225 N Pearl Street
Jacksonville, Florida 32202

April 1st , 2025

ELECTRIC

WATER

SEWER

Commission Clerk
Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Commission Clerk:

On behalf of JEA, please accept the 2025 Ten Year Site Plan Submission in accordance with Florida Statutes section 186.80.

If you have any questions, please contact me by email at landsg@jea.com.

Sincerely,

Stephany Landaeta Gutierrez
Staff Engineer
JEA

Building Community®

TEN-YEAR SITE PLAN

April 2025

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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. The 2025 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, 2025 to December 31st, 2034. 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 of 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	12-031	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	173,200	179	191	Utility	
	8	12-031	GT	NG	DFO	PL	WA	06/2009	(a)	224,000	173,200	179	191	Utility	
Northside										1,601,856	1,407,100	1,310	1,356		
	1	12-031	ST	PC	BIT	WA		05/2003	(a)	350,000	297,500	293	293	Utility	
	2	12-031	ST	PC	BIT	WA		04/2003	(a)	350,000	297,500	293	293	Utility	
	3	12-031	ST	NG	RFO	PL	WA	07/1977	01/2030	626,300	563,700	524	524	Utility	
	33-36	12-031	GT	DFO		TK		01/1975	(a)	275,556	248,400	200	246	Utility	
Brandy Branch										946,200	745,100	758	831		
	1	12-031	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	173,200	179	191	Utility	
	2	12-031	CT	NG		PL		05/2001	(a)	237,000	173,200	190	212	Utility	
	3	12-031	CT	NG		PL		10/2001	(a)	237,000	173,200	190	212	Utility	
	4	12-031	CA	WH				01/2005	(a)	268,400	225,500	200	216	Utility	
Greenland Energy Center										448,000	346,400	357	382		
	1	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	
	2	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	
JEA System Total												**2,782**	**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.

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.

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 American Electric Power (AEP). 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, however due to costly wetland impacts at the proposed Peterson Solar Center, the project scope was narrowed to the following three facilities, totaling 200 MW_{AC}: Forest Trail Solar Center, 50 MW_{AC}; Caldwell Solar Center, 74.9 MW_{AC}; Miller Solar Center, 74.9 MW_{AC}. The Caldwell and Miller Solar Centers will each be paired with 50 MW, 4-hour battery energy storage systems. JEA and FRP have executed power purchase agreements, lease option contracts, and energy storage agreements for the projects. All facilities are expected to be commissioned by December 31st, 2026.

JEA has also 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 project schedules for the facilities have been delayed as a result of longer network upgrade timelines. Both facilities are now set to commission by October 2028, however project timelines will be routinely revisited and refined as able.

JEA will continue to pursue solar PV opportunities and conduct studies to assess potential reliability considerations associated with increased solar penetration. These efforts are part of JEA's ongoing work to achieve its Clean Energy Goals by 2030, with ongoing assessments ensuring alignment with system needs and reliability requirements. More information on JEA's Planned Solar Power Purchase Agreements can be found in Table 1.1b.

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. After accounting for transmission losses, JEA receives a total of approximately 200 MW of net firm capacity from these units.

Vogtle Units 3 and 4 were commissioned on July 31st, 2023 and April 29th, 2024, respectively. Each unit is supplying approximately 100 MW of net firm capacity to JEA.

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(1)**	07/31/2023	07/31/2043	100	Annual
	Unit 4(1)	04/29/2024	04/29/2044	100	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

(1) After accounting for transmission losses, JEA receives ~100 MW from Vogtle Unit 3 and ~100 MW from Vogtle Unit 4.

Table 1.1b: JEA Future Solar Power Purchase Agreement Schedule

Contract	Start Date	End Date	Nameplate MW_{AC}	Product Type
Forest Trail Solar PPA	December 2026	December 2061	50	Annual
Caldwell Solar PPA	December 2026	December 2061	74.9	Annual
Miller Solar PPA	December 2026	December 2061	74.9	Annual
Two (2) 74.9 MW Solar PPAs	Q1 2028	Q1 2053	149.8	Annual
Two (2) 74.9 MW Solar PPAs	Q2 2028	Q2 2053	149.8	Annual
FMPA Solar PPAs	October 2028	October 2048	149.8	Annual
Eight (8) 74.9 MW Solar PPAs	Q4 2030	Q4 2055	599.2	Annual
One (1) 30 MW Solar PPA	Q4 2030	Q4 2055	30	Annual

(1) Refer to section 1.1.3.5 and section 1.3.3 for details about the planned and future solar PPAs.
(2) All dates are subjected to change upon finalization of the agreements.

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 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 smaller loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,479 miles of distribution circuits of which approximately 60 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

On April 25th, 2023, JEA's Clean Energy Goals by 2030 were approved by the JEA Board of Directors. These goals include 35 percent of the total energy mix of the JEA Electric System to be from clean energy, the retirement of the least efficient generating units in JEA's Electric System, 80 percent carbon emissions reductions as compared to 2005 levels, JEA facilities' house load to be served with 100 percent clean energy, and the offset of electrification demand by continuing to create and promote effective energy efficiency programs.

JEA continues to explore opportunities to incorporate clean energy into JEA's power supply portfolio while ensuring alignment with system reliability, affordability, and adaptability.

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 International Airport, 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 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 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 acts in concert with the JEA Battery Incentive Program and allows existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years. JEA's residential Battery Incentive Program pilot, enacted on April 1st, 2018, provided financial incentive towards the cost of an energy storage system, subject to lawfully appropriated funds. The pilot, 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 were able to offset electricity consumption from JEA up to the limits of their storage devices. Funds allotted to each customer under the pilot is subject to review and change to optimize adoption. Since its inception until 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 and meet our 2030 goals, a portion of those attributes have been inventoried. In 2024, JEA certified over 150,000 Solar RECs under the Green-e certification structure and tracked over 80,000 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 percent (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 is 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 allows large business customers to choose to have up to 100 percent of their energy needs met by solar power. Companies select either a five or ten-year contract term. JEA retires the RECs in NAR on behalf of the SolarMax customers. The SolarMax rate replaces the fuel charge with a solar price. The program is currently closed to new customers as JEA continues 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 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 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. At present, the price of petroleum coke continues to be volatile, and biomass is typically co-fired when available and economically beneficial.

1.3.3 Future Utility-Scale Renewable Energy

JEA's Clean Energy Goals, which call for 35 percent clean energy by 2030, were approved by the JEA Board of Directors. To support the goal, JEA will continue to pursue solar PV opportunities and conduct studies to assess potential reliability considerations associated with increased solar penetration. Moving forward, JEA will continue to evaluate and plan for the remaining solar additions needed to align with its goals while ensuring reliability, affordability and adaptability in its energy portfolio. For this TYSP, JEA has considered all new solar generation as PPAs, as summarized in Table 1.1b.

1.3.4 Clean Energy Research Efforts

1.3.4.1 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.

1.3.4.2 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 100 MW of BESS alongside the 200 MW_{AC} of solar PV. As JEA continues to seek additional solar generation, JEA will be looking for opportunities to pair the new solar facilities with storage systems.

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, 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 2025 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, total population, number of households, median household income, total housing starts from Moody's Analytics, JEA's total residential accounts and JEA's residential electric rate.

The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy, total commercial employment, gross domestic product from Moody's Analytics, and commercial inventory square footage from the CBRE Market view 2024 Report.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy, gross domestic product, and total proprietors' profits 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 percent 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 Average Annual Growth Rate (AAGR) for net energy for load during the TYSP period is 0.84 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 AAGR for net firm peak demand during the TYSP period is 0.74 percent for summer and 0.65 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 105 MW of interruptible peak load for the summer and 102 MW for the winter which remain constant throughout the study period. For 2025, 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 implement DSM programs that are economically beneficial and meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. 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 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		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Energy (GW)	Residential	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67	10.67
	Commercial	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87
	Total	**23.54**	**23.54**	**23.54**	**23.54**	**23.54**	**23.54**	**23.54**	**23.54**	**23.54**	**23.54**
Summer Peak (MW)	Residential	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
	Commercial	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26
	Total	**2.66**	**2.66**	**2.66**	**2.66**	**2.66**	**2.66**	**2.66**	**2.66**	**2.66**	**2.66**
Winter Peak (MW)	Residential	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13
	Commercial	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
	Total	**2.71**	**2.71**	**2.71**	**2.71**	**2.71**	**2.71**	**2.71**	**2.71**	**2.71**	**2.71**

Table 3: DSM Programs

Commercial Programs	Residential Programs
Commercial Energy Assessment Program	Residential Energy Assessment Program
Commercial/Industrial Prescriptive & Prescriptive Lighting Program	Residential Home Efficiency Upgrades Program
Commercial 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 over the IRP forecast horizon. 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 + 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 customer-sited renewable forecast was included in JEA's 2025 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 AAGRs for PEVs summer and winter coincidental peak demand of 35.07 percent and 40.86 percent, respectively, and total energy of 35.07 percent during the TYSP period.

2.6 Electrification

JEA's electrification load growth assumptions are aligned with the annual program goals for the Electrification Rebates Program (ERP) through calendar year 2030 (CY30). Beginning in CY31, the market potential is assumed to decline at a rate of 5% annually over the remainder of the planning period. These goals were established based on a market potential study conducted by the Electric Power Research Institute (EPRI) in March 2025, covering 10 categories of non-road equipment measures, JEA's forecasts for new Level 2 and DC fast charger (DCFC) EVSE installations, and forecasts for Custom measures within JEA's service territory.

The EPRI study identified 171,205 MWh of existing convertible load across a prescriptive list of electrification measures, each categorized by high, medium, or low use cases. JEA's EVSE forecast added an additional 16,897 MWh of new load, while the Custom project forecast contributed another 93,381 MWh of new electric load eligible for participation in the ERP. In total, these forecasts represent 281,483 MWh of new electrification potential over the planning horizon.

The current ERP contract runs through CY25, with a new procurement in progress for a 3- to 5-year contract term following its expiration. After the next program cycle, it is assumed that the program will continue to be renewed, resulting in sustained load growth that diminishes by 5% annually as the market for new electrification opportunities becomes increasingly saturated.

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
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	5,723	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	5,859	476,268	12,302	4,019	57,516	69,881	2,729	207	13,183,287
2026	5,966	482,282	12,371	4,021	58,311	68,964	2,753	209	13,174,530
2027	6,063	488,276	12,417	4,028	59,107	68,148	2,782	211	13,182,689
2028	6,146	494,097	12,438	4,037	59,905	67,395	2,795	212	13,185,963
2029	6,232	499,697	12,471	4,049	60,705	66,695	2,805	213	13,169,024
2030	6,320	504,993	12,514	4,061	61,508	66,028	2,810	214	13,131,911
2031	6,406	509,926	12,563	4,073	62,313	65,365	2,827	216	13,089,988
2032	6,492	514,518	12,617	4,085	63,121	64,713	2,830	217	13,043,174
2033	6,576	518,782	12,676	4,097	63,932	64,083	2,830	218	12,982,600
2034	6,662	522,730	12,744	4,108	64,746	63,447	2,830	219	12,922,680

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)	
2015	87	0	12,091	392	385	12,868	2	442,249
2016	77	0	12,184	490	263	12,937	2	450,032
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,794
2019	57	0	12,328	58	411	12,797	0	474,179
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	12,664	0	355	13,019	0	533,991
2026	57	0	12,799	0	358	13,156	0	540,802
2027	58	0	12,931	0	361	13,292	0	547,594
2028	59	0	13,037	0	364	13,401	0	554,214
2029	59	0	13,145	0	366	13,511	0	560,615
2030	60	0	13,251	0	368	13,619	0	566,715
2031	60	0	13,367	0	371	13,738	0	572,455
2032	61	0	13,468	0	373	13,841	0	577,856
2033	62	0	13,565	0	377	13,941	0	582,932
2034	62	0	13,662	0	380	14,042	0	587,695

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.	
2015	2,618	0	0	0	0	0	0	2,618
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	2,814	105	0	0	0	2	2	2,705
2026	2,844	105	0	0	0	3	3	2,733
2027	2,873	105	0	0	0	6	5	2,758
2028	2,898	105	0	0	0	8	7	2,778
2029	2,921	105	0	0	0	10	9	2,797
2030	2,944	105	0	0	0	12	11	2,815
2031	2,968	105	0	0	0	14	13	2,836
2032	3,008	105	0	0	0	15	14	2,874
2033	3,008	105	0	0	0	17	15	2,872
2034	3,032	105	0	0	0	19	17	2,891

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.	
2014/15	2,791	0	0	0	0	0	0	2,791
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	2,975	102	0	0	0	4	1	2,868
2025/26	3,008	102	0	0	0	9	3	2,894
2026/27	3,038	102	0	0	0	15	4	2,917
2027/28	3,061	102	0	0	0	11	3	2,945
2028/29	3,086	102	0	0	0	26	7	2,951
2029/30	3,108	102	0	0	0	19	5	2,982
2030/31	3,135	102	0	0	0	29	8	2,995
2031/32	3,154	102	0	0	0	38	10	3,004
2032/33	3,174	102	0	0	0	26	7	3,038
2033/34	3,192	102	0	0	0	39	11	3,040

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.	
2015	12,868	0	0	0	0	0	0	12,868
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	13,043	0	0	0	0	11	13	13,043
2026	13,204	0	0	0	0	22	26	13,204
2027	13,364	0	0	0	0	33	39	13,364
2028	13,497	0	0	0	0	44	52	13,497
2029	13,631	0	0	0	0	55	65	13,631
2030	13,763	0	0	0	0	66	78	13,763
2031	13,906	0	0	0	0	77	91	13,906
2032	14,033	0	0	0	0	88	104	14,033
2033	14,157	0	0	0	0	99	117	14,157
2034	14,282	0	0	0	0	110	130	14,282

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 2024**		**Forecast 2025**		**Forecast 2026**		**Forecast 2027**	
	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	2,416	1,061	2,868	1,053	2,894	1,064	2,917	1,075
February	2,043	904	2,502	917	2,530	926	2,557	936
March	1,767	912	2,292	959	2,318	969	2,342	979
April	2,121	946	2,162	939	2,186	948	2,210	958
May	2,470	1,194	2,487	1,096	2,515	1,107	2,541	1,118
June	2,664	1,302	2,686	1,229	2,716	1,242	2,745	1,255
July	2,592	1,366	2,695	1,330	2,725	1,344	2,755	1,358
August	2,675	1,349	2,705	1,313	2,733	1,327	2,758	1,341
September	2,486	1,187	2,589	1,180	2,617	1,192	2,645	1,205
October	2,280	1,037	2,519	1,050	2,548	1,061	2,574	1,072
November	1,942	968	2,221	948	2,246	958	2,270	968
December	2,161	1,028	2,475	1,006	2,503	1,016	2,529	1,027
Annual Peak/ Total Energy	2,675	13,255	2,868	13,019	2,894	13,156	2,917	13,292

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
(1)	**NUCLEAR**													
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**													
		TOTAL	**1000 TON**	**336**	**109**	**199**	**178**	**490**	**589**	**788**	**276**	**254**	**323**	**360**
	RESIDUAL													
(3)		STEAM	1000 BBL	7	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		**TOTAL**	**1000 BBL**	**7**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**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	11	194	107	109	39	58	66	20	27	36	26
(10)		**TOTAL**	**1000 BBL**	**11**	**194**	**107**	**109**	**39**	**58**	**66**	**20**	**27**	**36**	**26**
	NATURAL GAS													
(11)		STEAM	1000 MCF	22,740	15,464	21,658	23,520	19,524	16,861	15,198	1,226	1,138	1,432	1,584
(12)		CC	1000 MCF	32,525	30,104	30,416	28,175	30,271	29,524	28,588	45,838	46,122	46,478	47,196
(13)		CT/GT	1000 MCF	13,265	29,673	21,008	19,868	10,801	10,238	10,054	4,946	5,063	6,149	5,944
(14)		**TOTAL**	**1000 MCF**	**68,529**	**75,240**	**73,083**	**71,563**	**60,596**	**56,623**	**53,840**	**52,010**	**52,324**	**54,058**	**54,725**
(15)	**OTHER (BIOMASS)**													
		TOTAL	**TRILLION BTU**	**34**	**34**	**62**	**56**	**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 2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
(1)	**Firm Inter-Region Intchg.**		GWH	**2,401**	**1,077**	**1,047**	**1,198**	**1,064**	**1,060**	**1,031**	**418**	**405**	**469**	**448**
(2)	**Firm Inter-Region Intchg. - Nuclear**		GWH	**1,275**	**1,613**	**1,644**	**1,560**	**1,658**	**1,663**	**1,596**	**1,592**	**1,729**	**1,615**	**1,596**
(3)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(4)	**COAL**[(a)]		GWH	**774**	**283**	**537**	**489**	**1,369**	**1,652**	**2,219**	**756**	**696**	**886**	**986**
(5)	**RESIDUAL**	STEAM	GWH	4	0	0	0	0	0	0	0	0	0	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**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**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	0	0
(11)		CT		4	71	37	39	11	19	21	5	9	12	9
(12)		**TOTAL**		**4**	**71**	**37**	**39**	**11**	**19**	**21**	**5**	**9**	**12**	**9**
(13)	**NATURAL GAS**	STEAM	GWH	2,094	1,603	2,242	2,449	1,987	1,710	1,533	125	115	146	163
(14)		CC		4,886	4,876	4,926	4,565	4,899	4,773	4,615	7,196	7,243	7,320	7,437
(15)		CT		1,278	2,858	2,053	1,983	1,067	1,000	975	470	481	589	573
(16)		**TOTAL**		**8,257**	**9,337**	**9,221**	**8,998**	**7,953**	**7,482**	**7,123**	**7,791**	**7,839**	**8,055**	**8,172**
(17)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(18)	**RENEWABLES**	LANDFILL GAS	GWH	56	129	128	0	0	0	0	0	0	0	0
(19)		SOLAR		427	449	449	922	1,323	1,612	1,606	3,152	3,140	2,880	2,808
(20)		SOLARSMART/SOLARMAX		24	24	24	24	24	24	24	24	24	24	24
(21)		**TOTAL**		**507**	**602**	**601**	**946**	**1,346**	**1,636**	**1,630**	**3,176**	**3,164**	**2,904**	**2,832**
(22)	**OTHER (BIOMASS)**		GWH	**32**	**37**	**70**	**63**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**[(b)]		GWH	**13,255**	**13,019**	**13,156**	**13,292**	**13,401**	**13,511**	**13,619**	**13,738**	**13,841**	**13,941**	**14,042**

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 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	**Firm Inter-Region Intchg.**		%	**18.1**	**8.3**	**8.0**	**9.0**	**7.9**	**7.8**	**7.6**	**3.0**	**2.9**	**3.4**	**3.2**
(2)	**Firm Inter-Region Intchg. - Nuclear**		%	**9.6**	**12.4**	**12.5**	**11.7**	**12.4**	**12.3**	**11.7**	**11.6**	**12.5**	**11.6**	**11.4**
(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)]		%	**5.8**	**2.2**	**4.1**	**3.7**	**10.2**	**12.2**	**16.3**	**5.5**	**5.0**	**6.4**	**7.0**
(5)	**RESIDUAL**	STEAM	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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**	**0.0**	**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		0.0	0.5	0.3	0.3	0.1	0.1	0.2	0.0	0.1	0.1	0.1
(12)		**TOTAL**		**0.0**	**0.5**	**0.3**	**0.3**	**0.1**	**0.1**	**0.2**	**0.0**	**0.1**	**0.1**	**0.1**
(13)	**NATURAL GAS**	STEAM	%	15.8	12.3	17.0	18.4	14.8	12.7	11.3	0.9	0.8	1.0	1.2
(14)		CC		36.9	37.5	37.4	34.3	36.6	35.3	33.9	52.4	52.3	52.5	53.0
(15)		CT		9.6	22.0	15.6	14.9	8.0	7.4	7.2	3.4	3.5	4.2	4.1
(16)		**TOTAL**		**62.3**	**71.7**	**70.1**	**67.7**	**59.3**	**55.4**	**52.3**	**56.7**	**56.6**	**57.8**	**58.2**
(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	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)		SOLAR		3.2	3.4	3.4	6.9	9.9	11.9	11.8	22.9	22.7	20.7	20.0
(20)		SOLARSMART/SOLARMAX		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(21)		**TOTAL**		**3.8**	**4.6**	**4.6**	**7.1**	**10.0**	**12.1**	**12.0**	**23.1**	**22.9**	**20.8**	**20.2**
(22)	**OTHER (BIOMASS)**		%	**0.2**	**0.3**	**0.5**	**0.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(23)	**NET ENERGY FOR LOAD**		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

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 Integrated Resource Planning Study

JEA completed an Integrated Resource Plan (IRP) at the end of May 2023. The IRP was developed by Black and Veatch consulting group (B&V) using a multi-scenario and sensitivity approach, which allowed for evaluations of new resource options under different potential futures. The primary variables and considerations that defined these different potential futures included the following:

- Environmental Legislative and Regulatory Action
  - Cost for emissions of CO_2
  - Specific goals or targets for percentages of energy from sources that do not emit carbon dioxide (CO_2)
  - Retirement of solid fuel and/or natural gas-fired generation
  - 316(b) regulations
- Load Growth Forecasts
  - Energy
  - Peak demand
  - Demand-side management and energy efficiency
  - Plug-in electric vehicles
  - Electrification
  - Customer-sited renewables
- Fuel Costs
- Cost of New Generation
- Continued Operation of Existing Generating Units
- Other Considerations
  - Affordability
  - Reliability
  - Environmental
  - Economic development

- CO_2 emissions reductions

The resource expansion plan included in this TYSP is representative of what is presently indicated by the IRP and consists of the most common/frequent near-term resource additions identified across multiple scenarios and sensitivities within the IRP study. 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 IRP was developed reflecting consideration of JEA's existing 524 MW Northside Unit 3 being removed from service in 2030. Removal of this unit from service is influenced by multiple factors, including the need for capital upgrades to remain reliable and as a potential means of compliance with 316(b) surface water withdrawal regulations.

The IRP results consistently identified a 1x1 advanced-class combined cycle combustion turbine (CCCT) configuration in the 2030 timeframe as part of the least-cost resource plan across the majority of scenarios and sensitivities. Modeling results show that the retirement and replacement of JEA's Northside Unit 3 with an efficient, advanced-class CCCT provides JEA with a new cost-effective resource. This new resource will provide reliable dispatchable power, allow for more efficient use of natural gas, reduce system CO_2, NO_x and SO_2 emissions, provide support to reliably integrate more renewable energy into the JEA system, and will also avoid costly upgrades that would otherwise be necessary to extend the life of the 46-year-old unit. It should be noted that in order to maintain reliable operation of JEA's system, Northside Unit 3 cannot be retired until a replacement unit has achieved commercial operation. Due to permitting requirements associated with the Florida Power Plant Siting Act (PPSA), specifically Determination of Need and Site Certification (environmental permitting) for a CCCT, Northside Unit 3 may need to continue to operate until the earliest commercial operation date of a new CCCT resource, which is estimated to be in the late 2030 timeframe. Development considerations, such as permitting delays, supply chain difficulties, or construction delays, could impact the earliest commercial operation date.

Data from the 2023 IRP indicated the need for an additional 1,275 MW_{AC} of Solar PV to meet JEA's Clean Energy Goals by 2030. JEA will continue to evaluate and plan for solar additions needed to align with its Clean Energy Goals while ensuring reliability, affordability, and adaptability.

JEA is currently conducting Power Island and Market Power solicitation processes to refine estimated costs of an advanced-class CCCT and identify potential viable alternatives. The solicitation processes are expected to conclude by the end of summer 2025. To support solicitation processes and related evaluations, JEA is collaborating with B&V to update the input assumptions, forecasts, and cost estimates included in JEA's 2023 IRP.

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 seasonal market purchases to maintain JEA's 15 percent reserve margin for years 2027-2030 and 2034. These purchases will account for less than 3 percent of JEA's forecasted firm winter peak demand. Please refer to Table 4 for more information related to the projected timing and magnitude of these short-term seasonal purchases.

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA included a review of existing electric supply resources, forecast of customer energy requirements and peak demand, forecast of fuel prices and fuel availability, committed unit additions, existing capacity changes and annual and seasonal capacity purchase additions, and consideration of JEA Clean Energy Goals by 2030. The resource plan reflected in this TYSP considers all of these factors and provides JEA with sufficient capacity to cover peak demand and reserve margin requirements throughout the 2025 through 2034 planning period. Table 4 presents the ten-year resource addition plan, which meets JEA's strategic goals. TYSP Schedules 7-10 provide further detail of this plan.

Table 4: Resource Plan

Year (1)	Resource Plan
2025	
2026	Trail Ridge Contract Expires (-15 MW) (2) Forest Trail Solar PPA (50 MW_{AC}) (3) Caldwell Solar PPA (~75 MW_{AC}) (3) Miller Solar PPA (~75 MW_{AC}) (3)
2027	TEA Purchase (~5 MW Winter)
2028	Two (2) 74.9 MW_{AC} Solar PPAs (~150 MW_{AC}) (4) FPL Solar PPA Expires (-150 MW) Two (2) 74.9 MW_{AC} Solar PPAs (~150 MW_{AC}) (4) FMPA Solar PPAs (~150 MW_{AC}) (3) TEA Purchase (~38 MW Winter)
2029	TEA Purchase (~44 MW Winter)
2030	Future Solar PPAs (~630 MW_{AC}) (4) Northside 3 Retires (-524 MW) (5) 1x1 CCCT (669.8 MW Winter) (5) TEA Purchase (~81 MW Winter)
2031	
2032	
2033	
2034	TEA Purchase (~3 MW Winter)

Notes:

(1) All dates are subjected 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 1.3.3 for details about Future Solar PPAs.
(5) 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
2025	2,782	517	0	0	3,299	2,705	593	22%	0	593	22%
2026	2,782	516	0	0	3,298	2,733	564	21%	0	564	21%
2027	2,782	540	0	0	3,322	2,758	564	20%	0	564	20%
2028	2,782	507	0	0	3,289	2,778	511	18%	0	511	18%
2029	2,782	535	0	0	3,317	2,797	520	19%	0	520	19%
2030	2,782	655	0	0	3,437	2,815	621	22%	0	621	22%
2031	2,834	660	0	0	3,494	2,836	658	23%	0	658	23%
2032	2,834	659	0	0	3,493	2,874	618	22%	0	618	22%
2033	2,834	658	0	0	3,492	2,872	620	22%	0	620	22%
2034	2,834	656	0	0	3,490	2,891	599	21%	0	599	21%

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
2024/25	2,952	415	0	0	3,367	2,868	499	17%	0	499	17%
2025/26	2,952	415	0	0	3,367	2,894	473	16%	0	473	16%
2026/27	2,952	405	0	0	3,357	2,917	440	15%	0	440	15%
2027/28	2,952	438	0	0	3,390	2,945	445	15%	0	445	15%
2028/29	2,952	444	0	0	3,396	2,951	445	15%	0	445	15%
2029/30	2,952	481	0	0	3,433	2,982	451	15%	0	451	15%
2030/31	3,098	400	0	0	3,498	2,995	502	17%	0	502	17%
2031/32	3,098	400	0	0	3,498	3,004	493	16%	0	493	16%
2032/33	3,098	400	0	0	3,498	3,038	459	15%	0	459	15%
2033/34	3,098	403	0	0	3,501	3,040	461	15%	0	461	15%

Schedule 8: Planned and Prospective Generating Facility Additions and Changes

Planned and Prospective Generating Facility and Purchased Power Additions and Changes														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transport		Construction Start Date	Commercial/ In-Service or Change Date	Expected Retirement/ Shutdown Date	Gen Max Nameplate	Net Capability		Status
				Primary	Alternate	Primary	Alternate				kW	Summer MW	Winter MW	
Northside	Unit 3	12-031	ST	NG	RFO	PL	WA	N/A	Jul-1977	Dec-2030	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Apr-2027	Dec-2030	Unknown	TBD	576	669.8	P

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

1	**Plant Name and Unit Number:**	Advanced-Class 1x1 CC(2)
2	**Capacity:**	
3	Summer MW:	576
4	Winter MW:	669.8
5	**Technology Type:**	CCCT
6	**Anticipated Construction Timing:**	
7	Field Construction Start-date:	Apr-2027
8	Commercial In-Service date:	Dec-2030
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):	6%
20	Forced Outage Factor (FOF):	3%
21	Equivalent Availability Factor (EAF):	91%
22	Resulting Capacity Factor (%):	55%
23	Average Net Operating Heat Rate (ANOHR)(1):	Confidential
24	**Projected Unit Financial Data:**	
25	Book Life:	25 years
26	Total Installed Cost (In-Service year $/kW)(1):	Confidential
27	Direct Construction Cost ($/kW)(1):	Confidential
28	AFUDC Amount ($/kW)(1):	Confidential
29	Escalation ($/kW)(1):	Confidential
30	Fixed O&M (2024 $/kW-yr)(1):	Confidential
31	Variable O&M ($/MWh)(1):	Confidential

Note:
(1) Data is confidential. JEA is currently undergoing a bid process for the new CCCT.
(2) Data does not include additional costs and constraints for GHG Rule compliance.

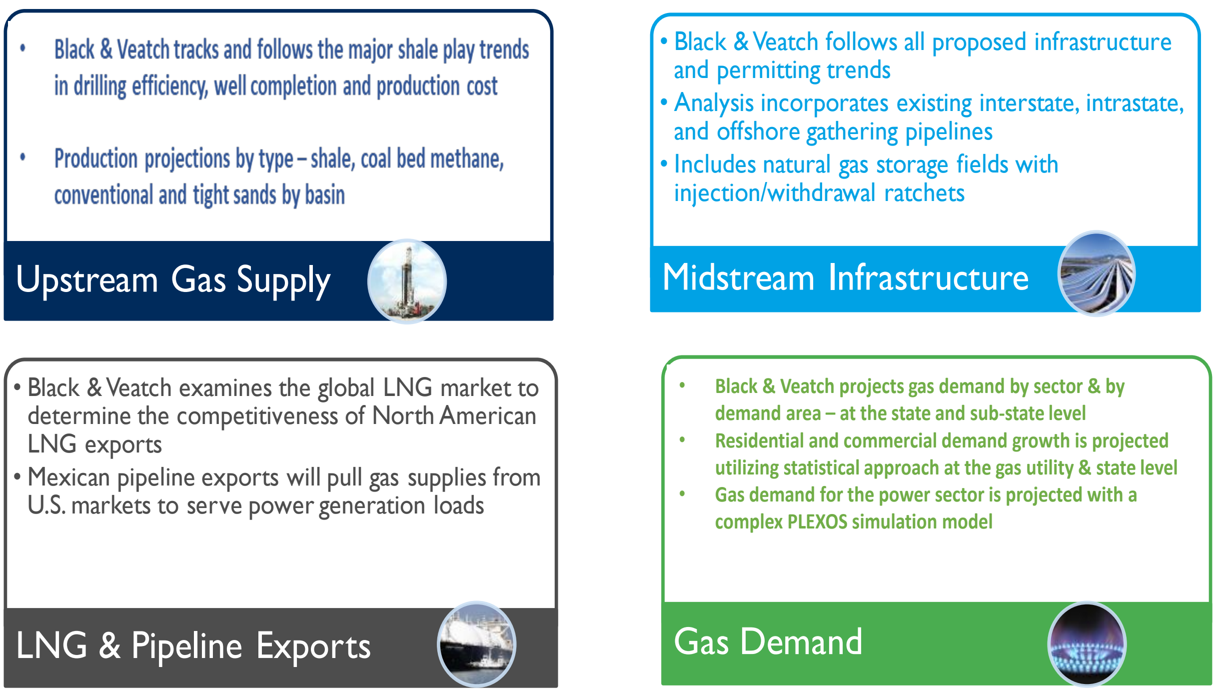
Schedule 10: Status Report and Specification of Proposed Directly Associated Transmission Lines

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

Fuel prices reflected in this TYSP were developed by Black & Veatch consulting group and are based upon established approaches and reflect current market conditions. Black & Veatch utilizes the Gas Pipeline Competition Model (GPCM) that incorporates recent developments in the natural gas market to project future market trends. GPCM is a market simulation system which models the entire North America natural gas value chain, including production basins, gas pipelines and storage facilities and market demand by sectors. GPCM is widely utilized by the natural gas market players, including upstream E&P companies, midstream pipelines and storage owners and operators, downstream utilities, independent power producers, industrial gas users, government agencies and investment, trading, and banking firms. An overview of the GPCM considerations is provided in the figure below.



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 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, 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 0.57 percent annual property insurance cost. The resulting 20-year FCR is 8.34 percent and the 25-year FCR is 7.38 percent.

5. Environmental and Land Use Information

As discussed throughout this TYSP, JEA is evaluating the potential addition of a 1x1 advanced-class CCCT. If JEA ultimately determines to add this resource, it may be added to an existing JEA-owned site. Further updates will be presented in subsequent TYSPs as JEA continues the evaluation process.