225 N Pearl St.
Jacksonville, Florida 32202

May 1st , 2025

JEA

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

Commission Clerk:

E L E C T R I C

W A T E R

S E W E R

On behalf of JEA, please accept the Staff's Data Request #1.

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

Sincerely,

Stephany Landaeta Gutierrez
Staff Engineer
JEA

Instructions: Accompanying this data request is a Microsoft Excel (Excel) document titled "Data Request #1.Excel Tables," (Excel Tables File). For each question below that references the Excel Tables File, please complete the table and provide, in Excel Format, all data requested for those sheet(s)/tab(s) identified in parenthesis.

General Items

1. Please provide an electronic copy of the Company's Ten-Year Site Plan (TYSP) for the current planning period (2025-2034) in PDF format.

2. Please provide an electronic copy of all schedules and tables in the Company's current planning period TYSP in Excel format.

3. Please refer to the Excel Tables File tabs listed below. Complete the tables by providing information on the financial assumptions and financial escalation assumptions used in developing the Company's TYSP. If any of the requested data is already included in the Company's current planning period TYSP, state so on the appropriate form. (Please see excel file)

    a. Excel Tables File (Financial Assumptions)
    b. Excel Tables File (Financial Escalation)

Load & Demand Forecasting

Historic Load & Demand

4. **[Investor-Owned Utilities Only]** Please refer to the Excel Tables File (Hourly System Load). Complete the table by providing, on a system-wide basis, the hourly system load in megawatts (MW) for the period January 1 through December 31 of the year prior to the current planning period. For leap years, please include load values for February 29. Otherwise, leave that row blank.

    a. Please also describe how loads are calculated for those hours just prior to and following Daylight Savings Time (March 10, 2024, to November 3, 2024).

5. Please refer to the Excel Tables File (Historic Peak Demand). Complete the table by providing information on the monthly peak demand experienced during the three-year period prior to the current planning period, including the actual peak demand experienced, the amount of demand response activated during the peak, and the estimated total peak if demand response had not been activated. Please also provide the day, hour, and system-average temperature at the time of each monthly peak. (Please see excel file)

Forecasted Load & Demand

6. Please identify the weather station(s) used for calculation of the system-wide temperature for the Company's service territory. If more than one weather station is utilized, please describe how a system-wide average is calculated.

   JEA utilizes NOAA Weather Station: Jacksonville International Airport (13889/JAX).

7. Please explain, to the extent not addressed in the Company's current planning period TYSP, how the reported forecasts of the number of customers, demand, and total retail energy sales were developed. In your response, please include the following information:

   a. Methodology.
   b. Assumptions.
   c. Data sources.
   d. Third-party consultant(s) involved.
   e. Anticipated forecast accuracy.
   f. Any difference/improvement(s) made compared with those forecasts used in the Company's most recent prior TYSP.

Customers

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.

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.

Demand

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.

Energy Sales

The total Energy Sales Forecasts is developed by combining 8 different forecasts which include:

- Residential, Commercial and Industrial Forecast (discussed above)
- PEV Forecast
- Electrification Forecast
- Conservation Forecast
- Customer-Sited Renewables
- Lighting Forecast

8. Please identify all closed and open Florida Public Service Commission (FPSC) dockets and all non-docketed FPSC matters which were/are based on the same load forecast used in the Company's current planning period TYSP.

   None.

9. Please explain if your Company evaluates the accuracy of its forecasts of customer growth and annual retail energy sales presented in its past TYSPs by comparing the actual data for a given year to the data forecasted one, two, three, four, five, or six years prior.

a. If your response is affirmative, please explain the method used in your evaluation, and provide the corresponding results, including work papers, in Excel format for the analysis of each forecast presented in the TYSPs filed with the Commission during the 20-year period prior to the current planning period. If your Company limits its analysis to a period shorter than 20 years prior to the current planning period, please provide what analysis you have and a narrative explaining why your Company limits its analysis period.
b. If your response is negative, please explain.

JEA compares forecasted values with actual values to determine if reevaluation of our forecast process is necessary. In the recent year, JEA had an independent consulting firm review JEA's forecast methodology, and it was determined JEA to be consistent with industry standards and within acceptable forecast error range.

JEA compares actual values against forecasted values for years 2004-2024 in a matrix. Then, the percentage variance between the actual and forecasted values is calculated for each year to determine whether the forecast overestimated or underestimated the actual value. For 2024 there is a 2.8% forecast error for the Net Energy when comparing to actual value. JEA will continue to observe its forecast errors for the remainder of this year. Should the forecast error remain above the acceptable error range, JEA will reevaluate and revamp its forecast process and methodology or solicit help from an independent consulting firm.

Please see attached file for more information.

10. Please explain if your Company evaluates the accuracy of its forecasts of Summer/Winter Peak Energy Demand presented in its past TYSPs by comparing the actual data for a given year to the data forecasted one, two, three, four, five, or six years prior.

    a. If your response is affirmative, please explain the method used in your evaluation, and provide the corresponding results, including work papers, in Excel format for the analysis of each forecast presented in the TYSPs filed with the Commission during the 20-year period prior to the current planning period. If your Company limits its analysis to a period shorter than 20 years prior to the current planning period, please provide what analysis you have and a narrative explaining why your Company limits its analysis period.
    b. If your response is negative, please explain why.

    JEA utilizes the same method as explained in question 9. After a review provided by the independent consulting firm, JEA's forecast method is determined to be within industry standard. JEA's winter peak forecasts remain to have high forecast errors, primary due to the mild winters experienced over the past decade, however, JEA's summer peak forecasts are within an acceptable forecast error range.

    JEA will continue to observe its forecast errors for the remainder of this year and determine if it needs reevaluate and revamp its forecast process and methodology or solicit help from an independent consulting firm.

Please see attached file for more information.

11. Please explain any historic trends or other information as requested below in each of the following components of Summer/Winter Peak Demand:

    a. Demand Reduction due to the Company's demand-side management program(s) and Self Service, by customer type (residential, commercial, industrial) as well as Total Customers, and identify the major factors that contribute to the growth/decline in the trends.

       JEA's demand reduction due to conservation and self-service (or self-conservation from energy audit program) is the estimated peak reductions correlated to the energy savings from its conservation programs offered to JEA's residential, commercial, and industrial customers.

    b. Demand Reduction due to Demand Response, by customer type (residential, commercial, industrial), and identify the major factors that contribute to the growth/decline of the trends.

       JEA currently do not have any demand response for residential customers. Currently, the only demand reduction is JEA's interruptible customers, which consist on large commercial and industrial customers.

    c. Total Demand, and identify the major factors that contribute to the growth/decline in the trends.

       JEA funded demand-side management programs continue to be the contributors to the decrease in annual use per residential customer. There are other several factors that contribute to the declining trend in average kWh/customer. Customer behavioral changes over the last 10 years and increased in electric rates contributed to the continuous decline. JEA does not expect this behavior to change. Also, JEA continues to observe more multifamily housing constructions compared to single-family housing, which use less energy per customer. JEA expects this trend toward multifamily housing construction to continue throughout the TYSP forecast period.

       Similar to JEA's offerings to residential customers, JEA offers energy audit programs to audit commercial and industrial customers' businesses and provides education and recommendations on low-cost or no-cost energy-saving practices and measures. JEA offers financial incentives to commercial customers on energy efficient lighting, and other energy efficient products.

       JEA's peak forecast is developed by using the forecasted energy for residential, commercial and industrial and the average load factor based on historical peaks and net energy for summer/winter peak months. JEA's 2025 summer total peak forecast AAGR is 0.83%. The 2025 winter total peak forecast AAGR is 0.79%

d. Net Firm Demand, by the sources of peak demand appearing in Schedule 3.1 and Schedule 3.2 of the current planning period TYSP, and identify the major factors that contribute to the growth/decline in the trends.

JEA's 2025 forecasted cumulative conservation continues to grow. Consequently, bringing down JEA's Net Firm due to the demand-side management program discussed in c.

12. Please explain any current and forecasted trends or other information as requested below in each of the following components of Summer/Winter Peak Demand:

a. Demand Reduction due to the Company's demand-side management program(s) and Self Service, by customer type (residential, commercial, industrial) as well as Total Customers, and identify the major factors that contribute to the growth/decline in the trends.

No different trends other than the ones mentioned in question 11.

b. Demand Reduction due to Demand Response, by customer type (residential, commercial, industrial), and identify the major factors that contribute to the growth/decline of the trends.

JEA currently do not have any demand response for residential customers. Currently, the only demand reduction is JEA's interruptible customers, which consist on large commercial and industrial customers.

c. Total Demand, and identify the major factors that contribute to the growth/decline in the trends.

No different trends other than the ones discussed in question 11.

d. Net Firm Demand, by the sources of peak demand appearing in Schedule 3.1 and Schedule 3.2 of the current planning period TYSP, and identify the major factors that contribute to the growth/decline in the trends.

Same as discussed in question 11.

13. **[FEECA Utilities Only]** Do the Company's energy and demand savings amounts reflected on the DSM and Conservation-related portions of all energy and demand savings schedules (Schedules 2.1, 2.2, and 2.3 for energy savings and Schedules 3.1, 3.2, and 3.3 for demand savings) reflect the Company's goals that were approved by the Commission in the 2024 FEECA Goalsetting dockets? If not, please explain what assumptions are incorporated within those amounts, and why.

The DSM and Conservation-related portions of Schedules 3.1, 3.2 and 3.3 reflect projections of demand and energy reductions, set by JEA, that our customers may achieve through DSM, Energy Efficiency, and Conservation. The projections includes the goals established in the 20204 goal setting. In addition, it also includes JEA's internal DSM Residential and Commercial programs.

14. Please explain any anomalies caused by non-weather events with regard to annual historical data points for the period 10 years prior to the current planning period that have contributed to the following, respectively:

    a. Summer Peak Demand.
    b. Winter Peak Demand.
    c. Annual Retail Energy Sales.

Many factors contributed to the decrease in peak demand and energy sales. Since the recession, there was change in customers behavior to conserve energy. Continuous improvement in efficiency in new appliances and equipment, the phase-out of incandescent bulbs and conversion to LED bulbs, the change in technologies to high energy efficient technologies also contribute to the decrease in energy consumptions. Another big contributor is the new US Government's SEER Requirement Changes for 2015, that required new split system central air conditioners to be a minimum 14 SEER, had contributed to the majority of decrease in use over the past years, as customers replaced their old units with more energy efficient units that complied with or exceeded the standard, and as the new constructions complied with the standard. The new 2023 SEER rating standards, now requiring new air conditioners in Southern states to be a minimum 15 SEER, will continue to contribute to the decrease in electricity usage. COVID- 19 pandemic also contributed to the decline in consumption.

15. Please provide responses to the following questions regarding the weather factors considered in the Company's retail energy sales and peak demand forecasts:

    a. Please identify, with corresponding explanations, all the weather-related input variables that were used in the respective Retail Energy Sales, Winter Peak Demand, and Summer Peak Demand models.

       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.

    b. Please specify the source(s) of the weather data used in the aforementioned forecasting models.

       NOAA Weather Station - Jacksonville International Airport

c. Please explain in detail the process/procedure/method, if any, the Company utilized to convert the raw weather data into the values of the model input variables.

JEA does not convert raw weather data. JEA pairs the hourly load with the respective hourly temperature, the heating and cooling degree with the respective daily energy.

d. Please specify with corresponding explanations:
  (1) How many years' historical weather data was used in developing each retail energy sales and peak demand model.

  10 years

  (2) How many years' historical weather data was used in the process of these models' calibration and/or validation.

  10 years

e. Please explain how the projected values of the input weather variables (that were used to forecast the future retail energy sales or demand outputs for each planning years 2025–2034) were derived/obtained for the respective retail energy sales and peak demand models.

Energy sales Forecast:
NOAA historical actual Heating and Cooling Degree Days are used to develop the normalized Energy sales. Days are divided into three categories: Weekdays, Saturday & Holiday, and Sunday. The LINEST excel function is used on actual Degree Days and Net Energy for each customer class (Residential, Commercial & Industrial) to produce a normal curve. This normal curve is created under three categories mentioned above. Under each category we look at Oct (shoulder month), Winter and Summer segments. Finally, the normal degree days are applied to the normal curve to produce the normal MWH consumption for each customer class.

Peak Forecast:
JEA uses SAS to develop the normalize peak forecast. Hourly system load data and max and min temperatures are input into SAS. A non-linear regression analysis is performed on our 10-year historical peaks and temperatures to identify the least squared peaks for each year and use that as our normalized peaks. Some of the assumptions used for this model includes:

- JEA Load = Hourly Load – AUX – CMC Steel & Max and Min temperatures
- The Winter peak is the lowest daily temperature during the months of December, January and February
- The Summer peak is the highest daily temperature during the months of July, August and September

- Two of the parameters used in the non-linear regression analysis are highest and lowest record temperatures in Jacksonville of 103°F for summer and 16°F for winter

16. **[Investor-Owned Utilities Only]** If not included in the Company's current planning period TYSP, please provide load forecast sensitivities (high band, low band) to account for the uncertainty inherent in the base case forecasts in the following TYSP schedules, as well as the methodology used to prepare each forecast:

    a. Schedule 2.1 – History and Forecast of Energy Consumption and Number of Customers by Customer Class.
    b. Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class.
    c. Schedule 2.3 - History and Forecast of Energy Consumption and Number of Customers by Customer Class.
    d. Schedule 3.1 - History and Forecast of Summer Peak Demand.
    e. Schedule 3.2 - History and Forecast of Winter Peak Demand.
    f. Schedule 3.3 - History and Forecast of Annual Net Energy for Load.
    g. Schedule 4 - Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month.

17. Please address the following questions regarding the impact of all customer-owned/leased renewable generation (solar and otherwise) and/or energy storage devices on the Utility's forecasts.

    a. Please explain in detail how the Utility's load forecast accounts for the impact of customer's renewables and/or storage.

    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.

b. Please provide the annual impact, if any, of customer's renewables and/or storage on the Utility's retail demand and energy forecasts, by class and in total, for 2025 through 2034.

For 2025, the Customer-Site renewable represents 0.053% of the forecasted total peak demand in the winter and 0.7% of the forecasted total peak demand in the summer. The AAGR of Customer-Sited Renewable load during the TYSP period is 9.52%.

c. If the Utility maintains a forecast for the planning horizon (2025-2034) of the number of customers with renewables and/or storage, by customer class, please provide.

	Number of Customers	
	Residential	**Non-Residential**
2025	9,223	144
2026	10,158	164
2027	11,232	185
2028	12,438	210
2029	13,778	237
2030	15,243	266
2031	16,800	297
2032	18,447	331
2033	20,009	347
2034	21,481	365

Plug-in Electric Vehicles (PEVs)

18. Please refer to the Excel Tables File (PEV Charging). Complete the table by providing estimates of the requested information within the Company's service territory for the current planning period. Direct current fast charger (DCFC) PEV charging stations are those that require a service drop greater than 240 volts and/or use three-phase power.

JEA included Plug-in Electric Vehicle (PEV) in the forecast used for this TYSP. JEA's forecasted AAGRs for PEV winter is 35.07%, summer coincidental peak demand is approximately 40.86% and total energy are approximately 35.07% percent during the TYSP period. JEA will continue to monitor PEV technology and its impact on JEA's load forecast.

19. Please describe what method(s) the Utility has used, if any, to address the impact of PEVs charging on seasonal peak demand, including any special rates or tariffs, demand-side management programs (including PEV-centric demand response), customer education, or other means. As part of your response, identify each and provide the estimated impact on seasonal peak demand.

    JEA has a voluntary behavior-based load management program that encourages residential customers to charge their electric vehicles at home during off-peak hours. Currently, about 2,800 plug-in electric vehicles are enrolled in Drive Electric Program (DEP) off-peak charging. Enrollees in the program earn a small incentive payment each month if they refrain from charging during on-peak hours. Compliance is monitored through the existing residential AMI network. More details of the DEP are included in the response to question 22.

    JEA and EPRI are conducting a study to better understand the impact of this program on seasonal peak demand. Results from the study are expected in May 2025.

20. Please explain any <u>historic</u> trends related to the following:
    a. PEV counts
    b. PEV charging installation counts
    c. Annual energy consumption
    d. Seasonal Peak Demand (Summer and Winter)

    There is no major driver on the forecasted PEV counts that JEA can identify at this time. JEA sees the adoption in its service territory driven by the desired of TESLA ownership. TESLA ownership represents a 75% of Duval County total PEV registrations in 2024. Follow by Ford as the next highest ownership in Duval County and representing 4% of the total PEV registrations.

    JEA does not have any technology in placed to be notified when a customer has installed a PEV charging station in their home. However, we have seen an increase in the number of public charging stations installed throughout our service territory as new developments are built.

21. Please explain any <u>current or forecasted</u> trends related to the following:
    a. PEV counts
    b. PEV charging installation counts
    c. Annual energy consumption
    d. Seasonal Peak Demand (Summer and Winter)

As mentioned in question #20, JEA does not have any technology in placed to be notified when a customer has installed a PEV charging station in their home. However, we have seen an increase in the number of public charging stations installed throughout our service territory as new developments are built.

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

JEA forecasted the number of vehicles in Duval County using multiple regression analysis of historical and forecasted Duval population, median household income and number of households from Moody's Analytics. The forecasted number of PEVs is modeled using multiple regression analysis of the number of vehicles, disposable income from Moody's Analytics, the average motor gasoline price from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO), and JEA's electric rates.

The peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecast peak capacity per PEV grows by 0.01 kW per year.

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

22. Please describe any Company programs or tariffs currently offered to customers relating to PEVs, and describe whether any new or additional programs or tariffs relating to PEVs will be offered to customers within the current planning period.

JEA operates three programs that are directly related to PEVs and charging infrastructure deployment in the service area.

(1) JEA Drive Electric Program (DEP) is a residential program that focuses primarily on education and awareness. Website tools are used to educate customers about the basics of EV driver, charging, and available rebates. At the program website customers are encouraged to engage in a one-on-one conversation with an EV Expert to discuss the benefits of electric vehicles as well as to explore electric vehicle 'fit' as it compares to the caller's driving habits. Other features of the website include an EV shopping tool, a simple tool that calculates total cost of ownership of fossil fuel and electric vehicles. Users can compare multiple PEV and fossil fuel vehicles at once. Customers that own a PEV and would like to install Level 2 charging at home may take advantage of the program rebate available to offset part of the wiring costs of Level 2 charger installation. The rebate covers 15% of the installation costs (excluding the PEV charger) up to a maximum of $300.00. Residential customers that participate in the wiring rebate offer are required to enroll in the passive off-peak charging part of the DEP. For PEV owners JEA offers a voluntary off-peak charging benefit of $7.00 per month if the customer only charges the enrolled vehicle during the off-peak hours: Weekdays

10:00 PM – 6:00 AM, Weekends – Anytime. Compliance with the charging hours is monitored through the customers' whole home AMI meters. Incentives are paid quarterly. EVents are held multiple times per year in the community to raise awareness of the benefits of EV ownership, and to allow prospective EV owners to interact directly with current EV owners, dealerships, and charging companies. At the EVents customers may inspect, ride and drive multiple PEVs in a low stress environment. EVents sponsored by JEA DEP are some of the biggest in the Southeastern United States, and are co-sponsored by stakeholders like the North Florida Transportation Planning Organization, North Florida Clean Fuels Coalition, Jacksonville Transit Authority, North Florida Green Chamber of Commerce, Sierra Club and others. Multiple dealerships bring current PEV models for demonstrations and to allow customers the opportunity for test drives.

(2) JEA Fleet Electrification Program (FEP) is a program for commercial and industrial customers. The FEP focuses on education and awareness largely through a robust online Total Cost of Ownership (TCO) Tool. The free online tool takes customer inputs on current fleet makes, models, and usage in a simple and easy-to-use format. Comparison with a generic electric vehicle replacement or a specific electric vehicle is performed by the software to calculate the TCO of the current fleet vehicle and the PEV replacement. The robust application produces an estimate of costs and benefits derived from switching to PEVs that includes GHG and other air quality pollutant reductions associated with the change. The TCO calculator is a free tool that is designed to educate and facilitate small and less sophisticated fleets as they explore switching to electric fuel. We call this level of service Service Level 1, which is for fleets with less than five vehicles or fleets that already possess sufficient PEV expertise to develop their own Fleet Conversion Plans (FCP). For fleet customers that need more assistance JEA offers Service Level 2, a fleet advisory service that includes development of a comprehensive Fleet Conversion Plan. FCPs evaluate the current fleet operations and site facilities, determine PEV replacements, determine charging requirements, power requirements, infrastructure requirements, fuel costs, maintenance costs and other parameters to develop a high-quality plan that is actionable by the fleet to convert over time to electric fuel. Of particular value to the customer fleet and the utility is that these conversations about infrastructure availability, timeline and costs happens early in the decision-making process.

Service Level 1 and Service Level 2 customers that require electric service upgrades may qualify for some make-ready funding from JEA when they implement the FCP and install electric infrastructure for powering their electric fleet vehicles. Electric Vehicle Charging Equipment (EVSE) that is installed by commercial and industrial customers may qualify for rebates from the JEA Electrification Rebate Program.

(3) JEA Electrification Rebate Program (ERP) provides commercial and industrial customers rebates for the purchase of certain electric devices, including Level 2 and Level 3 EVSE. EVSE purchased for public, private, and fleet use is eligible for rebate under the ERP. EVSE for use at multifamily apartments, public spaces, commercial, retail, and parking facilities are typically eligible for rebates under the ERP.

a. Of these programs or tariffs, are any designed for or do they include educating customers on electricity as a transportation fuel?

Yes, all programs contain significant educational and marketing components designed to engage customers about the economic and environmental benefits of PEV ownership.

b. Does the Company have any programs where customers can express their interest or expectations for electric vehicle infrastructure as provided for by the Utility, and if so, please describe in detail.

Yes, all programs gather customer feedback for the purposes of increasing effectiveness and customer engagement. Customer surveys are conducted, and the DEP has a social media presence on two popular applications.

23. Has the Company conducted or contracted any research to determine demographic and regional factors that influence the adoption of PEVs applicable to its service territory? If so, please describe in detail the methodology and findings.

JEA has successfully used outputs from customer AMI meters to detect Level 2 charging events. Those events have been used to plot sites where Level 2 charging events have taken place, and to visually display clustering on a map. Sequential map studies indicate general spreading into more broad areas of the service area and increased concentration in certain areas within the Southeast, Northeast and Southwest quadrants of the service area.

24. Please describe if and how the 2024 presidential election and the new administration has impacted the Company's projection of PEV growth and related demand and energy growth.

At this time, JEA is unable to predict how the new administration will impact the company's projections for PEV growth, along with the associated demand and energy growth.

25. If applicable, please list and briefly describe all PEV pilot programs the Company is currently implementing and the status of each program.

JEA is working on a project with the Electric Power Research Institute (EPRI) that will monitor telematics data from 400 local PEVs. The study will generate data on vehicle driving and charging behavior as well as battery state of charge information that will be helpful as the utility seeks to understand the impacts of PEV charging on the grid.

26. If applicable, please describe any key findings and metrics of the Company's PEV pilot program(s) which reveal the PEV impact to the demand and energy requirements of the Company.

As noted in the previous report JEA has detected increased EV charging activity the day before predicted major weather events.

Demand Response

27. **[FEECA Utilities Only]** Please refer to the Excel Tables File (DR Participation). Complete the table by providing for each source of demand response annual customer participation information for 10 years prior to the current planning period. Please also provide a summary of all sources of demand response using the table.
    (Please see excel file)

28. **[FEECA Utilities Only]** Please refer to the Excel Tables File (DR Annual Activation). Complete the table by providing for each source of demand response annual usage information for 10 years prior to the current planning period. Please also provide a summary of all demand response using the table.
    (Please see excel file)

Generation & Transmission

Utility-Owned Resources

29. Please refer to the Excel Tables File tabs listed below. Complete the tables by providing information on the utility-owned generation resources for the time period listed. When completing the tables, please consider the following factors: (i) for multiple small (<0.25 MW) distributed resources of the same type and fuel source, provide a single entry; (ii) for solar facilities, if available, provide the nameplate DC capacity as the gross capacity, the nameplate AC capacity as the net capacity, and the firm contribution during time of system peak as the firm capacity. If a solar facility is combined with an energy storage system, identify the capacity of the energy storage system in a separate line.

    a. Excel Tables File (Existing Utility), including each utility-owned generation resource in service as of December 31 of the year prior to the current planning period.
    b. Excel Tables File (Planned Utility), including each utility-owned generation resource that is planned to enter service during the current planning period.

    (Please see excel file)

30. For each planned utility-owned generation resource or group of resources, provide a narrative response discussing the current status of the project.

    JEA has identified a potential JEA-owned site to build a 1x1 advanced-class CCCT. The site is currently being evaluated. Further updates will be presented in subsequent TYSPs as the site evaluation process is finalized.

31. Please list and discuss any planned utility-owned renewable resources that have, within the past year, been cancelled, delayed, or reduced in scope. What was the primary reason for the changes? What, if any, were the secondary reasons?

    JEA does not have any planned or existing utility-owned renewable resources.

32. Discuss the impact of any recent federal actions on permitting for renewable generation. As part of your discussion, identify what projects, if any, were impacted and what those impacts were.

    At this time, there are no anticipated impacts to permitting schedules for those renewable projects in progress, but JEA will continue to monitor federal actions and account for any proposed impacts.-Permitting processes commenced prior to the issuance of the recent federal changes and project schedules incorporate a buffer for possible delays.

33. Please refer to the Excel Tables File (Planned PPSA). Complete the table by providing information on each planned generation resource that requires siting under the Power Plant Siting Act. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification, if applicable.
    (Please see excel file)

34. Please refer to the Excel Tables File (Planned Construction). Complete the table by providing information on all planned generating units with an in-service date within the current planning period. For each planned unit, provide the final decision ("drop dead") date for a decision on whether or not to construct each unit, and the estimated dates for site selection, engineering, permitting, procurement, and construction.
    (Please see excel file)

35. Please refer to the Excel Tables File (Unit Performance). Complete the table by providing information on each utility-owned generation resource in service during the current planning period. For historic performance, use the past three years for a historical average. For projected performance, use an average of the next 10-year period for projected factors.
    (Please see excel file)

36. Please refer to the Excel Tables File (Unit Dispatch). Complete the table by providing the actual and projected capacity factors for each existing and planned unit on the Company's system for the 11-year period beginning one year prior to the current planning period.
    (Please see excel file)

37. **47[Investor-Owned Utilities Only]** For each existing unit on the Company's system, please provide the planned retirement date. If the Company does not have a planned retirement date for a unit, please provide an estimated lifespan for units of that type and a non-binding estimate of the retirement date for the unit.

38. **[Investor-Owned Utilities Only]** Please refer to the Excel Tables File (Solar and Storage Sites). Complete the table by providing information on each of the Company's existing and planned solar and/or energy storage facilities, including the Order and date of Commission approval (or Pending if not yet approved). Identify the associated cost recovery mechanism (such as in a base rate case, the environmental cost recovery clause, solar base rate adjustment, or special tariffs such as SolarTogether, SolarTogether Extension, and Clean Energy Connection) for each facility as well.

39. In its planning process, did the Company consider constructing any solar or energy storage facilities that are co-located with other uses such as parking areas, waterways, existing buildings (including rooftops), or substations? If not, explain why not. If so, explain whether the analysis selected any facilities of this type and identify them.

JEA's current planning process did not include co-locating solar or storage resources with parking areas, waterways, or buildings. Preliminary discussions show there may be a benefit to the system to site storage resources at substations, however further analysis is needed to determine the full benefits. .

40. Please refer to the Excel Tables File (Unit Modifications). Complete the table by providing information on all of the Company's units that are either will or are potential candidates to change fuel types or be repower, such as conversion to a Combined Cycle unit component.
(Please see excel file)

41. Please refer to the Excel Tables File (Transmission Lines). Complete the table by providing a list of all proposed transmission lines for the current planning period that require certification under the Transmission Line Siting Act. Please also include in the table transmission lines that have already been approved, but are not yet in-service.
(Please see excel file)

Power Purchase and/or Sale Agreements

42. Please refer to the Excel Tables File tabs listed below. Complete the tables by providing information on each power purchase agreement (PPA) for the time period listed. If the PPA is associated with a particular generating unit(s), provide additional information about those units if available. When completing the tables, please consider the following factors: (i) for multiple small (<0.25 MW) distributed resources of the same type and fuel source, provide a single entry; (ii) for solar facilities, if available, provide the nameplate DC capacity as the gross capacity, the nameplate AC capacity as the net capacity, and the firm contribution during time of system peak as the firm capacity. If a solar facility is combined with an energy storage system, identify the capacity of the energy storage system in a separate line.

a. Excel Tables File (Existing PPA), including each PPA still in effect by December 31 of the year prior to the current planning period pursuant to which energy was delivered to the Company during said year.
b. Excel Tables File (Planned PPA), including each PPA pursuant to which energy will begin to be delivered to the Company during the current planning period.

(Please see excel file)

43. For each planned power purchase agreement, provide a narrative response discussing the current status of the associated generating project.

The scope of the Florida Renewable Partners projects (50 MW Forest Trail Solar, 74.9 MW Caldwell Solar, 74.9 MW Miller Solar, 74.9 MW Peterson Solar) has been adjusted. The 74.9 MW Peterson Solar project was canceled, as further site diligence showed there was a surplus of wetlands, making it not financially feasible to pursue. JEA will now be purchasing a total of 200 MW from these projects. The three remaining projects are undergoing permitting with construction set to commence in Fall 2025. COD for the sites are still set for December 31, 2026.

The Florida Municipal Power Agency project schedule has been delayed due to longer timelines for network upgrades. Facilities are now expected to commission in October 2028.

The remaining projects are planned in an effort to meet JEA's Clean Energy goal of 35% clean energy by 2030.

44. Please list and discuss any long-term power purchase agreements that have, within the past year, been cancelled, delayed, or reduced in scope. What was the primary reason for the change? What, if any, were the secondary reasons?

The 74.9 MW Peterson Solar project that was part of the Florida Renewable Partners portfolio was canceled, as further site diligence showed there was a surplus of wetlands, making it not financially feasible to pursue.

45. Please refer to the Excel Tables File tabs listed below. Complete the tables by providing information on each power sale agreement (PSA) for the time period listed. If the PSA is associated with a particular generating unit(s), provide additional information about those units if available. When completing the tables, please consider the following factors: (i) for multiple small (<0.25 MW) distributed resources of the same type and fuel source, provide a single entry; (ii) for solar facilities, if available, provide the nameplate DC capacity as the gross capacity, the nameplate AC capacity as the net capacity, and the firm contribution during time of system peak as the firm capacity. If a solar facility is combined with an energy storage system, identify the capacity of the energy storage system in a separate line.

a. Excel Tables File (Existing PSA), including each PSA still in effect by December 31 of the year prior to the current planning period pursuant to which energy was delivered by the Company during said year.
b. Excel Tables File (Planned PSA), including each PSA pursuant to which energy will begin to be delivered by the Company during the current planning period.

N/A

46. For each planned power sale agreement, provide a narrative response discussing the current status of the agreement.

    N/A

47. Please list and discuss any long-term power sale agreements within the past year that were cancelled, expired, or modified. What was the primary reason for the change? What, if any, were the secondary reasons?

    N/A

Renewable Generation

48. Please refer to the Excel Tables File (Renewables). Complete the table by providing the actual and projected annual energy output of all renewable resources on the Company's system, by source, for the 11-year period beginning one year prior to the current planning period.

    (Please see excel file)

49. Please describe any actions the Company engages in to encourage production of renewable energy within its service territory.

JEA offers a Solar Concierge Program aimed at before a JEA customer purchases a PV system. The program offers a PV-specific call center, customer education, a network of contractors for customers to view, and a Program Manager for customer outreach.

JEA also has a Distributed Generation Policy in place that credits the JEA customer for any energy export to the grid.

50. Please identify and describe any programs the Company offers that allows its customers to contribute towards the funding of specific renewable projects, such as community solar programs.

    JEA has SolarSmart which is a program for customers to contribute on-bill each month in any percentage of their monthly energy consumption to show support for utility owned solar facilities. There is a fixed monthly fuel charge and there is no term commitment – customer may unenroll at the end of any bill cycle.

    a. Please describe any such programs in development with an anticipated launch date within the current planning period.

None at this time.

Energy Storage

51. Briefly discuss any progress in the development and commercialization of non-lithium-ion based battery storage technology the Company has observed in recent years.

    There is still peaked interest in longer duration energy storage, as current technologies continue to prove to be geographically limited and/or financially infeasible. Solid state batteries and sodium ion batteries are also remaining on track to be viable competitors to lithium-ion due to their benefits with more energy density, more raw material availability, and charge rate. It will be interesting to see what impacts, if any, the recently increased tariffs have on these technologies.

52. If applicable, please describe the strategy of how the Company charges and discharges its energy storage facilities. As part of the response discuss if any recent legislation, including the IRA, has changed how the Company dispatches its energy storage facilities.

    JEA does not currently own or operate any battery energy storage facilities in its service territory. There is one existing utility scale lithium-ion storage system in the service territory, that is DC-coupled and co-located with the Imeson Solar facility; it is discharged to smooth the solar generation. Two additional utility scale storage systems will be added to the Caldwell Solar facility and the Miller Solar facility, set to commission in December 2026. These systems will have grid and solar-charge capability.

53. Briefly discuss any considerations reviewed in determining the optimal positioning of energy storage technology in the Company's system (e.g., closer to/further from sources of load, generation, or transmission/distribution capabilities).

    JEA is still in the process of identifying optimal placement of energy storage technology on the system.

54. Please explain whether customers have expressed interest in energy storage technologies. If so, describe the type of customer (residential, commercial industrial) and how have their interests been addressed.

    Customers have expressed interest in energy storage technologies. The vast majority have been residential customers with only a very small handful of commercial customers exploring the installation of energy storage.

    JEA has streamlined its interconnection process for both PV and energy storage.

55. Please refer to the Excel Tables File (Existing Storage). Complete the table by providing information on all energy storage technologies that are currently either part of the Company's system portfolio or are part of a pilot program sponsored by the Company.

    (Please see excel file)

56. Please refer to the Excel Tables File (Planned Storage). Complete the table by providing information on all energy storage technologies planned for in-service during the current planning period either as part of the Company's system portfolio or as part of a pilot program sponsored by the Company.

    (Please see excel file)

57. Please identify and describe the objectives and methodologies of all energy storage pilot programs currently running or in development with an anticipated launch date within the current planning period. If the Company is not currently participating in or developing energy storage pilot programs, has it considered doing so? If not, please explain.

    a. Please discuss any pilot program results, addressing all anticipated benefits, risks, and operational limitations when such energy storage technology is applied on a utility scale (> 2 MW) to provide for either firm or non-firm capacity and energy.
    b. Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the current planning period.
    c. Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

       JEA currently has no energy storage pilot programs running. In the past, a pilot microgrid was considered, leveraging the existing relationship with a local university, however those plans have not been finalized and there is no current identified in-service date.

Reliability

58. Please refer to the Excel Tables File (Reliability). Complete the table by providing the loss of load probability, reserve margin, and expected unserved energy for each year of the planning period.
    (Please see excel file)

59. Describe in detail the methodology the Utility used to determine the seasonal firm capacity contribution of its solar facilities or purchases and provide the percentage contribution for each facility, if applicable. As part of this discussion, please explain whether the Company's existing and/or future solar facilities shift the hour of system peak demand for reliability planning purposes net of solar generation.

    JEA includes 20% of its total solar portfolio in its summer firm capacity. Additionally, JEA includes the output from the FPL solar PPA at hour 17 in its summer firm capacity.

    There is no shift on the hour of system peak at this time.

60. **[Investor Owned Utilities Only]** Please refer to Excel Tables File (Firm Solar). Provide an example hourly contribution of the Company's generating units compared to the system demand for a typical seasonal peak day for each season (Summer and Winter). As part of this

response, provide the typical hourly demand and contribution of non-firm renewable resources (such as solar or wind), energy storage (charging and discharging separately), nuclear, natural gas, coal, oil, firm renewables, all other generation, purchased power, power sales, and demand response, if applicable.

61. If the Company utilizes non-firm generation sources in its system portfolio, please detail whether it currently utilizes or has considered utilizing energy storage technologies to provide firm capacity from such generation sources. If not, please explain.

    a. Based on the Company's operational experience, please discuss to what extent energy storage technologies can be used to provide firm capacity from non-firm generation sources. As part of your response, please discuss any operational challenges faced and potential solutions to these challenges.

       JEA currently has no energy storage technology providing firm capacity from non-firm generation sources.

Environmental

62. Please explain if the Company assumes carbon dioxide (CO_2) compliance costs in the resource planning process used to generate the resource plan presented in the Company's current planning period TYSP. If the response is affirmative, answer the following questions:

    a. Please identify the year during the current planning period in which CO2 compliance costs are first assumed to have a non-zero value.

    JEA has not modeled any costs for CO2 compliance at this time due to uncertainties of the proposed future requirements and what compliance options JEA would take.

    b. **[Investor-Owned Utilities Only]** Please explain if the exclusion of CO2 compliance costs would result in a different resource plan than that presented in the Company's current planning period TYSP.

    c. **[Investor-Owned Utilities Only]** Please provide a revised resource plan assuming no CO2 compliance costs.

63. Provide a narrative explaining the impact of any existing environmental regulations relating to air emissions and water quality or waste issues on the Company's system during the previous year. As part of your narrative, please discuss the potential for existing environmental regulations to impact unit dispatch, curtailments, or retirements during the current planning period.

    The current and planned electricity generation mix for JEA will be a key factor in complying with any new CO_2 requirements. In addition to the atmospheric sinks of CO_2 emissions, other avenues of offsetting the carbon footprint are carbon capture from industrial processes or direct capture from ambient air, storage and transport of the captured carbon, the use hydrogen and certain biologic processes. These avenues will require substantial technological advances for meaningful and cost-effective results, with their viability in Florida still uncertain. Under the new Trump administration, the future of these CO2 regulations is even more uncertain. The following paragraphs describe the historical efforts to regulate CO2 emissions in the U.S.

    The Clean Power Plan (CPP), introduced by the Obama EPA in 2015, aimed to set emission guidelines for existing utility units, with individual statewide emission rate goals. However, on October 16, 2017, the Trump EPA proposed to repeal the CPP, rejecting its beyond the fence line, generation-shifting approach. In its place, the Affordable Clean Energy (ACE) rule was proposed by the Trump EPA in 2018 and published in 2019. The ACE rule replaced the CPP, focusing on regulating CO_2 emissions from electric generating units, particularly coal-fired units, with an emphasis on heat rate improvement (HRI) as the Best System of Emission Reduction (BSER). Florida's electric utilities had already been reducing CO_2 emissions substantially, and the ACE rule aimed to reinforce these reductions while allowing states flexibility in designing their State Plans.

    However, the DC Circuit Court vacated the ACE rule on January 9, 2021, and remanded it back to the EPA. Despite this, the court did not reinstate the CPP. The court's decision was challenged, with a group of states and the North American Coal Corporation seeking U.S. Supreme Court review. On October 29, 2021, the Supreme Court agreed to review the appeal of the vacatur of the ACE rule. A decision was reached on June 30, 2022, reversing the previous decision made on January 9, 2021. Following this, the Biden EPA proposed a replacement for the ACE rule on May 23, 2023.

The proposed latest Greenhouse Gas (GHG) rule for power plants aims to address CO_2 and other GHG emissions from fossil fuel-fired electric generating units (EGU's) under Section 111 of the Clean Air Act (CAA). The rule was finalized on May 9, 2024, potentially avoiding Congressional Review Act (CRA) being before the deadline of August 1, 2024. However, the motion to hold the case in abeyance still exists at this time. As such, the state plans are due by May 9, 2026. This, however, provided an exemption for existing gas-fired combustion turbines, Starting on March 26, 2024, the EPA initiated the process of gathering input regarding the regulation of the entire fleet of existing gas combustion turbines under the Clean Air Act 111(d).

EPA has also proposed revisions to the New Source Review (NSR) program through a separate track, distinct from the ACE rule. This initiative involves issuing guidance memorandums and proposing an error correction rule, beginning in November 2019. While these reforms are not anticipated to affect JEA's existing Electric Generating Units (EGUs), they will have implications for any new, modified, or reconstructed EGUs in the future.

New Source Performance Standards (NSPS) Revisions: Concurrent with the CPP, EPA issued NSPS for new EGUs in 2015, i.e., CAA Section 111(b) rules. These standards, codified in Subpart TTTT, were not overturned by the Trump EPA or legal challenges, and were amended in 2018.

Despite the current uncertainties associated with the fate of the final GHG rule for power plants, it calls for the following Best System of Emission Reduction (BSER) for affected units:

New or Reconstructed Steam Generating Units. The new Power Plant GHG Rule does not propose new standards for new or reconstructed steam generating units, due to EPA's anticipation that no new coal-fired power plants will be constructed in the foreseeable future. However, the 2015 NSPS for these sources will continue to be upheld. For large units, the proposed emission rate remains at 1,900 pounds of CO_2 per megawatt-hour on a gross output basis (lb CO_2/MWh-gross), while for small units, it stands at 2,000 lb CO_2/MWh-gross.

Large Modifications of Existing Steam Generating Units. For existing coal-fired steam generators undergoing significant modifications, defined as changes resulting in an increase in hourly CO_2 emissions by more than 10% compared to the previous 5 years, the new Power Plant GHG Rule calls for the same guidelines as those for existing long-term coal-fired steam generators.

New or Reconstructed Fossil Fuel-fired Stationary Combustion. The new GHG Rule proposes categories for combustion turbine facilities constructed or reconstructed after its publication date in the Federal Register. Three subcategories are proposed based on function: low, intermediate, and base load. The Best System of Emission Reduction (BSER) for each subcategory is outlined as follow:

- Low-Load Combustion Turbines: Utilize lower emitting fuels, such as natural gas and distillate oil, with emissions rates ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu
- Intermediate-Load Combustion Turbines: BSER includes the following phases:
  - Implementation of highly efficient generating technology for the life of the unit, by finalization of the new GHG Rule
  - Co-firing of low-GHG hydrogen (30% by volume) by 2032.
- Base-Load Combustion Turbines: BSER is made up of two phases:
  - Utilization of highly efficient generating technology for the life of the unit, by finalization of the new Power Plant GHG Rule
  - Either of the following pathways:
    - Implementation of CCS to achieve 90% capture of GHG emissions by2035, or
    - Co-firing of low-GHG hydrogen (30% by volume) by 2032, ramping up to 96% by 2038.

These revisions are not expected to impact JEA's existing EGUs, unless they are significantly "modified or reconstructed". JEA's proposed new combined cycle combustion turbine project may be subject to these requirements.

Existing Fossil Fuel-fired Stationary Combustion Turbines (currently exempt). Under the new Power Plant GHG Rule, two BSER pathways would be established for large natural gas-fired combustion turbines (those larger than 300 MW) that are frequently operated, with an annual capacity factor exceeding 50%. These pathways track the second phase of the BSER for new or reconstructed baseload combustion turbines discussed previously. EPA is still collecting comments on their rule proposed on November 22, 2024 for Stationary Combustion Turbines, subparts GG, KKKK & KKKKa, till April 15, 2025.

Existing Fossil Fuel-Fired Steam Generating Units. Under new Power Plant GHG Rule, existing fossil fuel-fired steam generating units, particularly coal-fired units, are categorized based on their operating horizon or planned retirement dates. BSER and degree of emission limitation requirements for each subcategory of coal-fired units are delineated as follow:

- Long-term Units (i.e., beyond December 31, 2039)
  - BSER is CCS with 90% capture of CO_2
  - Associated degree of 88.4% reduction in emission rate by 2030.
- Medium-term Units (i.e., Ceasing operations between December 31, 2031 and January 1, 2040)
  - BSER is co-firing 40% (by volume) natural gas
  - Associated degree of 16% reduction in emission rate by 2030.
- Near-term Units (i.e., Ceasing operations between December 31, 2031 and January 1, 2035 with annual capacity factor limit of 20%):

- BSER is continued routine operation and maintenance.
- Imminent-term Units (i.e., Ceasing operations before January 1, 2032):
  - BSER is continued routine operation and maintenance

.

These categories and BSER pathways reflect varying strategies tailored to the anticipated lifespan and retirement dates of existing coal-fired steam generating units. They aim to balance emissions reduction targets with practical considerations related to unit retirement schedules and technological feasibility.

The EPA claims that, since it promulgated the ACE Rule, the costs of CCS have decreased due to technology advancements as well as new policies including the expansion of the Internal Revenue Code section 45Q tax credit for CCS in the Inflation Reduction Act (IRA); and the costs of natural gas co-firing have decreased as well, due in large part to a decrease in the difference between coal and natural gas prices. As a result, the EPA considered both CCS and natural gas co-firing as candidates for BSER for existing coal-fired steam EGUs. The agency also recognizes that CCS will be most cost-effective for existing steam EGUs that are in a position to recover the capital costs associated with CCS over a sufficiently long period of time. It is uncertain if the geological formations in Florida are suited for CCS wells and construction of a CCS pipeline would take many years. According to PSC, no Florida utility has successfully demonstrated a cost-effective CCS project or co-fired the required volume of low-GHG hydrogen at this time.

- Natural Gas- or Oil-fired Units**.** Under the new Power Plant GHG Rule, existing natural gas- and oil-fired steam generating units are categorized into subcategories based on their capacity factor. Given the limited operation of virtually all units in this category, the proposed BSER for baseload and intermediate load units involves routine methods of operation and maintenance. The associated degree of emission limitation aims to prevent any increase in emission rate from these units. However, for natural gas- and oil-fired steam generating units with low load, which exhibit large variations in emission rates, the new GHG Rule does not propose a specific BSER or degree of emission limitation. This recognition acknowledges the complexities and variations in emission rates among units operating at low loads and underscores the need for further assessment and consideration in addressing emissions from these units within the regulatory framework.

State plans for existing sources. Under the new Power Plant GHG Rule, states are mandated to submit plans to the EPA, establishing and enforcing performance standards for existing sources consistent with the Best System of Emission Reduction (BSER) and associated emissions guidelines set by the EPA. The proposed deadline for submitting these state plans is within 24 months of the effective date of the new GHG Rule, or by June 2026 if the rule is finalized according to EPA's timetable.

These state plans are expected to generally meet or surpass the emission guidelines established by the EPA. They must also address any adoption of less stringent standards based on factors such as remaining useful life, requiring states to demonstrate that achieving BSER is not feasible.Furthermore, states are obligated to engage in meaningful consultation with communities most affected by GHG emissions and other stakeholders. This engagement ensures that diverse perspectives are considered in the development and implementation of state plans. Lastly, the new Power Plant GHG Rule allows states to propose the use of measures such as trading and averaging in their plans. These mechanisms provide flexibility for states to achieve emissions reductions while considering economic and practical.

A coalition of 25 states (including Florida) sued the EPA, on January 16, 2024, over a final rule entitled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)," arguing that the EPA did not have the authority to institute the new rule (implementing regulations). The case is in the US Court of Appeals for the District of Columbia Circuit. Under Section 111(d) of the CAA, states must submit plans to the EPA that provide for establishing, implementing and enforcing performance standards for existing energy sources. The new final rule creates a tighter deadline that states must comply with.

Given the historical pattern of regulatory shifts accompanying changes in political party control of the White House, it is implausible that if the new Power Plant GHG Rule can withstand legal challenges, and could eventually lead to its repeal and replacement, similar to the fate of the ACE Rule and the CPP. As mentioned above, another potential avenue for overturning the new Power Plant GHG Rule is through a CRA resolution, which could void the rule and allow a future administration to bypass the lengthy rulemaking process required for repeal.

<u>National Emission Standard for Hazardous Air Pollutants (NESHAP): 40 CFR 63 Subpart YYYY (for Combustion Turbines)</u> has also been revised. As a result of the Residual Risk and Technical Review (RTR) in 2020, EPA will not be imposing additional controls. The agency is however proposing revisions to Start-up, Shut-down and Malfunction (SSM) provisions, adding requirements for E-reporting, and lifting of the stay for new gas-fired CTs. These revisions are not expected to impact JEA's existing EGUs, unless they are significantly "modified or reconstructed" or if JEA constructs a new combustion turbine.

Although the rule was stayed in 2004 after EPA received a petition to delist the gas turbines from source categories that would be subject to NESHAP. After the 2020 RTR, EPA decided to keep the stay because an updated petition was received to delist the source category. Then, after Sierra Club petition and EPA's own risk analysis, the stay was lifted on February 28, 2022. However, JEA's "existing" CTs at Northside Generating Station and Brandy Branch Generating Stations are not currently subject to the rule due to their commencement dates. Furthermore, JEA's "new" CTs at Kennedy Generation Station and Greenland Energy Center are not currently subject to the rule because neither facility is a major source of HAPs.(i.e., they do not have a potential to emit more than 10 tpy of any individual HAP or more than 25 tpy of total HAPs.)

40 CFR 63 Subpart UUUUU (a.k.a. Mercury Air Toxics Standard or MATS): On December 27, 2018, EPA signed a proposal regarding the MATS Supplemental Cost Finding and Residual Risk and Technology Review (RTR). It concluded as follows:

- Regulation of HAPs is not "appropriate or necessary," after reconsidering the cost analysis, because the costs "grossly outweigh the quantified HAP benefits."
- Coal- and oil-fired EGUs would not be delisted from 112 regulation, and the 2012 MATS rule would remain in place.
- Regarding the RTR, no revisions to MATS are warranted.
- On April 23, 2023, EPA proposed to strengthen and update MATS to reflect recent developments in control technologies and the performance of these plants. This proposed rule reflects the most significant improvements and updates to MATS since EPA first issued these standards in February 2012. JEA's CFBs at NGS may be required to implement continuous PM emission monitors to demonstrate compliance with the PM emission standards, in lieu of stack testing, within 3 years from the date of the final rule (May 7, 2024), i.e., by May 7, 2027.
- EPA proposed to revise the filterable PM emission standard from 0.030 pounds per million British thermal units of heat input (lb/MMBtu) to 0.010 lb/MMBtu or possibly even lower. Based on historical stack test results, JEA's CFBs should be able to meet the new limits.
- EPA is considering creating a subcategory for acid gas HAP emissions from EGUs burning eastern bituminous coal refuse, which would affect 10 units in PA and WV.

After the Supreme Court denied a motion to stay the rule, it remains in abeyance. The Trump EPA is to reconsider the MATS regulations based on the industry claim the EPA underestimated the compliance costs and that the rule imposes undue burden on certain coal plants.

Startup, Shutdown and Malfunction (SSM) SIP Call

On May 2015, EPA issued a SSM SIP call, which is a notice of rulemaking that would require 36 states (including Florida) to revise provisions in their State Implementation Plans ("SIPs") related to air emissions from sources during times of startup, shutdown, and equipment malfunction ("SSM"). Numerous parties have challenged the SSM Action in these consolidated cases. On October 31, 2016, the parties completed merits briefing. Oral argument is scheduled for May 8, 2017 has been cancelled. On April 18, 2017, the DOJ filed a motion for the DC Circuit Court continue the oral argument currently as scheduled to allow the new Administration adequate time to review the SSM Action to determine whether it will be reconsidered. With this continuance, EPA officials in the new Administration are expected to scrutinize the SSM Action to determine whether it should be maintained, modified, or otherwise reconsidered. EPA reversed its decision in 2020 stating that the cost of compliance outweighs the emissions benefits from the regulation. In January 2021, it was again reviewed by the Biden Administration and concluded that it was indeed appropriate and necessary.

On March 1, 2024, the U.S. Court of Appeals for the DC Circuit largely vacated EPA's "SIP Call" that required states to remove from their respective air quality plans regulatory waivers for excess air emissions during periods of SSM. The court held that EPA did not make the necessary or appropriate determination required by the CAA to order states to eliminate automatic SSM exemptions, director's discretion provisions, and affirmative defenses that function as SSM exemptions. The decision resolves, for now, a decades old debate over how the CAA can recognize elevated emissions associated with SSM events.

National Ambient Air Quality Standards (NAAQS):

- On June 2, 2010, EPA revised the primary NAAQS for sulfur dioxide (SO2) by implementing a new 1-hour standard of 75 parts per billion (ppb) (calculated as the three-year average of the 99th percentile of the annual distribution of daily maximum 1-hour average concentrations). JEA's NGS Unit 3 is permitted to burn No. 6 fuel oil with sulfur content of greater than 1% by weight and could potentially cause or contribute to exceedance of this 1-hour SO2 standard. Based on comprehensive dispersion modeling analyses, it was determined that probability of compliance with the 1-hour SO2 standard is greater than 99.5 percent as long as the unit does not burn No. 6 fuel oil for more than 14 days in a calendar year. Greater number of days of oil operation is also possible with less confidence levels. This determination is conservative since it also assumed all other NGS steam generating units are operating at full load.
- On December 27, 2024, a secondary NAAQS for SO2 of 10ppb, annual average over three consecutive years, was also published. The rule is in abeyance at this time.
- EPA finalized the NAAQS Fine Particulate Matter ("$PM_{2.5}$") standards in September 2006. Since then, the EPA established a more stringent 24-hour average $PM_{2.5}$ standard and kept the annual average $PM_{2.5}$ standard and the 24-hour coarse particulate matter standard unchanged. The EPA issued a final $PM_{2.5}$ rule on December 14, 2012, that reduced the annual $PM_{2.5}$ standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$. The rule left the 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$ unchanged. The change in the $PM_{2.5}$ has not resulted in non-attainment designation for Duval County and has not had a material adverse effect on the operations of JEA's generating facilities. The Biden administration is currently reviewing the PM NAAQS as contained in 85 Fed. Reg. 82854 dated December 18, 2020. On January 23, 2023, EPA proposed to retain the daily standard of 35 $\mu g/m^3$ and lower the annual standard from 12 to between 9 and 10 $\mu g/m^3$. Final rule is expected around August 2023. On March 6, 2024, EPA lowered the NAAQS for annual $PM_{2.5}$ to 9.0 $\mu g/m^3$, but retained the daily and secondary standards. This rule became effective on May 5, 2024. EPA also approved corrections to $PM_{2.5}$ data from T640/T640X monitors on May 16,2025, and the entire State of Florida is projected to be in attainment. This new NAAQS will only impact JEA if dispersion modeling is required to obtain an air permit.
- On October 1, 2015, the EPA revised its NAAQS for ground-level ozone to 70 parts per billion ("ppb"), which is more stringent than the 75-ppb standard set in 2008. The Clean Air Act mandates that EPA publish initial area designations within two years of the promulgation of a new standard (i.e., by October 2017), but allows for a one-year extension if the Administrator determines he "has insufficient information to promulgate the designations." On November 16, 2017, EPA published a final rule establishing initial area designations for the 2015 NAAQS for ozone EPA, designating 2,646 counties (including all counties in Florida) as "attainment/unclassifiable." EPA is designating areas as

"attainment/unclassifiable" where one or more monitors in the county are attaining the 2015 ozone NAAQS, or where EPA does not have reason to believe the county is violating the 2015 ozone NAAQS or contributing to a violation of the 2015 ozone NAAQS in another county. States with nonattainment areas will have up to three years following designation to submit a revised state implementation plan ("SIP") outlining strategy and emission control measures to achieve compliance. In November 2017, Duval County was deemed unclassifiable pending acceptable monitoring results expected at the end of 2018. Duval County is projected to be in attainment of the revised standard. On August 14, 2019, EPA published the proposal to redesignate Duval County from unclassifiable to attainment/unclassifiable for the 2015 Ozone NAAQS. In the event that Duval County was to become a non-attainment area, JEA's power plants (e.g., Northside and Brandy Branch) could be required to comply with additional emission control requirements (e.g., increased usage of ammonia in their Selective catalytic reduction/Selective non-catalytic reduction ("SCR/SNCR")) for nitrogen oxides and volatile organic compounds which are precursors to ozone formation. The nature and consequences of a non-attainment designation cannot be predicted at this time. On January 20, 2021, the Biden-Harris administration reviewed the Ozone NAAQS as contained in 85 Fed. Reg. 87256 dated December 31, 2020. In April 2022, EPA staff recommended retention of 70 ppb.

- On March 14, 2021, EPA withdrew a denial of petition to create a NAAQS for CO_2. At this time, there is a consideration by EPA to create a secondary NAAQS for CO_2.

Regional Haze

EPA and other agencies have been monitoring visibility in national parks and wilderness areas since 1988. In 1999, the EPA announced a major effort to improve air quality in national parks and wilderness areas. The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah.

As a result of the second planning period of the rule, JEA reduced the use of Fuel Oil No. 6 and its sulfur content. EPA is now considering revisions to the Regional Haze Rule that would affect the third planning period. The main regional haze Class I Areas affecting Florida are the Okefenokee Swamp, the St. Marks National Wildlife Refuge/Bradwell Bay, the Chassahowitzka NWR, and Everglades NP.

In order to satisfy the Regional Haze Phase II requirements, JEA applied for additional permit conditions to restrict the sulfur content of No. 6 fuel oil at Unit 3 and no additional controls are expected to be necessary. By December 2025, JEA is to inform FDEP if it will commit to burn only fuel oil with no more than 1% sulfur by weight in Unit 3, or decommission it.

64. For the U.S. EPA's Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units Rule:

    a. Will your Company be materially affected by the rule?

Yes, This rule will impact JEA if it builds new EGUs, or significantly modifies or reconstructs existing EGUs.

b. What compliance strategy does the Company anticipate employing for the rule?

Due to the uncertain fate of the new Power Plant GHG Rule as it is currently written, its potential impact to JEA is unclear.

c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

To be determined.

d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?

Yes, regulatory and applicability analyses will be done for any proposed new or modified EGUs, and permits will be obtained as needed. The timeline will incorporate the time needed to apply for and receive required regulatory approvals and permits.

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Refer to the Excel Tables File (Emissions Cost). Complete the table by providing information on the costs for the current planning period.

To be determined

65. Explain any expected reliability impacts resulting from each of the EPA rules listed below. As part of your explanation, please discuss the impacts of transmission constraints and changes to units not modified by the rule that may be required to maintain reliability.

a. Mercury and Air Toxics Standards (MATS) Rule. *N/A*
b. Cross-State Air Pollution Rule (CSAPR). *N/A*
c. Cooling Water Intake Structures (CWIS) Rule. *To be determined*
d. Coal Combustion Residuals (CCR) Rule. *N/A CCR Rule only applies to SJRPP, which is no longer generating energy.*
e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units. *To be determined*
f. Affordable Clean Energy Rule or its replacement. *To be determined*
g. Effluent Limitations Guidelines and Standards (ELGS) from the Steam Electric Power Generating Point Source Category. *To be determined*

66. Please refer to the Excel Tables File (EPA Operational Effects). Complete the table by identifying, for each unit affected by one or more of EPA's rules, what the impact is for each rule, including: unit retirement; curtailment; installation of additional emissions controls: fuel switching: or other impacts identified by the Company.
(Please see excel file)

67. Please refer to the Excel Tables File (EPA Cost Effects). Complete the table by identifying, for each unit impacted by one or more of the EPA's rules, what the estimated cost is for implementing each rule over the course of the planning period.
(Please see excel file)

Air Rules: Close monitoring and reduction of No. 6 fuel oil usage at NGS Unit 3 is required in order to assure continuous compliance with the 1-hour SO2 NAAQS as well as the Regional Haze Round II requirements. If the new Power Plant GHG rule passes legal challenges, retirements or installation of additional emission controls or continuous emissions monitoring systems (CEMS) may be required. Additional costs of renewable energy sources, and/or CO_2 credits may also be required, while tax credits from Inflation Reduction Act may also be possible. If the MATS rule is implemented, the PM CEMS will need to be installed and operated and maintained. The costs are unknown at this time.

Water Rules: CWIS has the potential to require upgrades to intake structures on NGS units. The final rule of Section 316(b) of the Federal Clean Water Act was published in the Federal Register on August 15, 2014. JEA does not believe that new standards in the final rule will affect any of its facilities other than NGS. It is possible that new standards may prospectively require upgrades to the system, varying from establishment of existing facilities as the Best Technology Available (BTA), to improvements to the existing screening facilities, to the installation of other cooling technologies. Biological studies were recently concluded for the NGS plant, and a full peer reviewed submittal to the regulatory agency is not expected to be completed until 2026. JEA's current estimate of compliance cost shows a one-time cost anywhere between $1 to 10 million.

Solid Waste Rules: The CCR rule applies to Area B of the former St. John's River Power Park (SJRPP) and does not apply to management of byproducts at Northside Generating Station as long as it continues to burn a fuel mix with less than 50 percent coal. The operating cell within Area B of SJRPP was closed and closure construction was completed in January 2022 in accordance with specified performance standards. The facility will continue to comply with the monitoring requirements of the rule in accordance with the post-closure and corrective action plans for groundwater. JEA's current estimate for corrective measures and long-term closure near $5 million. On November 4, 2024, EPA's Coal Combustion Residuals Surface Impoundments and CCR Management Units Rule became final. EPA finalized this Rule to regulate coal ash of inactive CCR Surface Impoundments and inactive CCR Management Units and establishes groundwater monitoring, corrective action, closure, and post-closure care requirements. The proposed rule applies to the closed Area A landfills (1&2) at SJRPP. Initial costs impacts are anticipated to be approx. $530k (Facility Evaluation: $35k, Groundwater Monitoring: $375k, Closure/Post-Closure Care: $60k, Legal: $60k). Level of effort beyond the initial two years will be determined by the facility evaluations, ground water testing results and closure plans.

68. Please refer to the Excel Tables File (EPA Unit Availability). Complete the table by identifying, for each unit impacted by one or more of EPA's rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Include important dates relating to each rule.
(Please see excel file)

69. If applicable, identify any currently approved costs for environmental compliance investments made by your Company, including but not limited to renewable energy or energy efficiency measures, which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations. Briefly describe the nature of these investments and identify which rule(s) they are intended to address.
N/A

Fuel Supply & Transportation

70. Please refer to the Excel Tables File (Energy Rates). Complete the table by providing information on the Utility's firm capacity and energy purchases, non-firm energy purchases, and the utility's as-available energy rate. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well.

(Please see excel file)

71. Please refer to the Excel Tables File (Fuel Usage & Price). Complete the table by providing, on a system-wide basis, the actual annual fuel usage (in GWh) and average fuel price (in nominal $/MMBTU) for each fuel type utilized by the Company in the 10-year period prior to the current planning period. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the current planning period.
(Please see excel file)

72. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

JEA compares its forecast to other independently produced forecasts at the commodity level excluding transportation, some commodity prices are compared with monthly granularity, while others are compared on an annual basis. Transportation forecasts tend to be too generic for JEA's specific circumstances, but JEA does consider rail, tanker, and dry bulk cargo freight rates and forecasts from various sources to judge general trends within the respective industries.

73. Please identify and discuss expected industry trends and factors for each fuel type listed below that may affect the Company during the current planning period.

a. Coal

Coal prices in nominal dollars are expected to increase during the forecast period. Delivered Colombian coal is forecasted to be priced lower than delivered domestic coal during the study period. Over the long term, coal consumption in the electric power sector is forecasted to continue to decline as a result of increased competition with natural gas and renewable generation.

b. Natural Gas

The price of natural gas is projected in nominal dollars to increase throughout the forecast period. Natural gas is used as a primary fuel at four of JEA's existing electric generation facilities. Over the forecast period, Black & Veatch assumes that there will be sufficient availability of natural gas for JEA from continued growth in new oil wells that produce associated natural gas and new unconventional gas wells.

c. Nuclear

N/A

d. Fuel Oil

JEA maintains diesel inventory at Brandy Branch, Kennedy, Greenland, and Northside. Additional diesel supply is purchased from time to time in the open market as needed. The price of diesel fuel oil is projected in nominal dollars to increase throughout the forecast period and remain higher than the price of natural gas.

e. Other (please specify each, if any)

JEA uses circulating fluidized bed technology in Northside Generating Station Units 1 and 2. This technology allows JEA to use a blend of petroleum coke, bituminous coal, and biomass in these units. During the planning period, JEA expects the petroleum coke market to typically trade at a discount to coal.

74. Please provide a comparison of the Utility's 2024 fuel price forecast used to prepare its 2024 TYSP and its actual 2024 delivered fuel prices. (Fuels team to draft response)

Actual 2024 delivered fuel prices came in lower for all the fuel types that JEA consumes compared to the 2024 fuel price forecast. On a percentage basis, prices for natural gas and solid fuel decreased by the largest margin.

75. Please explain any notable changes in the Utility's forecast of fuel prices used to prepare the Utility's current TYSP compared to the fuel process used to prepare the Utility's prior TYSP.

    JEA's process for preparing the Utility's 2025 TYSP was relatively similar to that used for the 2024 TYSP for coal, fuel oil and petroleum coke price forecasts. However, EIA did not issue the annual publication of the Annual Energy Outlook (AEO) in 2024, therefore, the Utility's 2025 TYSP continued to rely on the AEO 2023 for these forecasts. NYMEX exchange futures prices were updated to capture the latest price movements. Natural gas price forecasts are based on Black & Veatch's Energy Market Perspective (EMP) base case, a forecast derived from natural gas demand and supply trends utilizing the Gas Pipeline Competition Model (GPCM) and blended with NYMEX futures prices in the near term.

76. Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the current planning period.

    JEA utilizes firm transportation on Florida Gas Transmission, Southern Natural Gas, and SNG Elba Express/Cypress pipeline. In addition, JEA has a firm long-term agreement for gas supply delivered to Jacksonville using Florida Gas Transmission and Southern Natural Gas pipelines. To deliver natural gas to JEA's Greenland Energy Center, JEA has a long-term contract with SeaCoast Gas Transmission, LLC. The various transportation contracts allow JEA the ability to access natural gas from diverse supply regions.

Emerging Technologies

77. **[FEECA Utilities Only]** Please refer to the Excel Tables File tabs listed below. Complete the tables by providing information on the data centers for the time period listed.

    a. Excel Tables File (Existing Data Centers), including for data centers being served as of December 31 of the year prior to the current planning period.
    b. Excel Tables File (Planned Data Centers), including for data centers that are planned during the current planning period.
    No Planned Data Centers.

78. With respect to the load forecast included in the Utility's 2025 Ten-Year Site Plan to be filed in April this year, does the load forecast include projections of annual energy consumption and demand associated with data centers within your service area during the forecasting time horizon (2025-2034)?

    a. If any such projections have been made, please provide details of the projections including the type of data centers expected to contribute to such energy/demand, and what factors are driving such energy consumption and demand.

JEA did not perform a separate forecast for the existing data center due to its small demand. It is currently embedded in our forecast trend analysis. No other data center projections are included in the forecast.

b. If no specific projections have been made, what does the Utility believe is the likely pattern of load growth associated with this industry within its service territory?

JEA is currently assessing the potential impact of load growth driven by the increasing number of data centers. At this time, JEA has no planned load growth attributed to data centers.

79. Please identify the Utility's issues and/or concerns, if any, that are expected to result from the growth in data centers in your utility's service territory. Please also specify how has, and how does, your utility anticipate responding to such issues or concerns.

JEA has been receiving numerous Data Center inquires over the past year. In order to serve these data centers, JEA will need to construct more generating resources. As mentioned in question #78, JEA is actively assessing the potential impact of load growth driven by data centers. In addition, the utility is conducting internal evaluations to understand how this growth could affect operations and to determine whether existing resources can meet the anticipated demand.

80. **[FEECA Utilities Only]** Please identify and discuss the Company's role in the research and development of utility power technologies, including, but not limited to, research programs that are funded through the Energy Conservation Cost Recovery Clause. As part of this response, please describe any plans to implement the results of research and development into the Company's system portfolio, and the timing of such implementation. In addition, discuss how any anticipated benefits will affect your customers.

There are no ECCR related funds at JEA as this clause is not applicable to the company. JEA does not have R&D projects or research programs funded at this time.

81. Has the Utility employed, or considered using, any type of the artificial intelligence and/or other new technologies/tools in its load forecasting, operation, customer service, and cybersecurity management? Please explain your response. JEA has an AI Council that is reviewing and considering various opportunities to employ AI techniques in parts of the organization. Some preliminary AI technologies have been employed in operations and customer service (listed below) and the organization is continuing to develop policies, procedures, governance, infrastructure, and staffing to ensure effective deployment of AI. Examples include:

- Identification of broken water meters
- Forecasting incoming calls to contact center
- Customer Segmentation
- Call summary and classification (in development)

The call center is also in the middle of a deployment of AI technology that will provide quality scores for every incoming call, greatly improving our ability to coach call takers and improve the customer experience. JEA is in the very early phase of AI implementation.

82. Please identify and discuss emerging power generation and consumption technologies your Company is considering. As part of this response, please describe any formal steps the Company has or will take for possible implementation of the technology.

    At this time, JEA has no new technologies planned for implementation within the Ten-Year Site Plan horizon..

TYSP Year 2025

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Financial Assumptions			
Base Case			
AFUDC Rate		(%)	4.5
Capitalization Ratios	Debt	(%)	100
	Preferred	(%)	0
	Equity	(%)	0
Rate of Return	Debt	(%)	4.5
	Preferred	(%)	0
	Equity	(%)	0
Income Tax rate	State	(%)	0
	Federal	(%)	0
	Effective	(%)	0
Other Tax Rate:		(%)	0
Discount Rate:		(%)	4.5
Tax - Depreciation Rate:		(%)	N/A

Financial Escalation Assumptions				
Year	General Inflation (%)	Plant Construction Cost (%)	Fixed O&M Cost (%)	Variable O&M Cost (%)
2025	3.5	3.5	3.5	3.5
2026	3.5	3.5	3.5	3.5
2027	3.5	3.5	3.5	3.5
2028	3.5	3.5	3.5	3.5
2029	3.5	3.5	3.5	3.5
2030	3.5	3.5	3.5	3.5
2031	3.5	3.5	3.5	3.5
2032	3.5	3.5	3.5	3.5
2033	3.5	3.5	3.5	3.5
2034	3.5	3.5	3.5	3.5

TYSP Year 2025
Question No. 5

Year	Month	Actual Peak Demand (MW)	Demand Response Activated (MW)	Estimated Peak Demand (MW)	Day	Hour	System-Average Temperature (Degrees F)
2024	1	2416	0	2416	17	9	40
	2	2043	0	2043	20	8	51
	3	1767	0	1767	15	18	71
	4	2121	0	2121	19	18	77
	5	2470	0	2470	9	17	84
	6	2664	0	2664	10	17	85
	7	2592	0	2592	12	17	85
	8	2675	0	2675	9	16	88
	9	2486	0	2486	2	18	84
	10	2280	0	2280	1	16	84
	11	1942	0	1942	7	16	81
	12	2161	0	2161	4	8	46
2023	1	2326	0	2326	16	8	48
	2	1813	0	1813	24	16	76
	3	2049	0	2049	27	18	78
	4	2081	0	2081	5	18	76
	5	2230	0	2230	16	17	79
	6	2598	0	2598	27	18	87
	7	2699	0	2699	21	17	88
	8	2756	0	2756	7	17	87
	9	2463	0	2463	6	17	82
	10	2057	0	2057	5	17	79
	11	2043	0	2043	29	8	47
	12	2016	0	2016	20	8	48
	1	2529	0	2529	30	8	40
	2	2211	0	2211	10	8	51
	3	1862	0	1862	13	10	42
	4	2007	0	2007	26	17	73

2022	**5**	2452	0	2452	19	17	81
	6	2728	0	2728	23	17	87
	7	2598	0	2598	7	16	86
	8	2612	0	2612	2	17	85
	9	2574	0	2574	6	18	85
	10	1999	0	1999	13	17	76
	11	1899	0	1899	1	17	75
	12	2599	0	2599	25	9	34
Notes							
Hour is Peak Hour ending							

TYSP Year 2025
Question No. 18

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public DCFC PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand	Winter Demand	Annual Energy
				(MW)	(MW)	(GWh)
2025	24,074	258		2	1	24
2026	29,643	297		4	1	50
2027	35,787	338		7	2	79
2028	42,565	382		9	2	110
2029	50,017	429		12	3	145
2030	58,111	479		16	4	183
2031	66,844	531		19	5	224
2032	76,205	586		23	6	268
2033	86,227	644		39	7	315
2034	96,911	705		46	8	366
Notes						
(Include Notes Here)						

TYSP Year 2025
Question No. 27

[Demand Response Source or All Demand Response Sources]									
Year	**Participating Customers**			**Available Capacity (MW)**					
				Summer			**Winter**		
	Start of Year	Lost	Added	Start of Year	Lost	Added	Start of Year	Lost	Added
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
Notes									
JEA has not had a Demand Response program									

TYSP Year 2025
Question No. 28

[Demand Response Source or All Demand Response Sources]														
Year	Summer							Winter						
	Total Events	Customers Activated			Capacity Activated (MW)			Total Events	Customers Activated			Capacity Activated (MW)		
		Average Event	Max Event	Peak Day	Average Event	Max Event	Peak Day		Average Event	Max Event	Peak Day	Average Event	Max Event	Peak Day
2015														
2016														
2017														
2018														
2019														
2020														
2021														
2022														
2023														
2024														
Notes														
JEA has not had a Demand Response program														

TYSP Year 2025
Question No. 29(a)

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)					
							Gross		Net		Firm	
					Mo	Yr	Sum	Win	Sum	Win	Sum	Win
Brandy Branch	GT1	Duval	GT	NG	5	2001	150.5	192.7	149.9	191.2	149.9	191.2
Brandy Branch	CT2	Duval	CT	NG	5	2001	190.5	212.2	189.7	211.7	189.7	211.7
Brandy Branch	CT3	Duval	CT	NG	10	2001	190.5	212.2	189.7	211.7	189.7	211.7
Brandy Branch	STM4	Duval	CA	WH	1	2001	210	225	200	216.1	200	216.1
Greenland Energy Center	GT1	Duval	GT	NG	6	2011	150.5	192.7	149.9	191.2	149.9	191.2
Greenland Energy Center	GT2	Duval	GT	NG	6	2011	150.5	192.7	149.9	191.2	149.9	191.2
J. D. Kennedy	GT7	Duval	GT	NG	6	2000	150.5	192.7	149.9	191.2	149.9	191.2
J. D. Kennedy	GT8	Duval	GT	NG	6	2009	150.5	192.7	149.9	191.2	149.9	191.2
Northside	1	Duval	ST	PC	5	2003	310	310	293	293	293	293
Northside	2	Duval	ST	PC	4	2003	310	310	293	293	293	293
Northside	3	Duval	ST	NG	6	1977	540	540	524	524	524	524
Northside	GT3	Duval	GT	DFO	1	1975	50.4	62	50	61.6	50	61.6
Northside	GT4	Duval	GT	DFO	1	1975	50.4	62	50	61.6	50	61.6
Northside	GT5	Duval	GT	DFO	12	1974	50.4	62	50	61.6	50	61.6
Northside	GT6	Duval	GT	DFO	12	1974	50.4	62	50	61.6	50	61.6
Notes												
(Include Notes Here)												

TYSP Year 2025
Question No. 29(b)

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)					
							Gross		Net		Firm	
					Mo	Yr	Sum	Win	Sum	Win	Sum	Win
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	12	2030			576	669.8	576	669.8
Notes												
(Include Notes Here)												

TYSP Year 2025
Question No. 33

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Certification Dates (if Applicable)	
							Need Approved	PPSA Certified
					Mo	Yr	(Commission)	
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	12	2030	Mar-26	Mar-27
Notes								
(Include Notes Here)								

TYSP Year 2025
Question No. 34

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Final Decision ('Drop Dead') Date	Site Selection		Engineering / Permitting / Procurement		Construction		Commercial In-Service Date
						Begins	Ends	Begins	Ends	Begins	Ends	
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	8/26/2025	Jun-23	Aug-25	Jun-23	Sep-25	TBD	Dec-30	Dec-30
Notes												
(Include Notes Here)												

TYSP Year 2025
Question No. 35

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Performance (%)						Average Net Operating Heat Rate (ANOHR)	
							Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)			
					Mo	Yr	Historic	Projected	Historic	Projected	Historic	Projected	Historic	Projected
Brandy Branch	GT1	Duval	GT	NG	5	2001	4.76%	2.88%	0.09%	2.03%	95.04%	95.09%	10,895	10,279
Brandy Branch	CT2, CT3, STM4	Duval	CC	NG	1	2005	6.64%	5.07%	1.19%	1.86%	91.04%	93.07%	6,931	6,478
Greenland Energy Center	GT1	Duval	GT	NG	6	2011	3.65%	3.29%	2.85%	1.70%	93.09%	95.01%	11,155	10,828
Greenland Energy Center	GT2	Duval	GT	NG	6	2011	3.32%	2.30%	2.41%	1.94%	94.00%	95.75%	11,020	10,820
J. D. Kennedy	GT7	Duval	GT	NG	6	2000	8.68%	2.63%	0.65%	2.91%	88.16%	94.46%	11,455	10,509
J. D. Kennedy	GT8	Duval	GT	NG	6	2009	2.80%	2.87%	1.07%	2.76%	95.46%	94.37%	11,472	10,878
Northside	1	Duval	ST	PC	5	2003	7.36%	10.24%	1.54%	4.07%	90.51%	85.69%	14,052	9,904
Northside	2	Duval	ST	PC	4	2003	15.84%	9.31%	0.18%	4.13%	81.46%	86.57%	11,297	9,942
Northside	3	Duval	ST	NG	6	1977	10.49%	8.41%	1.83%	2.63%	86.06%	88.96%	11,397	6,100
Northside	GT3	Duval	GT	DFO	1	1975	7.63%	3.20%	21.22%	4.58%	69.49%	92.22%	18,774	17,634
Northside	GT4	Duval	GT	DFO	1	1975	4.50%	2.41%	4.33%	4.73%	80.08%	92.86%	23,593	17,371
Northside	GT5	Duval	GT	DFO	12	1974	1.15%	3.15%	2.42%	4.97%	90.91%	91.88%	24,683	17,371
Northside	GT6	Duval	GT	DFO	12	1974	0.88%	3.81%	9.03%	4.83%	86.97%	91.36%	25,770	15,669
Advanced-Class 1x1 CC	TBD	TBD	CCCT	NG	12	2030	N/A	6.00%	N/A	3.11%	N/A	90.90%	N/A	6,623
Notes														
(Include Notes Here)														

TYSP Year 2025
Question No. 36

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Capacity Factor (%)										
							Actual	Projected									
					Mo	Yr	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Brandy Branch	GT1	Duval	GT	NG	5	2001	19.6	35	28	28	17	12	12	5	5	6	6
Brandy Branch	CT2, CT3, STM4	Duval	CC	NG	1	2005	87.3	87	88	81	87	85	82	70	69	71	73
Greenland Energy Center	GT1	Duval	GT	NG	6	2011	23.1	50	38	34	19	18	17	9	9	11	10
Greenland Energy Center	GT2	Duval	GT	NG	6	2011	24.5	50	35	35	18	17	17	8	8	10	10
J. D. Kennedy	GT7	Duval	GT	NG	6	2000	8.1	18	13	14	6	7	7	4	3	5	5
J. D. Kennedy	GT8	Duval	GT	NG	6	2009	3.3	23	11	11	5	7	6	3	4	4	4
Northside	1	Duval	ST	PC	5	2003	17.6	8	20	14	35	56	32	9	25	23	26
Northside	2	Duval	ST	PC	4	2003	23.3	7	7	11	27	19	68	25	7	17	19
Northside	3	Duval	ST	NG	6	1977	44.8	34	47	52	38	31	25	0	0	0	0
Northside	GT3	Duval	GT	DFO	1	1975	0.1	4	2	2	1	1	1	0	0	1	0
Northside	GT4	Duval	GT	DFO	1	1975	0	4	2	2	1	1	1	0	0	1	0
Northside	GT5	Duval	GT	DFO	12	1974	0.1	3	2	2	1	1	1	0	0	1	0
Northside	GT6	Duval	GT	DFO	12	1974	0.1	3	2	2	0	1	1	0	0	0	0
Advanced-Class 1x1 CC	TBD	TBD	CCCT	NG	12	2030	0	0	0	0	0	0	21	56	57	57	58
Notes																	
(Include Notes Here)																	

TYSP Year 2025
Question No. 38

Facility Name	Unit No.	County Location	Solar Type	Energy Storage Type	Facility In-Service Date		Unit Capacity (MW)				Land Use	Commission Approval		Cost Reocvery Mechanism
							Net		Firm					
			(Fixed/Tracking)		Mo	Yr	Sum	Win	Sum	Win	(Acres)	Order No.	Approval Date	

Notes
N/A

TYSP Year 2025
Question No. 40

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Planned Modification (if any)	Eligible Modifications			Potential Issues
					Mo	Yr		Fuel Switching	Combined Cycle Conversion	Other (Explain)	
Brandy Branch	GT1	Duval	GT	NG	5	2001			X		
Greenland Energy Center	GT1	Duval	GT	NG	6	2011			X		
Greenland Energy Center	GT2	Duval	GT	NG	6	2011			X		
J. D. Kennedy	GT7	Duval	GT	NG	6	2000			X		
J. D. Kennedy	GT8	Duval	GT	NG	6	2009			X		
Northside	3	Duval	ST	NG	6	1977			X		Resulting Unit Size Too
Northside	1	Duval	ST	PC	5	2003		X			
Northside	2	Duval	ST	PC	4	2003		X			
Northside	GT3	Duval	GT	DFO	1	1975		X			
Northside	GT4	Duval	GT	DFO	1	1975		X			
Northside	GT5	Duval	GT	DFO	12	1974		X			
Northside	GT6	Duval	GT	DFO	12	1974		X			

Notes

(Include Notes Here)

TYSP Year 2025
Question No. 41

Transmission Line	Line Length	Nominal Voltage	Certification Dates		In-Service Date
	(Miles)	(kV)	Need Approved	TLSA Certified	
Notes					
NONE					

TYSP Year 2025
Question No. 42(a)

Contract Information						Provide If Associated with Specific Unit(s)												
Seller Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)[1]					
		Firm Capacity (MW)[1]		Delivery Dates									Gross		Net		Firm	
		Sum	Win	Start	End						Mo	Yr	Sum	Win	Sum	Win	Sum	Win
LES	05/06	0	0	12/08	12/26	Trail Ridge I	N/A	Duval	IC	Methane	Dec	2008	9.1	9.1	9.1	9.1	0	0
LES	08/13	0	0	02/14	12/26	Trail Ridge II	N/A	Sarasota	IC	Methane	Feb	2015	6	6	6	6	0	0
Rev Renewables	05/09	0	0	09/10	09/40	Jacksonville Solar	N/A	Duval	Solar PV	SUN	Sep	2010	12	12	12	12	0	0
Northwest Jacksonville Solar Partners, LLC	08/15	0	0	05/17	05/42	NW JAX Solar	N/A	Duval	Solar PV	SUN	May	2017	7	7	7	7	0	0
Old Plank Road Solar Farm LLC	12/15	0	0	10/17	10/37	Old Plank Road Solar	N/A	Duval	Solar PV	SUN	Oct	2017	3	3	3	3	0	0
C2 Starratt Solar LLC	11/15	0	0	12/17	12/37	Starratt Solar	N/A	Duval	Solar PV	SUN	Dec	2017	5	5	5	5	0	0
Inman Solar Incorporated	11/15	0	0	01/18	01/38	Simmons Road Solar	N/A	Duval	Solar PV	SUN	Jan	2018	2	2	2	2	0	0
Hecate Energy Blair Road, LLC	08/15	0	0	01/18	01/38	Blair Site Solar	N/A	Duval	Solar PV	SUN	Jan	2018	4	4	4	4	0	0
JAX Solar Developers, LLC	12/16	0	0	10/18	10/38	Old Kings Road Solar	N/A	Duval	Solar PV	SUN	Oct	2018	1	1	1	1	0	0
Imeson Solar, LLC (Solar)	03/16	0	0	12/19	12/39	SunPort Solar	N/A	Duval	Solar PV	SUN	Dec	2019	5	5	5	5	0	0
Imeson Solar, LLC (Battery)[3]	03/16	2	2	12/19	12/39	SunPort Solar	N/A	Duval	Solar PV	SUN	Dec	2019	2	2	2	2	2	2
FPL[2]	03/23	150	150	04/23	04/28	FPL Solar PPA	N/A	Multiple	Solar PV	SUN	Multiple	Multiple	-	-	-	-	150	150
FPL[4]	08/20	200	200	01/22	01/42	-	-	-	-	NG	-	-	200	200	200	200	200	200

Notes

(1) Solar capacity based on AC rating.
(2) Energy sourced from multiple facilities in FPL service territory. Will not extend at end of term.
(3) Battery rated at 2 MW/4MWh and is DC-coupled with solar system.
(4) Traditional purchase; system product.

TYSP Year 2025
Question No. 42(b)

Contract Information						Provide If Associated with Specific Unit(s)												
Seller Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)					
		Firm Capacity (MW)		Delivery Dates									Gross[1]		Net[1]		Firm[2]	
		Sum	Win	Start	End						Mo	Yr	Sum	Win	Sum	Win	Sum	Win
FRP Caldwell Solar, LLC	05/24	0	0	12/26	12/61	Caldwell Solar PPA	N/A	Duval	Solar PV	SUN	Dec	2026	74.9	74.9	74.9	74.9	15	0
FRP Miller Solar, LLC	05/24	0	0	12/26	12/61	Miller Solar PPA	N/A	Duval	Solar PV	SUN	Dec	2026	74.9	74.9	74.9	74.9	15	0
FRP Forest Trail Solar, LLC	05/24	0	0	12/26	12/61	Forest Trail Solar PPA	N/A	Duval	Solar PV	SUN	Dec	2026	50	50	50	50	10	0
Florida Municipal Power Agency	08/23	0	0	10/28	10/48	FMPA Solar PPA	N/A	Bradford	Solar PV	SUN	Oct	2028	150	150	150	150	30	0
TBD	TBD	0	0	03/28	03/53	74.9 Solar PPA 1	N/A	Duval	Solar PV	SUN	Q1	2028	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	03/28	03/53	74.9 Solar PPA 2	N/A	Duval	Solar PV	SUN	Q1	2028	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	03/28	03/53	74.9 Solar PPA 3	N/A	Duval	Solar PV	SUN	Q1	2028	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	03/28	03/53	74.9 Solar PPA 4	N/A	Duval	Solar PV	SUN	Q1	2028	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 5	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 6	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 7	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 8	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 9	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 10	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 11	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	74.9 Solar PPA 12	N/A	Duval	Solar PV	SUN	Q4	2030	74.9	74.9	74.9	74.9	15	0
TBD	TBD	0	0	12/30	12/55	35 MW Solar PPA	N/A	Duval	Solar PV	SUN	Q4	2030	35	35	35	35	7	0

Notes

(1) Solar capacity based on AC rating.

TYSP Year 2025
Question No. 45(a)

Contract Information						Provide If Associated with Specific Unit(s)												
Buyer Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)					
		Firm Capacity (MW)		Delivery Dates									Gross		Net		Firm	
		Sum	Win	Start	End						Mo	Yr	Sum	Win	Sum	Win	Sum	Win

Notes

N/A

TYSP Year 2025
Question No. 45(b)

Contract Information						Provide If Associated with Specific Unit(s)													
Buyer Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)						Land Use
		Firm Capacity (MW)		Delivery Dates									Gross		Net		Firm		
		Sum	Win	Start	End						Mo	Yr	Sum	Win	Sum	Win	Sum	Win	(Acres)

Notes

N/A

TYSP Year 2025
Question No. 48

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Utility - Firm	0	0	0	0	0	0	0	0	0	0	0
Utility - Non-Firm	0	0	0	0	0	0	0	0	0	0	0
Utility - Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Purchase - Firm	431	522	521	391	87	0	0	0	0	0	0
Purchase - Non-Firm	52	56	56	531	1,235	1,612	1,606	3,152	3,140	2,880	2,808
Purchase - Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Customer - Owned	24	24	24	24	24	24	24	24	24	24	24
Total	507	602	601	946	1,346	1,636	1,630	3,176	3,164	2,904	2,832
Notes											
(1) Firm purchases from landfill gas and FPL Solar PPA; non-firm from remaining solar PV.											

TYSP Year 2025
Question No. 56

Facility or Project Name	Unit No.	County Location	Energy Storage Type	Battery Chemistry (if applicable)	Land Use	Facility In-Service or Project Start Date		Unit Capacity (MW)						Storage Capacity	Conversion Efficency[1]
								Gross		Net		Firm			
					(Acres)	Mo	Yr	Sum	Win	Sum	Win	Sum	Win	(MWh)	(MWh)
FRP Caldwell Solar, LLC	N/A	Duval	Battery	Lithium-ion	5	Dec	2026	50	50	50	50	50	50	200	168
FRP Miller Solar, LLC	N/A	Duval	Battery	Lithium-ion	5	Dec	2026	50	50	50	50	50	50	200	168

Notes

(1) Energy for efficiency of first year of operation shown.

Loss of Load Probability, Reserve Margin, and Expected Unserved Energy						
Base Case Load Forecast						
Year	**Loss of Load Probability (Days/Yr)**	**Annual Isolated Reserve Margin (%) (Including Firm Purchases)**	**Expected Unserved Energy (MWh)**	**Loss of Load Probability (Days/Yr)**	**Annual Assisted Reserve Margin (%) (Including Firm Purchases)**	**Expected Unserved Energy (MWh)**
2025	0.07	22	130	N/A	N/A	N/A
2026	0.03	21	40	N/A	N/A	N/A
2027	0.03	20	40	N/A	N/A	N/A
2028	0.08	18	320	N/A	N/A	N/A
2029	0.01	19	10	N/A	N/A	N/A
2030	0.01	18	10	N/A	N/A	N/A
2031	0.00	23	0	N/A	N/A	N/A
2032	0.00	22	0	N/A	N/A	N/A
2033	0.00	22	0	N/A	N/A	N/A
2034	0.01	21	0	N/A	N/A	N/A

TYSP Year 2025
Question No. 60

Peak Summer Day Hourly Dispatch (MW)												
Hour	Customer Oriented		Power Transactions		Energy Storage		Generation Resources					
	Load	Demand Response	Sales	Purchases	Charging	Discharging	Nuclear	Natural Gas	Coal	Oil	Other	Solar
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												

Peak Winter Day Hourly Dispatch (MW)												
Hour	Customer Oriented		Power Transactions		Energy Storage		Generation Resources					
	Total Load	Demand Response	Sales	Purchases	Charging	Discharging	Nuclear	Natural Gas	Coal	Oil	Other	Solar
1												
2												
3												
4												
5												

6													
7													
8													
9													
10													
11													
12													
13													
14													
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16													
17													
18													
19													
20													
21													
22													
23													
24													

1

TYSP Year 2025
Question No. 64 e

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (Present-Year $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
Notes				
To be determined				

TYSP Year 2025
Question No. 55

Facility or Project Name	Unit No.	County Location	Energy Storage Type	Battery Chemistry (if applicable)	Land Use	Facility In-Service or Project Start Date		Unit Capacity (MW)						Storage Capacity	Conversion Efficency[1]
								Gross		Net		Firm			
					(Acres)	Mo	Yr	Sum	Win	Sum	Win	Sum	Win	(MWh)	(MWh)
Imeson (SunPort) Solar	N/A	Duval	Battery	Lithium-ion	0.08	Dec	2019	2	2	2	2	2	2	4	3.6

Notes

(1) Battery assumes 90% conversion efficiency.

TYSP Year 2025
Question No. 66

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW) Net		Estimated EPA Rule Impacts: Operational Effects					CCR	
					Mo	Yr	Sum	Win	ELGS	GHG	MATS	CSAPR/ CAIR	CWIS	Non-Hazardous Waste	Special Waste
NGS	1	Duval	ST	PC	5	2003	293	293	Possible additional equipment	TBD	Additioanl Equipment, Monitoring and Reporting	N/A	Possible additional equipment	N/A	N/A
NGS	2	Duval	ST	PC	4	2003	293	293	Possible additional equipment	TBD	Additioanl Equipment, Monitoring and Reporting	N/A	Possible additional equipment	N/A	N/A
NGS	3	Duval	ST	NG	6	1977	524	524	Possible additional equipment	TBD	N/A	N/A	N/A	N/A	N/A
BBGS	2-3-STM	Duval	CCCT	NG	1	2001	579	640	N/A	TBD	N/A	N/A	N/A	N/A	N/A
Notes															
TBD = To Be Determined															

TYSP Year 2025
Question No. 67

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		Estimated EPA Rule Impacts: Cost Effects						
							Net							CCR	
					Mo	Yr	Sum	Win	ELGS	GHG	MATS	CSAPR/ CAIR	CWIS	Non-Hazardous Waste	Special Waste
NGS	1	Duval	ST	PC	5	2003	293	293	TBD	TBD	PM CEMs	N/A	TBD	N/A	N/A
NGS	2	Duval	ST	PC	4	2003	293	293	TBD	TBD	PM CEMs	N/A	TBD	N/A	N/A
NGS	3	Duval	ST	NG	6	1977	524	524	TBD	TBD	N/A	N/A	N/A	N/A	N/A
BBGS	2-3-STM	Duval	CCCT	NG	1	2001	579	640	N/A	TBD	N/A	N/A	N/A	N/A	N/A
Notes															
TBD = To Be Determined															

TYSP Year 2025
Question No. 68

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW) Net		Estimated EPA Rule Impacts: Unit Availability					CCR	
					Mo	Yr	Sum	Win	ELGS	GHG	MATS	CSAPR/ CAIR	CWIS	Non-Hazardous Waste	Special Waste
NGS	1	Duval	ST	PC	5	2003	293	293	TBD	TBD	No impact expected	N/A	TBD	N/A	N/A
NGS	2	Duval	ST	PC	4	2003	293	293	TBD	TBD	No impact expected	N/A	TBD	N/A	N/A
NGS	3	Duval	ST	NG	6	1977	524	524	No impact expected	TBD	No impact expected	N/A	N/A	N/A	N/A
BBGS	2-3-STM	Duval	CCCT	NG	1	2001	579	640	No impact expected	TBD	No impact expected	N/A	N/A	N/A	N/A
Notes															
TBD = To Be Determined															

TYSP Year 2025
Question No. 70

Year		Firm Purchase Rates		Non-Firm Purchase Rates		As-Available Energy Rates		
		Annual Average ($/MWh)	Escalation Rate (%)	Annual Average ($/MWh)	Escalation Rate (%)	Annual Average ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2015							
	2016							
	2017							
	2018							
	2019	30.72						
	2020	88.00	186.46%					
	2021	89.97	2.24%					
	2022	67.65	-24.81%					
	2023	41.61	-38.48%					
	2024	24.45	-41.24%	31.32				
Projected	2025	105.76	332.58%	53.03	69.32%			
	2026	108.54	2.62%	60.05	13.23%			
	2027	94.89	-12.58%	45.43	-24.35%			
	2028	96.12	1.29%	44.85	-1.27%			
	2029	97.72	1.67%	47.06	4.93%			
	2030	96.87	-0.88%	60.54	28.62%			
	2031	86.45	-10.76%	58.43	-3.48%			
	2032	89.12	3.09%	60.11	2.87%			
	2033	88.08	-1.16%	60.63	0.87%			
	2034	89.87	2.03%	60.59	-0.06%			
Notes								
(Include Notes Here)								

TYSP Year 2025
Question No. 71

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil		Hydrogen		Biomass	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2015	N/A	N/A	6512	2.32	5312	2.96	6	6.71	2	12.57	N/A	N/A	N/A	N/A
	2016	N/A	N/A	6733	2.42	4724	2.98	16	5.39	3	11.00	N/A	N/A	N/A	N/A
	2017	N/A	N/A	5360	3.05	5751	3.28	0	7.69	3	13.39	N/A	N/A	N/A	N/A
	2018	N/A	N/A	3557	3.01	6574	3.66	24	10.01	18	15.98	N/A	N/A	N/A	N/A
	2019	N/A	N/A	3287	2.37	6306	2.78	1	9.66	4	14.85	N/A	N/A	N/A	N/A
	2020	N/A	N/A	3019	2.18	8215	2.19	1	6.53	5	11.46	N/A	N/A	N/A	N/A
	2021	N/A	N/A	2743	4.12	7656	4.14	11	10.57	7	15.35	N/A	N/A	N/A	N/A
	2022	N/A	N/A	1237	6.64	7559	7.63	40	13.81	5	21.03	N/A	N/A	45	2.58
	2023	N/A	N/A	1349	4.93	7263	3.09	11	11.70	3	18.36	N/A	N/A	56	2.63
	2024	N/A	N/A	780	3.45	8253	2.76	4	15.59	5	17.21	N/A	N/A	31	2.76
Projected	2025	N/A	N/A	282	4.62	9,327	3.46	N/A	N/A	71	16.96	N/A	N/A	48	2.64
	2026	N/A	N/A	535	4.75	9,202	4.02	N/A	N/A	37	16.81	N/A	N/A	90	2.64
	2027	N/A	N/A	489	4.89	8,979	4.35	N/A	N/A	39	16.51	N/A	N/A	82	2.64
	2028	N/A	N/A	1,371	5.01	7,727	4.9	N/A	N/A	11	15.92	N/A	N/A	223	2.64
	2029	N/A	N/A	1,655	5.23	7,210	5.57	N/A	N/A	19	16.45	N/A	N/A	269	2.64
	2030	N/A	N/A	2,223	5.36	6,757	6.31	N/A	N/A	21	16.98	N/A	N/A	362	2.64
	2031	N/A	N/A	758	5.5	7,666	6.53	N/A	N/A	5	17.41	N/A	N/A	123	2.64
	2032	N/A	N/A	697	5.63	7,724	6.69	N/A	N/A	9	17.95	N/A	N/A	113	2.64
	2033	N/A	N/A	888	5.82	7,909	6.9	N/A	N/A	12	18.41	N/A	N/A	144	2.64
	2034	N/A	N/A	988	5.96	8,010	7.08	N/A	N/A	9	19.00	N/A	N/A	161	2.64
Notes															
(Include Notes Here)															

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Table I: Current Data Center Information										
Data Centers Currently Located in Utility Service Area										
						For each of the Data Centers				
Total No. of Data Centers	**Customer Class Served**	**Total Energy Usage in 2024**	**Impact to Summer Peak Demand**	**Impact to Winter Peak Demand**	**Seasonality Observed, if any**		**Type of Data Center***	**Energy Used in 2024**	**Hours of Peak Usage****	**Impact to Peak Demand**
		(MWHs)	**(MWs)**	**(MWs)**				**(MWHs)**		**(MWs)**
(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**
						1				
						2				
						3				
						…				

*** Examples of the data center types: colocation, enterprise, cloud, edge, and micro data.**
** Based on military time 1 - 24.

TYSP Year	2025
Question No.	77(b)

Table II: Planned Data Center Information						
Planned Data Centers in Your Service Area						
	Type of Data Center*	Customer Class Served	Expected In-Service Data	Expected Annual Energy Usage	Expected Impact to Summer Peak Demand	Expected Impact to Winter Peak Demand
				(MWHs)	(MWs)	(MWs)
	(1)	(2)	(3)	(4)	(5)	(6)
1						
2						
3						
…						

* Examples of the data center types: colocation, enterprise, cloud, edge, and micro data.