purchase (22 MW Winter)
2030	Vogtle 3 & 4 Sale (-103 MW) TEA Purchase (15 MW Summer, 34 MW Winter)
2031	Vogtle 3 & 4 Sale (-103 MW) Advanced-Class 1x1 CCCT (677.6 MW Winter)[4] TEA Purchase (72 MW Winter)
2032	Vogtle 3 & 4 Sale (-103 MW)
2033	TEA Backfill Purchase Expires (-200 MW)
2034	
2035	Northside 3 Retires (-524 MW)[4] Advanced-Class 1x0 CT I (453 MW Winter) Advanced-Class 1x0 CT II (453 MW Winter)

Notes:
(1) All dates are subject to change.
(2) Trail Ridge contract ends December 31, 2026.
(3) Please refer to Section 1.1.3.5 for details about the Planned Solar PPAs.
(4) Please refer to Section 3.1.1 for more details.

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
2026	2,782	601	0	0	3,383	2,772	611	22%	0	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	0	522	18%
2028	2,782	794	-206	0	3,370	2,930	440	15%	0	440	15%
2029	2,782	753	-129	0	3,406	2,961	445	15%	0	445	15%
2030	2,782	768	-103	0	3,447	2,997	450	15%	0	450	15%
2031	3,364	753	-103	0	4,014	3,023	990	33%	0	990	33%
2032	3,364	753	-103	0	4,014	3,052	962	32%	0	962	32%
2033	3,364	553	0	0	3,917	3,070	846	28%	0	846	28%
2034	3,364	553	0	0	3,917	3,092	824	27%	0	824	27%
2035	3,588	553	0	0	4,141	3,119	1,022	33%	0	1,022	33%

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
2025/26	2,952	471	0	0	3,423	2,901	522	18%	0	522	18%
2026/27	2,952	690	-206	0	3,436	2,988	448	15%	0	448	15%
2027/28	2,952	793	-206	0	3,539	3,077	462	15%	0	462	15%
2028/29	2,952	758	-129	0	3,581	3,114	467	15%	0	467	15%
2029/30	2,952	770	-103	0	3,619	3,147	472	15%	0	472	15%
2030/31	3,630	736	-103	0	4,263	3,180	1,082	34%	0	1,082	34%
2031/32	3,630	736	-103	0	4,263	3,210	1,052	33%	0	1,052	33%
2032/33	3,630	536	0	0	4,166	3,226	940	29%	0	940	29%
2033/34	3,630	536	0	0	4,166	3,252	913	28%	0	913	28%
2034/35	4,011	536	0	0	4,547	3,275	1,272	39%	0	1,272	39%

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					Summer	Winter	
											kW	MW	MW	
Northside	Unit 3	Jacksonville, FL	ST	NG	RFO	PL	WA	N/A	Jul-1977	Jan-2035	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Jan-2028	Jan-2031	Unknown	706,000	582	678	P
Advanced-Class 1x0 CT I	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P
Advanced-Class 1x0 CT II	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

1	**Plant Name and Unit Number:**	Advanced-Class 1x1 CC
2	**Capacity:**	
3	Summer MW:	582
4	Winter MW:	678
5	**Technology Type:**	CCCT
6	**Anticipated Construction Timing:**	
7	Field Construction Start-date:	Jan-2028
8	Commercial In-Service date:	Jan-2031
9	**Fuel:**	
10	Primary:	NG
11	Alternate:	DFO
12	**Air Pollution Control Strategy:**	As required by new source Performance Standards
13	**Cooling Method:**	Wet mechanical draft cooling tower
14	**Total Site Area:**	Power Block approximately 30 acres
15	**Construction Status:**	Not started
16	**Certification Status:**	Not started
17	**Status with Federal Agencies:**	Permitting not started
18	**Projected Unit Performance Data:**	
19	Planned Outage Factor (POF):	4%
20	Forced Outage Factor (FOF):	3%
21	Equivalent Availability Factor (EAF):	93%
22	Resulting Capacity Factor (%):	75%
23	Average Net Operating Heat Rate (ANOHR)(1):	Confidential
24	**Projected Unit Financial Data:**	
25	Book Life:	30 years
26	Total Installed Cost (In-Service year $/kW):	$2,315.63
27	Direct Construction Cost ($/kW):	Included in Line 26
28	AFUDC Amount ($/kW):	Included in Line 26
29	Escalation ($/kW):	Included in Line 26
30	Fixed O&M (2024 $/kW-yr)(1):	Confidential
31	Variable O&M ($/MWh)(1):	Confidential

Notes:
(1) Data is confidential.

1	**Plant Name and Unit Number:**	Advanced-Class 1x0 CT I & II[(1)]
2	**Capacity:**	
3	Summer MW:	374 each
4	Winter MW:	453 each
5	**Technology Type:**	CT
6	**Anticipated Construction Timing:**	
7	Field Construction Start-date:	TBD
8	Commercial In-Service date:	Jan-2035
9	**Fuel:**	
10	Primary:	NG
11	Alternate:	DFO
12	**Air Pollution Control Strategy:**	As required by new source Performance Standards
13	**Cooling Method:**	TBD
14	**Total Site Area:**	TBD
15	**Construction Status:**	Not started
16	**Certification Status:**	Not started
17	**Status with Federal Agencies:**	Permitting not started
18	**Projected Unit Performance Data:**	
19	Planned Outage Factor (POF):	TBD
20	Forced Outage Factor (FOF):	TBD
21	Equivalent Availability Factor (EAF):	TBD
22	Resulting Capacity Factor (%):	TBD
23	Average Net Operating Heat Rate (ANOHR)[(1)]:	TBD
24	**Projected Unit Financial Data:**	
25	Book Life:	TBD
26	Total Installed Cost (In-Service year $/kW):	TBD
27	Direct Construction Cost ($/kW):	TBD
28	AFUDC Amount ($/kW):	TBD
29	Escalation ($/kW):	TBD
30	Fixed O&M (2024 $/kW-yr):	TBD
31	Variable O&M ($/MWh):	TBD

Notes:

(1) JEA has not made any commitments for the addition of these units and will continue to evaluate potential additions of such units as part of JEA's long-term resource planning process.

Schedule 10: Status Report and Specification of Proposed Directly Associated Transmission Lines

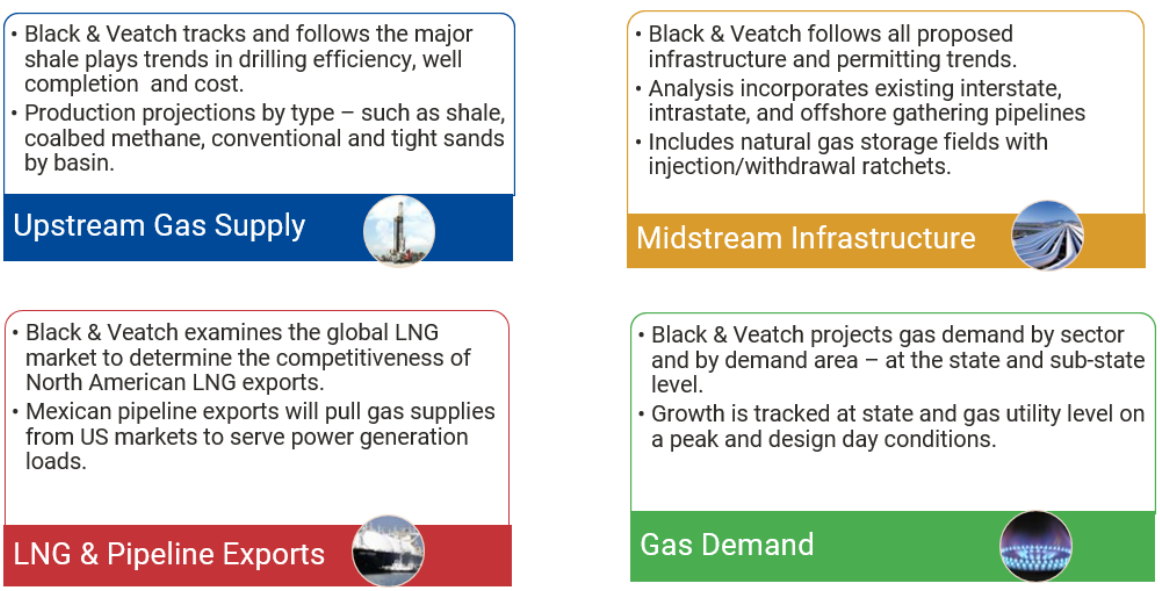
1	Point of Origin and Termination	None to Report
2	Number of Lines	
3	Right of Way	
4	Line Length	
5	Voltage	
6	Anticipated Construction Time	
7	Anticipated Capital Investment	
8	Substations	
9	Participation with Other Utilities	

4. Other Planning Assumptions and Information

4.1 Fuel Price Forecast

Forecasted fuel prices reflected in this TYSP were developed by Black & Veatch Management Consulting, LLC (Black & Veatch) using established industry-accepted methodologies, and current market conditions. Black & Veatch employs the Gas Pipeline Competition Model (GPCM) that incorporates recent developments in the natural gas market to project future supply, demand, and price trends. GPCM is a comprehensive market simulation system which models the entire North American natural gas value chain, including production basins, gas pipelines and storage infrastructure and sector-level demand. This model is widely utilized by the natural gas market participants such as upstream exploration and production companies, midstream pipelines and storage owners and operators, downstream utilities, independent power producers, industrial gas consumers, government agencies, and investment, trading, and banking organizations.

An overview of GPCM's key model assumptions is provided in the figure below.



4.2 Economic Parameters

This section presents the economic parameters used by JEA in the evaluations performed to determine JEA's least-cost expansion plan to satisfy forecast capacity requirements as presented in 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 3.50 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, debt service reserve contributions, and insurance cost. For JEA's plan development, the long term tax-exempt municipal bond rate is assumed to be 4.75 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 4.75 percent.

4.2.4 Interest during Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.75 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 4.75 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.63 percent annual property insurance cost. The resulting 20-year FCR is 8.56 percent and the 25-year FCR is 7.62 percent.

5. Environmental and Land Use Information

JEA intends to propose the addition of a 678 MW net winter-rated capability, dual-fired 1x1 advanced-class CCCT with a 2031 in-service date through a Petition for Determination of Need from the Commission pursuant to section 403.519, Florida Statutes, and a Site Certification Application (SCA) filed with the Florida Department of Environmental Protection pursuant to Florida's Electrical Power Plant Siting Act, section 403.501, et. seq., Florida Statutes, in 2026. The unit will be located at JEA's existing St. Johns River Power Park (SJRPP) site, occupying approximately 200 acres of the larger approximately 1,600-acre parcel. SJRPP is the former location of two 612 MW coal-fired units (SJRPP Units 1 & 2) decommissioned and demolished in 2018 and 2019. Location of the unit at SJRPP will allow utilization of existing infrastructure and minimize environmental impacts. The City of Jacksonville Planning Commission approved a Zoning Exception to allow use of the SJRPP site for the new unit on December 4, 2025. Detailed environmental and land use information will be presented in the SCA.