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DOCKET NO. 20260087-EM
FILED 6/4/2026
DOCUMENT NO. 03333-2026
FPSC - COMMISSION CLERK

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June 4, 2026

VIA ELECTRONIC FILING

Adam Teitzman, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: Petition of JEA for Determination of Need for St. Johns River Power Park Unit 3 for
JEA Combined Cycle Generating Unit; Docket No. 2026 _____-EC

Dear. Mr. Teitzman:

Enclosed for filing on behalf of JEA, are electronic copies of the following:

- Petition for Determination of Need for JEA's St. Johns River Power Park Unit 3 located in Duval County;
- Pre-filed Direct Testimony of **Jody Brooks** with Exhibit Nos. ____ (JB-1 through JB-4);
- Pre-filed Direct Testimony of **James Stancin** with Exhibit Nos. ____ (JS-1 through JS-6);
- Pre-filed Direct Testimony of **Melinda Fischer** with Exhibit Nos. ____ (MF-1 through MF-7);
- Pre-filed Direct Testimony of **Hua Fang** with Exhibit Nos. ____ (HF-1 through HF-3);
- Pre-filed Direct Testimony of **Matt Oakes** with Exhibit Nos. ____ (MO-1 & MO-2);
- Pre-filed Direct Testimony of **Jim Herndon** with Exhibit Nos. ____ (JH-1 through JH-3);
- Pre-filed Direct Testimony of **Brian Pippin** with Exhibit Nos. ____ (BP-1 & BP-2);
- Pre-filed Direct Testimony of **Bradley Kushner** with Exhibit Nos. ____ (BK-1 & BK-2);
- Pre-filed Direct Testimony of **Wayne Oliver** with Exhibit Nos. ____ (WO-1 & WO-2);

Mr. Adam Teitzman

June 4, 2026

Page 2

Please acknowledge receipt and filing of the above by return email or other means. If you have any questions concerning the filing, please contact me at (850) 829-4871.

Thank you for your assistance with this matter.

Very truly yours,

Stearns Weaver Miller
Weissler Alhadeff & Sitterson, P.A.

By: /s/ Brooke E. Humphrey
Counsel for JEA

BEH/rje

Enclosures

cc: Saad Farooqi, PSC
Shaw Stiller, PSC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of JEA for Determination of
Need for St. Johns River Power Park Unit 3

|| DOCKET NO. 2026-_____
|| DATE: June 4, 2026

**PETITION FOR DETERMINATION OF NEED FOR JEA'S
ST. JOHNS RIVER POWER PARK UNIT 3**

Pursuant to Section 403.519, Florida Statutes, and Rule 25-22.081, Florida Administrative Code (F.A.C.), JEA, by and through its undersigned counsel, hereby petitions the Florida Public Service Commission (Commission) for an affirmative determination of need for a new combined cycle generating unit and onsite associated facilities to be located at JEA's existing St. Johns River Power Park (SJRPP) site. In support of this petition, JEA states:

Introduction

JEA is a municipal utility provider for approximately 537,000 customers in the City of Jacksonville and portions of Clay and St. Johns Counties. JEA is governed by a Board of Directors consisting of four members appointed by the City Council and three members appointed by the Mayor of the City of Jacksonville, all of whom are approved by the City Council. JEA has a need for additional resources in the 2031 timeframe, and beyond.

JEA routinely assesses its resource portfolio against its load forecast and reliability criteria to determine when and how much capacity must be secured for reliability purposes. Based on that continuing evaluation, after accounting for demand-side management (DSM) and conservation measures, JEA projects a capacity need for an additional 72 MW in the 2031 timeframe, increasing to 222 MW in 2033 and 802 MW in 2035, to ensure a reliable long-term energy supply for JEA's service area. The need is based primarily on increased demand, load growth, and planned unit retirement.

Given this need for capacity and the over-arching strategic priority to achieve the most cost-effective solution for its customers, JEA thoroughly evaluated generating and non-generating alternatives to meet this need, including renewable resources and DSM options. As part of this analysis, JEA initiated a highly transparent, competitive solicitation for firm, fully dispatchable capacity. JEA conducted an extensive multi-phase economic and qualitative evaluation of the proposals received, as well as JEA's own self-build resource, monitored and confirmed by an independent evaluator. The self-build resource – a “one-on one” (1 x 1) natural gas- and fuel oil-fired combined cycle unit – was not only the most cost-effective alternative, but also highest ranked in terms of system benefits related to dispatch, flexibility and reliability. The evaluation resulted in JEA's Board of Directors unanimously approving moving forward with developing the self-build resource.

JEA subsequently performed additional economic modeling incorporating refined and updated information to confirm that the proposed resource is the most cost-effective alternative. Therefore, JEA submits this Petition and accompanying Need Study and pre-filed testimony in support of a proposed 678 MW (winter net) 1 x 1 natural gas- and ultra-low sulfur diesel (ULSD) fuel oil-fired, combined cycle electric generating unit, to be known as St. Johns River Power Park Unit 3 (SJRPP Unit 3), with an in-service date of January 2031. The Need Study and supporting testimony demonstrate that the addition of SJRPP Unit 3 is the most cost-effective and system beneficial way to meet JEA's capacity needs with new, highly efficient, state-of-the-art natural gas combined cycle technology.

Preliminary Information

1. Petitioner's full name and address are:

JEA
225 N. Pearl Street
Jacksonville, Florida 32202

2. All notices, pleading and other communications required to be served on the

Petitioner should be directed to:

Brooke E. Humphrey
Matthew E.W. Bryant
BHumphrey@stearnsweaver.com
MBryant@stearnsweaver.com
Stearns Weaver Miller
106 E. College Ave., Suite 700
Tallahassee, Florida 32301
(850) 580-7200

Primarily Affected Utility

3. JEA is a municipal electric utility under section 366.02, Florida Statutes, and an applicant as defined in section 403.503(5), for purposes of section 403.519, Florida Statutes. JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's approximately 900 square mile electric service area covers most of Duval County and portions of Clay and St. Johns Counties.

4. As discussed in greater detail in the Need Study, JEA serves customers with generating facilities located at four different sites, along with numerous power purchase contracts for a variety of generating resources, including renewable resources.

5. JEA is experiencing significant load growth in both the residential and commercial/industrial sectors. SJRPP Unit 3 will allow JEA to serve and foster organic growth in its service area, while continuing to provide reliable and affordable electric service to its existing

537,000 customers. All of the generation capacity from SJRPP Unit 3 will be committed to serving customers in JEA's service area.

6. JEA anticipates placing its existing, less efficient Northside Generating Station (NGS) Unit 3 in limited use, operating at or below an 8% capacity factor on fuel oil only, as a back-up for peak demand periods, emergencies, and unexpected outages coincident with commercial operation of SJRPP Unit 3.

The Proposed Power Plant

7. SJRPP Unit 3 involves construction and operation of a new state-of-the-art natural gas- (as the primary fuel) and ULSD fuel oil-fired 1 x 1 combined cycle generating facility and onsite associated facilities on an approximately 194-acre site that was part of the larger approximately 1,600-acre parcel upon which JEA owned and operated St. Johns River Power Park Units 1 and 2 (SJRPP Units 1 and 2). SJRPP Units 1 and 2 were 612 MW coal-fired steam electric generating units certified under the Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, in 1982. SJRPP Units 1 and 2 were decommissioned and demolished in 2018 and 2019. Three closed byproduct storage areas and associated groundwater monitoring wells, a switchyard, a portion of the stormwater management system, and 230 kV transmission lines exiting from the site remain certified under the PPSA.

8. SJRPP Unit 3 will consist of one combustion turbine generator (CTG), one heat recovery steam turbine generator (HRSG), and one steam turbine generator (STG). JEA has selected the advanced class GE Vernova model 7HA.03 CTG for SJRPP Unit 3. When operated in combined cycle mode, this large CTG creates the most efficient electric generating technology currently available for utility-scale power plants. The facility is expected to have a nameplate or "gross nominal" output of 706 MW and a "net nominal" output of 678 MW, which it is anticipated

to achieve across the entire range of ambient conditions typically experienced in Jacksonville, Florida. The facility will have significant flexibility in terms of its operational characteristics.

9. Locating SJRPP Unit 3 on the parcel formerly utilized for SJRPP Units 1 and 2 will significantly minimize overall environmental impacts as compared to locating new generation on a greenfield site. In addition, electricity generated by the new unit will be transmitted by the existing 230 kV transmission lines exiting the site. No new off-site associated electrical transmission facilities, pipelines, or other features are proposed as part of SJRPP Unit 3.

10. SJRPP Unit 3 also includes onsite associated facilities, such as the administration building/control room, mechanical draft cooling tower, exhaust stacks, CT maintenance area, CTG step-up transformer, above ground water storage tanks, ammonia storage tanks, a fuel storage tank, fire protection pumps, a warehouse, a gas compression area, a stormwater management system/stormwater ponds, fire protection pumps, a water treatment area, piping tie-ins, and other facilities necessary to integrate with existing water supply and discharge infrastructure. Gas will be delivered to the Site via a pipeline lateral to be permitted, owned and operated by Peoples Gas System (PGS).

11. Construction activities for SJRPP Unit 3 are scheduled to begin in 2028, with targeted commercial operation approximately 36 months later. JEA currently projects an in-service date of January 2031.

The Need for Additional Capacity

12. JEA primarily relies upon its targeted reserve margin to determine the amount of resource capacity needed in future years to meet forecast load. That generation reserve margin is fifteen percent above forecast coincident with one-hour peak for both winter and summer seasons. JEA evaluates future supply capacity needs for the electric system based on peak demand and

energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources.

13. JEA routinely assesses its resource portfolio against its load forecast and reliability criteria to determine when and how much capacity must be secured for reliability purposes. Based on that continuing evaluation, which incorporates existing and future DSM and other conservation measures, JEA projects a need for an additional 72 MW in the 2031 timeframe, increasing to 222 MW in 2033 and 802 MW in 2035, to ensure a reliable long-term energy supply for JEA's service area. This projected need results primarily from increased demand during the winter and summer peaks, organic load growth in both the residential and commercial/industrial sectors, and planned unit retirement.

14. SJRPP Unit 3 will provide reliable dispatchable power, allow for more efficient use of natural gas, reduce system CO₂ emissions, provide support to reliably integrate the import of power into the JEA system, enhance flexibility and reliability, and will help avoid costly updates that would otherwise be necessary to extend the life of JEA's existing NGS Unit 3. NGS Unit 3 (a 524 MW oil/gas steam turbine-generator unit commissioned in 1977) would require extensive capital upgrades to remain reliable and compliant with environmental regulations. While JEA initially anticipated fully retiring NGS Unit 3 coincident with commercial operation of SJRPP Unit 3, increased demand and load forecasts now require that JEA maintain NGS Unit 3 in limited use status for peak periods, emergencies, and unexpected outages. Following commercial operation of SJRPP Unit 3, use of NGS Unit 3 would be at a capacity factor below 8% and limited to oil-firing. JEA anticipates fully retiring NGS Unit 3 in 2035.

15. By providing the capacity necessary to meet JEA's reliability criteria, improving system flexibility, and relieving power import strains on JEA's electric transmission system, the

678 MW (net nominal) of generating capacity associated with SJRPP Unit 3 will contribute to the reliability and integrity of JEA's system.

Analysis of Generating Alternatives

16. JEA conducted a thorough and extensive evaluation of various technologies, including renewable options, to select a self-build 1 x 1, natural gas- and fuel oil-fired, combined cycle facility to meet its need.

17. Although JEA is not subject to the Commission's "Bid Rule" (Rule 25-17.082, F.A.C.), JEA tested the market by issuing a competitive request for proposal (RFP) for resource alternatives, informing respondents that JEA intended to evaluate proposals relative to a self-build resource. JEA received third-party responses from one respondent who provided four PPA proposals. JEA evaluated the proposals in a multi-stage process that included a quantitative/economic evaluation and a qualitative evaluation designed to compare and evaluate third-party proposals relative to JEA's self-build option. Based on this combined evaluation of economic and non-economic attributes, JEA determined that the most cost-effective, system beneficial alternative to meet its need is SJRPP Unit 3.

18. JEA also contracted with an independent evaluator, Mr. Wayne Oliver of Merrimack Energy Group, Inc. (Merrimack), to oversee and review JEA's RFP process. As discussed in his pre-filed direct testimony, Mr. Oliver concluded that the process was highly transparent, consistent, comprehensive, and fair; agreed that JEA's evaluation methodology was appropriate, the scoring and ranking of the resources was reasonable, and with the selection of the self-build resource. Together with JEA's analyses, Merrimack's independent evaluation demonstrates that SJRPP Unit 3 will help satisfy the need for adequate electricity at the lowest reasonable cost.

19. Updated economic modeling confirmed that SJRPP Unit 3 is the least-cost alternative, resulting in savings of approximately \$91 million in cumulative present worth cost (CPWC) revenue requirements over the next least cost alternative. Importantly, the next least cost alternative would include constructing a 1 x 1 combined cycle facility in 2035. The evaluation further indicated that the economic cost of even a one-year delay of SJRPP Unit 3 is approximately \$22 million in CPWC.

20. JEA considered the potential impact of SJRPP Unit 3 on fuel diversity and supply reliability. SJRPP Unit 3 will be dual fuel which will enhance fuel diversity and reliability of fuel supply to the project. Construction and operation of SJRPP Unit 3 will also allow JEA to place NGS Unit 3 (which is now predominately natural gas-fired) in limited use status fired only on fuel oil, and divert the natural gas currently utilized for NGS Unit 3 to SJRPP Unit 3. SJRPP Unit 3 will use 37% less natural gas per MWh than NGS Unit 3, increasing fuel diversity by reducing reliance on natural gas per unit of electricity generated.

Analysis of Non-Generating Alternatives

21. JEA is subject to the Florida Energy Efficiency and Conservation Act (FEECA), section 366.82, Florida Statutes, which requires the Commission to adopt and periodically review JEA's conservation goals. JEA's current numeric conservation goals were established by the Commission in 2024.¹ JEA continues to implement DSM programs that are economically beneficial and meet JEA's FEECA goals. JEA's programs focus on improving the efficiency of customer end use equipment, as well as improving the system load factor through behavioral education and technology incentives. Through these efforts, JEA achieved a winter peak reduction

¹ In re: Commission review of numeric conservation goals (JEA), Docket No. 20240016-EG, Order No. PSC-2024-0432-FOF-EG (Sept. 20, 2024).

of 1,545 kW, a summer peak reduction of 1,758 kW, and a MWh energy reduction of 9,738 in 2025.

22. The DSM and conservation savings actually and estimated to be achieved by JEA and its customers are reflected in JEA's load forecast, yet JEA will still need 72 MW of additional capacity in 2031, increasing to 222 MW in 2033 and 802 MW in 2035. As explained in the pre-filed testimony of Mr. Jim Herndon, JEA updated the analysis of potential DSM resources from that presented to the Commission in support of its FEECA goal-setting in 2024. This updated analysis, coupled with JEA's own analyses and ongoing efforts, demonstrate that cost-effective DSM or conservation measures are not reasonably available to JEA to mitigate the need for SJRPP Unit 3.

Adverse Consequences of Denial

23. Non-approval would mean that JEA and its customers would be denied the most cost-effective, system-beneficial, power supply solution to meet JEA's capacity need while providing dispatch and operational flexibility, enhancing grid reliability, and mitigating risk.

24. JEA will begin to fall below its minimum reserve margin level in 2028. While additional off-system purchases can be made to maintain the target reserve margin until 2031, denial of SJRPP Unit 3 would require JEA to import increasingly large volumes of power. The current configuration of JEA's transmission system cannot support importing additional large volumes of power.

25. JEA estimates that the CPWC impact of the denial of a need determination for SJRPP Unit 3 would be approximately \$91 million. A delay of just one year would have an CPWC impact of approximately \$22 million.

26. Denial of the need determination for SJRPP Unit 3 would also prevent JEA from placing NGS Unit 3 in limited use, resulting in substantial upgrade/reconstruction costs, less efficient use of natural gas, and increased CO₂ emissions.

Substantial Interests

27. The substantial interests of JEA will be affected by the Commission's decision on this Petition. As outlined above and in greater detail in the Need Study, if the Commission did not make an affirmative determination of need for SJRPP Unit 3, there would be adverse impacts on JEA system reliability, flexibility, fuel diversity, and cost of generating electricity.

Statutes and Rules that Warrant Requested Relief

28. JEA is entitled to the determination of need requested in this Petition pursuant to section 403.519, Florida Statutes, and Rule 25-22.080, Florida Administrative Code.

Statement of Relief Requested

WHEREFORE, based upon the foregoing, and the more detailed information in the attached Need Study and pre-filed testimony submitted contemporaneously with this Petition, JEA respectfully requests that the Commission grant an affirmative determination of need for SJRPP Unit 3. Specifically, JEA requests that:

(1) pursuant to section 403.519, Florida Statutes, and Rule 25-22.080(2), Florida Administrative Code, the Commission set a date commencement of a hearing within 90 days of the filing of this Petition;

(2) the Commission give notice of the commencement of the proceeding as required by Rule 25-22.080(3), Florida Administrative Code; and

(3) the Commission determine that there is a need for the proposed electrical power plant described in this Petition, and file its order making such determination with the Florida Department of Environmental Protection pursuant to section 403.507(2)(a)2, Florida Statutes.

Stearns Weaver Miller
Weissler Alhadeff & Sitterson, P.A.

/s/ Brooke E. Humphrey
Brooke E. Humphrey
Florida Bar No. 710881
Matthew E.W. Bryant
Florida Bar No. 93190
BHumphrey@stearnsweaver.com
MBryant@stearnsweaver.com
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Tallahassee, Florida 32301
(850) 580-7200

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served on this 4th day of June 2026 via Email to the following:

Saad Ul-Islam Farooqi
Florida Public Service Commission
2540 Shumard Oak Blvd
Tallahassee, FL 32399-7019
sfarooqi@psc.state.fl.us

Shaw P. Stiller
Florida Public Service Commission
2540 Shumard Oak Blvd
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/s/ Brooke E. Humphrey
Brooke E. Humphrey
Florida Bar No. 710881

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

JODY BROOKS

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR
ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP 3)

DIRECT TESTIMONY OF JODY L. BROOKS

DOCKET NO. _____-EC

June 4, 2026

Q. Please state your name and address.

A. My name is Jody Brooks. My business address is 225 N. Pearl St.,
Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am the Chief Administrative Officer at JEA.

Q. What are your responsibilities as Chief Administrative Officer.

A. As Chief Administrative Officer, I oversee the utility’s critical infrastructure
protection and compliance, environmental services, real estate, public records
and information governance, and electric system compliance. I also work with
the Office of General Counsel to oversee JEA legal matters. More specifically,
as it relates to this proceeding, I have responsibility for and oversight of the
licensing and development of St. Johns River Power Park Unit 3 (SJRPP Unit
3 or the Project) and am the Project’s chief champion.

1 **Q. Please summarize your educational background and professional**
2 **experience.**

3 A. I have a Juris Doctor, with honors, from the University of Florida Fredric G.
4 Levin College of Law, along with a Certificate in Environmental Land Use
5 Law. I returned to JEA as Chief Administrative Officer in 2024 after having
6 previously served in the role from 2021 through 2023. In addition to Chief
7 Administrative Officer, I have also served as JEA’s Chief Legal Officer, in the
8 City of Jacksonville Office of General Counsel, and held other public and
9 private legal positions.

10

11 **Q. Are you sponsoring any exhibits in this case?**

12 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
13 under my supervision and are attached to this pre-filed testimony:

14 • Exhibit No. ____ (JB-1) – Resume of Jody Brooks

15 • Sections 1.0, 1.1, 1.2, 1.7, 1.8, 2.0, 3.0, 3.1, 3.3, 3.3.3, 8.0, 9.0 (including all
16 referenced tables and figures in these sections) of JEA’s Need Study, which is
17 attached as Exhibit No. ____ (JB-2) (other witnesses will sponsor the sections
18 of the Need Study within their areas of responsibility)

19 • Exhibit No. ____ (JB-3) – JEA Service Territory

20 • Exhibit No. ____ (JB-4) – JEA Existing Power Purchase Agreement Schedule

21

22 **Q. What is the purpose of your testimony in this proceeding?**

23 A. The purpose of my testimony is to describe JEA and to provide an overview of
24 JEA’s case supporting our request for a determination of need for SJRPP Unit
25 3, which is more fully set forth in the Need Study attached as Exhibit No. ____

1 (JB-2). I will also introduce JEA's subject matter witnesses and discuss the
2 adverse consequences of denial of JEA's need petition.

3

4

JEA

5 **Q. Please describe JEA.**

6 A. JEA is the largest municipal utility in Florida and eighth largest municipally
7 owned electric utility in the United States in terms of number of customers.
8 JEA's electric service area covers most of Duval County and portions of Clay and
9 St. Johns Counties – approximately 900 square miles - and serves approximately
10 537,000 customers. JEA has been Jacksonville's community utility for 130
11 years.

12

13 **Q. Does Exhibit No. ____ (JB-3) accurately depict JEA's service territory?**

14 A. Yes.

15

16 **Q. How is JEA governed?**

17 A. JEA's governing body is made up of a seven-member Board of Directors. Four
18 of the members are nominated by the Jacksonville City Council President and
19 confirmed by the Council; three members are appointed by the Jacksonville
20 Mayor and confirmed by the Council. The Board of Directors appoints a
21 Managing Director and CEO, who selects the leadership team of eight others.
22 Our Managing Director and CEO is Vickie Cavey.

23

24 **Q. Are you a member of the Leadership Team?**

25 A. I am.

1

2 **Q. How does JEA meet the electrical needs of its customers?**

3 A. JEA serves customers with generating facilities located at four different sites,
4 along with numerous power purchase contracts for a variety of generating
5 resources, including renewable resources.

6

7 **Q. Please describe the generating units JEA owns to meet the needs of its**
8 **customers.**

9 A. The JEA Electric System consists of generating facilities located on four plant
10 sites within the City of Jacksonville: the J. Dillon Kennedy Generating Station
11 (Kennedy), the Northside Generating Station (NGS), the Brandy Branch
12 Generating Station (Brandy Branch), and the Greenland Energy Center (GEC).

13

14 Collectively, these plants consist of two multifuel-fired (coal/petroleum
15 coke/natural gas/biomass) circulating fluidized bed (CFB) steam turbine-
16 generator units (NGS Units 1 and 2), each with a net generating capacity
17 (winter) of approximately 293 MW; one dual-fired (oil/gas) steam turbine-
18 generator unit (NGS Unit 3), with a net generating capacity (winter) of
19 approximately 524 MW; five dual-fired (gas/diesel) combustion turbine-
20 generator units (Kennedy GT7 and GT8, GEC GT1 and GT2, and Brandy
21 Branch GT1) each with a net generating capacity (winter) of approximately
22 191 MW; four diesel-fired combustion turbine-generator units (NGS GTs 3, 4,
23 5, and 6) with a combined net generating capacity (winter) of approximately
24 246 MW; and one combined cycle system that comprises two gas-fired
25 combustion turbine-generator units and one combined cycle heat recovery

1 steam generator unit (Brandy Branch CT2 and CT3, and Brandy Branch steam
2 Unit 4) with a total net generating capacity (winter) of approximately 640 MW.

3

4 **Q. What are JEA's current purchased power resources?**

5 A. Exhibit No. ____ (JB-4) is a table summarizing JEA's existing purchased power
6 agreements (PPAs).

7

8 **Q. Does JEA's portfolio include any renewable energy resources?**

9 A. Yes, as outlined in the table in Exhibit No. ____ (JB-4), JEA has entered into
10 several solar PPAs along with the Trail Ridge (landfill gas) PPA. JEA's clean
11 energy portfolio also includes the Vogtle (nuclear) PPA.

12

13 **Q. Does JEA have clean energy requirements?**

14 A. No. JEA's Board of Directors approved aspirational clean energy goals in
15 2023. We have incorporated a substantial amount of clean energy into our
16 power supply portfolio, but there have been significant challenges meeting
17 these aspirational goals on the proposed timeline. First, several solar projects
18 in which we intended to participate have been delayed or cancelled. In
19 addition, locating environmentally suitable land of appropriate size for solar
20 facilities in Duval County is prohibitively expensive and extensive
21 transmission upgrades would be necessary to import the solar power to JEA's
22 system. Finally, regulatory changes such as the elimination of subsidies on
23 utility-scale solar projects, EPA's proposed repeal of Greenhouse Gas
24 standards for electric generating units (GHG Rule), and EPA's repeal of the

1 2009 Endangerment Finding have fundamentally impacted the economics and
2 affordability of clean energy projects.

3
4 As with many utilities, JEA has utilized an Integrated Resource Planning (IRP)
5 process to inform long-term resource decisions for decades, with the most
6 recent IRP in 2023 and another planned in the 2026/2027 timeframe. The
7 upcoming IRP is expected to focus on reliably and affordably addressing
8 JEA's load growth in the current regulatory context as well as the current cost
9 and practical ability to meet the aspirational clean energy goals. While we
10 continue to pursue clean energy opportunities where consistent with system
11 reliability, affordability, and adaptability, we are not doing so on any specified
12 timeline or to meet a particular mandate based on aspirational clean energy
13 goals.

14

15 **JEA'S REQUEST FOR A NEED DETERMINATION**

16 **Q. What is JEA seeking in this proceeding?**

17 A. JEA requests that the Commission grant an affirmative determination of need
18 for SJRPP Unit 3 with an in-service date of January 1, 2031. SJRPP Unit 3
19 will be a state-of-the-art natural gas- and ultra low sulfur diesel- (ULSD) fired
20 one-on-one (1 x 1) combined cycle unit with a net generating capacity of 678
21 MW (winter). The new unit will be located on an approximately 194-acre site
22 that was part of the larger approximately 1,600-acre parcel upon which JEA
23 owned and operated SJRPP Units 1 & 2 – two 612 MW coal-fired steam
24 electric generating units decommissioned and demolished in 2018 and 2019.
25 The projected cost of SJRPP Unit 3, which is presented in more detail in the

1 pre-filed testimony of Mr. James Stancin, is approximately \$1.57 billion (in
2 2031 dollars). JEA intends to finance the Project largely through the issuance
3 of tax-exempt municipal bonds.
4

5 **Q. What is the basis for JEA's request for a need determination?**

6 A. Based on an evaluation of its resource portfolio against its load forecast and
7 reliability criteria, JEA projects a need for approximately 72 MW in the winter
8 of 2031, increasing to 222 MW in 2033 and 802 MW in 2035. JEA's Board
9 selected moving forward with construction and operation of SJRPP Unit 3
10 based on the results of a multi-stage resource planning process that began over
11 three years ago and has been continually refined with updated information and
12 assumptions through present. That process included extensive economic
13 analyses of generating alternatives, including renewable generation, a robust
14 request for proposal (RFP) process that was overseen by an independent
15 evaluator, as well as careful consideration of non-economic attributes and risk
16 factors.
17

18 **Q. What were the results of JEA's economic evaluation?**

19 A. As discussed in the pre-filed direct testimony of Mr. Bradley Kushner, the
20 economic evaluation demonstrates that in cumulative present worth cost
21 (CPWC) terms, SJRPP Unit 3 will save JEA's customers approximately \$91
22 million as compared to the next least cost alternative.
23

24 **Q. What were the results of JEA's evaluation of non-economic attributes?**

1 A. In addition to evaluating cost-effectiveness, JEA considered non-economic
2 factors such as system reliability and flexibility. For example, SJRPP Unit 3
3 will have the significant benefit of providing JEA with full control over
4 dispatch and operations, enabling JEA to maintain grid reliability, quickly
5 adapt to changing demand, and optimize resources.

6

7 **Q. Did JEA consider the potential for new renewable energy resources as**
8 **part of its evaluation?**

9 A. Yes. JEA's evaluation process included extensive analysis of numerous
10 options, including renewable generation. The results of JEA's economic
11 evaluation show that the addition of renewable energy resources would not be
12 cost-effective relative to SJRPP Unit 3.

13

14 **Q. Did JEA consider whether additional conservation measures are**
15 **reasonably available to mitigate the projected capacity need?**

16 A. Yes. JEA's current demand-side management (DSM) goals and additional
17 conservation efforts are reflected in JEA's load forecast and in the need for
18 additional capacity addressed earlier in my testimony. As discussed in the pre-
19 filed direct testimonies of Mr. Brian Pippin and Mr. James Herndon, there is
20 not sufficient cost-effective and reasonably achievable DSM potential to offset
21 the need for SJRPP Unit 3.

22

23 **Q. Did JEA consider fuel diversity and supply reliability?**

24 A. Yes. The dual-fuel capability of SJRPP Unit 3 will enhance fuel diversity and
25 reliability of fuel supply to the Project. In terms of JEA's overall system,

1 commercial operation of SJRPP Unit 3 will allow JEA to place NGS Unit 3 in
2 limited use. The addition of SJRPP Unit 3 will result in use of 37% less
3 natural gas per MWh as compared to operation of NGS Unit 3.
4

5 **Q. Please explain JEA's intent relative to NGS Unit 3.**

6 A. NGS Unit 3 is a natural gas- and oil-fired unit placed in service in 1977. Upon
7 commercial operation of SJRPP Unit 3, NGS Unit 3 will be placed in limited
8 use status and operated at or below an 8% capacity factor as a fuel-oil only
9 back-up resource during peak demand periods, system emergencies, or
10 unexpected equipment outages. JEA anticipates fully retiring NGS Unit 3 in
11 2035.
12

13 **INTRODUCTION OF JEA'S WITNESSES**

14 **Q. Please identify JEA's other witnesses in this proceeding and subjects each**
15 **witness will address in his/her direct pre-filed written testimony:**

16 A. The names and areas of responsibility for each of the other eight witnesses are
17 (in alphabetical order):

18 **Hua Fang**, of Black & Veatch, presents the natural gas fuel price forecasts
19 used in the analyses that examined the various options for meeting JEA's
20 capacity needs.
21

22 **Melinda Fischer**, JEA's Director of Electric Systems Planning, addresses
23 JEA's load forecast and power supply planning process, including renewable
24 resources. She will also describe JEA's RFP to address its need for capacity
25 and evaluation of bids received as well as JEA's Board approval process and

1 updates and refinements to assumptions and information subsequent to the
2 approval. In addition, Ms. Fischer will address the natural gas supply and
3 transportation plans for SJRPP Unit 3 as well as fuel diversity. Finally, Ms.
4 Fischer will discuss JEA's transmission planning and facilities and the benefits
5 of SJRPP Unit 3 to JEA's transmission system.

6
7 **Jim Herndon**, Resource Innovations, Inc. (RI), describes the results of the
8 work RI performed to confirm the absence of available additional DSM or
9 conservation measures to mitigate the need for SJRPP Unit 3.

10
11 **Bradley E. Kushner**, nFront Consulting LLC, will describe JEA's need
12 assessment, including the economic analysis and parameters, reliability
13 criteria, and economic evaluation methodology and results. Mr. Kushner will
14 also address the cost and performance estimates for solar, battery energy
15 storage systems, and small modular reactor generating alternatives utilized in
16 the economic analysis. Most importantly, he explains why SJRPP Unit 3 is the
17 most cost-effective option to meet JEA's need for capacity.

18
19 **Matt M. Oakes**, Black & Veatch, will discuss the capital and operating cost
20 and performance estimates for the natural gas generating unit alternatives to
21 SJRPP Unit 3.

22
23 **Wayne Oliver**, Merrimack Energy, who conducted an independent evaluation
24 of JEA's overall RFP evaluation process, confirms that JEA's RFP process

1 was consistent with industry standards, transparent, comprehensive, and fair
2 and that selection of SJRPP Unit 3 was a reasonable decision.

3
4 **Brian Pippin**, JEA's Director of Customer Solutions, will discuss JEA's DSM
5 and conservation measures and why additional conservation and DSM
6 measures are not reasonably available to mitigate the need for SJRPP Unit 3.

7
8 **James Stancin**, JEA's Director of Energy Production and Project Manager for
9 SJRPP Unit 3, describes the SJRPP Unit 3 Project, including its site,
10 technology, related facilities, operating assumptions and costs, and
11 construction schedule. Finally, Mr. Stancin will describe JEA's experience in
12 the construction and operation of electrical generation.

13
14 **ADVERSE CONSEQUENCES OF DENIAL**

15 **Q. Would there be adverse consequences to JEA if the Commission does not**
16 **grant an affirmative determination of need for SJRPP Unit 3?**

17 **A.** Yes. Non-approval of the requested need determination would mean that
18 JEA's customers would be denied the most cost-effective option to meet JEA's
19 need for capacity while providing flexibility relative to dispatch and operations
20 to enhance grid reliability and mitigate risk. JEA will begin to fall below its
21 minimum reserve margin level in 2028. While additional off-system purchases
22 can be made to maintain the target reserve margin until commercial operation
23 of SJRPP Unit 3, absent the new unit, JEA would be required to import
24 increasingly large volumes of power. The current configuration of JEA's
25 transmission system cannot support importing this amount of power and would

1 require substantial and costly upgrades, the completion of which is not feasible
2 by the time the increased import capability is needed. The CPWC impact to
3 JEA's customers of denial of SJRPP Unit 3 is approximately \$91 million.
4 Delay of even one year would cost JEA's customers approximately \$22 million
5 in CPWC. Finally, JEA would not be able to place NGS Unit 3 in limited use,
6 resulting in substantial upgrade/reconstruction costs, increased system costs,
7 and increased carbon dioxide (CO₂) emissions.

8

9 **Q. Does this complete your testimony?**

10 A. Yes.

JODY BROOKS

PROFESSIONAL EXPERIENCE

- JEA** **JUNE 2024 – PRESENT**
MARCH 2021 – JULY 2023
CHIEF ADMINISTRATIVE OFFICER
- ♦ Key member on JEA Leadership Team
 - ♦ Direct supervision responsibilities for Legal, Ethics, Environmental Services, Real Estate, Public Records and Information Governance, Critical Infrastructure Protection, Electric System Compliance.
- CITY OF JACKSONVILLE, OFFICE OF GENERAL COUNSEL** **APRIL 2020 – MARCH 2021**
CHIEF LEGAL COUNSEL TO JEA
- ♦ Resumed former role as Chief Legal Counsel to JEA
 - ♦ Provided legal guidance to newly appointed JEA governing Board and assisted with the recruitment and selection process for JEA's current Chief Executive Officer
- CLAY COUNTY ATTORNEY'S OFFICE** **MARCH 2019 – APRIL 2020**
ASSISTANT COUNTY ATTORNEY
- ♦ Provided legal advice and support of local government matters on behalf of the Clay County Board of County Commissioners with a focus on procurement and contracts
- CITY OF JACKSONVILLE OFFICE OF GENERAL COUNSEL** **April 2013 – March 2019**
ASSISTANT GENERAL COUNSEL
JEA VICE PRESIDENT & CHIEF LEGAL OFFICER – PROMOTED AUGUST 2016
- ♦ Provided legal support to all departments, divisions, and independent authorities on environmental and regulatory matters including the Environmental Protection Board, Loblolly Mitigation Bank, Project New Ground (ash remediation program under consent order with EPA), Jacksonville Port Authority and JEA
 - ♦ In 2016, promoted to become the first Chief Legal Officer for JEA, the 8th largest municipal utility in the country providing electric, water and sewer service – handled all aspects of legal representation to municipal utility
- ALLEN LAND GROUP, INC.** **January 2009 – February 2013**
GENERAL COUNSEL
- ♦ Represented Allen Land Group, Inc. and all affiliated companies with environmental, real estate, development, and land use matters including the operation and management of the Northeast Florida Wetland Mitigation Bank
- JODY LANE BROOKS, P.A.** **November 2007 – January 2009**
PRINCIPAL
- ♦ Organized and operated legal practice primarily providing legal services for three main clients on environmental permitting, real estate transactions and compliance matters – The St. Joe Company, VCNA, and Allen Land Group
- THE ST. JOE COMPANY** **March 2004 – November 2007**

SENIOR COUNSEL

- ♦ Provided legal advice and representation to St. Joe Commercial and the Division of Regulatory Affairs

LEWIS, LONGMAN & WALKER, P.A.
ASSOCIATE

March 2001 - March 2004

- ♦ Represented clients on real estate development, regulatory permitting and environmental matters with a focus on marina permitting, wetland mitigation banking and eminent domain matters

UF LEVIN COLLEGE OF LAW, CGR
RESEARCH ASSISTANT

March 1998 – December 2000

- ♦ Researched and assisted on water policy issues for the Center for Governmental Responsibility

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

Summer 1999

SUMMER EXTERN - NEPA Project and Presentation to District management and staff

MARKS GRAY

1992-1996

LEGAL ASSISTANT - Mass Tort Litigation Team

LEON COUNTY ATTORNEY'S OFFICE

1991-1992

PARALEGAL

ATTORNEY GENERAL'S OFFICE, STATE OF FLORIDA

1990-1991

PARALEGAL SPECIALIST – EMPLOYMENT DISCRIMINATION SECTION

DIVISION OF CORPORATIONS, STATE OF FLORIDA

1988-1990

CORPORATE DOCUMENT AND LICENSING EXAMINER

EDUCATION

UNIVERSITY OF FLORIDA, FREDRIC G. LEVIN COLLEGE OF LAW — Gainesville, FL

- ♦ Juris Doctor *with Honors*, December 2000
- ♦ Certificate in Environmental and Land Use Law, December 2000
- ♦ UF Environmental Moot Court Team, 1999/2000
- ♦ Book Award in Professional Responsibility
- ♦ Dean Maloney Law School Writing Competition, 3rd Place Winner, *Tranquil Waters; Federal, State and Local Governments Authority to Restrict or Exclude Vessels in Florida Waters* – Published in ELULS Section Reporter, October 2000
- ♦ Co-Chair of the Public Interest Environmental Conference, 1999/2000

JACKSONVILLE UNIVERSITY — Jacksonville, FL

Bachelor of Science in Management *with Honors*, May 1997

TALLAHASSEE COMMUNITY COLLEGE — Tallahassee, FL

Paralegal Certificate, 1990

PROFESSIONAL / CIVIC / COMMUNITY INVOLVEMENT

- ◆ The Florida Bar – Admitted April 2001
- ◆ North Florida Land Trust, 2004 Board of Directors
- ◆ JTA E/SW Rapid Transit Corridor Study Citizen Advisory Committee, Secretary
- ◆ Co-Author of Chapter 7, *The Endangered Species Act, Essentials of Environmental Law*, Craig Simonsen, Managing Editor, 3d Edition, 2007
- ◆ Board of Directors, Clay County Soccer Association, 2009-2012
- ◆ CREW Jacksonville Chapter, Board of Directors, 2010-2013
- ◆ Florida Trend's, Florida Legal Elite, Government & Non-Profit Lawyers 2021
- ◆ Leadership Florida - Cornerstone Class 40

JEA NEED STUDY

Need for the SJRPP Unit 3

BLACK & VEATCH PROJECT NO. 410163

PREPARED FOR



3 JUNE 2026



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1.0 Executive Summary

JEA submits this Need Study in support of a proposed 678 MW (winter net rating) advanced class one-on-one (1x1) natural gas-fired, combined cycle electric generating unit to be constructed at JEA's existing St. John's River Power Park site and to be known as St. John's River Power Park Unit 3 (SJRPP Unit 3 or Project). The analyses discussed throughout this Need Study demonstrate that the Project is the most cost-effective, system-beneficial alternative to meet JEA's capacity needs in the 2031 timeframe and beyond.

1.1 The Primarily Affected Utility

JEA is a municipal electric utility under section 366.02, Florida Statutes, with an approximately 905 square mile electric service area. JEA provides electricity for approximately 537,000 customers in the City of Jacksonville and portions of Clay and St. Johns Counties, making it the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA is governed by a Board of Directors consisting of four members appointed by the City Council and three members appointed by the Mayor of the City of Jacksonville, all of whom are approved by the City Council.

1.2 The Power Plant Siting Act and Need Determination Process

The Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, or the Florida Department of Environmental Protection (FDEP) in cases where all parties stipulate there are no disputed issues of law or fact, takes final action on the site certification application. The Commission's need determination is a critical step in the PPSA certification process. Along with the reports submitted by FDEP and other agencies, the Commission's need determination allows the Siting Board or FDEP Secretary to balance "the increasing demand for electrical power plant location and operation with the broad interests of the public." § 403.502, Fla. Stat. Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity;
- The need for adequate electricity at a reasonable cost;
- The need for fuel diversity and supply reliability;
- Whether the proposed plant is the most cost-effective alternative available;
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available; and
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

1.3 The Proposed New Facilities

JEA has determined that the most cost-effective and system-beneficial way to meet its capacity needs is the construction of a 678 MW (winter net rating) dual-fuel, advanced class 1x1 combined cycle unit at its existing SJRPP site. The Project will be located on an approximately 194-acre site that was part of the larger approximately 1,600-acre parcel upon which JEA owned and operated SJRPP Units 1 & 2—two 612 MW coal-fired steam electric generating units certified under the PPSA in 1982. SJRPP Units 1 & 2 were

decommissioned and demolished in 2018 and 2019; although some facilities, including a substation, byproduct storage areas, and electrical transmission lines remain certified under the PPSA.

The Project will be primarily natural gas-fired, but capable of operating on ultra-low sulfur diesel (ULSD) as a back-up in the event natural gas is unavailable or uneconomic for JEA's customers, and will also be capable of operating on up to 50 percent hydrogen if available in the future. Location of SJRPP Unit 3 on the SJRPP property will allow utilization of existing infrastructure, including the existing substation, existing 230 kV electrical transmission lines, existing reclaimed water lines, existing water discharge pipelines, and an existing discharge structure. Natural gas will be delivered via pipeline to be permitted, constructed, owned, operated, and maintained by Peoples Gas System (PGS). SJRPP Unit 3 will primarily utilize reclaimed water from JEA's nearby District II Water Reclamation Facility (WRF) for cooling.

1.4 JEA's Need for Generation Capacity

Based on an evaluation of its resource portfolio against its load forecast and reliability criteria, JEA projects a need for 72 MW in the winter of 2031, increasing to 222 MW in 2033 and 802 MW in 2035. The need is primarily driven by increased demand during the summer and winter peaks, along with significant load growth in the residential and industrial sectors. JEA anticipates placing its existing less efficient Northside Generating Station (Northside or NGS) Unit 3 in limited use, operating at or below 8% capacity factor, as a back-up for peak demand periods, emergencies, and unexpected outages coincident with commercial operation of SJRPP Unit 3; JEA currently anticipates retiring NGS Unit 3 in 2035.

1.5 Generating Alternatives

JEA's Board selected moving forward with construction and operation of SJRPP Unit 3 based on the results of a multi-stage resource planning process. That process considered various generating resource options, including multiple configurations of solar photovoltaic (PV) and energy storage options, numerous different natural gas options (including a range of sizes, types, simple and combined cycle configurations, and the conversion of existing simple cycle units to combined cycle configuration), biomass technologies, and nuclear. JEA also considered multiple power purchase alternatives identified during a robust Request for Proposal (RFP) process that was overseen by an independent evaluator, as well as careful consideration of economic and non-economic attributes and risk factors. JEA's analyses demonstrate that SJRPP Unit 3 is the most cost-effective and system-beneficial alternative to meet JEA's capacity needs. SJRPP Unit 3, becoming operational in 2031, would result in projected cumulative present worth cost (CPWC) savings of approximately \$91 million to JEA's customers compared to the next most economical plan and the lowest long-term cost per MWh. It is important to note that even the next lowest cost resource plan would include a 1x1 advanced class combined cycle (similar to SJRPP Unit 3) in 2035. SJRPP Unit 3 will also increase operational flexibility, grid reliability, and fuel diversity while decreasing per MWh natural gas consumption and system carbon dioxide (CO₂) emissions. Finally, SJRPP Unit 3 will have the significant benefit of providing JEA with full control over dispatch and operations, enabling JEA to adapt to changing demand, ensure economic efficiency, and optimize resources in the face of sustained load growth.

1.6 Non-Generating Alternatives

JEA is subject to the Florida Energy Efficiency and Conservation Act (FEECA), section 366.82, Florida Statutes, which requires the Commission to adopt and periodically review goals to increase the efficiency of energy consumption, increase the development of demand side renewable energy systems, reduce and control the growth rate of electric consumption and weather sensitive peak demand, and encourage the development of demand side management (DSM) goals. The Florida Public Service Commission (Commission) established JEA's current DSM goals in 2024 based on the detailed analysis of DSM

potential and economic analysis.¹ JEA's annual combined residential and commercial/industrial DSM goals for the 2025 to 2034 timeframe are less than 3 MW. The Commission found that these goals were "based on an adequate assessment of the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems."² JEA recently updated the analysis of DSM potential to confirm that cost-effective, reasonably available conservation measures would not mitigate the need for SJRPP Unit 3.

1.7 Adverse Consequences of Denial

Non-approval of the requested need determination would deny JEA's customers the most cost-effective option to meet JEA's need. The additional CPWC to JEA's customers resulting from denial of SJRPP Unit 3 is approximately \$91 million. A delay to the in-service date of SJRPP Unit 3 of even one year would cost JEA's customers approximately \$22 million in CPWC. Denial would also prevent JEA from placing NGS Unit 3 in limited use status, triggering extremely costly upgrades conservatively estimated at more than \$834 million. Denial of SJRPP Unit 3 would also prevent JEA and its customers from realizing numerous non-economic system benefits such as increased flexibility and grid reliability, reduction in natural gas consumption, increased fuel diversity, and decreased system emissions. JEA will begin to fall below its minimum reserve margin level in 2028. While additional off-system purchases can be made to maintain the target reserve margin until commercial operation of SJRPP Unit 3, absent the new unit, JEA would be required to import increasingly large volumes of power (72 MW by 2031, increasing to 222 MW by 2033 and 802 MW by 2035). The current configuration of JEA's transmission system cannot support importing this amount of power and would require substantial and costly upgrades, the completion of which is not feasible by the time the increased import capability is needed.

1.8 Conclusion

The analyses and other information described herein demonstrate that an affirmative need determination is warranted for SJRPP Unit 3 based on consideration of the relevant factors set forth in section 403.519, Florida Statutes. Due primarily to significant load growth and demand, and anticipated retirement of NGS Unit 3 in 2035, JEA will have a need for 72 MW of additional capacity by 2031, increasing to 222 MW by 2033 and 802 MW by 2035. JEA's Board selected SJRPP Unit 3 based on the results of a rigorous, multi-stage planning process that involved extensive economic analyses of generation alternatives, including power purchase alternatives identified during the RFP process, as well as careful consideration of non-economic attributes and risk factors. There are no reasonably available, cost-effective additional DSM/conservation measures that could mitigate JEA's projected need for SJRPP Unit 3.

¹ *In re: Commission review of numeric conservation goals (JEA)*, Docket No. 20240016-EG, Order No. PSC-2024-0432-FOF-EG (Sept. 20, 2024) (FEECA Order).

² FEECA Order at 5 (recognizing approval of all proposed stipulations in Attachment A, including ¶ 6).

2.0 Purpose and Overview of Need Study

JEA is submitting this Need Study in support of its petition for determination of need for SJRPP Unit 3 pursuant to section 403.519, Florida Statutes. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each petition for need determination must include to allow the Commission to address the statutory factors. This Need Study is organized as follows to provide the information required for such need determinations by Rule 25-22.081:

- Section 3 provides a general description of the utility primarily affected, including the load and electrical characteristics, generating capability, and interconnections;
- Section 4 provides a general description of the proposed electrical power plant, including the size, number of units, fuel type and supply modes, the approximate costs, and projected in-service date;
- Section 5 provides a statement of the specific conditions, contingencies or other factors which indicate a need for the proposed electrical power plant including the general time within which the generating unit will be needed;
- Section 6 provides a discussion of the major available generating alternatives (including renewable energy sources) which were examined and evaluated in arriving at the decision to pursue the proposed generating unit;
- Section 7 provides a discussion of non-generating alternatives; and
- Section 8 provides an evaluation of the adverse consequences which will result if the proposed electrical power plant is not added in the approximate size sought or in the approximate time sought.

3.0 Primarily Affected Utilities

3.1 JEA

JEA is a municipal electric utility under section 366.02, Florida Statutes, with an approximately 905 square mile electric service area. JEA provides electricity for approximately 537,000 customers in the City of Jacksonville and portions of Clay and St. Johns Counties, making it the eighth largest municipally owned electric utility in the United States in terms of number of customers. Figure 3-1 shows JEA's service territory.



Figure 3-1 JEA Service Territory

JEA is governed by a Board of Directors consisting of four members appointed by the City Council and three members appointed by the Mayor of the City of Jacksonville, all of whom are approved by the City Council. JEA's headquarters is located at 225 N. Pearl Street, Jacksonville, Florida 32202.

3.2 Load and Electrical Characteristics

JEA meets the power supply needs of its customers with JEA-owned generation, power purchase agreements (PPAs) with independent power producers and utilities, and energy purchases on the spot market through The Energy Authority (TEA) when economical. JEA's portfolio has changed greatly over the last 25 years. The 2000s included multiple additions to JEA's generating fleet to meet the growing energy needs in the Jacksonville area. At that time, energy sales were consistently growing year over year. Beginning in the late 2010s and through the early 2020s, slow economic recovery following the housing market crash and financial crisis drove a drastic drop in MWh sales to customers, resulting in less need for resources than was original forecasted. The lower demand for energy led to the ultimate decision to retire SJRPP Units 1 & 2 and Scherer Unit 4 in 2022. Since 2011, JEA has only entered into PPAs for additional energy and capacity needs.

JEA's current load is more unpredictable. JEA remains a winter peaking utility but is becoming more bi-modal. In 2025, a hot summer and cold winter drove the load increasing demand from JEA resources, including an all-time summer peak of 2,980 MW, exceeding the previous summer high of 2,937 MW in 2007. Six of the top 40 peaking days since 2007 occurred in 2025, four in January and two in July. JEA's 2026 Ten-Year Site Plan (TYSP, included as Attachment A hereto) forecast shows a 6.8% increase in summer peak demand and a 5.6% increase in winter peak demand in 2031 over the 2025 forecast. It is this increased demand that requires JEA to maintain NGS Unit 3 in limited use status upon commercial operation of SJRPP Unit 3 rather than full retirement as initially contemplated.

In addition to anticipated organic residential growth, JEA has confirmed a total of 347 MW of new load since the 2025 forecast in projects in design and construction phases. The growth is generally split 50% residential and 50% commercial. This growth trend is being seen industry-wide as a result of reindustrialization, AI, data centers, and electrification. This has led to sustained industry growth for the first time in nearly two decades.

3.3 Generating Capability

JEA's generation portfolio is comprised of a mix of owned assets and PPAs that together aim to ensure affordable, reliable and sustainable energy supply for JEA's customers. JEA's goal is to maintain a portfolio that balances operational flexibility, financial stability, and alignment with regulatory and sustainability objectives while positioning the system to meet both current and future energy demands. JEA meets the demands of its customers with generating facilities located on four plant sites within the City of Jacksonville. Together, these generating facilities total 2,952 MW of net winter capacity, and 2,782 MW of net summer capacity. JEA also has a variety of PPAs, including solar and other renewable facilities, totaling approximately 661 MW of firm winter capacity and 601 MW of firm summer power as of June 1, 2026.

3.3.1 JEA's Owned Generation Facilities

JEA's existing owned generating resources are located at four generating facilities and are summarized in Table 3-1.

- J. Dillon Kennedy Generating Station (Kennedy) uses natural gas with diesel fuel as back-up, in two large combustion turbines (commissioned 2000 and 2009). Total site capacity is 357 MW summer and 382 MW winter.

- NGS uses natural gas, fuel oil, biomass, coal and petroleum coke in three large steam units and four small diesel-powered peaking units. Total site capacity is approximately 1,310 MW summer and 1,356 MW winter.
 - o Unit 1 (coal, petroleum coke, and biomass) commissioned in 1966; repowered in 2000.
 - o Unit 2 (coal, petroleum coke, and biomass) commissioned in 1972; decommissioned in 1984; repowered in 2000.
 - o Unit 3 (natural gas and fuel oil) commissioned in 1977; anticipated placing in limited use limited to oil-firing coincident with commercial operation of SJRPP Unit 3.
- Brandy Branch Generating Station (Brandy Branch) houses three natural gas combustion turbines with a heat recovery steam generator to recover excess heat from two of the turbines. Total site capacity is 758 MW summer and 851 MW winter.
- Greenland Energy Center (GEC) uses natural gas with diesel fuel as back up in two large combustion turbines. Total site capacity is 357 MW summer and 382 MW winter.

Table 3-1 Summary of JEA's Existing Generating Units

Plant Name	Unit Number	Unit Type	Fuel Type		Commercial In-Service Mo/Year	Net MW Capability	
			Primary	Alt.		Summer	Winter
Kennedy	7	GT	NG	DFO	06/2000	179	191
	8	GT	NG	DFO	06/2009	179	191
NGS	1	ST	PC	BIT	05/2003	293	293
	2	ST	PC	BIT	04/2003	293	293
	3	ST	NG	RFO	07/1977	524	524
	33-36	GT	DFO		01/1975	200	246
Brandy Branch	1	GT	NG	DFO	05/2001	179	191
	2	CT	NG		05/2001	190	212
	3	CT	NG		10/2001	190	212
	4	CA	WH		01/2005	200	216
Greenland Energy Center	1	GT	NG	DFO	06/2011	179	191
	2	GT	NG	DFO	06/2011	179	191
NG: Natural Gas; DFO: Distillate Fuel Oil; PC: Petroleum Coke; BIT: Bituminous Coal; WH: Waste Heat GT: Gas Turbine; ST: Steam Turbine; CT: Combustion Turbine portion of Combined Cycle; CA: Steam Turbine portion of Combined Cycle							

3.3.2 Power Purchase Agreements

In the last 15 years, JEA has only added new PPAs to its portfolio; it has not added a new generating facility into its system since 2011. JEA currently has firm PPAs for 601 MW (summer of 2026) with independent power producers and utilities. These PPAs include nuclear power (206 MW), natural gas (280 MW), landfill gas energy (15 MW), and solar (100 MW). JEA's existing PPAs are summarized in Table 3-2, which states capacity on a nameplate basis, and are described in more detail below.

Table 3-2 Summary of JEA's Existing Power Purchase Agreements

Contract	Start Date	End Date	MW(AC)	Energy Source
LES Trail Ridge I	12/06/08	12/31/26	9	Landfill Gas
LES Trail Ridge II	02/01/14	12/31/26	6	Landfill Gas
MEAG Plant Vogtle Unit 3	07/31/2023	07/31/2043	103	Nuclear
MEAG Plant Vogtle Unit 4	04/29/2024	04/29/2044	103	Nuclear
FPL PPA	01/01/22	01/01/42	280	Natural Gas
FPL Solar PPA	04/01/23	04/01/28	150	Solar
Jacksonville Solar	09/30/10	09/30/40	12	Solar
NW Jacksonville Solar	05/30/17	05/30/42	7	Solar
Old Plank Road Solar	10/13/17	10/13/37	3	Solar
Starratt Solar	12/20/17	12/20/37	5	Solar
Simmons Road Solar	01/17/18	01/17/38	2	Solar
Blair Site Solar	01/23/18	01/23/38	4	Solar
Old Kings Solar	10/15/18	10/15/38	1	Solar
SunPort Solar	12/04/19	12/04/39	5	Solar (w/Storage)
Forest Trail Solar PPA	12/31/26	12/31/61	50	Solar
Miller Solar PPA	12/31/26	12/31/61	74.9	Solar (w/Storage)

3.3.2.1 FPL Natural Gas Power Purchase Agreement

On August 25, 2020, JEA and Florida Power & Light (FPL) executed a Cooperation Agreement for the retirement of Plant Scherer Unit 4 with the firm capacity and energy to be replaced by a 20-year power purchase agreement (PPA) between JEA and FPL for a natural gas-fired system product beginning January 1st, 2022, with a solar conversion option on or after the 10th anniversary from the PPA start date. An increase of up to 100 MW in capacity and transmission service for the Cooperation Agreement was approved by the JEA Board to help meet JEA's growing demand. JEA and FPL agreed to an increase to the natural gas PPA to a total of 280 MW which began on June 1, 2026.

3.3.2.2 Trail Ridge Landfill Power Purchase Agreement

In 2006, JEA entered into a PPA with Trail Ridge Energy, LLC (TRE) to purchase energy and environmental attributes from up to 9 net MW of firm renewable generation capacity utilizing the methane gas from The City's Trail Ridge landfill located in western Duval County (the "Phase One Purchase"). The facility was one of the largest landfill gas-to-energy facilities in the Southeast when it began commercial operation on December 6th, 2008.

JEA and TRE executed an amendment to this PPA on March 9th, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began in February 2015. The contract for Trail Ridge Phase One and Phase Two will expire in December 2026.

3.3.2.3 Jacksonville Solar Power Purchase Agreement

In May 2009, JEA entered into a PPA with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW_{AC} of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100-acre site. The Jacksonville Solar plant began commercial operation at full designed capacity on September 30th, 2010. The contract for Jax Solar will expire in September 2040.

3.3.2.4 Small Utility-Scale Solar Power Purchase Agreements

JEA issued two Solar Photovoltaic (PV) Request for Proposals (RFP), one in December 2014 and another in April 2015, and awarded a total of 31.5 MW_{AC} of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements were finalized for a total of 27 MW_{AC}. The last of these seven projects was completed in December 2019.

The following are the seven PPAs that are installed within JEA's service territory of which JEA pays for the energy and has rights to the associated environmental attributes produced by the facilities:

- Northwest Jacksonville Solar: 7 MW_{AC} / 25-year PPA. The NW Jax facility began commercial operations on May 30th, 2017.
- Old Plank Road Solar: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility began commercial operations on October 13th, 2017.
- Starratt Solar: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility began commercial operations on December 20th, 2017.
- Simmons Road: 2 MW_{AC} / 20-year PPA. The Simmons Road Solar facility began commercial operations on January 17th, 2018.
- Blair Site Solar: 4 MW_{AC} / 20-year PPA. The Blair Site Solar facility began commercial operations on January 23rd, 2018.
- Old Kings Solar.: 1 MW_{AC} / 20-year PPA. The Old Kings Solar facility began commercial operation on October 15th, 2018.
- SunPort Solar: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The BESS began commercial operations on December 4th, 2019.

3.3.2.5 FPL Solar Power Purchase Agreements

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

3.3.2.6 Planned Solar Power Purchase Agreements

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

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

3.3.2.7 MEAG Nuclear Power Purchase Agreements

In June 2008, JEA entered into a 20-year PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4. These two new nuclear units are located at the existing Plant Vogtle in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity.

Vogtle Units 3 and 4 were commissioned on July 31st, 2023 and April 29th, 2024, respectively. Each unit is supplying approximately 103 MW of net firm capacity to JEA. In May 2026, the JEA Board approved the sale of 103 MW of Vogtle capacity and energy to Dalton Utilities in 2028; increasing to 123 MW in 2029, and decreasing to 111 MW in 2030 and 103 MW in 2031 and 2032.

3.3.3 Renewable Resources

JEA currently receives or has contracts in place for a total of approximately 329 MW from renewable energy sources, including 15 MW from landfill gas-to-energy via a PPA and 314 MW from solar via PPAs and 50 MW battery energy storage. JEA co-fires more than 10% biomass in NGS Units 1 and 2 and has also installed solar PV systems at various customer sites in the community, including the Chamber of Commerce, Jacksonville International Airport, Jacksonville University, a fire station, and multiple Duval County public school locations totaling approximately 100 kW. JEA also established a residential net material program to encourage the use of customer-sited solar PV systems and has partnered with the University of North Florida Engineering Department to focus on the development of clean energy technologies.

JEA's Board of Directors approved aspirational clean energy goals in 2023. JEA has incorporated a significant amount of clean energy into its power supply portfolio, including numerous solar PPAs, and continues to explore opportunities to incorporate additional clean energy while ensuring alignment with system reliability, affordability, and adaptability. These efforts have not, however, been without challenges. Many factors have impacted JEA's ability to achieve the aspirational goals on the proposed timeline – several planned and/or proposed clean energy projects in which JEA intended to participate were cancelled; transmission/interconnection equipment supply chain issues persist and continue to impact project costs and schedule; and finding appropriately sized, environmentally suitable land to support utility-scale solar in Duval County is prohibitively expensive such that extensive transmission upgrades would be necessary to import solar power to JEA's system. In addition, regulatory changes have fundamentally impacted the economics and affordability of clean energy projects and timeline for retirement of existing generating units, including the elimination of subsidies on utility-scale solar projects, EPA's proposed repeal of Greenhouse Gas (GHG) standards for electric generating units (GHG Rule), and EPA's repeal of the 2009 Endangerment Finding. Finally, JEA is experiencing significant load growth, warranting careful reevaluation of the timing of retirement of existing generating units.

JEA utilizes its Integrated Resource Planning (IRP) process to evaluate and inform long-term resource decisions, including scenarios and sensitivities to consider environmental legislative and regulatory action, load growth forecasts, fuel costs, costs of new generation, continued operation of existing generating units, and other factors. JEA has used the IRP process for decades, with the most recent IRP conducted in 2023 and another planned in the 2026/2027 timeframe. The assumptions and information utilized in JEA's IRPs are continually updated to fully inform JEA leadership decisions relative to resource additions. Given regulatory changes and other factors affecting practicality and affordability, as well as significant load growth, JEA continues to evaluate the current cost and practical ability to meet the aspirational clean energy goals and will utilize information from its ongoing IRP process to inform leadership decisions moving forward.

3.4 Transmission Interconnections

JEA's existing transmission facilities consist of 744 circuit miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV. The 500 kV transmission lines are jointly owned by JEA and FPL, completing the path from FPL's Duval substation (located in the westerly portion of JEA's system) to the north to interconnect with the Georgia Integrated Transmission System (ITS). JEA's import capacity is 1,228 MW over the 500 kV lines through the Duval substation. Prior to the decommissioning of SJRPP Units 1 & 2, JEA was a net exporter of power and JEA's transmission system was developed accordingly to export power out of JEA's service territory. JEA is now a net power importer. The majority of any power purchase – whether from the north (Georgia) or the south (FPL), enters JEA's transmission system through FPL's Duval substation.

The 230 kV and 138 kV transmission lines provide a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. Four 230 kV transmission lines exit the SJRPP site. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest; covering the area not covered by the 230 kV and 138 kV transmission lines.

4.0 Description of the Proposed Generating Units

4.1 Proposed Project

The Project involves construction and operation of a new, state-of-the-art, dual-fuel natural gas- and ULSD-fired 1x1 advanced class combined cycle generating facility and onsite associated facilities on an approximately 194-acre site, wholly contained within JEA's existing 1,600-acre SJRPP parcel adjacent to JEA's existing NGS in Jacksonville, Duval County, Florida (Figure 4-1).



Figure 4-1 Proposed Project Certified Site

SJRPP Unit 3 consists of one combustion turbine generator (CTG), one heat recovery steam generator (HRSG) and one steam turbine generator (STG). SJRPP Unit 3 will have a maximum nameplate capacity of 706 MW with a net capacity (winter) of 678 MW and will be capable of firing natural gas or ULSD fuel oil. The primary fuel source will be natural gas provided via a PGS-owned and -operated lateral, with USLD fuel oil as a back-up fuel source. JEA anticipates placing its existing, less efficient, NGS Unit 3 into limited use, operating at or below an 8% capacity factor as a back-up during peak demand periods, emergencies, and unexpected outages coincident with commercial operation of SJRPP Unit 3. Existing natural gas capacity supply for NGS Unit 3 will be diverted to SJRPP to support operation of SJRPP Unit 3, with a relatively small amount of additional firm natural gas capacity (18,000 MMBtu/day) needed to support full operation of SJRPP Unit 3 during winter peak. Figure 4-2 provides a conceptual rendering of SJRPP Unit 3.



Figure 4-2 Conceptual Project Rendering

4.1.1 Project Site

SJRPP Unit 3 is proposed to be located at JEA's existing SJRPP site in the City of Jacksonville, Duval County, Florida (Figure 4-3). The SJRPP site is approximately 9.3 miles northeast of downtown Jacksonville, east of Interstate I-95, north of State Highway 105 (Heckscher Road), and south of Cedar Point Road. SJRPP is contiguous to NGS to the south. SJRPP Unit 3 will be located on the southern portion of the larger SJRPP parcel. Areas surrounding the parcel are largely used for industrial and commercial purposes.

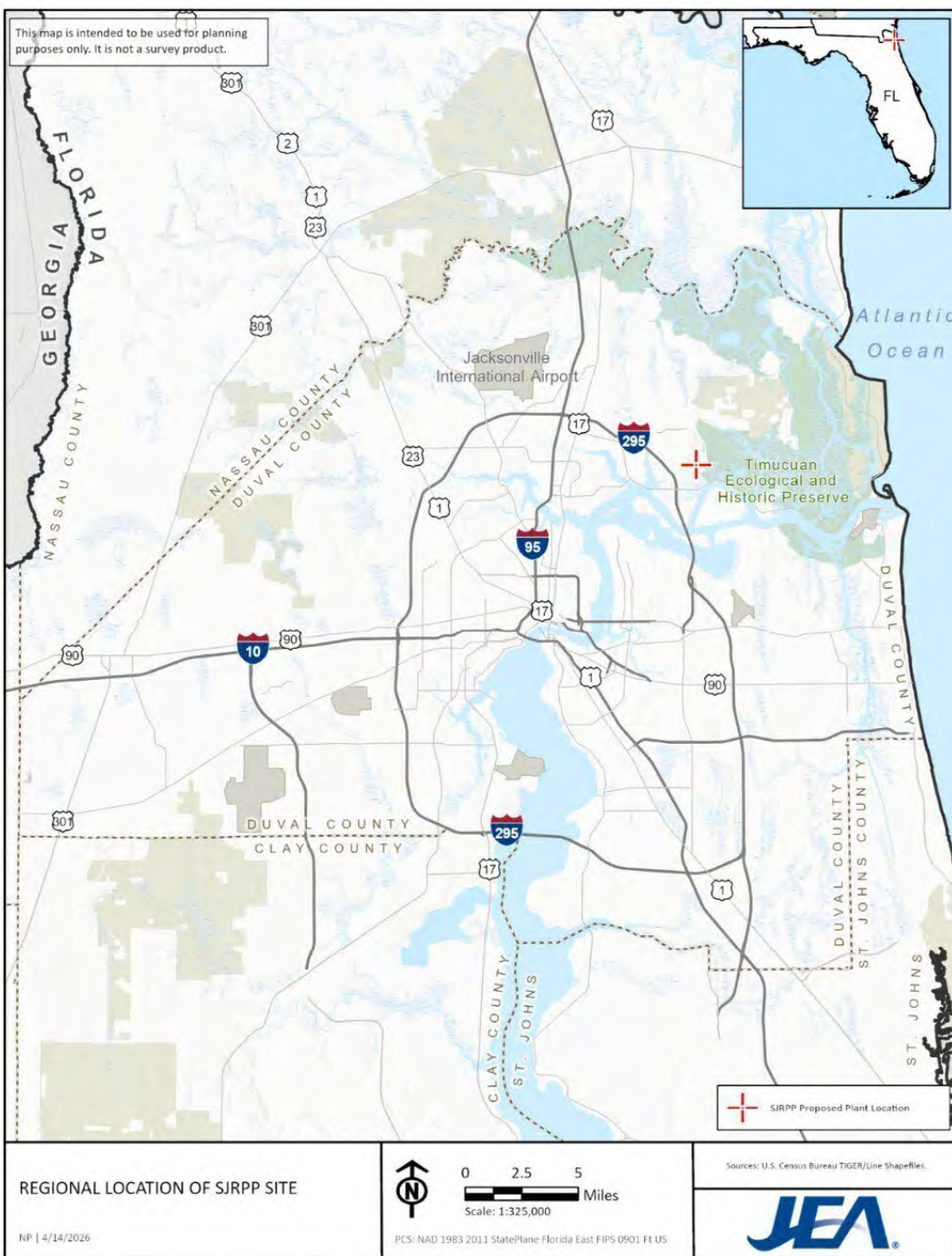


Figure 4-3 Proposed Project Site Location

4.1.2 Power Generation Technology

SJRPP Unit 3 will consist of one CTG, one HRSG, and one STG. When operated in combined cycle mode, large advanced-class CTGs, like that selected for this Project, are the most efficient electric generating technology currently available for utility-scale power plants. These combined cycle plants can achieve efficiencies greater than 60 percent, compared to CTGs alone in simple-cycle mode at 42 to 43 percent and coal-fired steam plants at 33 to 45 percent. When a CTG is operated alone in simple-cycle mode, combustion exhaust energy is released directly to the atmosphere. In a combined cycle configuration, a portion of the combustion exhaust energy is recovered in an HRSG to produce steam, which is used to drive an STG to generate additional electricity. Therefore, a combined cycle power plant can generate more electricity without burning additional fuel or producing additional air emissions. Figure 4-4 presents a conceptual schematic of a one-on-one combined cycle unit.

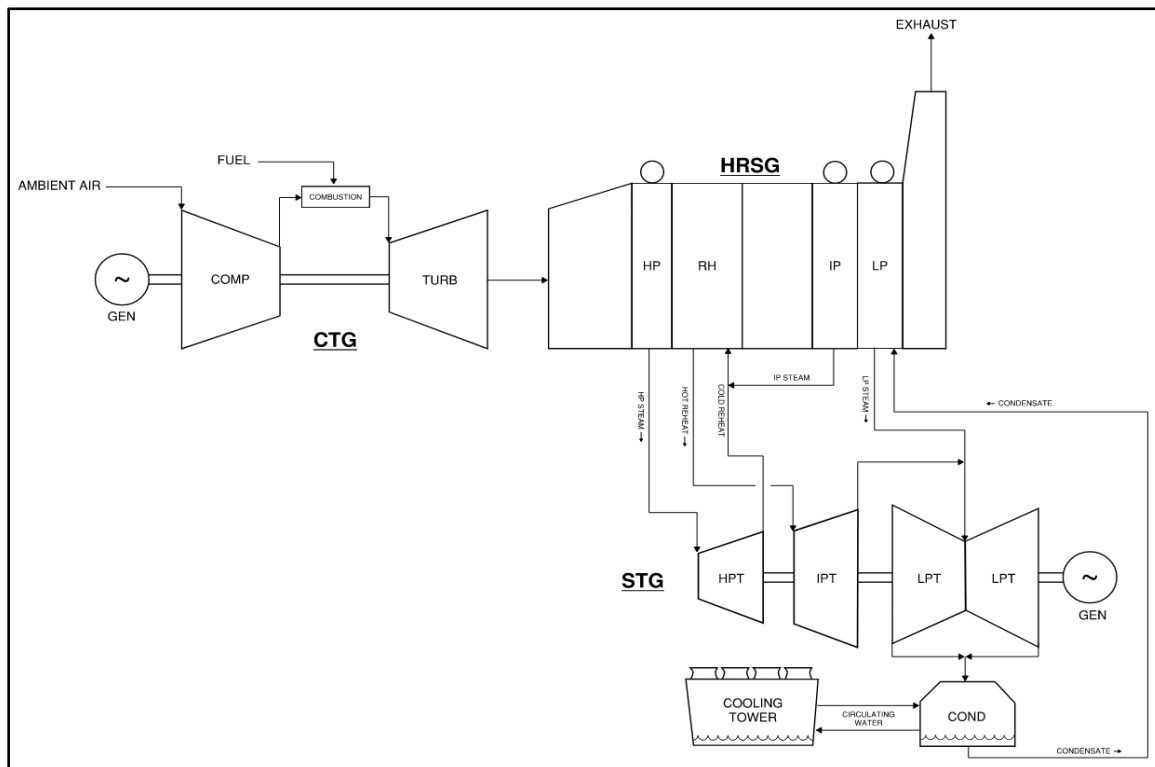


Figure 4-4 Conceptual Schematic of a 1-on-1 Combined Cycle Plant

SJRPP Unit 3 is expected to have a nameplate or gross output of 706 MW and a “net nominal” output of 678 MW (winter) and 582 MW (summer). During peak load periods, SJRPP Unit 3 will be able to fire supplemental natural gas in the HRSG duct burners to provide an increase of ~12% to 15% in STG electrical output. The 7HA.03 gas turbine has an extended “turndown” capability which will allow it to meet emissions compliance levels while operating as low as ~20% - 25% of full-load. This low turn-down capability is valuable as it will allow the facility to remain operational during low-load periods typically experienced at night and avoid the thermal stresses, wear, and additional emissions associated with a shut-down/start-up cycle. SJRPP Unit 3 will be primarily natural gas-fired, but capable of operating on ULSD fuel oil as a back-up. SJRPP Unit 3 will also be capable of operating on up to 50 percent hydrogen if available in the future. The combination of low turndown capabilities, as well as fuel diversity, provides the facility with significant flexibility in terms of operational characteristics.

The SJRPP site arrangement is depicted on Figure 4-5. The Power Island Equipment (PIE) will include one GE Vernova (GEV) 7HA.03 advanced class CTG, one GEV triple-pressure HRSG, and one GEV STF-D650 STG. The CTG will be equipped with a Dry Low NOx (DLN) combustion system designed for firing natural gas fuel and back-up ULSD fuel oil. The triple pressure HRSG will be a horizontal natural circulation design with supplemental duct-firing capabilities and equipment for emissions reductions. The STG will be configured as a tandem compound reheat unit with a side exhaust, dual flow LP cylinder. Cycle heat rejection will consist of a surface condenser and mechanical draft cooling tower. Control systems for the CTG, STG and HRSG will be integrated into the plant Distributed Control System (DCS). The facility will be operated primarily from the DCS.

4.1.3 Existing Infrastructure

SJRPP Unit 3 will utilize existing infrastructure, including the existing substation on the SJRPP property, four existing 230 kV electrical transmission lines exiting the property, existing reclaim water lines from JEA's District II Water Reclamation Facility, existing potable water lines from JEA's Major Grid Water Treatment Plant, existing sanitary sewer lines to District II Water Treatment Plant, conveyance channels for a portion of the stormwater management system design, existing SJRPP cooling tower blowdown water discharge pipeline which discharges to an existing basin located at NGS, an existing discharge pipe from the NGS basin to the St. Johns River, and the existing discharge structure. Use of existing transmission line infrastructure alone reduces the cost of the Project by approximately \$100 million in necessary transmission line upgrades compared to alternatives that would require importing power to JEA's system.

4.1.4 Associated Facilities

SJRPP Unit 3 also includes other onsite associated facilities, such as an administration building with the DCS, a warehouse/maintenance building, roadways, parking and laydown areas, a temporary spoils area, a demineralized water treatment building, an open-frame turbine structure, electrical equipment and enclosures, step-up and auxiliary transformers, a natural gas metering and regulation station with gas-fired heaters, a mechanical draft cooling tower, HRSG exhaust stack, natural gas-fired auxiliary boiler with exhaust stack, emissions monitoring and reduction equipment, fire water pumps (electric primary with diesel back-up), diesel-fired emergency generator, above-ground service water storage tank, fire water storage tank, reclaim water storage tank, fuel oil storage tank, aqueous ammonia tank, wells, oil/water separators, a stormwater management system with stormwater ponds, piping tie-ins with existing infrastructure, and other ancillary equipment.

SJRPP Unit 3 will utilize existing on and off-site infrastructure. Natural gas will be delivered to a Metering & Regulation (M&R) yard onsite via an approximately 25-mile pipeline lateral. The M&R yard and pipeline lateral will be permitted, constructed, owned, operated, and maintained by PGS. Reclaimed water from JEA's nearby District II Water Reclamation Facility will be used for makeup to the cooling tower utilizing existing reclaimed water pipelines. Use of the existing piping system will require installation of an off-site booster pump station. The booster pump station will be located on a 0.38-acre property owned by JEA's separately owned and operated Water and Sewer System approximately 2 miles northwest of SJRPP, adjacent to I-295 to the south. These off-site facilities are not "associated facilities" proposed for certification under the PPSA. § 403.503(7), (14), Fla. Stat.

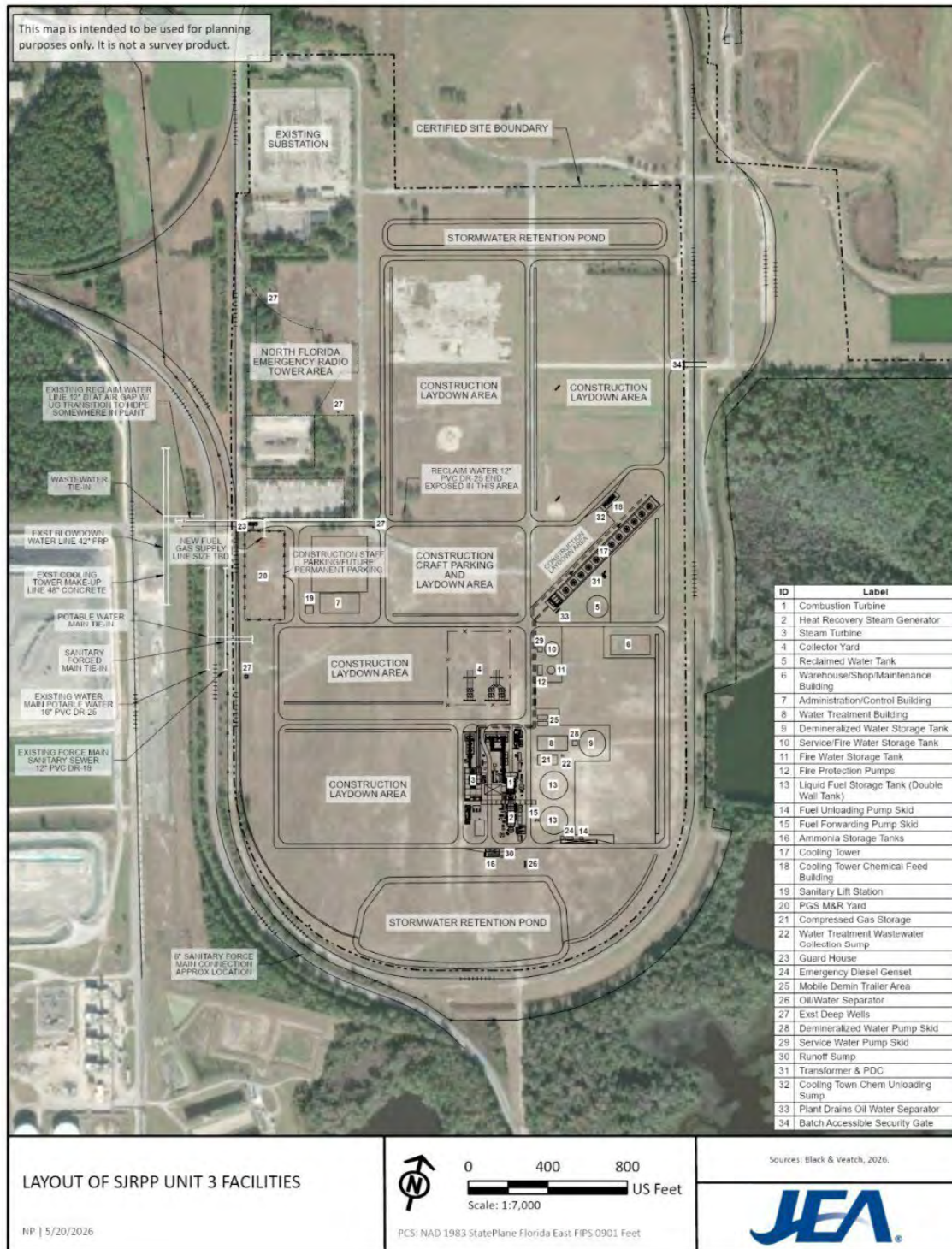


Figure 4-5 Proposed Project Site Arrangement

4.1.5 Air Emission Controls

SJRPP Unit 3 will be designed with technologies to minimize air emissions. The CTG will be equipped with DLN combustors to limit the formation of nitrous oxides (NO_x) during combustion. The HRSG will be equipped with an SCR system to further reduce NO_x emissions. Water injection will be implemented to reduce NO_x emissions when operating on ULSD fuel oil. Emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) will be limited through use of an oxidation catalyst system. Emissions of other regulated air pollutants, such as sulfur dioxide (SO₂) and particulate matter (PM), will be controlled through use of pipeline-quality natural gas and good combustion practices. In addition, SJRPP Unit 3 will minimize GHG emissions through the primary use of clean-burning natural gas along with the highly efficient combined cycle electric generating technology.

4.1.6 Water Use and Supply

SJRPP Unit 3 is designed to minimize the use of water. The condenser cooling system will consist of a 12-cell mechanical draft cooling tower and large pumps/pipes that circulate water between the cooling tower and a condenser located next to the steam turbine. Water is lost from the system at the cooling tower through drift, evaporation, and blowdown. Makeup for these losses will be predominately supplied by reclaimed water. Tie-in will take place with an existing pipeline previously used by SJRPP Units 1 & 2 and currently utilized by NGS. Reclaimed water will be cycled up to four times in the cooling tower (4 cycles of concentration) before blowdown is directed to an existing blowdown line which remains from the decommissioning of SJRPP Units 1 & 2. The existing blowdown line routes from SJRPP to the southwest through NGS where it discharges to an existing mixing basin at NGS. Wastewater from SJRPP mixes with wastewater from NGS in the mixing basin then passes through an existing pipe where it finally discharges through an existing structure to the St. Johns River.

Higher quality freshwater needs for general services and process water uses in the facility will be provided through groundwater withdrawals from new onsite wells. General plant service water will pass through a basic filtration stage to eliminate any sedimentation in the stream that could damage downstream equipment. Service water uses include equipment wash water, emergency fire water for fire protection, HRSG blowdown quench, and pump mechanical seal water. Process water goes through an additional filtration process to yield high-quality demineralized water which is required for steam-cycle makeup, NO_x injection water when firing ULSD and closed cycle cooling makeup water. The volume of groundwater needed will be significantly less than the current groundwater allocation in the SJRPP Unit 3 Conditions of Certification. Potable water for drinking, safety showers, eyewash stations, and other sanitary uses will be provided by JEA's Highlands Water Treatment Facility. Tie-in will take place with an existing line which currently routes along the western boundary of the Site. Sanitary sewer from restrooms and domestic facility drains will be routed to JEA's District II Water Treatment Facility. Tie-in will take place with an existing line which currently routes parallel to potable water along the western boundary of the site.

General facility wastewater will be combined with cooling tower blowdown in the existing blowdown line and routed through the mixing basin at NGS before being released through an existing structure in the St. Johns River. Potential oil-contaminated drains will be routed through an oil-water separator prior to discharging to the existing blowdown line. Other potentially contaminated wastewater (e.g. chemical contamination) will be contained and treated in place or removed for off-site treatment.

4.1.7 Stormwater Management

The stormwater management system for SJRPP Unit 3 is designed to handle and treat the 25-year, 24-hour storm event and is designed to meet all federal, state, regional, and local requirements. Potential

contact stormwater runoff from the power block and equipment areas will be collected and treated through an oil/water separator and routed to a stormwater retention pond prior to discharge to the St. Johns River. Noncontact stormwater runoff from the facility area will be collected and routed directly to a stormwater retention pond through a network of catch basins, culverts, and conveyance channels. During construction, stormwater runoff from the construction laydown and parking areas will also be collected through a series of culverts and conveyance channels and treated in swales and ponds in dry retention ponds. Best Management Practices (BMPs) will be utilized to minimize erosion from the disturbed areas during construction activities.

4.1.8 Fuel Type & Supply

SJRPP Unit 3 will burn natural gas as the primary fuel. At peak operation, including duct-firing, the facility will require approximately 104,200 million British thermal units (MMBtu) of natural gas per day on a higher-heating value (HHV) basis. In the event that natural gas is unavailable or uneconomic for JEA's customers, SJRPP Unit 3 will be capable of operating on ULSD distillate fuel as a back-up. When ULSD is used as fuel, the consumption rate will be approximately 93,500 MMBtu per day.

Natural gas will be supplied to SJRPP Unit 3 via a new approximately 25-mile lateral from the JEA Brandy Branch Generating Station area to a new M&R yard on the SJRPP property. The pipeline lateral and gas yard will be permitted, constructed, owned, operated, and maintained PGS. Gas will be supplied to the region via existing interstate gas pipelines owned and operated by Florida Gas Transmission (FGT) and Southern Natural Gas (SNG). JEA currently owns firm interstate transmission on each of these lines.

The efficiency of SJRPP Unit 3 over NGS Unit 3 represents a significant improvement in the utilization of existing natural gas supplies. At full load operation, SJRPP Unit 3 will use 37% less gas per MWh produced than NGS Unit 3. The existing interstate capacity made available from placing NGS Unit 3 in limited use on liquid fuel will be adequate to supply natural gas for normal operation of SJRPP Unit 3. JEA will, however, require a relatively small amount of additional firm natural gas capacity (18,000 MMBtu/day) to support full operation of SJRPP Unit 3 during winter peak.

With regard to back-up fuel, ULSD adequate in quantity to supply SJRPP Unit 3 for five (5) days at full load will be stored onsite. The fuel will be stored in double-walled above-ground storage tanks, in compliance with all applicable regulations. JEA anticipates that the fuel will primarily be delivered to the site by tanker truck.

As outlined above, the dual-fuel capability of SJRPP Unit 3 will enhance fuel diversity and reliability of fuel supply to the Project, which will support increased plant availability during operation.

4.1.9 Transmission Interconnections

Prior to the decommissioning of SJRPP Units 1 & 2 in 2018, JEA was a net exporter of power and JEA's transmission system was developed accordingly – to export power out of JEA's service territory. Following the decommissioning, and with JEA's load growth in recent years, JEA is now a net power importer. The majority of any power purchased – whether from the north (Georgia) or the south (FPL), enters JEA's transmission system through FPL's Duval substation. During normal system operations, the swing of over 900 MW in power interchange (from 428 MW net export in 2017 to over 500 MW net import currently) does not create significant issues. However, when JEA makes additional power purchases for economic reasons or unplanned events (e.g., unscheduled generation outages), the JEA transmission system undergoes significant stress due to the increased import of power through the tie lines. Operation planning becomes more challenging during these times, especially when transmission contingencies are considered as required by NERC Reliability Standards.

The addition of the proposed SJRPP Unit 3 will help reduce this stress on the tie lines by making the power available closer to the load within JEA's system. This will also result in lower overall system loss as the load and generation are much closer and the system is better balanced. Finally, the addition of SJRPP Unit 3 will increase reliability under normal and probable contingency conditions and help insulate JEA from transmission contingencies outside of the JEA system that could negatively impact power import. Conversely, if SJRPP Unit 3 is denied, the current configuration of JEA's transmission system could not support importing the amount of power needed to maintain JEA's target reserve margin (72 MW by 2031, 222 MW by 2033, 802 MW by 2035) without substantial and costly transmission upgrades. These upgrades are not feasible in the timeframe to meet JEA's need in 2031.

There are currently four 230 kV transmission lines exiting the existing substation on the SJRPP property. SJRPP Unit 3 will connect to this existing substation via two new 230 kV generator tie (gen-tie) lines. Beyond the gen-ties, no additional transmission upgrades will be needed to integrate the new unit into JEA's system. If JEA did not construct new generation within its geographic footprint to serve its need for additional power, the construction of additional transmission lines would be required to reliably import power under both planned normal and contingency transmission events.

JEA performed a System Impact Study to assess the impact of the proposed SJRPP Unit 3 on JEA's transmission system. The base cases for steady state (thermal and voltage analysis), short circuit, and transient stability were developed by the Florida Reliability Coordinating Council (FRCC) Planning staff and consisted of all the existing transmission system information (including the generation units) in Florida. Those cases also included the future transmission and generation projects proposed by other FRCC members. The SJRPP Unit 3 data was then included in the base cases to create the study cases. Probable transmission contingencies within JEA were simulated simultaneously in the base and study cases, and the results were compared to ensure compliance with NERC Reliability Standards. The results showed no adverse impacts to JEA's transmission system.

Additionally, JEA coordinated with FRCC members to assess the transmission system in the FRCC region following the interconnection of SJRPP Unit 3 in accordance with the *FRCC Reliability Evaluation Process for Generator and Transmission Service Requests*. All the base cases, study cases, contingency files, the results, and the Reliability Evaluation Report were made available to all FRCC members for their review and comment. JEA also shared the findings with the members during scheduled FRCC meetings. Based on the comments and feedback, JEA analyzed additional scenarios and shared the results with the members. Two technical subcommittees of FRCC recommended acceptance of the Reliability Evaluation Report to the FRCC Planning Committee, which accepted the Report.

Based on JEA's System Impact Study, and FRCC's reliability evaluation, the interconnection of SJRPP Unit 3 will have no adverse impact on JEA's transmission system or any transmission system outside of JEA within the FRCC footprint.

4.1.10 Estimated Capital Costs

The estimated total in-service capital cost of SJRPP Unit 3 in 2031 is \$1.57 billion. As summarized in Table 4-1, this estimate includes plant structures and equipment, equipment for interconnection, construction and development costs, interest during construction, insurance, and other owner's costs.

Table 4-1 SJRPP Unit 3 1x1 CCGT Capital Cost Estimate

Equipment and Interconnection, Development, and EPC Contract*	\$ 1,277,246,973
Other Owner's Costs and Contingency	\$ 119,929,576
Interest During Construction	\$ 136,925,018
Insurance	\$ 35,898,433
TOTAL	\$ 1,570,000,000
*Cost component information is confidential and cannot be further broken down absent confidentiality protections.	

4.1.11 Construction Schedule & Projected In-Service Date

Subject to receipt of all regulatory approvals, construction activities for SJRPP Unit 3 are scheduled to begin in early 2028, with targeted commercial operation approximately 36 months later. JEA currently projects an in-service date of January 2031.

5.0 The Need for Proposed Generating Units

5.1 Overview of Need Assessment

JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources as well as other planning assumptions. The remainder of this section discusses JEA's load forecast, reserve margin criteria, capacity resources, and the resulting projected need for capacity that underpins the economic analysis demonstrating the proposed SJRPP Unit 3 is part of JEA's least-cost resource plan to meet projected capacity requirements.

5.2 The Load Forecast

Annually, JEA develops forecasts of seasonal peak demands, net energy for load (NEL), interruptible customer demand, demand-side management (DSM), and the impact of plug-in electric vehicles (PEVs). JEA's baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the most recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections. JEA's load forecast methodology is discussed in the following subsections.

5.2.1 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class using National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. The methodologies used to develop the various components of JEA's load forecast are summarized as follows.

- The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy sales, total population, number of households, median household income and total housing starts from Moody's Analytics, JEA's total residential accounts and JEA's residential electric rate.
- The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy sales, total commercial employment and gross domestic product from Moody's Analytics, JEA's total commercial accounts, and commercial inventory square footage from the CBRE Jacksonville Office Figures Q3 2025 Report.
- The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy sales, gross domestic product, total industrial employment, and total proprietors' profits from Moody's Analytics, and JEA's total industrial accounts. The first 7 years of the forecast also incorporate confirmed new development projects and their expected demand, as well as increase consumption from existing industrial customers due to expansion.
- The lighting energy forecast was developed using the historical actual energy and number of luminaries. JEA developed the forecasted number of luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries.

5.2.2 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 25°F as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA develops the seasonal peak forecasts using normalized historical and forecasted residential, commercial, and industrial energy for winter/summer peak months, and the average load factor based on historical peaks and net energy for winter/summer peak months.

5.2.3 Demand-Side Management (DSM)

5.2.3.1 Interruptible Load

JEA currently offers Interruptible and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to interruption of their full nominated load during times of system emergencies, including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 120 MW of interruptible peak load for the summer through 2027, increasing to 124 MW beginning in the summer of 2028, and 107 MW for the winter through 2027, increasing to 111 MW beginning in the winter of 2028.

5.2.3.2 Demand-Side Management Programs

JEA's forecast of annual incremental demand and energy reductions associated with its current DSM programs (as discussed in Section 7 herein) are summarized as follows for 2026; demand and energy reductions associated with DSM are forecast to increase annually thereafter.

- Annual Energy Reductions
 - o Residential: 12.04 GWh
 - o Commercial/Industrial: 11.36 GWh
 - o Total: 23.40 GWh
- Summer Peak Demand Reductions
 - o Residential: 2.26 MW
 - o Commercial/Industrial: 2.08 MW
 - o Total: 4.34 MW
- Winter Peak Demand Reductions
 - o Residential: 3.28 MW
 - o Commercial/Industrial: 1.01 MW
 - o Total: 4.29 MW

5.2.4 Customer-Sited Renewables

JEA's forecast of customer-sited renewables takes into account available roof space, power density of rooftop solar systems, hourly solar generation patterns, AC/DC ratios, and other factors. The potential peak demand and energy reductions associated with customer-sited renewables are reflected in JEA's load forecast.

5.2.5 Plug-in Electric Vehicles Peak Demand and Energy

JEA develops forecasts of demand and energy associated with PEVs based on a number of factors, including historical and forecast PEVs and population, median household income and number of households.

5.2.6 Electrification

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

5.2.7 Historical Data and Forecast Net Peak Demand and Net Energy for Load

Tables 5-1 through 5-5 illustrate JEA's number of customers and energy usage by customer class; system-wide annual energy, summer and winter peak demands; load factors for the previous 10 years (2016 through 2025); and forecasts for the 2026 through 2035 period. Table 5-6 illustrates JEA's forecast system-wide, annual summer and winter firm peak demand, annual NEL, and load factors over the 2026 through 2060 period reflected in this Need Study.

Table 5-1 JEA Rural and Residential Customers and Energy Usage

Calendar Year	Average Number of Customers	% Growth	GWh Sales	% Growth	Average kWh/Customer	% Growth
History						
2016	398,387	--	5,351	--	13,431	--
2017	404,806	1.6%	5,199	-2.8%	12,842	-4.4%
2018	412,070	1.8%	5,460	5.0%	13,251	3.2%
2019	420,831	2.1%	5,479	0.3%	13,019	-1.8%
2020	429,575	2.1%	5,679	3.7%	13,220	1.5%
2021	438,470	2.1%	5,551	-2.3%	12,660	-4.2%
2022	447,308	2.0%	5,723	3.1%	12,795	1.1%
2023	458,764	2.6%	5,658	-1.1%	12,334	-3.6%
2024	470,564	2.6%	6,022	6.4%	12,797	3.8%
2025	479,288	1.9%	6,081	1.0%	12,641	-1.2%
Forecast						
2026	485,840	1.4%	6,075	-0.1%	12,504	-1.1%
2027	492,159	1.3%	6,174	1.6%	12,546	0.3%
2028	498,274	1.2%	6,262	1.4%	12,568	0.2%
2029	504,171	1.2%	6,351	1.4%	12,597	0.2%
2030	509,869	1.1%	6,441	1.4%	12,633	0.3%
2031	515,323	1.1%	6,531	1.4%	12,674	0.3%
2032	520,487	1.0%	6,620	1.4%	12,719	0.4%
2033	525,330	0.9%	6,707	1.3%	12,766	0.4%
2034	529,885	0.9%	6,794	1.3%	12,822	0.4%
2035	534,234	0.8%	6,892	1.4%	12,901	0.6%
Average Annual Growth Rate (2016 - 2025)		2.1%		1.4%		-0.7%
Average Annual Growth Rate (2026 - 2035)		1.1%		1.4%		0.3%

Table 5-2 JEA Commercial Customers and Energy Usage

Calendar Year	Average Number of Customers	% Growth	GWh Sales	% Growth	Average kWh/Customer	% Growth
History						
2016	51,441	--	4,064	--	78,994	--
2017	51,970	1.0%	4,011	-1.3%	77,176	-2.3%
2018	52,525	1.1%	4,042	0.8%	76,954	-0.3%
2019	53,153	1.2%	4,060	0.4%	76,389	-0.7%
2020	53,701	1.0%	3,886	-4.3%	72,363	-5.3%
2021	54,374	1.3%	3,848	-1.0%	70,767	-2.2%
2022	55,082	1.3%	4,005	4.1%	72,717	2.8%
2023	55,946	1.6%	3,968	-0.9%	70,922	-2.5%
2024	56,724	1.4%	4,104	3.4%	72,359	2.0%
2025	57,376	1.1%	4,194	2.2%	73,096	1.0%
Forecast						
2026	58,168	1.4%	4,022	-4.1%	69,136	-5.4%
2027	58,935	1.3%	4,027	0.1%	68,335	-1.2%
2028	59,713	1.3%	4,035	0.2%	67,577	-1.1%
2029	60,504	1.3%	4,046	0.3%	66,865	-1.1%
2030	61,311	1.3%	4,057	0.3%	66,176	-1.0%
2031	62,134	1.3%	4,070	0.3%	65,498	-1.0%
2032	62,969	1.3%	4,082	0.3%	64,829	-1.0%
2033	63,813	1.3%	4,097	0.4%	64,196	-1.0%
2034	64,666	1.3%	4,109	0.3%	63,548	-1.0%
2035	65,527	1.3%	4,122	0.3%	62,901	-1.0%
Average Annual Growth Rate (2016 - 2025)		1.2%		0.4%		-0.9%
Average Annual Growth Rate (2026 - 2035)		1.3%		0.3%		-1.0%

Table 5-3 JEA Industrial Customers and Energy Usage

Calendar Year	Average Number of Customers	% Growth	GWh Sales	% Growth	Average kWh/Customer	% Growth
History						
2016	202	--	2,692	--	13,322,934	--
2017	202	0.0%	2,777	3.2%	13,717,349	3.0%
2018	196	-3.0%	2,765	-0.4%	14,081,384	2.7%
2019	194	-1.0%	2,733	-1.2%	14,085,278	0.0%
2020	196	1.0%	2,698	-1.3%	13,759,522	-2.3%
2021	196	0.0%	2,612	-3.2%	13,348,772	-3.0%
2022	199	1.5%	2,708	3.7%	13,641,119	2.2%
2023	199	0.0%	2,614	-3.5%	13,151,607	-3.6%
2024	203	2.0%	2,691	2.9%	13,254,576	0.8%
2025	198	-2.5%	2,648	-1.6%	13,389,674	1.0%
Forecast						
2026	211	6.6%	2,754	4.0%	13,054,071	-2.5%
2027	215	1.9%	3,033	10.1%	14,107,857	8.1%
2028	219	1.9%	3,285	8.3%	15,001,436	6.3%
2029	222	1.4%	3,357	2.2%	15,120,763	0.8%
2030	224	0.9%	3,427	2.1%	15,297,656	1.2%
2031	227	1.3%	3,475	1.4%	15,307,034	0.1%
2032	230	1.3%	3,526	1.5%	15,329,031	0.1%
2033	233	1.3%	3,544	0.5%	15,209,228	-0.8%
2034	236	1.3%	3,567	0.6%	15,114,511	-0.6%
2035	240	1.7%	3,600	0.9%	14,999,094	-0.8%
Average Annual Growth Rate (2016 - 2025)		-0.2%		-0.2%		0.1%
Average Annual Growth Rate (2026 - 2035)		1.4%		3.0%		1.6%

Table 5-4 JEA Other and Total Customers and Energy Usage

Calendar Year	Street & Highway Lighting (GWh)	Other Sales to Ultimate Customers (GWh)	Total Sales to Ultimate Customers (GWh)	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers	Total Number of Customers
History								
2016	77	0	12,184	490	263	12,937	2	450,033
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,793
2019	57	0	12,328	58	411	12,797	0	474,178
2020	56	0	12,319	7	414	12,740	0	483,471
2021	55	0	12,066	25	449	12,540	0	493,039
2022	55	0	12,491	30	408	12,930	0	502,588
2023	55	0	12,295	63	376	12,733	0	514,909
2024	56	0	12,873	60	321	13,255	0	527,491
2025	57	0	12,980	69	431	13,479	0	536,862
Forecast								
2026	57	0	12,908	0	479	13,386	0	544,219
2027	58	0	13,293	0	493	13,785	0	551,309
2028	58	0	13,641	0	506	14,147	0	558,206
2029	59	0	13,812	0	512	14,324	0	564,897
2030	59	0	13,984	0	518	14,503	0	571,404
2031	59	0	14,135	0	524	14,659	0	577,684
2032	60	0	14,288	0	530	14,817	0	583,686
2033	60	0	14,407	0	534	14,941	0	589,376
2034	61	0	14,531	0	539	15,070	0	594,787
2035	61	0	14,675	0	544	15,219	0	600,001

Table 5-5 JEA System Total Net Energy for Load, Peak Demand, and Load Factor

Calendar Year	Net Energy for Load (GWh)	% Growth	Net Firm Summer Peak Demand (MW)	% Growth	Net Firm Winter Peak Demand (MW)	% Growth	Load Factor	% Growth
History								
2016	12,937	--	2,689	--	2,600	--	54.9%	--
2017	12,672	-2.0%	2,631	-2.2%	2,433	-6.4%	55.0%	0.1%
2018	12,813	1.1%	2,495	-5.2%	3,011	23.8%	48.6%	-11.6%
2019	12,797	-0.1%	2,591	3.8%	2,410	-20.0%	56.4%	16.1%
2020	12,740	-0.4%	2,582	-0.3%	2,445	1.5%	56.3%	-0.1%
2021	12,540	-1.6%	2,511	-2.7%	2,532	3.6%	56.5%	0.4%
2022	12,930	3.1%	2,728	8.6%	2,599	2.6%	54.1%	-4.3%
2023	12,733	-1.5%	2,753	0.9%	2,326	-10.5%	52.8%	-2.4%
2024	13,255	4.1%	2,675	-2.8%	2,416	3.9%	56.6%	7.1%
2025	13,479	1.7%	2,849	6.5%	2,913	20.6%	52.8%	-6.6%
Forecast								
2026	13,386	-0.7%	2,772	-2.7%	2,901	-0.4%	52.7%	-0.3%
2027	13,785	3.0%	2,850	2.8%	2,988	3.0%	52.7%	0.0%
2028	14,147	2.6%	2,930	2.8%	3,077	3.0%	52.5%	-0.3%
2029	14,324	1.3%	2,961	1.1%	3,114	1.2%	52.5%	0.0%
2030	14,503	1.2%	2,997	1.2%	3,147	1.1%	52.6%	0.2%
2031	14,659	1.1%	3,023	0.9%	3,180	1.0%	52.6%	0.0%
2032	14,817	1.1%	3,052	1.0%	3,210	0.9%	52.7%	0.1%
2033	14,941	0.8%	3,070	0.6%	3,226	0.5%	52.9%	0.3%
2034	15,070	0.9%	3,092	0.7%	3,252	0.8%	52.9%	0.1%
2035	15,219	1.0%	3,119	0.9%	3,275	0.7%	53.0%	0.3%
Average Annual Growth Rate (2016 - 2025)		0.5%		0.6%		1.3%		-0.4%
Average Annual Growth Rate (2026 - 2035)		1.4%		1.3%		1.4%		0.1%

Table 5-6 Forecast Firm Peak Demand and Net Energy for Load

Calendar Year	Summer Firm Peak Demand (MW)	Winter Firm Peak Demand (MW)	Net Energy for Load (GWh)	Load Factor
2026	2,772	2,901	13,386	52.7%
2027	2,850	2,988	13,785	52.7%
2028	2,930	3,077	14,147	52.5%
2029	2,961	3,114	14,324	52.5%
2030	2,997	3,147	14,503	52.6%
2031	3,023	3,180	14,659	52.6%
2032	3,052	3,210	14,817	52.7%
2033	3,070	3,226	14,941	52.9%
2034	3,092	3,252	15,070	52.9%
2035	3,119	3,275	15,219	53.0%
2036	3,146	3,289	15,372	53.4%
2037	3,177	3,321	15,530	53.4%
2038	3,203	3,338	15,679	53.6%
2039	3,226	3,358	15,833	53.8%
2040	3,253	3,388	15,979	53.8%
2041	3,291	3,399	16,134	54.2%
2042	3,325	3,437	16,285	54.1%
2043	3,361	3,454	16,444	54.3%
2044	3,394	3,469	16,601	54.6%
2045	3,434	3,505	16,757	54.6%
2046	3,469	3,518	16,882	54.8%
2047	3,503	3,515	17,010	55.2%
2048	3,530	3,553	17,146	55.1%
2049	3,568	3,550	17,278	55.3%
2050	3,598	3,561	17,414	55.3%
2051	3,634	3,593	17,555	55.1%
2052	3,679	3,610	17,707	54.9%
2053	3,717	3,634	17,862	54.9%
2054	3,759	3,640	18,028	54.7%
2055	3,790	3,650	18,149	54.7%
2056	3,797	3,660	18,174	54.6%
2057	3,814	3,695	18,196	54.5%
2058	3,830	3,683	18,221	54.3%
2059	3,840	3,735	18,247	54.2%
2060	3,852	3,733	18,273	54.2%

5.3 JEA Reliability Criteria

JEA's system capacity is planned with a targeted 15 percent generation reserve margin above forecasted firm customers coincident one-hour peak demand, for both winter and summer seasons in accordance with Rule 25-6.035, Florida Administrative Code.

JEA's Planning Reserve Policy establishes a guideline that provides an allowance to meet the 15 percent reserve margin with up to 3 percent of the forecasted firm peak demand in any season from purchases acquired in the operating horizon. If up to 3 percent of firm peak demand in any season is needed, TEA, JEA's affiliated energy market services company, will acquire short-term seasonal market purchases for JEA no later than the season prior to the need. TEA actively trades energy with a large number of counterparties throughout the United States and is generally able to acquire capacity and energy from other market participants when any of its members require additional resources.

5.4 JEA's Existing and Planned Capacity Resources

As discussed in Section 3 herein, JEA's existing owned generating units consist of generating facilities located on four plant sites within the City of Jacksonville: Kennedy, (NGS, Brandy Branch, and GEC. JEA has a number of PPAs, as discussed in Section 3 herein. These PPAs provide JEA with diverse sources of power, including solar, landfill gas, nuclear, and natural gas.

5.5 JEA's Capacity Needs

Table 5-7 and Table 5-8, respectively, illustrate JEA's projected need for additional winter and summer capacity to maintain JEA's 15 percent reserve margin. The projected capacity requirements shown in Table 5-7 and Table 5-8 take into account JEA's forecast annual winter and summer firm peak demand, existing owned generating units, existing and planned PPAs, and JEA's 15 percent reserve margin, all as discussed previously in Section 3. As illustrated in Table 5-7 and Table 5-8, JEA is projected to require additional capacity to maintain reserve margin requirements beginning in the winter of 2028, with capacity requirements increasing thereafter, particularly in 2035 due to the planned retirement of NGS 3. Given the near-term need for capacity, for purposes of this Need Study it has been assumed that JEA will purchase capacity through TEA as needed through 2030, with 2031 as the initial year in which installation of new generating resources is feasible.

At the time of filing its 2026 TYSP, JEA anticipated short-term sales of Vogtle capacity to Dalton Utilities and to Santee Cooper in amounts different than those shown as "Exports (MW)" in Table 5-7 and Table 5-8, which reflect current expectations. More specifically, the 2026 TYSP anticipated exports of 206 MW in 2027 and 2028, 129 MW in 2029, and 103 MW in 2030, consistent with the analyses discussed in Section 6.4 and throughout this Need Study. JEA now anticipates short-term sales only to Dalton Utilities. The difference between the "Exports (MW)" reflected in Table 5-7 and Table 5-8, which affect only the short-term period prior to the anticipated in-service date of SJRPP Unit 3, as compared to the sales reflected in the 2026 TYSP and analyses discussed in this Need Study do not impact the timing of the need for capacity in 2031 or the relative economics between expansions plans specifically detailed in Section 6.4 and discussed throughout this Need Study.

Table 5-7 Projected Annual Capacity Requirements - Winter

Calendar Year	Firm Winter Peak Demand (MW)	Firm Winter Peak Demand + 15% Reserves	Existing Owned Capacity (MW)	Existing and Planned Purchases (MW)	Exports (MW)	Total Available Capacity (MW)	Excess Capacity (Deficit) to Maintain 15% Reserve Margin
2026	2,901	3,336	2,952	468	0	3,420	84
2027	2,988	3,436	2,952	661	0	3,613	177
2028	3,077	3,538	2,952	686	(103)	3,535	(3)
2029	3,114	3,581	2,952	736	(123)	3,565	(16)
2030	3,147	3,619	2,952	736	(111)	3,577	(42)
2031	3,180	3,657	2,952	736	(103)	3,585	(72)
2032	3,210	3,692	2,952	736	(103)	3,585	(107)
2033	3,226	3,710	2,952	536	0	3,488	(222)
2034	3,252	3,740	2,952	536	0	3,488	(252)
2035	3,275	3,766	2,428	536	0	2,964	(802)
2036	3,289	3,782	2,428	536	0	2,964	(818)
2037	3,321	3,819	2,428	536	0	2,964	(855)
2038	3,338	3,838	2,428	536	0	2,964	(874)
2039	3,358	3,862	2,428	536	0	2,964	(898)
2040	3,388	3,896	2,428	536	0	2,964	(932)
2041	3,399	3,908	2,428	536	0	2,964	(944)
2042	3,437	3,953	2,428	256	0	2,684	(1,269)
2043	3,454	3,972	2,428	256	0	2,684	(1,288)
2044	3,469	3,989	2,428	153	0	2,581	(1,408)
2045	3,505	4,030	2,428	50	0	2,478	(1,552)
2046	3,518	4,046	2,428	50	0	2,478	(1,568)
2047	3,515	4,043	2,428	50	0	2,478	(1,565)
2048	3,553	4,086	2,428	50	0	2,478	(1,608)
2049	3,550	4,082	2,428	50	0	2,478	(1,604)
2050	3,561	4,095	2,428	50	0	2,478	(1,617)
2051	3,593	4,132	2,428	50	0	2,478	(1,654)
2052	3,610	4,152	2,428	50	0	2,478	(1,674)
2053	3,634	4,179	2,428	50	0	2,478	(1,701)
2054	3,640	4,186	2,428	50	0	2,478	(1,708)
2055	3,650	4,198	2,428	50	0	2,478	(1,720)
2056	3,660	4,209	2,428	50	0	2,478	(1,731)
2057	3,695	4,249	2,428	50	0	2,478	(1,771)
2058	3,683	4,236	2,428	50	0	2,478	(1,758)
2059	3,735	4,295	2,428	50	0	2,478	(1,817)
2060	3,733	4,293	2,428	50	0	2,478	(1,815)

Table 5-8 Projected Annual Capacity Requirements – Summer

Calendar Year	Firm Summer Peak Demand (MW)	Firm Summer Peak Demand + 15% Reserves	Existing Owned Capacity (MW)	Existing and Planned Purchases (MW)	Exports (MW)	Total Available Capacity (MW)	Excess Capacity (Deficit) to Maintain 15% Reserve Margin
2026	2,772	3,188	2,782	601	0	3,383	195
2027	2,850	3,277	2,782	796		3,578	301
2028	2,930	3,369	2,782	703	(103)	3,382	13
2029	2,961	3,406	2,782	753	(123)	3,412	6
2030	2,997	3,447	2,782	753	(111)	3,424	(23)
2031	3,023	3,477	2,782	753	(103)	3,432	(45)
2032	3,052	3,510	2,782	753	(103)	3,432	(78)
2033	3,070	3,531	2,782	553	0	3,335	(196)
2034	3,092	3,556	2,782	553	0	3,335	(221)
2035	3,119	3,587	2,258	553	0	2,811	(776)
2036	3,146	3,618	2,258	553	0	2,811	(807)
2037	3,177	3,653	2,258	553	0	2,811	(842)
2038	3,203	3,684	2,258	550	0	2,809	(875)
2039	3,226	3,710	2,258	550	0	2,808	(902)
2040	3,253	3,741	2,258	549	0	2,807	(934)
2041	3,291	3,785	2,258	547	0	2,806	(979)
2042	3,325	3,823	2,258	266	0	2,524	(1,299)
2043	3,361	3,866	2,258	163	0	2,421	(1,444)
2044	3,394	3,903	2,258	60	0	2,318	(1,584)
2045	3,434	3,949	2,258	60	0	2,318	(1,631)
2046	3,469	3,989	2,258	60	0	2,318	(1,671)
2047	3,503	4,028	2,258	60	0	2,318	(1,710)
2048	3,530	4,059	2,258	60	0	2,318	(1,741)
2049	3,568	4,103	2,258	60	0	2,318	(1,785)
2050	3,598	4,138	2,258	60	0	2,318	(1,820)
2051	3,634	4,179	2,258	60	0	2,318	(1,860)
2052	3,679	4,231	2,258	60	0	2,318	(1,913)
2053	3,717	4,274	2,258	60	0	2,318	(1,956)
2054	3,759	4,322	2,258	60	0	2,318	(2,004)
2055	3,790	4,359	2,258	60	0	2,318	(2,040)
2056	3,797	4,366	2,258	60	0	2,318	(2,048)
2057	3,814	4,386	2,258	60	0	2,318	(2,068)
2058	3,830	4,404	2,258	60	0	2,318	(2,086)
2059	3,840	4,416	2,258	60	0	2,318	(2,098)
2060	3,852	4,430	2,258	60	0	2,318	(2,112)

6.0 Evaluation of Generating Alternatives

6.1 Overview of Evaluation Process

JEA conducted a comprehensive analysis to evaluate the need for the proposed SJRPP Unit 3 and the relative economics of this option and other candidate resource options. JEA's Board selected moving forward with construction and operation of SJRPP Unit 3 based on the results of an IRP process that began over three years ago and has been continually refined with updated information and assumptions through the date of this Need Study. That process included extensive economic analyses of self-build options, including renewable generation and energy storage. Multiple power purchase alternatives were evaluated through a robust market test RFP process that was overseen by an independent evaluator. The evaluations also considered non-economic attributes and risk factors. JEA then performed additional comprehensive economic modeling utilizing updated and refined information, including its 2026 load forecast and updated cost information, to verify that the addition of SJRPP Unit 3 in the 2031 timeframe remained the most cost-effective alternative to meet its need for power.

6.2 Selection of SJRPP Unit 3

6.2.1 Technology Assessment

The IRP process considered various generating resource options, including multiple configurations of solar photovoltaic (PV) and energy storage options, numerous different natural gas options (including a range of sizes, types, simple and combined cycle configurations, and conversion of existing simple cycle units to combined cycle configuration), biomass technologies, and nuclear. Other renewable resources such as hydropower, geothermal, and wind, were not considered as they are not feasible within JEA's service territory. Given regulatory limitations, JEA did not evaluate the addition of any new coal-fired generating units. While the use of hydrogen may be an option as a fuel source in the future, including for SJRPP Unit 3, units operating solely on hydrogen were not evaluated given the lack of necessary infrastructure and demonstrated use for large-scale power production.

JEA performed a detailed assessment of various technologies at multiple locations on the JEA system, including economic modeling and consideration of system benefits and risks. Through this assessment, JEA selected an advanced class 1x1 combined cycle generating unit, which provides reliable dispatchable power, allows for more efficient use of natural gas, reduces system emissions, and provides support to reliably integrate more renewable energy into the JEA system.

6.2.2 Site Assessment

After selection of combined cycle technology, JEA considered two existing JEA-owned sites for the location of the Project - GEC and SJRPP. The GEC site is located south and east of the St. John's River. The site has generated electricity since 2011 and has two natural gas-fired combustion turbines with a total capacity of 382 MW in the winter and 357 MW in the summer. The SJRPP site is located on the north side of Jacksonville and is the previous location of SJRPP Units 1 & 2.

JEA carefully evaluated both sites based on a variety of economic, environmental, and strategic factors, including but not limited to existing and neighboring land uses, existing infrastructure, fuel supply, water availability, wastewater disposal options, environmental impacts, site access, and project schedule. After careful evaluation of the GEC and SJRPP locations, the SJRPP site was selected based on advantages related to surrounding land uses, potential environmental impacts, existing infrastructure, and overall site compatibility.

6.2.3 Vendor Selection

JEA initiated a competitive solicitation process to solicit proposals from major equipment manufacturers that provide the major equipment associated with construction of an advanced class 1x1 combined cycle unit. The major equipment, referred to as the “power island,” includes the CTG, HRSG, STG, and associated ancillary equipment. JEA’s power island solicitation was issued in September 2024 through a posting on the Zycus platform. The solicitation was managed by the JEA Procurement team. Proposals were received in December 2024 from GE Vernova and Mitsubishi Power Americas in response to the power island solicitation. Following review and evaluation of the responses to the power island solicitation, JEA selected GE Vernova for the power island for SJRPP Unit 3 as the most economic option.

6.3 Market Alternatives Considered

Following the identification of SJRPP Unit 3 as the best self-build option, JEA sought to determine whether there was a lower cost alternative available in the power market from another utility or from an independent power producer through the issuance of a *Solicitation for Long-Term Firm Dispatchable Capacity and Energy Resources* on October 2, 2024 (Market Test RFP) with responses due on April 21, 2025. The Market Test RFP process was overseen by an independent evaluator (Merrimack Energy).

The Market Test RFP was issued to solicit proposals for firm, dispatchable capacity and associated energy. JEA indicated in the Market Test RFP Instructions document that it intended to provide a 1x1 combined cycle self-build resource (Self-Build Resource) in response to the Market Test RFP and evaluate resource alternatives submitted that complied with the requirements of the Market Test RFP relative to the Self-Build Resource. JEA also stated that it anticipated that the generation technology having the highest likelihood of success as an alternative to the Self-Build Resource would be an advanced-class combined cycle technology resource, with operating parameters that included the ability to operate in baseload and load-following roles across the full unit load range. The general characteristics of the Self-Build Resource were included in the Market Test RFP instructions.

JEA received four proposals from one respondent in response to the Market Test RFP, three of which were deemed compliant with the minimum requirements. A team of JEA staff with specialized expertise in a variety of areas (JEA Evaluators) reviewed and evaluated the three compliant third-party responses and the Self-Build Resource relative to the evaluation criteria and methodology provided in the Market Test RFP documents available to all respondents.

JEA first conducted an economic/quantitative evaluation of the RFP-compliant proposals and Self-Build Resource. The economic evaluation utilized PLEXOS® modeling to assess the CPWC to the JEA system over a 35-year time horizon of the proposed resources and the Self-Build Resource as part of competing expansion plans. PLEXOS® is a widely used planning tool that is routinely used by JEA and within the industry. The proposals and Self-Build Resource were compared using CPWC, which includes the sum of present value of annual system costs for each year. In the CPWC calculation, annual costs are discounted to the start of the evaluation period using the JEA cost of capital and then the present worth of the annual costs are summed. Individual cost components accounted for in the CPWC calculation include the capital costs associated with new resource additions, variable and fixed operating and maintenance (VOM and FOM) costs, system fuel costs, and power purchase costs.

Figure 6-1 illustrates, conceptually, how the CPWC is derived. The CPWC figure is compared against competing expansion plans developed under base case (most likely case) assumptions, and under sensitivity cases in which one or more base case input assumptions are considered in the PLEXOS® model. Generally, the plan having the lowest CPWC under the base case plan and that is also the least-

cost plan or at least competitive across the selected sensitivities is considered the preferred plan from an economic perspective.

	2026	2027	2028	2029	2030	...	2060
System-wide Variable Costs							
Fuel Costs	\$	\$	\$	\$	\$		\$
Variable O&M Costs	\$	\$	\$	\$	\$		\$
Variable PPA Costs	\$	\$	\$	\$	\$		\$
Fixed Costs							
New Unit Capital Costs	\$	\$	\$	\$	\$		\$
System Fixed O&M	\$	\$	\$	\$	\$		\$
Fixed PPA Costs (Capital plus Fixed O&M)	\$	\$	\$	\$	\$		\$
Total Incremental Annual Cost	\$	\$	\$	\$	\$		\$
	↓	↓	↓	↓	↓		↓
Cumulative Present Worth Costs	CPWC \$ ←						

Figure 6-1 Conceptual Calculation of the Cumulative Present Worth Cost (CPWC) of an Expansion Plan

The quantitative/economic evaluation of the proposals and Self-Build Resource included base cases with varying assumptions relative to the GHG Rule³ as well as various sensitivities, including high load forecast, low load forecast, and high gas price. The qualitative/risk assessment evaluation considered commercial experience and credit worthiness, transmission status, costs and impacts, fuel supply, operational flexibility, project status and design, and environmental considerations.

The Self-Build Resource was scored by the JEA Evaluators as the highest-ranking resource option from both a quantitative and qualitative perspective. Merrimack Energy reviewed the quantitative scores, conducted a review of the qualitative scoring, and likewise agreed that the Self-Build Resource ranked highest in quantitative and qualitative categories.

6.4 Updated Economic Evaluation of Generation Alternatives

6.4.1 Methodology

To confirm SJRPP Unit 3 as the least-cost alternative utilizing the most up-to-date and refined information available, JEA again engaged Black & Veatch to perform an updated evaluation of generating unit alternatives reflecting updated load forecasts and fuel price projections, updates to existing and planned future resources, updated cost and performance estimates, and updated assumptions relative to the GHG Rule and clean energy goals. This evaluation and underlying assumptions are detailed below.

The updated economic evaluations were performed using PLEXOS® and involved the development of multiple competing expansion plans involving different resource option additions. For each expansion plan, the total cost resulting from the addition of new resources and the dispatch of resources to meet energy requirements over the planning horizon was calculated. The economics of competing expansion plans were compared using the CPWC over the 35-year planning period (i.e., 2026 through 2060).

³ At the time of the RFP, EPA had not proposed repeal of the GHG Rule or the 2009 Endangerment Finding. As such, JEA's analysis included multiple base cases with assumptions relative to implementation of the GHG Rule.

6.4.2 Economic Parameters

The updated economic analysis consisted of a base case simulation and several sensitivity cases modeled in PLEXOS®. These cases differed according to the input assumptions made. In this section, the primary input assumptions are described, beginning with the base case.

6.4.2.1 JEA's Cost of Capital, Discount Rate, Levelized Fixed Charge Rates, and General Inflation Rate

In the base case simulations, it was assumed that JEA's cost of financing was 4.75 percent. The interest during construction rate and the discount rate used for present worth calculations were also 4.75 percent.

The analysis utilized a levelized fixed charge rate, defined as the single, levelized rate that is applied to the total in-service capital cost of a new resource to determine the levelized dollar return needed to recover the capital cost over the designated recover period. An annual bond issuance fee of 1 percent and an annual property insurance cost of 0.63 percent were also part of the levelized fixed charge rate. Table 6-1 shows the resulting levelized fixed charge rates that were applied to various technologies. The rates differ due to the different capital recovery periods assumed for the candidate technologies.

Table 6-1 Levelized Fixed Charge Rates

Capital Recovery Period (Years)	Levelized Fixed Charge Rate	Technology
20	8.56%	Reciprocating Engine / Combustion Turbine / Energy Storage
30	7.01%	Combined Cycle / Nuclear

The analysis assumed a general inflation rate of 3.5 percent. This rate was applied to all inputs subject to escalation other than fuel costs, which were forecasted in real terms, then escalated to current year dollars using the general inflation rate.

6.4.3 Clean Energy and Greenhouse Gas Assumptions

Consistent with the discussion regarding JEA's aspirational clean energy goals in Section 3 herein, the updated evaluations outlined in this Need Study do not include the requirement that a specified percentage of JEA's energy requirements be met using clean energy. The PLEXOS® modeling, however, allowed the addition of solar and energy storage resources beyond JEA's existing and planned solar and energy storage resources if economical. Similarly, the PLEXOS® modeling allowed the addition of nuclear resources beyond JEA's existing nuclear resources if economical. It was assumed that no federal tax incentives would apply to solar projects.

Based upon EPA's proposed repeal of the GHG Rule and repeal of the 2009 Endangerment Finding as discussed in Section 3 herein, the updated evaluations did not reflect any costs or other limitations associated with regulations related to the emissions of CO₂/GHG; i.e., the modeling assumed GHG regulations were not in place.

6.4.4 Capital and Operating Cost and Performance Estimates

The estimated capital and operating costs and performance for the generating unit alternatives, as applicable to each alternative in the updated modeling are summarized on Table 6-2. Inputs consist of capital costs, seasonal output (MW), net plant heat rate (NPHR), fixed and variable operating and maintenance (O&M) costs, and start costs (if not otherwise reflected in the variable O&M cost). The capital and operating cost assumptions/estimates in the updated analysis are based on various models and data bases that were adjusted for this study based on recent market conditions and contracts.

6.4.5 Fuel Cost Assumptions

JEA's existing units operate on various fuel types, including natural gas, diesel petroleum coke, and biomass. In order to evaluate JEA's existing units and the generating unit alternatives JEA engaged Black & Veatch to develop projections of fuel prices. The fuel price projections include projections of delivered fuel forecasts for natural gas, the mix of solid fuel used in NGS Units 1 and 2, diesel, and nuclear. For the base case, Black & Veatch utilized natural gas price projections developed as part of its proprietary Energy Market Perspective (EMP) forecast, updated in 2025. The EMP is Black & Veatch's in-house integrated North America energy markets outlook, that incorporates projections of load growth, energy efficiency, distributed energy resources (DER), thermal and renewable capacity additions, generation unit retirements, plus energy and fuel market trends.

To reflect near-term market conditions, Black & Veatch combined the long-term fundamental forecasts developed in the EMP process with the six-month average NYMEX Henry Hub futures from July to December 2024. The specific blending strategy was as follows:

- 2025: 100% Henry Hub Futures
- 2026: 75% Henry Hub Futures + 25% fundamental-based projection
- 2027: 50% Henry Hub Futures + 50% fundamental-based projection
- 2028: 25% Henry Hub Futures + 75% fundamental-based projection
- 2029: 15% Henry Hub Futures + 85% fundamental-based projection
- From 2030 onwards: 100% fundamental-based projection

Driven by the advance in shale production technology, the US is the leading natural gas producer and exporter of natural gas. Consumers in the US lower 48 have been enjoying a relatively stable cost of gas even in the face of rising demand. For example, in the ten-year period between 2016 and 2025, total LNG exports and gas delivered to the power sector grew from 28 Bcf/d⁴ to 51 Bcf/d while the natural gas Citygate price has only increased from \$3.71/MMBtu to \$4.85⁵/MMBtu. In the base case, the Henry Hub price is expected to increase from the current level, driven primarily by rising demand from Gulf Coast LNG terminals and demand for natural gas from the power sector due, in part, to data center demand. Over 30 Bcf/d of growth is expected from these two sources between now and 2050.

⁴ <https://www.eia.gov/dnav/ng/hist/n3045us2a.htm>; <https://www.eia.gov/dnav/ng/hist/n9133us2A.htm>

⁵ <https://www.eia.gov/dnav/ng/hist/n3050us3a.htm>

Table 6-2 Cost (in 2031\$) and Performance Assumptions for Generating Alternatives

Candidate Option	In-Service Capital Cost (\$M)	In-Service Capital Cost (\$/kW of Winter MW)	Summer Rating (MW)	Winter Rating (MW)	Full Load Net Plant Heat Rate (Btu/kWh; higher heating value)	Fixed O&M Cost (\$/kW-yr)	Variable O&M Cost (\$/MWh)	Start Cost (\$/Start)
GE LM6000 PF SPRINT 2x0	\$401.11	\$4,031.26	76.1	99.5	8,831	\$21.52	\$10.66	N/A
GE 7FA.05 1x0	\$617.95	\$2,621.76	208.7	235.7	10,080	\$12.13	N/A	\$13,214
GE 7HA.03 1x0	\$925.75	\$2,044.05	374.2	452.9	9,031	\$7.06	N/A	\$34,419
Wartsila 18V50DF 5x0	\$322.31	\$3,605.26	83.8	89.4	8,380	\$33.02	\$9.65	N/A
GE 7FA.05 1x1	\$1,501.66	\$5,372.67	342.2	279.5	6,940	\$14.89	\$3.52	N/A
GE 7HA.03 1x1	\$1,570.00	\$2,317.00	581.6	677.6	6,317	\$13.08	\$1.11	\$69,884
Conversion of existing GEC CTGs	\$817.58	\$2,486.56	297.3	328.8	6,832	\$13.78	\$3.38	N/A
Conversion of existing GEC CTGs	\$1,447	\$2,191.43	597.2	660.3	6,803	\$8.75	\$3.28	N/A
75 MW Photovoltaic Solar Array ⁽¹⁾⁽²⁾	First year PPA cost \$72.81/MWh	N/A	75	75	N/A	N/A	N/A	N/A
50 MW Lithium Ion 4-hour Battery Storage ⁽¹⁾	\$41.93	\$838.53	50	50	N/A	\$69.50	N/A	N/A
100 MW Vanadium Redox 10-hour Battery Storage ⁽¹⁾	\$233.07	\$2,330.6	100	100	N/A	\$129.22	N/A	N/A
Small Modular Reactors ⁽²⁾	\$1,480.02	\$19,221.04	77	77	10,400	\$157.55	\$4.12	N/A
GE 7HA.03 1x1 with Carbon Capture and Sequestration	\$3,716.90	\$6,206.21	509.9	598.9	7,162	\$75.24	\$15.33	N/A
GE 7HA.03 1x1 Hydrogen	\$2,364.96	\$3,489.17	583.5	677.8	6,522	\$10.39	\$6.55	N/A
GE LM6000 PF SPRINT 2x0 Hydrogen	\$466.75	\$4,690.95	76.1	99.5	9,477	\$21.52	\$10.66	N/A
1. "Summer Rating" and "Winter Rating" represents nameplate rating; summer and winter ratings are less than nameplate ratings shown. 2. For battery energy storage options and nuclear options, the capital costs shown in this table reflect a 30% investment tax credit (ITC). It has been assumed that beginning in 2034 the ITC is reduced to 22.5% and further reduced to 15% in 2035, with no subsequent ITC.								

The total delivered cost of natural gas was estimated by adding the estimated cost of natural gas transportation to the natural gas commodity price forecasts. These transportation costs include high-pressure interstate transportation from Henry Hub to Florida and low-pressure transportation and distribution across the local gas distribution utility PGS. The forecasted costs of transportation and distribution were developed in close coordination with the JEA fuels group and PGS, particularly with respect to JEA's existing natural gas transportation arrangements and incremental requirements for firm and interruptible gas delivery.

Diesel and coal price forecasts for the near-term are the six-month average settlement futures prices between July and December 2024 on NYMEX. Prices beyond the NYMEX futures horizon were derived based on the Energy Information Administrations (EIA's) Annual Energy Outlook (AEO) projected price growth rates for these fuels.

Table 6-3 shows the delivered fuel price assumptions for base case simulations in 2025 dollars per MMBtu. These 2025 costs were escalated at the general inflation rate to arrive at nominal fuel costs for the Need Study.

Table 6-3 Base Case Fuel Price Assumptions \$2025/MMBtu

Year	Natural Gas (\$/MMBtu)	Northside Units 1 and 2 (\$/MMBtu)	Diesel (\$/MMBtu)
2026	3.91	4.76	16.53
2027	4.12	4.77	15.82
2028	4.54	4.79	14.87
2029	5.03	4.79	14.98
2030	5.56	4.88	15.07
2031	5.61	4.88	15.06
2032	5.59	4.87	15.13
2033	5.63	4.86	15.12
2034	5.62	4.89	15.21
2035	5.66	4.89	15.27
2036	5.59	4.88	15.32
2037	5.54	4.89	15.35
2038	5.54	4.94	15.37
2039	5.49	4.83	15.42
2040	5.41	4.83	15.48
2041	5.47	4.83	15.58
2042	5.48	4.83	15.57
2043	5.47	4.83	15.64
2044	5.51	4.83	15.61

Year	Natural Gas (\$/MMBtu)	Northside Units 1 and 2 (\$/MMBtu)	Diesel (\$/MMBtu)
2045	5.56	4.83	15.68
2046	5.62	4.83	15.83
2047	5.78	4.84	15.85
2048	5.98	4.85	15.88
2049	6.20	4.87	15.96
2050	6.25	4.88	15.96
2051	6.38	4.89	16.01
2052	6.52	4.91	16.05
2053	6.67	4.92	16.08
2054	6.81	4.94	16.13
2055	6.96	4.95	16.16
2056	7.11	4.96	16.20
2057	7.27	4.98	16.24
2058	7.43	4.99	16.27
2059	7.59	5.00	16.31
2060	7.75	5.02	16.35

Black & Veatch also developed a high and a low fuel forecast for the required fuels. The high case Henry Hub price forecast assumed, depending on the year, approximately 10 to 15 percent higher demand from the power sector than in the base case and blended with the same NYMEX forward curves.

Black & Veatch derived the low case Henry Hub price forecasts leveraging the EIA AEO 2025 cases—specifically the “High Oil and Gas Supply, High Oil Prices, Low Economic Growth”, and “Low Zero-Carbon Technology” cases. For each case and each year, a price “scaler” was derived relative to the AEO reference case Henry Hub price projection. These scalars were then averaged across both EIA cases listed in the previous sentence and applied to Black & Veatch’s base case Henry Hub price forecasts to develop the low case prices.

Black & Veatch’s high and low case Henry Hub price forecasts are shown in Table 6-4, expressed in 2025 dollars.

Table 6-4 High and Low Fuel Price Assumptions, \$2025/MMBtu

Year	High Fuel Price Forecast, \$/MMBtu			Low Fuel Price Forecast, \$/MMBtu		
	Natural Gas	NS CFB	Diesel	Natural Gas	NS CFB	Diesel
2026	4.00	4.76	16.53	3.79	4.76	16.53
2027	4.48	4.77	15.82	3.86	4.77	15.82
2028	5.37	4.79	14.87	4.12	4.79	14.87
2029	5.97	4.79	14.98	4.46	4.79	14.98
2030	6.43	4.88	15.07	4.84	4.88	15.07
2031	6.52	4.88	15.06	4.85	4.88	15.06
2032	6.25	4.87	15.13	4.74	4.87	15.13
2033	6.32	4.86	15.12	4.61	4.86	15.12
2034	6.37	4.89	15.21	4.53	4.89	15.21
2035	6.49	4.89	15.27	4.53	4.89	15.27
2036	6.41	4.88	15.32	4.47	4.88	15.32
2037	6.31	4.89	15.35	4.43	4.89	15.35
2038	6.22	4.94	15.37	4.45	4.94	15.37
2039	6.12	4.83	15.42	4.47	4.83	15.42
2040	6.03	4.83	15.48	4.43	4.83	15.48
2041	6.08	4.83	15.58	4.49	4.83	15.58
2042	6.07	4.83	15.57	4.48	4.83	15.57
2043	6.07	4.83	15.64	4.40	4.83	15.64
2044	6.11	4.83	15.61	4.42	4.83	15.61
2045	6.15	4.83	15.68	4.46	4.83	15.68
2046	6.22	4.83	15.83	4.51	4.83	15.83
2047	6.39	4.84	15.85	4.59	4.84	15.85
2048	6.51	4.85	15.88	4.74	4.85	15.88
2049	6.70	4.87	15.96	4.94	4.87	15.96
2050	6.74	4.88	15.96	4.98	4.88	15.96
2051	6.85	4.89	16.01	5.08	4.89	16.01
2052	6.97	4.91	16.05	5.19	4.91	16.05
2053	7.08	4.92	16.08	5.29	4.92	16.08
2054	7.20	4.94	16.13	5.40	4.94	16.13
2055	7.32	4.95	16.16	5.52	4.95	16.16

Year	High Fuel Price Forecast, \$/MMBtu			Low Fuel Price Forecast, \$/MMBtu		
	Natural Gas	NS CFB	Diesel	Natural Gas	NS CFB	Diesel
2056	7.44	4.96	16.20	5.63	4.96	16.20
2057	7.57	4.98	16.24	5.75	4.98	16.24
2058	7.70	4.99	16.27	5.87	4.99	16.27
2059	7.82	5.00	16.31	5.99	5.00	16.31
2060	7.96	5.02	16.35	6.11	5.02	16.35

6.4.6 Existing JEA NGS Generation and Bridge Purchase Assumptions

For the 35-year planning period, it was necessary to make assumptions about the operation and possible retirement dates for the three largest JEA NGS units. Based on JEA's current plans, the updated analysis assumed that NGS Unit 3 would continue normal operation until new generation is commercially operable at which time, NGS Unit 3 would be placed in limited use status limited to operating on fuel oil, serving as a back-up resource during peak demand periods, system emergencies, or unexpected equipment outages and limited to fuel oil. JEA's analysis assumes NGS Unit 3 will be taken out of service in 2035. NGS Units 1 and 2 are assumed to continue operating without limitations during the planning period.

As described elsewhere in this Study, JEA has a need for additional capacity beginning in the winter of 2028. For purposes of the updated PLEXOS® evaluations, JEA assumed that short-term bridge purchases would be utilized to meet capacity needs through 2030, given the time required to bring a new generating resource into service.

6.4.7 Results

6.4.7.1 Base Case and Next Lowest Cost Alternative

For the Base Case, the PLEXOS® modeling indicates the addition of a 7HA.03 678 MW (net winter output) 1x1 advanced class combined cycle (the proposed SJRPP Unit 3) with an in-service date of 2031 is included in the resource plan having the lowest CPWC. The CPWC of the resource plan including the proposed SJRPP Unit 3 plan is approximately \$28,459 million, which is approximately \$91 million lower in cost than the next lowest cost resource plan (Next Lowest Cost Alternative).

The Next Lowest Cost Alternative is the resource plan which utilizes the Base Case assumptions but does not allow the model to select the addition of a combined cycle unit in 2031 for the purpose of comparing the cost of the Base Case to the next lowest cost alternative. This Next Lowest Cost Alternative resource plan includes the addition of a 7HA.03 simple cycle combustion turbine in 2031 followed by a 7HA.03 1x1 advanced class combined cycle plus a 7HA.03 simple cycle in 2035. Importantly, the Next Lowest Cost Alternative resource plan would still include the addition of combined cycle technology in the relatively near-term, essentially reflecting a 4-year delay of the addition of the proposed SJRPP Unit 3 as compared to the Base Case least-cost resource plan, further confirming JEA's need for SJRPP Unit 3.

6.4.7.2 Sensitivity Analyses

In recognition that forecasting key modeling inputs and assumptions over a 35-year timeframe involves some uncertainty, JEA performed a number of sensitivity analyses:

- Delay of the Unit 1 Year – Reflects delaying the addition of SJRPP Unit 3 from 2031 to 2032.
- High Load Growth – Reflects a 0.74 percent average annual growth rate with the winter peak starting at 2,991 MW in 2026 and ending at 3,847 MW in 2060. The summer peak is projected to increase from 2,858 MW in 2026 to 3,959 MW in 2060, a 0.93 percent average annual growth rate. The overall average annual growth rate in system peak that accounts for the shift in system peak from winter to summer is 0.83 percent. The NEL was projected to increase at an average annual rate of 0.92 percent in the high load growth case, from 13,787 GWh in 2026 to 18,795 GWh in 2060.
- Low Load Growth – Reflects a 0.74 average annual growth rate with the winter peak starting at 2,810 MW in 2026 and ending at 3,612 MW in 2060. The summer peak is projected to increase from 2,685 MW in 2026 to 3,736 MW in 2060, a 0.98 percent average annual growth rate. The overall average annual growth rate in system peak that accounts for the shift in system peak from winter to summer is 0.84 percent. The NEL was projected to increase at an average annual rate of 0.92 percent in the low load growth case, from 12,984 GWh in 2026 to 17,751 GWh in 2060.
- High Natural Gas Prices – Reflects the high natural gas price as shown in Table 6-4.
- Low Natural Gas Prices – Reflects the low natural gas price as shown in Table 6-4.
- High Capital Cost – Reflects a 10 percent higher capital cost than shown in Table 6-2 for all resources.

6.5 Results of the Expansion Planning Model Runs

The results of the PLEXOS® simulations for the Base Case and the sensitivity cases listed above are shown in Table 6-5. As shown in Table 6-5, in all cases and sensitivities (with the exception of the Next Lowest Cost Alternative and one-year delay sensitivities, in which the model was not allowed to choose the combined cycle in 2031), the combined cycle was selected as the preferred incremental resource and part of the least-cost plan.

As shown in Table 6-5:

- Denying the addition of SJRPP Unit 3 in 2031 would increase the CPWC by \$91 million, and the lowest cost resource plan (Next Lowest Cost Alternative) that does not include the addition of SJRPP Unit 3 includes an equivalent 7HA.03 1x1 combined cycle in 2035.
- Delaying the proposed SJRPP Unit 3 from 2031 until 2032 would increase the CPWC of the resource plan by \$22 million as compared to the Base Case resource plan that includes the addition of SJRPP Unit 3 in 2031.

Table 6-5 CPWC Results for Base Case and Sensitivities

Case Description	CPWC (\$ Millions)	Resource Addition Selected for 2031
Base Case (Least-cost)	\$28,459	7HA.03 1x1 CC (SJRPP Unit 3)
Next Lowest Cost Alternative (Base Case, but not allowed to build 1x1 CC in 2031)	\$28,550	1x0 GE 7HA.03 Simple Cycle (7HA.03 1x1 CC added in 2035)
Delay of the Unit 1 Year	\$28,481	7HA.03 1x1 CC (in 2032) (SJRPP Unit 3)
High Load Growth	\$29,328	7HA.03 1x1 CC (SJRPP Unit 3)
Low Load Growth	\$26,758	7HA.03 1x1 CC (SJRPP Unit 3)
High Natural Gas Prices	\$29,805	7HA.03 1x1 CC (SJRPP Unit 3)
Low Natural Gas Prices	\$25,759	7HA.03 1x1 CC (SJRPP Unit 3)
High Capital Cost	\$28,864	7HA.03 1x1 CC (SJRPP Unit 3)

7.0 Evaluation of Non-Generating Alternatives

JEA is subject to the Florida Energy Efficiency and Conservation Act (FEECA), section 366.82, Florida Statutes, which requires the Commission to adopt and periodically review JEA's conservation goals. JEA's current numeric conservation goals were established by the Commission in 2024.⁶ Subsequently, the Commission approved JEA's 2025 Demand-Side Management Plan (2025 DSM Plan). JEA continues to implement DSM programs that are beneficial and meet JEA's FEECA goals as well as additional programs that are beneficial. Projected demand and energy reductions associated with JEA's existing DSM programs are reflected in the load forecast and associated projected need for capacity discussed throughout Section 5 herein, which demonstrates JEA's need for capacity beyond the demand reductions projected to result from JEA's DSM programs.

7.1 Current Conservation & Demand-Side Management

7.1.1 DSM Programs Included in JEA's 2025 DSM Plan

JEA offers the following DSM programs that are included in JEA's 2025 DSM Plan:

- Energy Survey Programs: Free efficiency assessments to residential, commercial, and industrial customers. The JEA representative breaks down the customer's utility consumption into components to discuss with the customer and conducts a walk-through inspection to identify where improvements can be made.
- Residential Home Efficiency Upgrades Rebates Program: The Residential Home Efficiency Upgrades Rebates Program consists of incentives (rebates) for customers to improve the efficiency of their homes through the installation of qualifying heat pump water heaters, improvements to the heating, ventilation, and air conditioning (HVAC) systems, or ceiling insulation.
- Residential Energy Efficient Products Rebates Program: The Residential Energy Efficient Products Rebates Program consists of incentives (rebates) for customers to improve the efficiency of their homes through the installation of ENERGY STAR clothes washers, room air conditioners, and smart thermostats.
- Residential Neighborhood Energy Efficiency Program: Offers education concerning the efficient use of energy and water as well as the direct installation of an array of energy and water efficient measures at no cost to income-qualified customers.
- Commercial/Industrial Prescriptive Lighting Rebates Program: Pays a financial incentive to customers to install high efficiency lighting technology.

7.1.2 Additional DSM Programs

In addition to the DSM programs included in JEA's 2025 DSM Plan (as described above), JEA offers the following programs to its customers as of the date of this report.

- Energy Efficient Products, which pays a financial incentive to encourage the use of high efficiency appliances.

⁶ In re: Commission review of numeric conservation goals (JEA), Docket No. 20240016-EG, Order No. PSC-2024-0432-FOF-EG (Sept. 20, 2024).

- MyWay Prepaid Program, which is available to all residential customers and especially appropriate for those who prefer to prepay for services. It is consumer-focused experience for environmentally conscious consumers who like to keep consumption in mind. Customers who participate in prepaid programs, like MyWay, typically reduce consumption because they're frequently informed of how they're using their utilities.
- Commercial Prescriptive Program, which pays a financial incentive to encourage the use of high efficiency HVACR, cooking and water heating products and services.
- Small Business Program, which promotes the use of high efficiency HVAC, water heating, and appliances in the small business sector.
- Custom Commercial Program, which promotes the use of custom efficiency measures based on the specific application for each customer.

JEA's overall DSM achievements in 2025 through FEECA programs were a winter peak reduction of 1,545 kW, a summer peak reduction of 1,758 kW, and an energy reduction of 9,738 MWh. Through non-FEECA DSM programs, JEA achieved a winter peak reduction of 103 KW, a summer peak reduction of 201 kW, and an energy reduction of 1,043 MWh.

7.2 Potential for Conservation and DSM Savings to Mitigate Need

JEA's forecast of resource needs presented in Section 5 herein takes into account projected reductions associated with the DSM programs included in JEA's 2025 DSM Plan and approved by the Commission, as well as JEA's additional conservation efforts. The DSM goals and programs proposed by JEA and approved by the Commission were based on the evaluations of technical, economic, and achievable potential conducted by Resource Innovations and presented in a DSM Market Potential Study (MPS) in 2024. To ensure that the analysis regarding the ability of reasonably available conservation measures to mitigate the need for SJRPP Unit 3 was as current as possible, Resource Innovations performed an update of the analysis, as described below.

Resource Innovations utilized the framework of the 2024 FEECA MPS, including customer segmentation, forecast disaggregation, and DSM measure impacts, and applied updates that aligned with JEA's current load and economic forecasts. The updated MPS found no material change in energy efficiency (EE) achievable potential as compared to the 2024 FEECA MPS – 0.01 MW in 2031, 0.02 MW in 2033, and 0.02 MW in 2035 for winter peak savings, and 0.06 MW in 2031, 0.07 MW in 2033, and 0.09 MW for summer peak savings. For demand response (DR), the updated MPS resulted in achievable potential of 50.2 MW in 2031, 60.2 MW in 2033, and 68.0 MW for winter peak savings, and 49.3 MW in 2031, 59.7 MW in 2033, and 67.9 MW in 2035 for the summer peak savings. The DR potential reflects maximum achievable potential and is not reflective of what may be practicably achievable by JEA as it included several measures competing for the same load and did not consider practical limitations to implementation. Even if JEA could practicably and cost-effectively realize the full achievable DR potential described above, it falls well short of mitigating the need for SJRPP Unit 3. To mitigate the need for SJRPP Unit 3, JEA would need more than 30 times the amount of DSM reflected in JEA's current goals for 2031 and 46 times the amount of DSM JEA achieved. The updated MPS confirms that there are no additional cost-effective, reasonably available conservation or DSM measures to mitigate the need for SJRPP Unit 3.

8.0 Adverse Consequences of Denial

As discussed throughout this Need Study, JEA will require additional capacity to maintain winter and summer reserve margin requirements beginning as early as the winter of 2028, with the need for capacity increasing significantly over the 2031 through 2035 period and consistently increasing thereafter. JEA's projected need for capacity is influenced by a number of factors, including projected load growth (winter and summer peak demand as well as annual energy requirements) and the assumption that NGS Unit 3 is removed from service beginning in 2035. Figure 8-1 illustrates JEA's projected need for additional capacity to maintain reserve margin requirements.



Figure 8-1 JEA's Projected Need for Capacity

The analysis presented throughout this Need Study demonstrates that the addition of SJRPP Unit 3 in 2031 is part of JEA's least-cost (most economic) resource plan to reliably meet JEA's forecast demand (peak demand and annual energy requirements) for JEA's base case (expected capital costs, loads, and fuel prices) as well as sensitivities that encompass a wide range of variations to capital costs, load forecasts, and fuel price projections. SJRPP Unit 3 is the most cost-effective alternative under the base case and all sensitivities. For the base case evaluations, the least-cost resource plan including SJRPP Unit 3 in 2031 is approximately \$91 million lower in CPWC than the least-cost resource plan that does not include SJRPP Unit 3 in 2031. It is important to note that the least-cost resource plan within the base case evaluations that does not include SJRPP Unit 3 in 2031 includes a similar advanced class, 1x1 combined cycle in 2035, which is essentially just a delay in the addition of a unit similar to SJRPP Unit 3 for a 4 year period, further demonstrating the benefit to JEA's system (and customers) of the addition of an advanced class, combined cycle resource such as SJRPP Unit 3.

Reflected in the economic analysis is the benefit of JEA being able to place NGS Unit 3 in limited use on liquid fuel which also serves to make more efficient use of natural gas by utilizing natural gas in SJRPP Unit 3 rather than NGS Unit 3, reflecting an efficiency improvement of approximately 37 percent. Not only does the addition of SJRPP Unit 3 result in more efficient utilization of natural gas, increasing fuel diversity by reducing reliance on natural gas per unit of electricity generated, SJRPP Unit 3 will allow JEA

to reduce CO₂ emissions, as SJRPP Unit 3 will have a CO₂ emissions rate of 0.37 tons CO₂ per MWh, as compared to NGS Unit 3's CO₂ emissions rate of 0.59 tons CO₂ per MWh. For illustrative purposes, the least-cost resource plan including the addition of SJRPP Unit 3 in 2031 as compared to the least-cost resource plan that does not include SJRPP Unit 3 in 2031 is projected to decrease CO₂ emissions by 5.7 million tons; as noted above, this reduction in CO₂ essentially occurs over only a 4 year period as the least-cost resource plan without SJRPP Unit 3 in 2031 includes a similar advanced class combined cycle in 2035.

Non-approval of the requested need determination would mean that JEA's customers would be denied the most cost-effective option to meet JEA's need while providing flexibility relative to dispatch and operations to enhance grid reliability and mitigate risk. Further, if SJRPP Unit 3 is not approved, JEA would be unable to place NGS Unit 3 into limited use and would instead have to continue to rely on a less efficient resource that is approaching the end of its ability to continue to operate reliably. The cost to upgrade NGS Unit 3 to allow continued operation absent SJRPP Unit 3 would exceed \$834 million.

JEA's required reserve margin is projected to fall below the minimum reserve level beginning in the winter of 2028 with increasing capacity requirements thereafter. While additional off-system purchases could perhaps be made to contribute towards maintaining the target reserve margin, this would require importing increasingly large volumes of power (72 MW by 2031, increasing to 222 MW by 2033 and 802 MW by 2035). The current configuration of JEA's transmission system could not support importing this amount of power and would require substantial and costly upgrades; further, the timing of such transmission system upgrades may not be feasible to meet JEA's needs.

9.0 Conclusions

As demonstrated throughout this Need Study, SJRPP Unit 3 affirmatively addresses the criteria set forth in Section 403.519(3), Florida Statutes, and as such the Florida Public Service Commission should approve the addition of SJRPP Unit 3.

JEA performed a robust analysis of supply-side (including technically and commercially viable renewable energy and energy storage resources), including a transparent and competitive process to solicit power supply proposals as potential alternatives to SJRPP Unit 3 that was overseen by an independent evaluator. As discussed throughout this Need Study, JEA's resource planning process and analysis demonstrates that the proposed SJRPP Unit 3 is the most cost-effective and system-beneficial way for JEA to continue to reliably serve its customers, and there are no alternatives (including renewable and energy storage) that are more cost-effective than the proposed SJRPP Unit 3.

SJRPP Unit 3 will provide reliable dispatchable power, allow for more efficient use of natural gas, reduce system CO₂ emissions, provide support to reliably integrate power import into the JEA system, enhance flexibility and reliability, and help avoid costly updates that would otherwise be necessary to extend the life of JEA's existing NGS unit 3. JEA offers numerous DSM programs to its customers to support reductions in peak demand and energy requirements. There are no reasonably available, cost-effective conservation measures to mitigate the need for the proposed SJRPP Unit 3.

Denial of the proposed SJRPP Unit 3 would mean that JEA and its customers would be denied the most cost-effective, system-beneficial, power supply solution to meet JEA's need while providing flexibility relative to dispatch and operations to enhance grid reliability and mitigate risk. JEA estimates that the CPWC impact of the denial of a need determination for SJRPP Unit 3 would be approximately \$91 million. A delay of just one year would have CPWC economic impacts of approximately \$22 million.

Attachment A. JEA 2026 Ten-Year Site Plan



TEN-YEAR SITE PLAN

April 2026

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List of Abbreviations

Type of Generation Units

CA	Combined Cycle – Steam Turbine Portion, Waste Heat Boiler (only)
CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
GT	Combustion Turbine
FC	Fluidized Bed Combustion
IC	Internal Combustion
ST	Steam Turbine, Boiler, Non-Nuclear

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Under construction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
DFO	No. 2 Fuel Oil
RFO	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke
WH	Waste Heat

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Introduction

The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities, the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.

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

1. Description of Existing Facilities and Resources

1.1 Power Supply System Description

1.1.1 JEA Electric System

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 510,000 customers.

1.1.1.1 Existing Generation System

The JEA Electric System consists of generating facilities located on four plant sites within the City of Jacksonville (The City); the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), the Brandy Branch Generating Station (Brandy Branch), and the Greenland Energy Center (GEC).

Collectively, these plants consist of two multifuel-fired (coal/petroleum coke/natural gas/biomass) Circulating Fluidized Bed (CFB) steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2, and Brandy Branch GT1); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle system that comprises two gas-fired combustion turbine-generator units and one combined cycle heat recovery steam generator unit (Brandy Branch CT2 and CT3, and Brandy Branch steam Unit 4). Details of the existing facilities are displayed in Schedule 1.

JEA 2026 Ten-Year Site Plan**Description of Existing Facilities & Resources****Schedule 1: Existing Generating Facilities**

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

Notes:

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

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

1.1.2 Power Purchases

1.1.2.1 FPL Natural Gas Power Purchase Agreement

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

1.1.3 Clean Energy Power Purchases

1.1.3.1 Trail Ridge Landfill Power Purchase Agreement

In 2006, JEA entered into a PPA with Trail Ridge Energy, LLC (TRE) to purchase energy and environmental attributes from up to 9 net MW of firm renewable generation capacity utilizing the methane gas from The City's Trail Ridge landfill located in western Duval County (the "Phase One Purchase"). The facility was one of the largest landfill gas-to-energy facilities in the Southeast when it began commercial operation on December 6th, 2008.

JEA and TRE executed an amendment to this PPA on March 9th, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began in February 2015. The contract for Trail Ridge Phase One and Phase Two will expire in December 2026.

1.1.3.2 Jacksonville Solar Power Purchase Agreement

In May 2009, JEA entered into a PPA with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW_{AC} of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100-acre site. The Jacksonville Solar plant began commercial operation at full designed capacity on September 30th, 2010. The facility was acquired by Rev Renewables, LLC, an LS Power company, on June 15th, 2021. The contract for Jax Solar will expire in September 2040.

1.1.3.3 Small Utility-Scale Solar Power Purchase Agreements

JEA issued two Solar Photovoltaic (PV) Request for Proposals (RFP), one in December 2014 and another in April 2015, and awarded a total of 31.5 MW_{AC} of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements

JEA 2026 Ten-Year Site Plan

were finalized for a total of 27 MW_{AC}. The last of these seven projects was completed in December 2019.

The following are the seven PPAs that are installed within JEA's service territory of which JEA pays for the energy and has rights to the associated environmental attributes produced by the facilities:

- Northwest Jacksonville Solar Partners, LLC: 7 MW_{AC} / 25-year PPA. The NW Jax facility consists of 28,000 single-axis tracking photovoltaic panels on a vendor-leased site, owned by OnSite Partners, LLC (formerly American Electric Power OnSite Partners). The facility became operational on May 30th, 2017.
- Old Plank Road Solar Farm, LLC: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility consists of 12,800 single-axis tracking photovoltaic panels on a vendor-leased 40-acre site, owned by Southeast Solar Farm Fund, a partnership between PEC Velo & Cox Communications. The site attained commercial operation on October 13th, 2017.
- C2 Starratt Solar, LLC: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility, on a vendor-leased site, is now owned by EDPR DR (acquired C2 Starratt Solar, LLC) and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20th, 2017.
- Inman Solar Holdings 2, LLC: 2 MW_{AC} / 20-year PPA. The Simmons Solar facility, on a vendor-leased site, is owned by Inman Solar Holdings 2, LLC and was constructed by Inman Solar, Inc. The site attained commercial operation on January 17th, 2018.
- Hecate Energy Blair Road, LLC: 4 MW_{AC} / 20-year PPA. The Blair Road facility, on a vendor-leased site, is owned by Hecate Energy Blair Road, LLC and was constructed by Hecate Energy, LLC. The site attained commercial operation on January 23rd, 2018.
- JAX Solar Developers, a wholly-owned subsidiary of Mirasol Fafco Solar, Inc.: 1 MW_{AC} / 20-year PPA. The Old Kings Rd Solar facility is owned by EcoPower Development, LLC and was constructed by Mirasol Fafco Solar, Inc. The site attained commercial operation on October 15th, 2018.
- Imeson Solar, LLC: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The primary function of the BESS is to smooth the solar generation. It is the first utility scale solar plus storage facility interconnected to the JEA grid. The site, labeled SunPort Solar, was constructed by 174 Power Global and attained commercial operation on December 4th, 2019.

1.1.3.4 FPL Solar Power Purchase Agreements

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

1.1.3.5 Planned Solar Power Purchase Agreements

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

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

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

1.1.3.6 MEAG Nuclear Power Purchase Agreement

In June 2008, JEA entered into a 20-year PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4. These two new nuclear units

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

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

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

1.1.4 Cogeneration

Cogeneration facilities help meet the energy needs of JEA’s system on an as-available, non-firm basis. Since these facilities are considered energy only resources, they are not forecasted to contribute towards firm capacity to JEA’s reserve margin requirements.

Currently, JEA has contracts with one customer-owned qualifying facility (QF), as defined in the Public Utilities Regulatory Policy Act of 1978. Anheuser Busch has a total installed summer rated capacity of 8 MW and winter rated capacity of 9 MW.

Table 1a: JEA Existing Power Purchase Agreement Schedule

Contract		Start Date	End Date	MW_{AC}	Product Type
LES Trail Ridge	I	12/06/08	12/31/26	9	Annual
	II	02/01/14	12/31/26	6	Annual
MEAG Plant Vogtle	Unit 3	07/31/2023	07/31/2043	103	Annual
	Unit 4	04/29/2024	04/29/2044	103	Annual
FPL PPA		01/01/22	01/01/42	200	Annual
FPL Solar PPA		04/01/23	04/01/28	150	Annual
Jacksonville Solar		09/30/10	09/30/40	12	Annual
NW Jacksonville Solar		05/30/17	05/30/42	7	Annual
Old Plank Road Solar		10/13/17	10/13/37	3	Annual
Starratt Solar		12/20/17	12/20/37	5	Annual
Simmons Road Solar		01/17/18	01/17/38	2	Annual
Blair Site Solar		01/23/18	01/23/38	4	Annual
Old Kings Solar		10/15/18	10/15/38	1	Annual
SunPort Solar		12/04/19	12/04/39	5	Annual
Forest Trail Solar PPA		12/31/26	12/31/61	50	Annual
Miller Solar PPA		12/31/26	12/31/61	74.9	Annual

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

JEA's transmission system consists of 744 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL, completing the path from FPL's Duval substation (located in the westerly portion of JEA's system) to the north to interconnect with the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Duke Energy Florida and the City of Tallahassee each own transmission interconnections with the Georgia ITS. JEA's import capacity is 1,228 MW over the 500 kV transmission lines through Duval substation.

The 230 kV and 138 kV transmission systems provide a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest; covering the area not covered by the 230 kV and 138 kV transmission backbone.

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

JEA has a 138 kV tie with Beaches Energy Services at JEA's Neptune substation. JEA owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to JEA's Nassau substation. This substation serves as a 138 kV transmission interconnection point for FPL's O'Neil substation and Florida Public Utilities Company's (FPU) Step Down substation. JEA's ownership of these two 138 kV interconnections end at the first transmission structure outside of the Nassau substation.

1.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. In compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, JEA continually assesses the needs and options for increasing the capability of the transmission system.

Since the FRCC region became the FL-Peninsula sub-region of SERC in July 2019, JEA has been following additional guidelines and actively participating in the SERC activities towards the reliability and security of the bulk electric system.

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JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process. FRCC's published Regional Transmission Planning Process facilitates coordinated planning by all transmission providers, owners, and stakeholders within the FRCC Region.

FRCC's members include investor-owned utilities, municipal utilities, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Technical Subcommittee in conjunction with the FRCC Staff to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 for: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

1.2.3 Transmission Service Requirements

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

1.2.4 Distribution

The JEA distribution system operates at three primary voltage levels (4.16 kV, 13.2 kV, and 26.4 kV). The 4.16 kV system serves a permanently defined area in older residential neighborhoods. The 13 kV system serves a permanently defined area in the urban downtown area. These two distribution systems serve any new customers that are located within their defined areas, but there are no plans to expand these two systems beyond their present boundaries. The 26.4 kV system serves approximately 94 percent of JEA's distribution load, including 57 percent of the 4.16 kV substations. The current standard is to expand the 26.4 kV system as required to serve all new distribution loads, except smaller loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,607 miles of distribution circuits of which approximately 59.2 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

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

1.3.2 Renewable Energy

1.3.2.1 JEA Distributed Energy

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

In 2009 JEA established a residential net metering program to encourage the use of customer-sited solar PV systems. The policy has since evolved with several revisions:

- 2009: Tier 1 & 2 Net Metering policy launched to include all customer-owned renewable generation systems less than or equal to 100 kW
- 2011: Tier 3 Net Metering policy established for customer-owned renewable generation systems greater than 100 kW up to 2 MW
- 2014: Policy updated to define Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as 100 kW – 2 MW. This policy was capped at 10 MW for total generation. All customer-owned generation in excess of 2 MW would be addressed in JEA's Distributed Generation (DG) Policy.
- 2017: In October, the JEA Board of Directors approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1st, the comprehensive DG Policy qualified renewable and non-renewable customer-owned generation systems under the following ranges:
 - o DG-1 – Less than or equal to 2 MW
 - o DG-2D – Over 2 MW with distribution level connection

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- o DG-2T – Over 2 MW with transmission level connection

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

1.3.2.2 Renewable Energy Credits (REC)

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

1.3.2.3 SolarSmart and SolarMax

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

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

1.3.2.4 Landfill Gas and Biogas

JEA owned three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997 and was fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, methane gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and the remaining Girvin landfill generation facilities were decommissioned in 2014.

JEA's Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using three anaerobic digesters and one sludge dryer to produce a pelletized fertilizer product. The methane gas from the digesters can be used as a fuel for the sludge dryer and the digester heaters.

1.3.2.4 Biomass

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

In 2011, JEA co-fired biomass in Northside units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. They produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. At that time, JEA received bids from local sources to provide biomass for potential continued use.

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

1.3.3 Clean Energy Research Efforts

1.3.3.1 Collaboration with University of North Florida

JEA's clean energy research efforts have focused on the development of clean energy technologies through a partnership with the University of North Florida's (UNF) Engineering Department. In the past, UNF and JEA have worked on the following projects:

- JEA and UNF worked to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF evaluated the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway, where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15-acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3-year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.
- JEA, Miller Electric, and UNF have joined forces under the DOE-backed "Emerge" initiative to train the next generation of energy professionals. Through hands-on training, industry certifications, and expert mentorship, EMERGE equips participants with cutting-edge skills in renewable energy and microgrid technologies. This program is shaping the "Technician of the Future," preparing a workforce capable of building and maintaining resilient, sustainable energy systems to meet the demands of an evolving grid.
- On November 28th, 2023, JEA and UNF commemorated the grand opening of the JEA Sustainable Solutions Lab, a collaboration with UNF's College of Computing, Engineering and Construction, that allows undergraduate and graduate students to research clean energy technologies. JEA has committed to contributing \$100,000 per year, for five years, for a total contribution of \$500,000. The lab will serve as a hub for research to develop sustainable solutions for JEA and a variety of industries.

1.3.3.2 Energy Storage

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

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

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continue to evaluate the integration of additional storage resources as future studies are conducted.

2. Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peak demands, net energy for load (NEL), interruptible customer demand, demand-side management (DSM), and the impact of plug-in electric vehicles (PEVs). JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

JEA uses National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for the weather parameters, Moody's Analytics (Moody) economic parameters for Duval County, JEA's Data Warehouse to determine the total number of accounts and CBRE Jacksonville for total commercial inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Calendar Year 2026 baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the most recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections.

2.1 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. JEA updates its normal weather every 5 years or more frequently, if needed.

The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy sales, total population, number of households, median household income and total housing starts from Moody's Analytics, JEA's total residential accounts and JEA's residential electric rate.

The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy sales, total commercial employment and gross domestic product from Moody's Analytics, JEA's total commercial accounts, and commercial inventory square footage from the CBRE Jacksonville Office Figures Q3 2025 Report.

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

The lighting energy forecast was developed using the historical actual energy and number of luminaries. JEA developed the forecasted number of luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries.

JEA's forecasted Compounding Annual Growth Rate (CAGR) for net energy for load during the TYSP period is 1.43 percent.

2.2 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 25°F as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA develops the seasonal peak forecasts using normalized historical and forecasted residential, commercial, and industrial energy for winter/summer peak months, and the average load factor based on historical peaks and net energy for winter/summer peak months. JEA's forecasted CAGR for net firm peak demand during the TYSP period is 1.32 percent for summer and 1.36 percent for winter.

2.3 Demand-Side Management (DSM)

2.3.1 Interruptible Load

JEA currently offers Interruptible and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to interruption of their full nominated load during times of system emergencies, including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 120 MW of interruptible peak load for the summer and 107 MW for the winter which remain constant throughout the study period. For 2026, the interruptible load represents 3.7 percent of the forecasted total peak demand in the summer and 3.4 percent of the forecasted total peak demand in the winter.

2.3.2 Demand-Side Management Programs

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

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption**

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

Table 2: DSM Portfolio – Energy Efficiency Programs

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

Table 3: DSM Programs

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

2.4 Customer-Sited Renewables

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

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

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

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

2.5 Plug-in Electric Vehicles Peak Demand and Energy

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

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

The usable battery capacity (85 percent of battery capacity) per vehicle was determined based on the current plug-in electric vehicle models in Duval County. The average usable battery capacity per PEV is calculated using the average usable battery capacity of each vehicle brand and then assumes the annual growth of usable battery capacity per PEV by using the historical 5-year average of 0.001 kWh. Similarly, the peak capacity is determined based on the average

on-board charging rate of each vehicle brand and the forecasted peak capacity per PEV grows by 0.01 kW per year.

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

JEA forecasts Average Annual Growth Rate (AAGR) for PEVs summer and winter coincidental peak demand of 41.18 percent and 35.39 percent, respectively, and total energy of 34.86 percent during the TYSP period.

2.6 Electrification

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

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

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

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Class**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Calendar Year	Rural and Residential			Commercial			Industrial		
	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,692	202	13,322,934
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,777	202	13,717,349
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,765	196	14,081,384
2019	5,479	420,831	13,019	4,060	53,153	76,389	2,733	194	14,085,278
2020	5,679	429,575	13,220	3,886	53,701	72,363	2,698	196	13,759,522
2021	5,551	438,470	12,660	3,848	54,374	70,767	2,612	196	13,348,772
2022	5,723	447,308	12,795	4,005	55,082	72,717	2,708	199	13,641,119
2023	5,658	458,764	12,334	3,968	55,946	70,922	2,614	199	13,151,607
2024	6,022	470,564	12,797	4,104	56,724	72,359	2,691	203	13,254,576
2025	6,081	479,288	12,641	4,194	57,376	73,096	2,648	198	13,389,674
2026	6,075	485,840	12,504	4,022	58,168	69,136	2,754	211	13,054,071
2027	6,174	492,159	12,546	4,027	58,935	68,335	3,033	215	14,107,857
2028	6,262	498,274	12,568	4,035	59,713	67,577	3,285	219	15,001,436
2029	6,351	504,171	12,597	4,046	60,504	66,865	3,357	222	15,120,763
2030	6,441	509,869	12,633	4,057	61,311	66,176	3,427	224	15,297,656
2031	6,531	515,323	12,674	4,070	62,134	65,498	3,475	227	15,307,034
2032	6,620	520,487	12,719	4,082	62,969	64,829	3,526	230	15,329,031
2033	6,707	525,330	12,766	4,097	63,813	64,196	3,544	233	15,209,228
2034	6,794	529,885	12,822	4,109	64,666	63,548	3,567	236	15,114,511
2035	6,892	534,234	12,901	4,122	65,527	62,901	3,600	240	14,999,094

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Class**

Calendar Year	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	Street & Highway Lighting	Other Sales to Ultimate Customers	Total Sales to Ultimate Customers	Sales for Resale	Utility Use & Losses	Net Energy for Load	Other Customers	Total Number of Customers
	GWH	GWH	GWH	GWH	GWH	GWH	(Avg. Number)	
2016	77	0	12,184	490	263	12,937	2	450,033
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,793
2019	57	0	12,328	58	411	12,797	0	474,178
2020	56	0	12,319	7	414	12,740	0	483,471
2021	55	0	12,066	25	449	12,540	0	493,039
2022	55	0	12,491	30	408	12,930	0	502,588
2023	55	0	12,295	63	376	12,733	0	514,909
2024	56	0	12,873	60	321	13,255	0	527,491
2025	57	0	12,980	69	431	13,479	0	536,862
2026	57	0	12,908	0	479	13,386	0	544,219
2027	58	0	13,293	0	493	13,785	0	551,309
2028	58	0	13,641	0	506	14,147	0	558,206
2029	59	0	13,812	0	512	14,324	0	564,897
2030	59	0	13,984	0	518	14,503	0	571,404
2031	59	0	14,135	0	524	14,659	0	577,684
2032	60	0	14,288	0	530	14,817	0	583,686
2033	60	0	14,407	0	534	14,941	0	589,376
2034	61	0	14,531	0	539	15,070	0	594,787
2035	61	0	14,675	0	544	15,219	0	600,001

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 3.1: History and Forecast of Summer Peak Demand**

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

Note: All projections coincident at time of peak.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 3.2: History and Forecast of Winter Peak Demand**

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

Note: All projections coincident at time of peak.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 3.3: History and Forecast of Annual Net Energy for Load**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Energy for Load (GWH)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy for Load (GWH)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2016	12,937	0	0	0	0	0	0	12,937
2017	12,672	0	0	0	0	0	0	12,672
2018	12,813	0	0	0	0	0	0	12,813
2019	12,797	0	0	0	0	0	0	12,797
2020	12,740	0	0	0	0	0	0	12,740
2021	12,540	0	0	0	0	0	0	12,540
2022	12,930	0	0	0	0	0	0	12,930
2023	12,733	0	0	0	0	0	0	12,733
2024	13,255	0	0	0	0	0	0	13,255
2025	13,479	0	0	0	0	0	0	13,479
2026	13,409	0	0	0	0	12	11	13,386
2027	13,831	0	0	0	0	24	22	13,785
2028	14,216	0	0	0	0	36	33	14,147
2029	14,416	0	0	0	0	48	44	14,324
2030	14,618	0	0	0	0	60	55	14,503
2031	14,797	0	0	0	0	72	66	14,659
2032	14,978	0	0	0	0	84	77	14,817
2033	15,125	0	0	0	0	96	88	14,941
2034	15,277	0	0	0	0	108	99	15,070
2035	15,449	0	0	0	0	120	110	15,219

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 4:** Previous Year Actual and Two-Year Forecast of Firm Peak Demand and Net Energy for Load by Month

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

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 5: Fuel Requirements**

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

Note:

(a) Coal includes Northside Coal and Petroleum Coke.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 6.1: Energy Sources (GWh)**

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

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

(c) May not add due to rounding.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 6.2: Energy Sources (Percent)**

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

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

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

JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources as well as other planning assumptions.

3.1.1 Resource Planning

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

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

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

during periods of extreme weather and/or when other generating units or purchased power are unavailable.

3.1.2 JEA Planning Reserve Policy

JEA's Planning Reserve Policy establishes a guideline that provides an allowance to meet the 15 percent reserve margin with up to 3 percent of the forecasted firm peak demand in any season from purchases acquired in the operating horizon. If up to 3 percent of firm peak demand in any season is needed, The Energy Authority (TEA), JEA's affiliated energy market services company, will acquire short-term seasonal market purchases for JEA no later than the season prior to the need. TEA actively trades energy with a large number of counterparties throughout the United States and is generally able to acquire capacity and energy from other market participants when any of its members require additional resources.

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

3.2 Resource Plan

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

Table 4a: Resource Needs after Committed Units - Summer

Summer										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2026	2,782	601	0	0	3,383	2,772	611	22%	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	522	18%
2028	2,782	703	-206	0	3,279	2,930	349	12%	349	12%
2029	2,782	753	-129	0	3,406	2,961	445	15%	445	15%
2030	2,782	753	-103	0	3,432	2,997	435	15%	435	15%
2031	2,782	753	-103	0	3,432	3,023	409	14%	409	14%
2032	2,782	753	-103	0	3,432	3,052	380	12%	380	12%
2033	2,782	553	0	0	3,335	3,070	265	9%	265	9%
2034	2,782	553	0	0	3,335	3,092	243	8%	243	8%
2035	2,258	553	0	0	2,811	3,119	-308	-10%	-308	-10%

Table 4b: Resource Needs after Committed Units - Winter

Winter										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2025/26	2,952	471	0	0	3,423	2,901	522	18%	522	18%
2026/27	2,952	661	-206	0	3,407	2,988	419	14%	419	14%
2027/28	2,952	686	-206	0	3,432	3,077	355	12%	355	12%
2028/29	2,952	736	-129	0	3,559	3,114	445	14%	445	14%
2029/30	2,952	736	-103	0	3,585	3,147	438	14%	438	14%
2030/31	2,952	736	-103	0	3,585	3,180	405	13%	405	13%
2031/32	2,952	736	-103	0	3,585	3,210	375	12%	375	12%
2032/33	2,952	536	0	0	3,488	3,226	262	8%	262	8%
2033/34	2,952	536	0	0	3,488	3,252	236	7%	236	7%
2034/35	2,428	536	0	0	2,964	3,275	-311	-9%	-311	-9%

Table 5: Resource Plan

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

Notes:

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

JEA 2026 Ten-Year Site Plan**Schedule 7.1:** Summer Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2026	2,782	601	0	0	3,383	2,772	611	22%	0	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	0	522	18%
2028	2,782	794	-206	0	3,370	2,930	440	15%	0	440	15%
2029	2,782	753	-129	0	3,406	2,961	445	15%	0	445	15%
2030	2,782	768	-103	0	3,447	2,997	450	15%	0	450	15%
2031	3,364	753	-103	0	4,014	3,023	990	33%	0	990	33%
2032	3,364	753	-103	0	4,014	3,052	962	32%	0	962	32%
2033	3,364	553	0	0	3,917	3,070	846	28%	0	846	28%
2034	3,364	553	0	0	3,917	3,092	824	27%	0	824	27%
2035	3,588	553	0	0	4,141	3,119	1,022	33%	0	1,022	33%

JEA 2026 Ten-Year Site Plan**Schedule 7.2: Winter Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak**

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

JEA 2026 Ten-Year Site Plan**Schedule 8: Planned and Prospective Generating Facility Additions and Changes**

Planned and Prospective Generating Facility and Purchased Power Additions and Changes														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transport		Construction Start Date	Commercial/ In-Service or Change Date	Expected Retirement/ Shutdown Date	Gen Max Nameplate	Net Capability		Status
				Primary	Alternate	Primary	Alternate					Summer	Winter	
				kW	MW	MW								
Northside	Unit 3	Jacksonville, FL	ST	NG	RFO	PL	WA	N/A	Jul-1977	Jan-2035	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Jan-2028	Jan-2031	Unknown	706,000	582	678	P
Advanced-Class 1x0 CT I	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P
Advanced-Class 1x0 CT II	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

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

Notes:

(1) Data is confidential.

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

Notes:

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

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

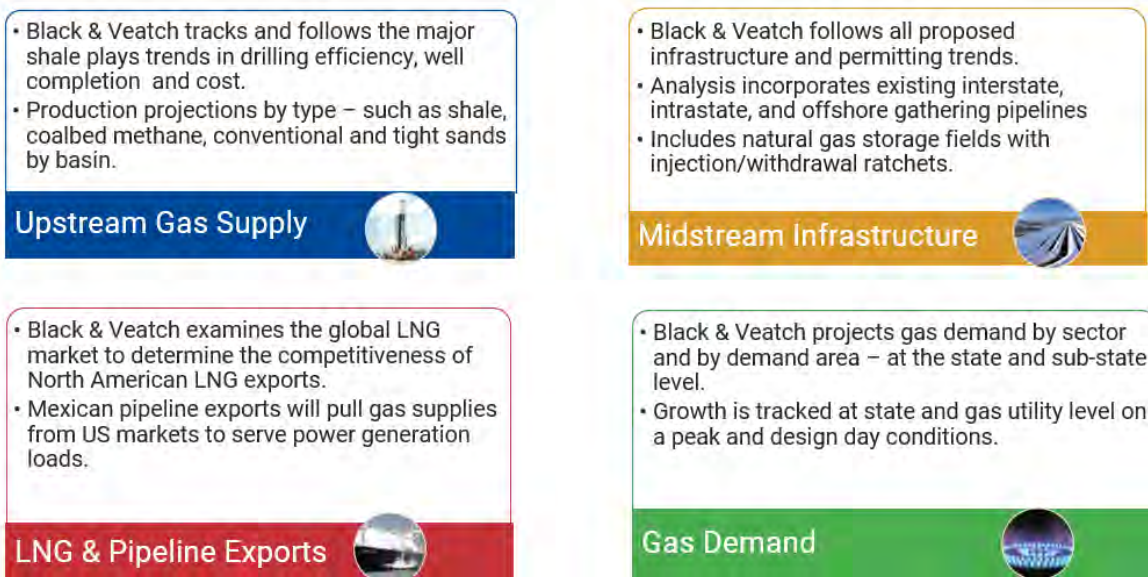
1	Point of Origin and Termination	None to Report
2	Number of Lines	
3	Right of Way	
4	Line Length	
5	Voltage	
6	Anticipated Construction Time	
7	Anticipated Capital Investment	
8	Substations	
9	Participation with Other Utilities	

4. Other Planning Assumptions and Information

4.1 Fuel Price Forecast

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

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



4.2 Economic Parameters

This section presents the economic parameters used by JEA in the evaluations performed to determine JEA's least-cost expansion plan to satisfy forecast capacity requirements as presented in the TYSP period.

4.2.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and non-fuel variable O&M escalation rate are each assumed to be 3.50 percent.

4.2.2 Municipal Bond Interest Rate

JEA performs sensitivity assessments of project cost to test the robustness of JEA's resource plan. Project cost includes forecast of direct cost of construction, indirect cost, and financing cost. Financing cost includes the forecast of long term tax-exempt municipal bond rates, issuance cost, debt service reserve contributions, and insurance cost. For JEA's plan development, the long term tax-exempt municipal bond rate is assumed to be 4.75 percent. This rate is based on JEA's judgment and expectation that the long-term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax-exempt municipal bond interest rate of 4.75 percent.

4.2.4 Interest during Construction Interest Rate

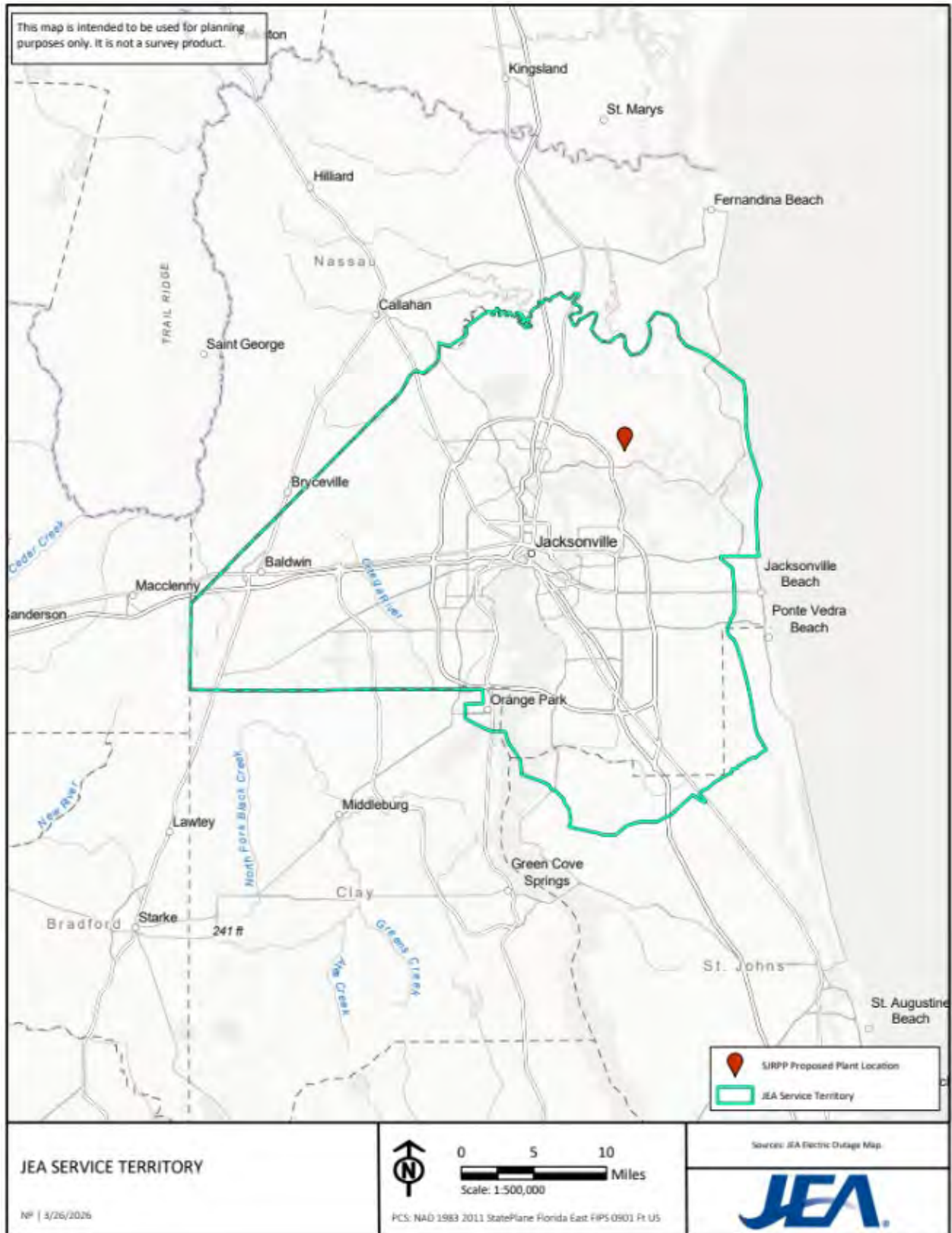
The interest during construction rate, or IDC, is assumed to be 4.75 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR (LFCR) that has the same present value as the year-by-year FCR. Different generating technologies are assumed to have different economic lives and therefore different financing terms. Simple cycle combustion turbines are assumed to have a 20-year financing term, while natural gas-fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different LFCRs were developed. All LFCR calculations assume the 4.75 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.63 percent annual property insurance cost. The resulting 20-year FCR is 8.56 percent and the 25-year FCR is 7.62 percent.

5. Environmental and Land Use Information

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



JEA Existing Power Purchase Agreement Schedule

Contract	Start Date	End Date	MW(AC)	Energy Source
LES Trail Ridge I	12/06/08	12/31/26	9	Landfill Gas
LES Trail Ridge II	02/01/14	12/31/26	6	Landfill Gas
MEAG Plant Vogtle Unit 3	07/31/2023	07/31/2043	103	Nuclear
MEAG Plant Vogtle Unit 4	04/29/2024	04/29/2044	103	Nuclear
FPL PPA	01/01/22	01/01/42	280	Natural Gas
FPL Solar PPA	04/01/23	04/01/28	150	Solar
Jacksonville Solar	09/30/10	09/30/40	12	Solar
NW Jacksonville Solar	05/30/17	05/30/42	7	Solar
Old Plank Road Solar	10/13/17	10/13/37	3	Solar
Starratt Solar	12/20/17	12/20/37	5	Solar
Simmons Road Solar	01/17/18	01/17/38	2	Solar
Blair Site Solar	01/23/18	01/23/38	4	Solar
Old Kings Solar	10/15/18	10/15/38	1	Solar
SunPort Solar	12/04/19	12/04/39	5	Solar (w/Storage)
Forest Trail Solar PPA	12/31/26	12/31/61	50	Solar
Miller Solar PPA	12/31/26	12/31/61	74.9	Solar (w/Storage)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

JAMES STANCIN

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF JAMES STANCIN

DOCKET NO. _____-EC

June 4, 2026

Q. Please state your name and address.

A. My name is James Stancin. My business address is 225 N. Pearl Street,
Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as the Director of Electric Production.

Q. What are your responsibilities in your current position.

A. As JEA’s Director of Electric Production, I am responsible for overseeing
operations across multiple sites. I also lead several critical teams that support
generation across the fleet, including Reliability Engineering, Outage and
Asset Management, Predictive Maintenance, Project Management, and
Support and Controls. These groups are responsible for everything from asset
health and outage execution to technical specifications, key performance
indicators, and continuous improvement efforts that keep our facilities running
safely and efficiently. Finally, I am the Project Director for St. Johns River
Power Park Unit 3 (SJRPP Unit 3).

1

2 **Q. Please describe your professional experience.**

3 A. I have over 30 years of experience in power generation. I began my career at
4 PG&E where I spent a decade developing foundational expertise in power
5 plant operations and generation systems. I have been at JEA since 2004,
6 starting as an Operator at Northside Generating Station (NGS). I steadily
7 moved up through the ranks as a Unit Operator, Operating Engineer,
8 Operations Manager, Senior Manager of Electric Production Operations, and
9 Director of Electric Production at NGS. I have been in my current position
10 since 2019.

11

12 **Q. Do you have experience with construction of capital projects?**

13 A. Yes. As the Director of the Electric Production Project Management Team, I
14 oversee scope, project definition, evaluation and execution of all capital as well
15 as operation and maintenance (O&M) projects for JEA's generation fleet and
16 facilities.

17

18 **Q. What is the purpose of your testimony in this proceeding?**

19 A. The purpose of my testimony is to provide an overview of the St. Johns River
20 Power Park Unit 3 Project (SJRPP Unit 3 or Project) from a technical
21 perspective. Specifically, I will describe the Project site, technology, related
22 facilities, operating assumptions, fuel supply, and estimated costs of the
23 Project.

24

1 **Q. Are you sponsoring any exhibits in the case?**

2 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
3 under my supervision and are attached to this pre-filed testimony:

- 4 • Exhibit No. __ (JS-1) - Resume of James Stancin
- 5 • Exhibit No. __ (JS-2) - Project Layout
- 6 • Exhibit No. __ (JS-3) - Site Location
- 7 • Exhibit No. __ (JS-4) - Renderings
- 8 • Exhibit No. __ (JS-5) - Site and Vicinity
- 9 • Exhibit No. __ (JS-6) - Capital Cost Estimate

10 I am also sponsoring Sections 1.3, 3.3.1, 4.1, 4.1.1, 4.1.2, 4.1.3, 4.1.4, 4.1.5,
11 4.1.6, 4.1.7, 4.1.8, 4.1.10, 4.1.11, and 6.2.2 (including all referenced tables and
12 figures in those sections) of JEA's Need Study, which is identified as Exhibit
13 No. ____ (JB-2).

14

15 **Q. Please summarize your testimony.**

16 A. SJRPP Unit 3 will be a highly efficient resource that will provide flexible and
17 fully dispatchable quantities of reliable energy to JEA's customers. The
18 facility will be located on the existing SJRPP site where JEA owned and
19 operated SJRPP Units 1 & 2 prior to their decommissioning and demolition.
20 The use of the SJRPP site reduces SJRPP Unit 3 impacts as compared to a
21 greenfield location. Construction and operation of SJRPP Unit 3 will have
22 significant benefits in terms of efficiency, reduced emissions, fuel diversity,
23 and avoiding costly and infeasible updates to extend the life of Northside
24 Generating Station (NGS) Unit 3. JEA plans to bring SJRPP Unit 3 into
25 commercial service in 2031.

1

2

SJRPP UNIT 3

3

Q. Please describe the combined cycle technology that will be used for the Project.

4

5

A. SJRPP Unit 3 will have a nameplate or gross capacity of 706 MW and a net nominal output of 678 MW (winter) and 582 MW (summer). The proposed facility will utilize one natural gas fired advanced class combustion turbine (CTG) coupled with an associated heat recovery steam generator (HRSG) that will produce steam to drive a steam turbine generator (STG). This configuration is commonly referred to as a “one on one” or combined cycle plant. The GE Vernova (GEV)-manufactured CTG will be equipped with a Dry Low NO_x (DLN) combustion system designed for firing natural gas fuel and backup ULSD fuel oil. It will also be capable of operating on 50% hydrogen should this become available in the future. The GEV-manufactured HRSG will be a horizontal natural circulation design with supplemental duct-firing capabilities and equipment for emissions reductions. Steam exhausting from the GEV-manufactured STG will be condensed in a water-cooled condenser which cools the steam by means of a 12-cell mechanical draft cooling tower utilizing reclaimed water for cooling. Exhibit No. ____ (JS-2) shows the layout of the facility.

21

22

Q. Please describe the site where SJRPP Unit 3 will be located.

23

A. SJRPP Unit 3 is proposed to be located at JEA’s existing SJRPP site in the City of Jacksonville, Duval County, Florida. Exhibit No. ____ (JS-3) shows the site location. SJRPP is approximately 9.3 miles northeast of downtown

25

1 Jacksonville, east of Interstate I-95, north of State Highway 105 (Heckscher
2 Road), and south of Cedar Point Road. SJRPP Unit 3 will be located on an
3 approximately 194-acre area that is part of the larger approximately 1,600-acre
4 parcel upon which JEA owned and operated SJRPP Units 1 & 2 – two 612
5 MW coal-fired steam electric generating units certified under the Florida
6 Electrical Power Plant Siting Act (PPSA) in 1982, and decommissioned and
7 demolished in 2018 and 2019. SJRPP is also contiguous to JEA’s NGS.
8 Portions of SJRPP, including the electrical substation, 230kV electrical
9 transmission lines, and byproduct storage areas remain certified under the
10 PPSA.

11

12 **Q. Are there any advantages to locating SJRPP Unit 3 at the existing SJRPP**
13 **site?**

14 A. Yes. Locating SJRPP Unit 3 on the parcel formerly utilized for SJRPP Units 1
15 and 2 will significantly minimize overall impacts compared to locating new
16 generation on a greenfield site. SJRPP Unit 3 will utilize existing certified
17 infrastructure, including the existing substation on the SJRPP property and the
18 existing 230kV electrical transmission lines. Using the site adjacent to NGS
19 allows SJRPP Unit 3 to utilize existing infrastructure such as reclaimed water
20 pipelines, potable water lines, sanitary sewer lines, the cooling tower
21 blowdown pipeline, and discharge structure.

22

23 **Q. Beyond the combined cycle generating unit itself, what other on-site**
24 **facilities will be constructed as part of the SJRPP Unit 3 Project?**

1 A. Onsite associated facilities include an administration building with control
2 room, a warehouse/maintenance building, roadways, parking and laydown
3 areas, a temporary spoils area, a demineralized water treatment building, an
4 open-frame turbine structure, electrical equipment and enclosures, step-up and
5 auxiliary transformers, a natural gas metering and regulation station with gas-
6 fired heaters, a mechanical draft cooling tower, HRSG exhaust stack, natural
7 gas-fired auxiliary boiler with exhaust stack, emissions monitoring and
8 reduction equipment, fire water pumps (electric primary with diesel backup),
9 diesel-fired emergency generator, above-ground service water storage tank, fire
10 water storage tank, reclaim water storage tank, fuel oil storage tank, aqueous
11 ammonia tank, wells, oil/water separators, a stormwater management system
12 with stormwater ponds, piping tie-ins with existing infrastructure, and other
13 ancillary equipment. Exhibit No. ____ (JS-4) includes conceptual renderings of
14 SJRPP Unit 3.

15

16 **Q. Will SJRPP Unit 3 require additional off-site facilities?**

17 A. Yes. Natural gas will be delivered to a Metering & Regulation (M&R) yard via
18 an approximately 25-mile pipeline lateral. The M&R yard and pipeline lateral
19 will be permitted, constructed, owned, operated, and maintained by PGS and
20 are therefore not part of the SJRPP Unit 3 Project proposed here. While existing
21 reclaimed water lines will be utilized, use of the existing piping system will
22 require installation of an off-site booster pump station. The booster pump
23 station will be located on a 0.38-acre property owned by JEA approximately 2
24 miles northwest of SJRPP, adjacent to I-295 to the south. Because it will be
25 permitted, constructed, and maintained by JEA's separately owned and

1 operated water utility, it is not proposed as part of this Project. Exhibit No. ____
2 (JS-5) shows off-site infrastructure to be utilized by SJRPP Unit 3.

3
4 **Q. What experience does JEA have with the evaluation and construction of**
5 **combustion turbine and combined cycle units and related facilities?**

6 A. JEA has used its Integrated Resource Planning (IRP) process for decades to
7 evaluate and inform long-term resource decisions. JEA's experience with
8 modern combustion turbine (CT) based units began in the mid-1990s. Since
9 then, JEA has gained extensive experience with evaluating, developing, siting,
10 permitting and constructing simple-cycle and combined-cycle resource options
11 including CTs at Kennedy Generating Station (Kennedy) (2000 and 2009),
12 Brandy Branch Generating Station (Brandy Branch) (2001), and Greenland
13 Energy Center (GEC), (2011) as well as conversion of CTs to a combined
14 cycle unit at Brandy Branch in 2005.

15
16 JEA will continue to advance SJRPP Unit 3 through a well-structured,
17 integrated approach aligned with its mission to reliably serve electric
18 customers. We operate under a strong matrix structure, enabling cross-
19 functional teams to collaborate efficiently to permit and construct electrical
20 generation on schedule and within budget.

21
22 **Q. How did JEA evaluate the feasibility and appropriateness of the combined**
23 **cycle technology selected for the SJRPP Unit 3 Project?**

1 A. JEA retained Black & Veatch to help evaluate numerous power generation
2 technologies as potential future resources prior to selecting the advanced class
3 gas turbine technologies incorporated in SJRPP Unit 3. Combined cycle
4 technology was chosen because it provides economic, reliable, dispatchable
5 power; allows for more efficient use of natural gas; and reduces system
6 emissions.

7
8 **Q. Please elaborate on the benefits of combined cycle generation related to**
9 **dispatch and flexibility.**

10 A. Combined cycle generation provides numerous system benefits in terms of
11 response times, ability to efficiently operate at partial load, start-up and shut-
12 down times, and fuel flexibility. More specifically, combined cycle plants are
13 designed to be highly responsive to changing grid demands, allowing them to
14 adjust their output quickly in real-time. This makes them ideal for following
15 fluctuations in electricity demand.

16
17 Combined cycle units are also designed to operate efficiently, even at partial
18 loads. This makes them more adaptable to the varying demands of the grid as
19 they can adjust output in response to lower demand periods without significant
20 efficiency loss. Traditional power plants experience significant efficiency
21 losses at lower load levels. Combined cycle plants are designed to maintain
22 higher efficiency across a wider range of loads. This means they can be
23 dispatched more often without sacrificing fuel efficiency.

24

1 In addition, combined cycle units can start up and shut down quickly. The
2 modern gas turbines used in these units are engineered for rapid cycling,
3 meaning the plant can come online or go offline quickly as grid conditions
4 change. Advanced class combined cycle units can play a critical role in
5 facilitating the integration of renewable energy sources into the grid. Their
6 flexibility in dispatching power and their ability to quickly ramp up or down
7 facilitates integration of renewable generation.

8
9 Finally, combined cycle units like SJRPP Unit 3 are often designed to operate
10 on multiple types of fuel. This fuel flexibility allows operators to choose the
11 most cost-effective available fuel source, further enhancing the unit's
12 dispatchability and reliability.

13

14 **Q. What are the reliability benefits of combined cycle generation?**

15 A. Combined cycle generation has numerous reliability benefits. For example,
16 combined cycle systems have significantly higher thermal efficiency compared
17 to conventional combined cycle plants. More efficient operation generally
18 leads to fewer cycles of starting and stopping, which reduces stress on
19 equipment and extends operational life. The use of advanced materials and
20 enhanced turbine technology also leads to operation for longer periods without
21 unexpected failures. This reduces the frequency and cost of repairs and
22 improves plant availability. Finally, many of the systems within a combined
23 cycle unit are integrated with advanced monitoring and diagnostic tools that
24 help predict when maintenance is required. This predictive maintenance model

1 can minimize unplanned outages and ensure the plant operates reliably without
2 unexpected shutdowns.

3

4 **Q. Please describe how JEA monitors the operational performance and**
5 **reliability of its power plants.**

6 A. JEA uses various industry standard techniques to measure and report on the
7 performance and reliability of its power plants. Daily, monthly, and annual
8 reports are created, as appropriate, describing the thermal efficiency (heat rate),
9 availability factor, forced outage rate, capacity factor, energy generated, and
10 fuel consumed for JEA's generating fleet. We also monitor first start
11 reliability and start-up and shut-down times. Real-time data from sensors on
12 critical components (such as turbines, compressors, and generators) is collected
13 to predict and prevent failures. This includes parameters like vibration,
14 temperature, pressure, and fuel quality. We also monitor emission levels to
15 ensure compliance with environmental regulations.

16

17 **NORTHSIDE GENERATING STATION UNIT 3**

18 **Q. Please elaborate on why updates would be necessary to extend the life of**
19 **JEA's existing NGS Unit 3.**

20 A. NGS Unit 3 has been in operation for nearly 50 years and would require
21 substantial capital renewal and replacement (R&R) investment to operate
22 reliably through 2050. JEA engaged Black & Veatch to perform an assessment
23 of the R&R cost to extend the life of NGS Unit 3 in 2024. That assessment,
24 which is conservative, estimated R&R costs at \$477.8 million. In addition,

1 those R&R costs would trigger additional emissions requirements
2 conservatively estimated at \$356.2 million, bringing the total cost to extend the
3 life of NGS Unit 3 to over \$834.1 million.

4
5 **Q. You previously stated that SJRPP Unit 3 would allow for more efficient**
6 **use of natural gas and reduce emissions. Could you please explain.**

7 A. SJRPP Unit 3 will use 37% less gas per MWh than NGS Unit 3. This
8 increased efficiency will result in a reduction of 0.22 tons of carbon dioxide
9 (CO₂) per MWh.

10
11 **COST AND SCHEDULE**

12 **Q. Have you estimated the in-service cost for SJRPP Unit 3?**

13 A. Yes. JEA started with capital cost estimates that were formed around major
14 equipment estimates received from manufacturers and equipment and
15 procurement contract (EPC) estimates developed by Black & Veatch. The
16 capital cost estimates have been significantly refined to increase accuracy as
17 JEA contracted for power island equipment and began solicitation of EPC
18 services.

19
20 **Q. What is the estimated in-service capital cost for SJRPP Unit 3?**

21 A. The estimated in-service capital cost of SJRPP Unit 3 is \$1.57 billion. Exhibit
22 No. ____ (JS-6) is a summary table providing a breakdown of capital costs.

23
24 **Q. In your opinion, is this estimated in-service capital cost reflective of**
25 **current market conditions?**

1 A. Yes. In my opinion and based largely on information provided through
2 extensive discussions with EPC representatives, the estimated in-service
3 capital cost is reflective of current market conditions.
4

5 **Q. What is the anticipated schedule for SJRPP Unit 3?**

6 A. JEA anticipates completing permitting activities in 2027, beginning
7 construction in 2028, and achieving commercial operation in 2031.
8

9 **Q In your opinion, will JEA be able to meet a January 2031 commercial**
10 **operation date?**

11 A. Yes.
12

13 **ADVERSE CONSEQUENCES OF DENIAL**

14 **Q. Would denial of SJRPP Unit 3 have adverse consequences for JEA's**
15 **system?**

16 A. Yes. Denial of SJRPP Unit 3 would prevent JEA from moving forward with a
17 resource that represents a 37% more efficient use of natural gas and reduces
18 system emissions. It would also prevent JEA and its customers from
19 experiencing the numerous benefits outlined above relative to flexibility and
20 dispatch control.
21

22 **Q. Does this complete your testimony?**

23 A. Yes.

PROFESSIONAL SUMMARY

Accomplished power generation executive with more than 30 years of progressive experience in utility operations, power plant management, infrastructure reliability, compliance, and large-scale energy project leadership. Proven track record of advancing from plant operations roles into executive leadership through deep operational expertise, strategic planning, and team development. Extensive experience overseeing multi-site generation operations, asset management, outage execution, environmental services, predictive maintenance, and capital improvement initiatives. Recognized for driving operational excellence, safety performance, regulatory compliance, and continuous improvement across complex generation facilities.

CORE COMPETENCIES

- Power Generation Operations
- Utility Leadership & Strategy
- Conventional and Combined Cycle & Combustion Turbine Operations
- Capital Projects & Infrastructure
- Reliability Engineering
- Outage & Asset Management
- Regulatory Compliance & CIP Oversight
- Environmental Services
- Predictive Maintenance Programs
- Budgeting & Financial Planning
- Project Management
- Procurement & Contract Management
- Operational Excellence & KPI Management
- Safety Leadership & Risk Management
- Team Development & Coaching
- Stakeholder & Community Relations

PROFESSIONAL EXPERIENCE

JEA — Director of Electric Production

Present

Jacksonville, Florida

Lead operational, technical, and strategic initiatives supporting critical electric generation infrastructure for one of Florida's largest public utilities. Responsible for oversight of compliance, physical security, environmental services, asset reliability, outage execution, project delivery, and operational performance across generation facilities.

Key Responsibilities & Achievements

Direct critical infrastructure protection and compliance programs, ensuring adherence to local, state, and federal regulations.

Lead teams responsible for reliability engineering, outage and asset management, predictive maintenance, project management, support services, and operational controls.

Oversee all phases of energy generation projects including design, engineering, procurement, scheduling, construction, and execution.

Manage operational performance metrics, costs, schedules, and productivity to ensure safe, efficient, and reliable plant operations.

Partner with procurement teams on proposal development, evaluations, contract negotiations, and award recommendations.

Serve as key contributor to capital budget planning and long-term financial forecasting.

Ensure successful execution of capital improvement initiatives while maintaining safety and customer satisfaction goals.

Develop and mentor leadership and operational staff through performance management, coaching, and professional development initiatives.

Maintain strong working relationships with government agencies, contractors, developers, customers, and community stakeholders.

Champion continuous improvement initiatives and enterprise safety objectives.

Leadership Progression at JEA

2025 – Project Director, St. Johns River Power Plant Combined Cycle Project: Serving as Director of a major large-scale combined cycle generation project.

2021 – Director of Electric Production, Combustion Turbine Facilities: Oversee operations, maintenance and reliability engineering efforts across multiple combustion turbine generation sites.

2019 – Director of Electric Production, Northside Generating Station: Oversaw operations, maintenance and reliability engineering efforts of a 1500 MW facility

2014 – 2019 – Senior Manager of Operations

2014 – Operations Manager, Combustion Turbine Operations

2011 – 2014 – Operations Manager

2004 – 2011 – Operator, Northside Generating Station

PG&E National Energy Group – Cedar Bay Generating Facility

Jan 1994 – Jan 2004

Jacksonville, Florida

Developed foundational expertise in power plant operations and generation systems while progressing through operational responsibilities within a major energy production environment; supported daily power generation operations and plant performance initiatives; gained extensive hands-on operational knowledge in utility-scale generation facilities; built strong technical and operational expertise that supported advancement into senior leadership roles.

LEADERSHIP & PROFESSIONAL AFFILIATIONS

Electric Power Research Institute — Generation Council Member

Plant Scherer Managing Board — JEA Representative

ADDITIONAL INFORMATION

More than three decades of progressive utility and power generation experience.

Advanced from plant operations roles to executive leadership through demonstrated operational excellence and strategic leadership.

Extensive experience leading multi-site generation operations, large capital projects, and high-performing technical teams.

Strong commitment to safety, compliance, reliability, and workforce development.

SJRPP Unit 3 Layout



SJRPP Unit 3 Location



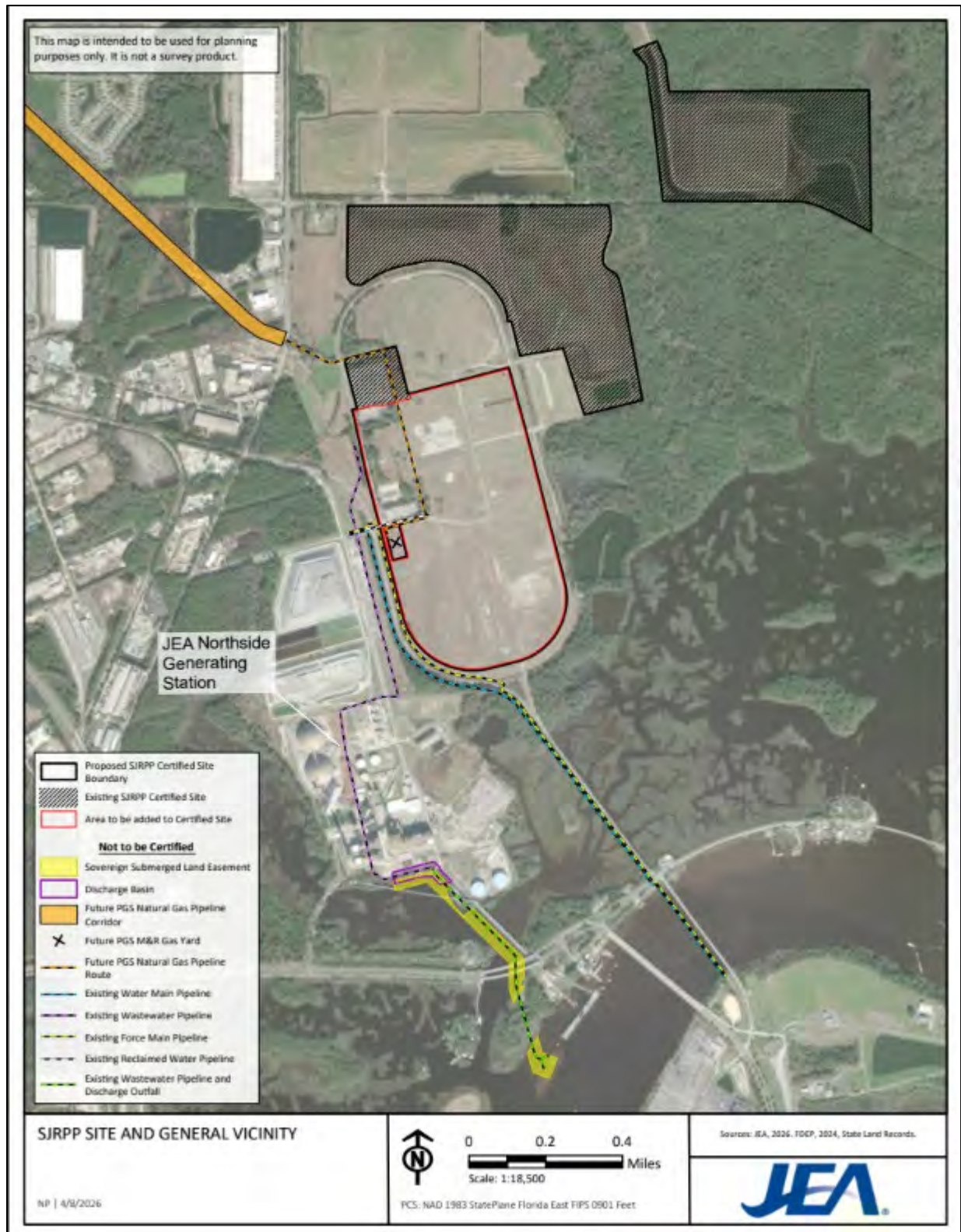
SJRPP Unit 3 Conceptual Renderings



This photograph simulation is intended as a visual representation and should not be used for construction purposes. Scale, materials and placement are subject to change.



SJRPP Unit 3 Site and Vicinity



SJRPP Unit 3 Capital Cost Estimate	
Equipment and Interconnection, Development, and EPC Contract	\$ 1,277,246,973
Other Owner's Costs and Contingency	\$ 119,929,576
Interest During Construction	\$ 136,925,018
Insurance	\$ 35,898,433
TOTAL	\$ 1,570,000,000

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

MELINDA FISCHER

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF MELINDA FISCHER

DOCKET NO. _____-EC

June 4, 2026

Q. Please state your name and address.

A. My name is Melinda Fischer. My business address is 225 N. Pearl Street,
Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as the Director of Electric Systems Planning.

Q. What are your responsibilities in your current position.

A. I am responsible for the long-term planning and strategy of JEA’s generation, transmission, and distribution systems to ensure reliable, cost-effective, and regulatory-compliant electric service. This includes leading JEA’s integrated resource planning (IRP) process and capital improvement planning, overseeing long-term demand and energy forecasting, directing development and solicitation of new energy resources, managing capital and operation and maintenance (O&M) budgets that support system growth and reliability. I also oversee long-term fuel supply strategy, planning, and agreements to

1 support JEA's future generation resources as well as transmission
2 interconnection on JEA's system.

3

4 **Q. Please describe your educational background and professional experience.**

5 A. I am a Florida Professional Engineer with a Bachelor of Science in Electrical
6 Engineering. I have been employed by JEA since 2008, beginning my career
7 as an Electric Generation Resource Planning Engineer responsible for
8 developing JEA's long-term demand and energy forecasts. In 2017, I became
9 the Segment Manager in Customer Solutions and Market Development,
10 leading the strategic development and implementation of electrification,
11 demand-side management (DSM), battery storage and low-income
12 conservation programs. In 2020, I became the Manager of Resource Planning,
13 responsible for developing JEA's IRP, ten-year site plan (TYSP), long-term
14 forecasts, and supply-side resource plans and strategies. I have been the
15 Director of Electric Systems Planning since 2024.

16

17 **Q. Is Exhibit No. __ (MF-1) a true and correct copy of your resume?**

18 A. Yes.

19

20 **Q. What is the purpose of your testimony in this proceeding?**

21 A. The purpose of my testimony is to address five areas. First, I will describe
22 JEA's load forecasting methodology and present and discuss the results of
23 JEA's most recent long-term load forecast. Second, I will describe JEA's
24 power supply planning process and need assessment. Third, I will describe
25 JEA's solicitations for power island equipment and market alternatives, and

1 JEA's assessment of market alternatives, including the request for proposals
2 (RFP) process that was used to identify the available alternatives. Fourth, I
3 will describe the steps JEA has taken to ensure an adequate fuel supply for the
4 facility. Finally, I will describe the interconnection to the transmission system,
5 consideration of transmission interconnection costs in the evaluation of
6 alternatives, and the transmission upgrades needed for St. John's River Power
7 Park Unit 3 (SJRPP Unit 3).

8
9 **Q. Are you sponsoring any exhibits in the case?**

10 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
11 under my supervision and are attached to this pre-filed testimony:

- 12 • Exhibit No. __ (MF-1) – Resume of Melinda Fischer
- 13 • Exhibit No. __ (MF-2) – 2026 Ten Year Site Plan
- 14 • Exhibit No. __ (MF-3) – Table of Large Load Assumptions
- 15 • Exhibit No. __ (MF-4) – Market Test RFP
- 16 • Exhibit No. __ (MF-5) – Tables of Economic Results and Scoring
- 17 • Exhibit No. __ (MF-6) – Table of Qualitative Evaluation
- 18 • Exhibit No. __ (MF-7) – Total RFP Scores

19 I am also sponsoring Sections 1.4, 1.5, 3.2, 3.3.2, 3.3.2.1, 3.3.2.2, 3.3.2.3,
20 3.3.2.4, 3.3.2.5, 3.3.2.6, 3.3.2.7, 3.4, 4.1.9, 5.1, 5.2, 5.2.1, 5.2.2, 5.2.3, 5.2.3.1,
21 5.2.3.2, 5.2.4, 5.2.5, 5.2.6, 5.2.7, 5.3, 5.4, 5.5, 6.0, 6.1, 6.2, 6.2.1, 6.2.3, and 6.3
22 (including all tables and figures referenced in these sections) of JEA's Need
23 Study, which is identified as Exhibit No. ____ (JB-2).

LOAD FORECAST

Q. Please describe JEA's existing service territory.

A. JEA's service territory covers most of Duval County and portions of Clay and St. Johns Counties – approximately 900 square miles – and serves approximately 537,000 customers.

Q. Please describe JEA's existing customer base.

A. JEA's customer mix is approximately 89% residential and 11% commercial/industrial. Residential customers represent approximately 47% of total energy sales, with commercial/industrial representing 52% and approximately 1% street/highway lighting. The commercial sector is primarily made up of service businesses, retail stores, offices, schools, hospitals, and transportation-related companies, while the industrial sector mainly includes manufacturing plants, military bases, utilities, and industries tied to natural resources.

Q. Please describe JEA's recent energy sales and peak demands.

A. In 2025, JEAs net energy for load (NEL) was approximately 13,479 GWh. Peak winter demand was approximately 2,913 MW.

Q. Please summarize JEA's load forecast methodology.

A. JEA utilizes generally accepted methodology currently employed in the electric utility industry to develop forecasts of peak demand and NEL based on customer growth, historical energy sales, and weather data,

1 **Q. How does JEA forecast customer growth?**

2 A. JEA forecasts customer growth utilizing Moody's Analytics (Moody's)
3 economic parameters for Duval County. JEA also considers the current
4 number of JEA customers and their class as well as on-the-ground knowledge
5 of projects in design and construction within the service territory. JEA's
6 current forecast is reflected in the 2026 TYSP filed with the Commission is in
7 Exhibit No. ____ (MF-2).

8
9 **Q. How does JEA forecast energy sales?**

10 A. JEA begins by weather normalizing energy for each customer class using
11 National Oceanic and Atmospheric Administration (NOAA) Weather Station -
12 Jacksonville International Airport for historical weather data. JEA develops the
13 normal weather using 10-year historical average heating/cooling degree days
14 and maximum/minimum temperatures. Normal months, with heating/cooling
15 degree days and maximum/minimum temperatures that are closest to the
16 averages, are then selected. JEA then develops residential, commercial, and
17 industrial energy forecasts using multiple regression analysis of weather
18 normalized historical energy sales, along with historical energy sales,
19 demographic information, Moody's information, and JEA account information.
20 The first 7 years of the forecast also incorporates confirmed new development
21 projects and their expected demand, as well as increased consumption from
22 existing industrial customers due to expansion. JEA also develops a lighting
23 energy forecast based on historical actual energy and number of luminaries
24 using a regression analysis of the number of JEA customers.

25

1 **Q. How does JEA forecast peak demand?**

2 A. JEA normalizes historical seasonal peaks using historical maximum and
3 minimum temperatures, using 25°F as the normal temperature for the winter
4 peak and 97°F for the normal summer peak demands. JEA develops the
5 seasonal peak forecasts using normalized historical and forecasted residential,
6 commercial, and industrial energy for winter/summer peak months, and the
7 average load factor based on historical peaks and net energy for winter/summer
8 peak months.

9

10 **Q. Does JEA's forecast incorporate DSM and interruptible load?**

11 A. Yes. JEA's forecast includes both interruptible load and DSM based on
12 current programs, JEA's approved goals under the Florida Energy Efficiency
13 Conservation Act (FEECA), and JEA's actual demand and energy reductions
14 associated with approved DSM programs and other conservation efforts.
15 JEA's forecast also incorporates 120 MW of interruptible peak load for the
16 summer through 2027, increasing to 124 MW beginning in the summer of
17 2027, and 107 MW for the winter through 2027, increasing to 111 MW in the
18 winter of 2028. The forecast also includes 4.34 MW of summer peak DSM
19 reductions and 4.29 MW of winter peak DSM reductions in 2026, increasing
20 thereafter.

21

22 **Q. Please describe JEA's current customer, energy, and seasonal demand**
23 **forecast.**

24 A. From 2026 through 2035, JEA projects the total number of residential
25 customers to grow at an average annual rate of 1.1%, with commercial

customer growth expected to average 1.3% annually, and industrial customer growth to average 1.4% annually. Average residential usage per customer is expected to increase at an average annual rate of 0.3% from 2026-2035, decrease at an average annual rate of 1.0% for commercial customers, and increase at an average annual rate of 1.6% for industrial customers.

Overall, NEL is projected to grow at an average annual rate of 1.4% from 13,386 GWh in 2026 to 15,219 GWh in 2035. Similarly, winter net firm demand is expected to grow at an average annual rate of 1.4% from 2,901 MW to 3,275 MW.

Q. How does JEA's current load forecast compare to its forecasts in recent years.

A. JEA's current load forecast reflects an upward shift compared to forecasts in recent years, driven by both higher-than-expected actual system peaks and significant new load commitments. In 2025, an unusually hot summer produced a new all-time net summer peak of 2,849 MW, surpassing the previous record of 2,827 MW set in 2007, after more than fifteen years during which summer peaks consistently remained below the 2007 level. This new peak signals the combined effects of stronger weather impacts and sustained customer growth. Historical winter peaks, which have traditionally exceeded summer levels, reached over 3,150 MW in 2010 before declining and stabilizing in the 2,400–2,700 MW range for much of the following decade. These peaks have recently rebounded, with actual winter peaks in 2025 and

1 2026 returning to levels above 2,900 MW. These trends support the need for a
2 higher long-term load trajectory than previously forecast.

3

4 Accordingly, the current forecast is higher than the 2025 forecast due to
5 increased organic growth, 347 MW of new large-load projects now in design
6 or construction, and higher overall system demand. Compared to the 2025
7 forecast, the updated outlook projects a 6.8 percent increase in summer peak
8 demand by 2031 and a 5.6 percent increase in winter peak demand by 2031.
9 Together, the record-setting 2025 summer peak, the rebound in winter peak
10 levels, and the newly committed load additions indicate that JEA's system is
11 entering a period of structurally higher demand, necessitating upward revisions
12 to its forward forecasts.

13

14 **Q. Please describe the larger load implications known or assumed in the**
15 **forecast.**

16 A. The load forecast reflects several significant known large developments
17 expected between 2026 and 2032, including major EV charging installations,
18 multiple industrial expansions such as data centers (<10 MW), manufacturing,
19 and large warehouse facilities, as well as new commercial, mixed-use, and
20 residential projects. As reflected on Exhibit No. ____ MF-3, collectively, these
21 developments represent approximately 347 MW of net new load and more than
22 1,070 GWh of annual energy, with industrial additions accounting for roughly
23 half of the total impact. Residential, commercial, and mixed-use projects are
24 incorporated through their respective organic growth trends, while industrial

1 and other large customer projects are applied as discrete additions. A 3.57%
2 net-to-sales loss factor is noted for planning purposes.

3

4 **Q. Is JEA's current load forecast reasonable for planning purposes?**

5 A. Yes. The load forecast is based on generally accepted methodology currently
6 utilized within the electric utility industry.

7

8 **JEA'S POWER SUPPLY PLANNING PROCESS AND PROJECTED NEED**

9 **Q. Please describe JEA's power supply planning process.**

10 A. JEA utilizes its IRP process to evaluate and inform long-term resource
11 decisions. JEA has used the IRP process for decades, with the most recent IRP
12 conducted in 2023 and another planned in the 2026/2027 timeframe. The
13 assumptions and information utilized in the IRPs are continually updated to
14 fully inform JEA leadership decisions relative to resource additions.

15

16 **Q. What reliability criteria does JEA use to determine the need for additional
17 resources?**

18 A. JEA's system capacity is planned with a targeted 15 percent generation reserve
19 margin above forecasted firm customers coincident one-hour peak demand for
20 both winter and summer seasons.

21

22 **Q. What is JEA's future capacity need?**

23 A. Based on JEA's current forecasted winter demand, JEA has a need for 72 MW
24 in 2031, increasing to 222 MW in 2033 and 802 MW in 2035.

25

- 1 **Q. What are the primary drivers of this need?**
- 2 A. The primary drivers of this need are projected load growth (winter and summer
- 3 peak demand as well as annual energy requirements) and the planned
- 4 retirement of Northside Generating Station Unit 3 (NGS Unit 3) in 2035.
- 5
- 6 **Q. How does JEA plan to meet that need?**
- 7 A. The most cost-effective and system-beneficial way for JEA to meet its need for
- 8 capacity is the construction and operation of SJRPP Unit 3.
- 9
- 10 **Q. What process did JEA utilize to evaluate and ultimately select SJRPP Unit**
- 11 **3 to meet its need?**
- 12 A. JEA’s Board selected moving forward with construction and operation of
- 13 SJRPP Unit 3 based on the results of the IRP process that began over three
- 14 years ago and has been continually refined with updated information and
- 15 assumptions. That process included extensive economic analyses of self-build
- 16 options, including renewable generation and energy storage; a power island
- 17 equipment request for proposals to solicit proposals from major equipment
- 18 manufacturers; a market test RFP to test the market for generating alternatives;
- 19 and additional comprehensive economic modeling utilizing updated and
- 20 refined information to verify that the addition of SJRPP Unit 3 in the 2031
- 21 timeframe remained the least cost alternative to meet its need for power. The
- 22 details of the economic modeling are discussed in Mr. Bradley Kushner’s pre-
- 23 filed direct testimony.
- 24
- 25 **Q. How did JEA select the technology for SJRPP Unit 3?**

1 A. The IRP process considered various generating resource options, including
2 multiple configurations of solar photovoltaic (PV) and energy storage options,
3 numerous different natural gas options (including a range of sizes, types,
4 simple and combined cycle configurations, and conversion of existing simple
5 cycle units to combined cycle configuration), biomass technologies, and
6 nuclear. Other renewable resources such as hydropower, geothermal, and
7 wind, were not considered as they are not feasible within JEA's service
8 territory. Given regulatory limitations, JEA did not evaluate the addition of
9 any new coal-fired generating units.

10

11 JEA engaged Black & Veatch to perform a detailed assessment, including
12 economic modeling and consideration of system benefits and risks, of various
13 technologies at multiple locations on the JEA system. Through this assessment
14 conducted as part of the IRP process, JEA selected an advanced class 1 x 1
15 combined cycle generating unit.

16

17 **Q. Did JEA consider the addition of renewable technologies and energy**
18 **storage as alternatives to SJRPP Unit 3?**

19 A. Yes. JEA currently receives or has contracts in place for a total of
20 approximately 329 MW from renewable energy sources, including 15 MW
21 from landfill gas-to-energy via a power purchase agreement (PPA) and 314
22 MW from solar via PPAs and 50 MW battery energy storage. JEA co-fires
23 more than 10% biomass in NGS Units 1 and 2 and has also installed solar PV
24 systems at various customer sites in the community. As Ms. Jody Brooks
25 discusses in her pre-filed direct testimony, we have faced challenges with

expanding renewable technologies within our service territory and regulatory changes have impacted their affordability. Nonetheless, additional renewable technologies and energy storage as alternatives to SJRPP Unit 3 were considered in our evaluation of generating alternatives.

POWER ISLAND EQUIPMENT AND MARKET TEST SOLICITATIONS

Q. Please describe the power island equipment solicitation.

A. JEA released a RFP for the power island equipment (PIE) – the combustion turbine, steam turbine, and heat recovery steam generator – on September 10, 2024. Two manufacturers submitted bids in response to the RFP. Based on those bids, JEA selected GE Vernova as the vendor for the combined cycle technology for SJRPP Unit 3.

Q. Please describe JEA’s philosophy regarding power supply RFPs.

A. JEA pursues least-cost resource solutions that provide the needed capacity (maintaining the 15% planning reserve margin), energy and ancillary services, and are firmly deliverable to JEA’s system, while providing the required efficiency, flexibility (controllability), and reliability. As part of this process, JEA may utilize power supply RFPs.

Q. What experience does JEA have with power supply RFPs?

A. JEA has conducted short-term (1-5 year) and long-term (5-30 year) RFPs as system needs arise, resulting in a range of PPAs documented in JEA’s TYSPs. Our experience includes coal-based PPAs (historical), natural-gas generation PPAs, small- and large-scale utility solar PPAs, and solar-plus-storage PPAs.

1 JEA also leverages The Energy Authority (TEA), our affiliated energy market
2 services company, to facilitate market solicitations and acquire short-term
3 seasonal market purchases.
4

5 **Q. Please describe the Market Test RFP JEA issued on October 2, 2024.**

6 A. On October 2, 2024, JEA issued a Solicitation for Long-Term Dispatchable
7 Capacity and Energy Resources (Market Test RFP) to solicit proposals for
8 firm, dispatchable net capacity and associated energy of 525-700 MW to help
9 meet projected customer peak demands and energy requirements in December
10 2030. JEA required that the proposals be for commercially proven technology,
11 firm delivery of energy, dynamic scheduling, and JEA dispatchability. JEA
12 was receptive to Build-Transfer Agreement (BTA) transactions, Asset
13 Purchase Agreements (APA), PPAs, and joint ownership. The Market Test
14 RFP solicitation documents were clear that JEA intended to evaluate a self-
15 build advanced-class combined cycle technology resource as part of the
16 solicitation evaluation and included the key attributes of that facility.
17

18 The Market Test RFP solicitation documents laid out the requirements for each
19 bidder and the necessary requirements for a proposal submittal including
20 financial viability, credit worthiness, and experience. JEA also asked for a
21 project development schedule and plans and schedules for transmission
22 interconnection. A copy of the final Market Test RFP documents, as amended
23 during the course of the solicitation, is included in Exhibit No. __ (MF-4).
24

- 1 **Q. Please describe the process by which the Market Test RFP was issued to**
2 **potential market counterparties.**
- 3 A. JEA issued the Market Test RFP through its standard procurement channels
4 and supplemented that outreach with targeted industry communications to
5 maximize competition. This included posting on JEA’s procurement webpage,
6 posting on Zycus, publishing a newspaper notice in the Daily Record,
7 inclusion in POWERnews newsletters, a Utility Dive email blast, and sending
8 the RFP to entities identified as potential candidates and/or that requested
9 receipt.
10
- 11 **Q. Please describe the proposal submittal process.**
- 12 A. JEA issued the Market Test RFP on October 2, 2024. All interested
13 respondents were required to attend a pre-response meeting held on December
14 2, 2024, to be eligible to submit a response. Four potential respondents
15 attended the pre-response meeting. All questions were required to be
16 submitted in writing electronically on the Zycus Supplier Network platform at
17 least 5 business days prior to the bid opening date. JEA responded to twelve
18 questions from respondents during this period. Responses were due on April
19 21, 2025.
20
- 21 **Q. Please describe the proposals JEA received in response to the Market Test**
22 **RFP.**
- 23 A. JEA received four proposals from one party, Florida Power & Light Company
24 (FPL), in response to the Market Test RFP. Three of the four proposals
25 included PPAs ranging from 20 to 30-year terms to be served by FPL’s

1 existing generation resources. The fourth included a PPA coupled with a
2 commitment to enter development of a future jointly owned and unspecified
3 electrical generating plant with JEA.
4

5 **Q. Was it a surprise to JEA that only one respondent submitted a proposal?**

6 A. No, it was not a surprise. FPL is only one transmission wheel away from JEA,
7 while other utilities would require two or more transmission wheels to deliver
8 power. Each additional wheel increases both cost and complexity, which
9 would be reflected in a higher PPA price. Given these inherent
10 transmission-related cost differentials, other utilities were unlikely to be
11 competitive with FPL, so a limited number of proposals was anticipated.
12

13 **Q. Please describe the process JEA utilized to evaluate proposals.**

14 A. JEA utilized a five-step process to evaluate proposals: (1) assessment of
15 compliance with minimum requirements; (2) follow-up clarifying questions;
16 (3) quantitative/economic evaluation; (4) qualitative evaluation; and (5)
17 resource selection.
18

19 **Q. Please describe the compliance with minimum requirements phase of the**
20 **evaluation process.**

21 A. JEA first reviewed the responses to assess if they complied with the RFP
22 minimum requirements. The three PPA-only proposals were classified as
23 conforming, despite concerns relative to compliance with certain terms of the
24 RFP, including the requirement for liquid fuel back-up, dispatch, and a detailed
25 transmission plan. The fourth proposal, which included a PPA and the

1 commitment to enter into a development agreement for a future unspecified
2 generating facility, lacked the detail, including pricing and operational
3 information, necessary to evaluate.
4

5 **Q. Did JEA ask any clarifying questions?**

6 A. Yes. To assist in assessing whether the proposals met the minimum
7 requirements and to ensure accuracy for modeling and evaluation purposes,
8 JEA sent two rounds of questions seeking additional information and
9 exchanged a number of questions and answers.
10

11 **Q. What occurred during the quantitative phase of the evaluation?**

12 A. We retained Black & Veatch to perform an economic evaluation of the three
13 compliant PPA proposals and the self-build resource. The economic
14 evaluation assessed the cumulative present worth cost (CPWC) to the JEA
15 system over a 35-year time horizon. The proposed resources, including the
16 self-build resource, were evaluated using the PLEXOS® capacity expansion
17 and production cost model, from which the CPWC of resource plans including
18 each of the proposed resources were determined. This modeling is addressed
19 in the pre-filed testimony of Mr. Kushner. The proposals and self-build
20 resource were then assigned quantitative scores out of a maximum of 70. The
21 results of the economic evaluation are shown on Exhibit No. ____ (MF-5).
22

23 **Q. What occurred during the qualitative evaluation phase?**

24 A. Three JEA evaluators were responsible for scoring each resource from a
25 qualitative perspective based on the risk assessment scorecard included with

1 the Market Test RFP documents. The self-build resource was scored as the
2 highest-ranking resource option from a qualitative or risk assessment
3 perspective by all three evaluators. In particular, the self-build resource scored
4 higher than the PPAs in the system reliability (flexibility), transmission status,
5 and project status and technical design categories. The results of the
6 qualitative evaluation scoring are shown on Exhibit No. ____ (MF-6).

7
8 **Q. Which resource scored highest overall considering both quantitative and**
9 **qualitative evaluations?**

10 A. As shown on Exhibit No. ____ (MF-7), the self-build resource was scored as the
11 highest-ranking resource option overall.

12

13 **Q. Did JEA engage an independent evaluator to oversee the Market Test**
14 **RFP?**

15 A. Yes. Recognizing that the proposals would essentially be competing with
16 JEA's own self-build resource, we engaged an independent evaluator,
17 Merrimack Energy (Merrimack), to ensure that the solicitation process was
18 undertaken in a fair and unbiased manner. As discussed in Mr. Oliver's pre-
19 filed direct testimony, Merrimack concurred with the fairness of the Market
20 Test RFP process and the results of the evaluation.

21

22 **Q. What resource did JEA select following the quantitative and qualitative**
23 **evaluation?**

24 A. Based on the results of the Market Test RFP evaluation, including the
25 comparative economic analysis conducted by Black & Veatch, JEA staff

recommended, and JEA's Board approved moving forward with, SJRPP Unit 3 on August 26, 2025.

UPDATED ANALYSIS

Q. Since Board approval in August 2025, what steps has JEA taken to move forward with the development of SJRPP Unit 3?

A. As directed by the Board, JEA moved forward with executing a reservation agreement on September 29, 2025, and PIE contract on December 19, 2025, with GE Vernova. JEA issued a RFP for Engineer, Procure, Construct (EPC) contractor on April 7, 2026. We have also moved forward with obtaining a zoning exception from the City of Jacksonville (October 21, 2025) and preparation of the application for certification under Florida's Electrical Power Plant Siting Act (PPSA) and this Petition for Determination of Need.

In support of this proceeding in particular, we engaged Black & Veatch to perform updated economic modeling to confirm SJRPP Unit 3 as the most cost-effective alternative utilizing the most up-to-date and refined information available relative to our 2026 TYSP load forecasts and fuel price projections; updates to existing and planned future resources; updated cost and performance estimates; and updated assumptions relative to the US Environmental Protection Agency's Greenhouse Gas standards for electric generating units. This updated modeling confirmed, under the base case and all sensitivities, that SJRPP Unit 3 is the most cost-effective alternative to meet JEA's need in the 2031 timeframe. Again, Mr. Kushner addresses the results and assumptions underlying this modeling in his pre-filed direct testimony.

1

2 **Q. Does JEA’s reservation PIE contract commit JEA to moving forward with**
3 **purchasing equipment if JEA is unable to obtain necessary approvals?**

4 A. No. Although the reservation agreement and PIE contract required
5 non-refundable payments to secure manufacturing queue position, JEA is not
6 required to proceed with purchasing the equipment if we do not receive a
7 Determination of Need from the Public Service Commission (Commission). If
8 the Commission does not grant the required approval, JEA would not be able
9 to move forward with construction and operation of SJRPP Unit 3. In that
10 circumstance, JEA could terminate or, more likely, assign the PIE contract to a
11 third party.

12

13 **TRANSMISSION SYSTEM INTERCONNECTION AND BENEFITS**

14 **Q. Please describe JEA’s existing transmission system.**

15 A. JEA has 744 circuit miles of bulk power transmission facilities operating at
16 four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV. The 500 kV
17 transmission lines are jointly owned by JEA and FPL, completing the path
18 from FPL’s Duval substation (located in the westerly portion of JEA’s system)
19 to the north to interconnect with the Georgia Integrated Transmission System.
20 The 230 kV and 138 kV transmission lines provide a backbone around JEA’s
21 service territory, with one river crossing in the north and no river crossings in
22 the south, leaving an open loop. Four 230 kV transmission lines exit the
23 SJRPP site. The 69 kV transmission system extends from JEA’s core urban
24 load center to the northwest, northeast, east, and southwest; covering the area
25 not covered by the 230 kV and 138 kV transmission lines.

1

2 **Q. Is JEA a net importer or exporter of power?**

3 A. Prior to the decommissioning of SJRPP Units 1 & 2 in 2018 and 2019, JEA
4 was a net exporter of power and JEA's transmission system was developed
5 accordingly – to export power out of JEA's service territory. Following the
6 decommissioning, and with JEA's load growth in recent years, JEA is now a
7 net power importer. During normal system operations, the swing of over 900
8 MW in power interchange (from 428 MW net export in 2017 to over 500 MW
9 net import currently) does not create significant issues. However, when JEA
10 makes additional power purchases for economic reasons or unplanned events
11 (e.g., unscheduled generation outages), the JEA transmission system undergoes
12 significant stress due to the increased import of power through the tie lines.
13 Operation planning becomes more challenging during these times, especially
14 when transmission contingencies are considered as required by North
15 American Electric Reliability Corporation (NERC) Reliability Standards.

16

17 **Q. Has JEA considered the impact of SJRPP Unit 3 on its transmission**
18 **system?**

19 A. Yes. JEA performed a System Impact Study to assess the impact of SJRPP
20 Unit 3 on JEA's transmission system. More specifically, JEA incorporated
21 SJRPP Unit 3 into Florida's regional transmission model and simulated a range
22 of contingency events to ensure compliance with the applicable NERC
23 Reliability Standards. JEA further assessed the transmission system in the
24 Florida Reliability Coordinating Council (FRCC) region in accordance with
25 FRCC standards. The results demonstrated no adverse impact to the JEA

1 system or any transmission system in the FRCC region. There results were
2 shared with FRCC members, recommended by two FRCC subcommittees, and
3 accepted by the FRCC Planning Committee.

4

5 **Q. Will SJRPP Unit 3 require any off-site transmission system upgrades?**

6 A. No. There are currently four 230 kV transmission lines exiting the existing
7 substation on the SJRPP property. SJRPP Unit 3 will interconnect to this
8 existing substation via two new 230 kV generator tie (gen-tie) lines at an
9 estimated cost of \$7.7 million. Beyond the gen-ties, no additional transmission
10 upgrades will be needed to integrate the new unit into JEA's system.

11

12 **Q. How will SJRPP Unit 3 affect JEA's transmission system?**

13 A. The addition of the proposed SJRPP Unit 3 will help reduce stress on JEA's
14 system. First, SJRPP Unit 3 will result in lower overall system loss as the load
15 and generation are much closer and the system is better balanced. This will
16 also increase reliability under normal and probable contingency conditions and
17 help insulate JEA from outside transmission contingencies that could
18 negatively impact power import. Conversely, if JEA does not construct new
19 generation within its geographic footprint to serve its need for additional
20 power, the construction of additional transmission lines would be required to
21 reliably import power under both planned normal and contingency
22 transmission events. JEA has estimated these transmission line costs at
23 approximately \$100 million. Apart from the pure economic cost, the
24 necessary, extensive transmission upgrades are simply not feasible in a
25 timeframe to meet JEA's capacity need in 2031.

1

2 **Q. Did JEA consider the projected costs and impacts of the transmission**
3 **improvements that would be required when comparing generating**
4 **alternatives?**

5 A. Yes. As part of the Market Test RFP process, JEA requested that respondents
6 include detailed plans and specifications for transmission interconnection and
7 any required transmission upgrades. As a result, JEA's evaluation included
8 estimated costs of upgrades to JEA's transmission system. JEA included
9 estimated costs of approximately \$100 million in the evaluation of PPAs
10 requiring power import. The cost of transmission upgrades for SJRPP Unit 3
11 were included in the evaluation of the self-build resource.

12

13 **NORTHSIDE GENERATING STATION UNIT 3**

14 **Q. Please describe NGS Unit 3.**

15 A. NGS Units 3 is a natural gas and fuel oil facility that has been in service since
16 1977.

17

18 **Q. Are there limitations to continuing to operate NGS Unit 3 long-term?**

19 A. Yes. As addressed in the pre-filed direct testimony of Mr. James Stancin,
20 continued operation of NGS Unit 3 would require substantial renewal and
21 replacement (R&R) investment, along with additional emissions reduction
22 technology with a conservatively estimated total cost of over \$834.1 million.

23

24 **Q. In addition to this substantial economic cost, are there other practical**
25 **limitations to performing this life extension and reconstruction of NGS 3?**

1 A. Yes. Performing this R&R would require taking NGS Unit 3 out of service for
2 at least twelve months. Without NGS Unit 3 available, JEA would be required
3 to import power to meet customer demand. JEA's transmission system cannot
4 support additional power import at this level. As such, reconstruction of NGS
5 Unit 3 is simply infeasible.

6

7 **Q. What are JEA's current plans relative to NGS Unit 3?**

8 A. At this time, JEA anticipates placing NGS Unit 3 in limited use as a fuel-oil
9 only back-up resource operated at or below an 8% capacity factor upon
10 commercial operation of SJRPP Unit 3. JEA anticipates fully retiring NGS
11 Unit 3 in 2035.

12

13 Although JEA previously anticipated retiring NGS Unit 3 upon commercial
14 operation of SJRPP Unit 3, updated load forecasts show that doing so would
15 create capacity shortfalls earlier than previously expected. While the 678 MW
16 capacity of SJRPP Unit 3 is sufficient to meet the projected 2031 winter and
17 summer reserve-margin needs without NGS Unit 3, the system begins to
18 experience deficits starting in 2032 (Summer) and 2033 (Winter) if NGS Unit
19 3 is retired at that time. Given the unprecedented load growth and resulting
20 reserve-margin deficits, maintaining NGS Unit 3 as a limited, fuel-oil-only
21 backup resource provides essential reliability support and helps JEA continue
22 meeting its 15% reserve margin requirement until its anticipated full retirement
23 in 2035.

24

1 **Q. Has JEA evaluated expectations regarding operation of NGS Unit 3 after**
2 **SJRPP Unit 3 is placed in-service?**

3 A. Yes. As part of the economic modeling, Black & Veatch evaluated expected
4 operation of NGS Unit 3 on JEA's system with SJRPP Unit 3 also in
5 operation. That modeling indicated that, upon commercial operation of SJRPP
6 Unit 3, NGS Unit 3 would be expected to operate at a capacity factor of less
7 than 1%.

8

9 **FUEL SUPPLY AND DIVERSITY**

10 **Q. What are the fuel requirements for SJRPP Unit 3?**

11 A. SJRPP Unit 3 will primarily utilize pipeline-quality natural gas as its main fuel
12 source. At peak operation, including duct firing, SJRPP Unit 3 will require
13 approximately 104,200 million British thermal units (MMBtu) of natural gas
14 per day. In the unexpected event natural gas is unavailable, ultra-low sulfur
15 diesel (ULSD) fuel oil will be utilized. When ULSD is used as fuel, the
16 consumption rate will be approximately 93,500 MMBtu per day.

17

18 **Q. What steps has JEA taken to ensure that natural gas will be available for**
19 **SJRPP Unit 3?**

20 A. Natural gas will be supplied to SJRPP Unit 3 via a new approximately 25-mile
21 lateral from the JEA Brandy Branch Generating Station area to a new Metering
22 & Regulation (M&R) yard on the SJRPP property. The pipeline lateral and
23 gas yard will be permitted, constructed, owned, operated, and maintained by
24 Peoples Gas System (PGS). Gas will be supplied to the region via existing

1 interstate gas pipelines owned and operated by Florida Gas Transmission
2 (FGT) and Southern Natural Gas (SNG). JEA already owns firm interstate
3 transmission on each of these lines.

4
5 Existing natural gas capacity supply for NGS Unit 3 will be diverted to SJRPP
6 to support operation of SJRPP Unit 3, with a relatively small amount of
7 additional firm natural gas capacity (18,000 MMBtu/day) needed to support
8 full operation of SJRPP Unit 3 on gas during winter peak. JEA has entered
9 negotiations with PGS for local natural gas transportation service and for the
10 required incremental firm interstate natural gas transmission for SJRPP Unit 3.
11 PGS has completed a route study and determined that the route is feasible.
12 Development of a Precedent Agreement leading to a contract is underway. In
13 the unlikely event natural gas is not available, ULSD adequate in quantity to
14 supply SJRPP Unit 3 for five days at full load will be stored onsite. The dual-
15 fuel capability of SJRPP Unit 3 will enhance fuel diversity and reliability of
16 fuel supply to the project, which will support increased plant availability
17 during operation.

18
19 **Q. What purchase arrangements will be used to procure the necessary gas?**

20 **A.** JEA will procure the natural gas required for the new unit under its established
21 arrangements, which include direct purchases under existing agreements and
22 purchases facilitated through PGS and/or TEA. These procurement activities
23 are governed by JEA's approved policies and procedures for gas hedging and
24 the management of firm gas supply, which collectively provide risk
25 management, reliability, and cost control.

1

2 **Q. In your opinion, will there be an adequate and reliable supply of natural**
3 **gas for SJRPP Unit 3?**

4 A. Yes. SJRPP Unit 3 is a combined cycle resource whose output will displace all
5 gas-fired energy currently produced by NGS Unit 3, which operates under
6 proven, reliable gas supply and firm transportation arrangements. Because
7 combined cycle generation requires materially less natural gas per MWh than
8 the gas-fired steam unit at NGS Unit 3, SJRPP Unit 3 is expected to use
9 approximately 37% less gas for equivalent energy. This efficiency reduces
10 JEA's aggregate gas requirement to serve the same load. Accordingly, the
11 existing supply and firm transportation arrangements are adequate and reliable
12 for SJRPP Unit 3, and JEA can serve incremental demand growth with
13 minimal additional gas supply or transportation.

14

15 **Q. How will SJRPP Unit 3 impact JEA's fuel diversity?**

16 A. JEA maintains a diversified portfolio to support reliability and stable costs for
17 customers. SJRPP Unit 3 is a combined cycle unit with dual-fuel capability
18 (natural gas or fuel oil), which enhances fuel supply resilience and overall
19 efficiency. By capturing turbine exhaust heat in a steam cycle, the unit uses
20 approximately 37% less natural gas per MWh than NGS Unit 3, reducing gas
21 consumption per unit of electricity produced. While natural gas will remain a
22 substantial share of JEA's portfolio, SJRPP Unit 3 will moderate exposure to
23 gas price volatility and support a more balanced and reliable generation mix.

24

25 **Q. Will SJRPP Unit 3 increase JEA's reliance on natural gas?**

1 A. No. SJRPP Unit 3's combined cycle design and dual-fuel capability reduce
2 natural gas use per MWh and add supply flexibility. SJRPP Unit 3 will not
3 increase reliance on gas, but rather improve efficiency, moderate fuel price
4 sensitivity, and support reliability.

5

6 **ADVERSE CONSEQUENCES OF DENIAL**

7 **Q. Would denial of SJRPP Unit 3 have adverse consequences on the**
8 **reliability of JEA's system?**

9 A. Yes. JEA's system drops below its 15% planning reserve margin starting in
10 2028 and, absent SJRPP Unit 3, remains constrained into the early 2030s. The
11 2031 in-service date for SJRPP Unit 3 is integral to covering the reserve
12 margin and meeting reliability criteria. Short-term PPAs can mitigate the
13 interim need, but sustained reliance on imports is limited by current
14 transmission interface constraints and available firm deliverability. Denial of
15 SJRPP Unit 3 would therefore extend the reserve margin deficiency and
16 increase reliability risk unless replaced by firm, deliverable capacity additions.

17

18 Denial of SJRPP Unit 3 would also result in higher operating costs to the
19 customer due to the need to meet increasing demand with generating
20 equipment that is significantly less efficient.

21

22 **Q. Would denial of SJRPP Unit 3 have adverse consequences to JEA's fuel**
23 **diversity?**

24 A. Yes. Denial would prevent the addition of a combined cycle, dual-fuel
25 resource that enhances fuel supply resilience and portfolio diversity. SJRPP

1 Unit 3 can operate on fuel-oil when natural gas is unavailable, providing
2 continuity of service during gas-supply disruptions, and its combined cycle
3 efficiency uses approximately 37% less natural gas per MWh than NGS Unit 3,
4 reducing gas consumption per unit of electricity produced. Without SJRPP
5 Unit 3, JEA would remain more dependent on less efficient gas generation and
6 purchased power, with less dispatch flexibility during peak conditions or
7 outages.

8
9 **Q. Would denial of SJRPP Unit 3 have other adverse consequences on the**
10 **reliability of JEA's system?**

11 A. Yes. Denial of SJRPP Unit 3 would cause significant additional stress on
12 JEA's transmission system. As discussed previously, the addition of SJRPP
13 Unit 3 will help reduce existing stress on JEA's transmission line system by
14 making the power available closer to the load within the system, increasing
15 reliability, and insulating JEA from transmission contingencies outside of
16 JEA's system. The current configuration of JEA's transmission system cannot
17 support importing the amount of power needed to maintain JEA's target
18 reserve margin without substantial and costly transmission upgrades that are
19 not feasible in a timeframe to meet JEA's need in 2031.

20
21 **Q. Does this complete your testimony?**

22 A. Yes.

Melinda Fischer, PE

Summary

Electric utility planning professional with 17+ years of experience in long-term resource planning, integrated system planning, demand and energy forecasting, renewable and storage procurement, and regulatory compliance. Experienced in leading integrated resource planning and TYSP processes, directing supply-side resource evaluations, and ensuring compliance with FPSC, FRCC, SERC, and NERC requirement.

Professional Experience

JEA

Director, Electric Systems Planning

Jul. '24 – Present

Responsible for the long-term planning and strategy of JEA's generation, transmission, and distribution systems to ensure reliable, cost-effective, and regulatory-compliant electric service. Lead managers and engineers across resource planning, transmission planning, distribution planning, system analysis, and grid modernization.

- Directed JEA's Post-IRP process through the Power Island RFP and Market Test RFP, culminating in a comprehensive evaluation and Board presentation that secured unanimous Board approval for JEA's self-build combined cycle project in August 2025.
- Lead the development of JEA's Integrated Resource Plan (IRP) and Integrated System Plan (ISP) covering generation, transmission, distribution, and grid modernization.
- Lead the annual Ten Year Site Plan (TYSP) filing and direct teams to ensure compliance with FPSC, FRCC, SERC, and NERC regulatory requirements.
- Oversee long-term demand and energy forecasting, spatial forecasting, electric master plans, and capital improvement planning.
- Direct the development and solicitation of renewable energy resources and demand response programs, including utility-scale solar and battery storage procurement strategies.
- Lead and develop multidisciplinary teams; establish talent development, knowledge management, and succession planning practices to support workforce readiness.
- Manage Capital and O&M budgets and support development of JEA's annual and long-term capital plans.

Manager, Resource Planning

Apr. '20 – Jul. '24

Led development of JEA's Integrated Resource Plan (IRP), Ten Year Site Plan (TYSP), long-term demand and energy forecasts, and supply-side resource plans and strategies. Ensured JEA's compliance with state and federal legislation, environmental regulations, and NERC reliability standards.

- Led cross-functional teams in developing JEA's IRP, identifying long-term supply-side resource options to meet forecasted electricity demand and state reserve margin requirements while maintaining system reliability. Led stakeholder engagement to communicate IRP results and incorporate feedback.
- Led development of JEA's Near-Term Action Plan for the combined cycle project, outlining the schedule, critical milestones, and capital cost framework.

Melinda Fischer, PE

- Led the solicitation process for utility-scale solar and battery storage resources on JEA-owned properties; conducted analysis that determined the Purchase Power Agreement to be more cost-effective than the Build Transfer Agreement option.
- Supported JEA's COO and senior executives in developing JEA's 2030 Clean Energy Goals based on IRP results; successfully secured Board of Directors approval.
- Supported JEA's C-suite and senior leadership in developing Board materials and presentations on IRP, TYSP, long-term resource plans, and demand and energy forecasts.

Segment Manager, Customer Solutions & Market Development

Nov. '17 – Apr. '20

Led strategic development and implementation of Electrification, Demand-Side Management (DSM), Battery Storage, and Low-Income Conservation programs. Oversaw JEA's Florida Energy Efficiency and Conservation Act (FEECA) process and Water DSM strategy in the Integrated Water Resource Plan (IWRP).

- Developed JEA's electrification expansion plan projected to generate approximately 2,000 GWh of electricity sales and \$120 million in revenue over the 10-year lifetime of electrified equipment.
- Oversaw implementation of the \$3 million electrification program, generating over 370 GWh of new electricity sales and approximately \$23 million in revenue over three years.
- Oversaw development of FEECA conservation goals filings and technical potential studies on DSM opportunities across all customer classes. Supported FEECA goal proceedings before the FPSC with written testimony, data request responses, and regulatory interrogatory responses.
- Led development of Water DSM strategy in the IWRP, including water demand forecasts and cost-effective water DSM measures.
- Developed and implemented JEA's battery incentive program for residential and small commercial rooftop solar customers.

Electric Generation Resource Planning Engineer

Mar. '08 – Nov. '17

Responsible for developing JEA's long-term demand and energy forecasts, the annual TYSP and supplemental FPSC responses, and production modeling analysis for TYSP, IRP, and various supply-side optimization and resource expansion scenarios.

- Revamped JEA's energy forecast methodology, reducing forecast error from over 7% to approximately 1%, through the development of a weather normalization model, customer class-level forecasting, and a new typical load profile reflecting energy efficiency trends.
- Pioneered a Plug-in Electric Vehicles (PEV) load forecast methodology using DMV registration data, which was shared at a load forecasting forum and subsequently adopted by multiple utilities.
- Led the universal solar solicitation process to expand JEA's universal solar portfolio; successfully secured eight utility-scale solar Purchase Power Agreements totaling 31.5 MW.
- Authored a whitepaper on the determination of solar firm capacity during JEA's system peak demand, establishing that fixed-mounted systems provide 20% of nameplate capacity and single-axis tracking systems provide at least 34% of nameplate capacity at system peak.

Melinda Fischer, PE

Leadership & Committee Positions

St. Johns River Power Park Pension Committee

Appointed Committee Member by JEA's Managing Director/CEO

Sep. '20 – Present

Florida Reliability Coordinating Council

Chairman, Load Forecast Working Group

Jul. '14 – Apr. '16

Education

2007 BS. Electrical Engineering - Summa Cum Laude, **University of North Florida**

2005 AA. Degree - High Honors, **Florida Community College at Jacksonville**

2000 Diploma in Electronics, Computer and Communication Engineering, **Nanyang Polytechnic**

Engineering Licensure

Florida Board of Professional Engineers

- Professional Engineer - License Number: 80316



TEN-YEAR SITE PLAN

April 2026

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JEA 2026 Ten-Year Site Plan

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List of Abbreviations

Type of Generation Units

CA	Combined Cycle – Steam Turbine Portion, Waste Heat Boiler (only)
CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
GT	Combustion Turbine
FC	Fluidized Bed Combustion
IC	Internal Combustion
ST	Steam Turbine, Boiler, Non-Nuclear

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Under construction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
DFO	No. 2 Fuel Oil
RFO	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke
WH	Waste Heat

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Introduction

The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities, the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.

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

1. Description of Existing Facilities and Resources

1.1 Power Supply System Description

1.1.1 JEA Electric System

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 510,000 customers.

1.1.1.1 Existing Generation System

The JEA Electric System consists of generating facilities located on four plant sites within the City of Jacksonville (The City); the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), the Brandy Branch Generating Station (Brandy Branch), and the Greenland Energy Center (GEC).

Collectively, these plants consist of two multifuel-fired (coal/petroleum coke/natural gas/biomass) Circulating Fluidized Bed (CFB) steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2, and Brandy Branch GT1); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle system that comprises two gas-fired combustion turbine-generator units and one combined cycle heat recovery steam generator unit (Brandy Branch CT2 and CT3, and Brandy Branch steam Unit 4). Details of the existing facilities are displayed in Schedule 1.

JEA 2026 Ten-Year Site Plan**Description of Existing Facilities & Resources****Schedule 1: Existing Generating Facilities**

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

Notes:

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

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

1.1.2 Power Purchases

1.1.2.1 FPL Natural Gas Power Purchase Agreement

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

1.1.3 Clean Energy Power Purchases

1.1.3.1 Trail Ridge Landfill Power Purchase Agreement

In 2006, JEA entered into a PPA with Trail Ridge Energy, LLC (TRE) to purchase energy and environmental attributes from up to 9 net MW of firm renewable generation capacity utilizing the methane gas from The City's Trail Ridge landfill located in western Duval County (the "Phase One Purchase"). The facility was one of the largest landfill gas-to-energy facilities in the Southeast when it began commercial operation on December 6th, 2008.

JEA and TRE executed an amendment to this PPA on March 9th, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began in February 2015. The contract for Trail Ridge Phase One and Phase Two will expire in December 2026.

1.1.3.2 Jacksonville Solar Power Purchase Agreement

In May 2009, JEA entered into a PPA with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW_{AC} of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100-acre site. The Jacksonville Solar plant began commercial operation at full designed capacity on September 30th, 2010. The facility was acquired by Rev Renewables, LLC, an LS Power company, on June 15th, 2021. The contract for Jax Solar will expire in September 2040.

1.1.3.3 Small Utility-Scale Solar Power Purchase Agreements

JEA issued two Solar Photovoltaic (PV) Request for Proposals (RFP), one in December 2014 and another in April 2015, and awarded a total of 31.5 MW_{AC} of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements

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were finalized for a total of 27 MW_{AC}. The last of these seven projects was completed in December 2019.

The following are the seven PPAs that are installed within JEA's service territory of which JEA pays for the energy and has rights to the associated environmental attributes produced by the facilities:

- Northwest Jacksonville Solar Partners, LLC: 7 MW_{AC} / 25-year PPA. The NW Jax facility consists of 28,000 single-axis tracking photovoltaic panels on a vendor-leased site, owned by OnSite Partners, LLC (formerly American Electric Power OnSite Partners). The facility became operational on May 30th, 2017.
- Old Plank Road Solar Farm, LLC: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility consists of 12,800 single-axis tracking photovoltaic panels on a vendor-leased 40-acre site, owned by Southeast Solar Farm Fund, a partnership between PEC Velo & Cox Communications. The site attained commercial operation on October 13th, 2017.
- C2 Starratt Solar, LLC: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility, on a vendor-leased site, is now owned by EDPR DR (acquired C2 Starratt Solar, LLC) and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20th, 2017.
- Inman Solar Holdings 2, LLC: 2 MW_{AC} / 20-year PPA. The Simmons Solar facility, on a vendor-leased site, is owned by Inman Solar Holdings 2, LLC and was constructed by Inman Solar, Inc. The site attained commercial operation on January 17th, 2018.
- Hecate Energy Blair Road, LLC: 4 MW_{AC} / 20-year PPA. The Blair Road facility, on a vendor-leased site, is owned by Hecate Energy Blair Road, LLC and was constructed by Hecate Energy, LLC. The site attained commercial operation on January 23rd, 2018.
- JAX Solar Developers, a wholly-owned subsidiary of Mirasol Fafco Solar, Inc.: 1 MW_{AC} / 20-year PPA. The Old Kings Rd Solar facility is owned by EcoPower Development, LLC and was constructed by Mirasol Fafco Solar, Inc. The site attained commercial operation on October 15th, 2018.
- Imeson Solar, LLC: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The primary function of the BESS is to smooth the solar generation. It is the first utility scale solar plus storage facility interconnected to the JEA grid. The site, labeled SunPort Solar, was constructed by 174 Power Global and attained commercial operation on December 4th, 2019.

1.1.3.4 FPL Solar Power Purchase Agreements

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

1.1.3.5 Planned Solar Power Purchase Agreements

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

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

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

1.1.3.6 MEAG Nuclear Power Purchase Agreement

In June 2008, JEA entered into a 20-year PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4. These two new nuclear units

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

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

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

1.1.4 Cogeneration

Cogeneration facilities help meet the energy needs of JEA’s system on an as-available, non-firm basis. Since these facilities are considered energy only resources, they are not forecasted to contribute towards firm capacity to JEA’s reserve margin requirements.

Currently, JEA has contracts with one customer-owned qualifying facility (QF), as defined in the Public Utilities Regulatory Policy Act of 1978. Anheuser Busch has a total installed summer rated capacity of 8 MW and winter rated capacity of 9 MW.

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Contract		Start Date	End Date	MW_{AC}	Product Type
LES Trail Ridge	I	12/06/08	12/31/26	9	Annual
	II	02/01/14	12/31/26	6	Annual
MEAG Plant Vogtle	Unit 3	07/31/2023	07/31/2043	103	Annual
	Unit 4	04/29/2024	04/29/2044	103	Annual
FPL PPA		01/01/22	01/01/42	200	Annual
FPL Solar PPA		04/01/23	04/01/28	150	Annual
Jacksonville Solar		09/30/10	09/30/40	12	Annual
NW Jacksonville Solar		05/30/17	05/30/42	7	Annual
Old Plank Road Solar		10/13/17	10/13/37	3	Annual
Starratt Solar		12/20/17	12/20/37	5	Annual
Simmons Road Solar		01/17/18	01/17/38	2	Annual
Blair Site Solar		01/23/18	01/23/38	4	Annual
Old Kings Solar		10/15/18	10/15/38	1	Annual
SunPort Solar		12/04/19	12/04/39	5	Annual
Forest Trail Solar PPA		12/31/26	12/31/61	50	Annual
Miller Solar PPA		12/31/26	12/31/61	74.9	Annual

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

JEA's transmission system consists of 744 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL, completing the path from FPL's Duval substation (located in the westerly portion of JEA's system) to the north to interconnect with the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Duke Energy Florida and the City of Tallahassee each own transmission interconnections with the Georgia ITS. JEA's import capacity is 1,228 MW over the 500 kV transmission lines through Duval substation.

The 230 kV and 138 kV transmission systems provide a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest; covering the area not covered by the 230 kV and 138 kV transmission backbone.

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

JEA has a 138 kV tie with Beaches Energy Services at JEA's Neptune substation. JEA owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to JEA's Nassau substation. This substation serves as a 138 kV transmission interconnection point for FPL's O'Neil substation and Florida Public Utilities Company's (FPU) Step Down substation. JEA's ownership of these two 138 kV interconnections end at the first transmission structure outside of the Nassau substation.

1.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. In compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, JEA continually assesses the needs and options for increasing the capability of the transmission system.

Since the FRCC region became the FL-Peninsula sub-region of SERC in July 2019, JEA has been following additional guidelines and actively participating in the SERC activities towards the reliability and security of the bulk electric system.

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JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process. FRCC's published Regional Transmission Planning Process facilitates coordinated planning by all transmission providers, owners, and stakeholders within the FRCC Region.

FRCC's members include investor-owned utilities, municipal utilities, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Technical Subcommittee in conjunction with the FRCC Staff to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 for: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

1.2.3 Transmission Service Requirements

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

1.2.4 Distribution

The JEA distribution system operates at three primary voltage levels (4.16 kV, 13.2 kV, and 26.4 kV). The 4.16 kV system serves a permanently defined area in older residential neighborhoods. The 13 kV system serves a permanently defined area in the urban downtown area. These two distribution systems serve any new customers that are located within their defined areas, but there are no plans to expand these two systems beyond their present boundaries. The 26.4 kV system serves approximately 94 percent of JEA's distribution load, including 57 percent of the 4.16 kV substations. The current standard is to expand the 26.4 kV system as required to serve all new distribution loads, except smaller loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,607 miles of distribution circuits of which approximately 59.2 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

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

1.3.2 Renewable Energy

1.3.2.1 JEA Distributed Energy

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

In 2009 JEA established a residential net metering program to encourage the use of customer-sited solar PV systems. The policy has since evolved with several revisions:

- 2009: Tier 1 & 2 Net Metering policy launched to include all customer-owned renewable generation systems less than or equal to 100 kW
- 2011: Tier 3 Net Metering policy established for customer-owned renewable generation systems greater than 100 kW up to 2 MW
- 2014: Policy updated to define Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as 100 kW – 2 MW. This policy was capped at 10 MW for total generation. All customer-owned generation in excess of 2 MW would be addressed in JEA's Distributed Generation (DG) Policy.
- 2017: In October, the JEA Board of Directors approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1st, the comprehensive DG Policy qualified renewable and non-renewable customer-owned generation systems under the following ranges:
 - o DG-1 – Less than or equal to 2 MW
 - o DG-2D – Over 2 MW with distribution level connection

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- o DG-2T – Over 2 MW with transmission level connection

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

1.3.2.2 Renewable Energy Credits (REC)

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

1.3.2.3 SolarSmart and SolarMax

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

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

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1.3.2.4 Landfill Gas and Biogas

JEA owned three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997 and was fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, methane gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and the remaining Girvin landfill generation facilities were decommissioned in 2014.

JEA's Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using three anaerobic digesters and one sludge dryer to produce a pelletized fertilizer product. The methane gas from the digesters can be used as a fuel for the sludge dryer and the digester heaters.

1.3.2.4 Biomass

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

In 2011, JEA co-fired biomass in Northside units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. They produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. At that time, JEA received bids from local sources to provide biomass for potential continued use.

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

1.3.3 Clean Energy Research Efforts

1.3.3.1 Collaboration with University of North Florida

JEA's clean energy research efforts have focused on the development of clean energy technologies through a partnership with the University of North Florida's (UNF) Engineering Department. In the past, UNF and JEA have worked on the following projects:

- JEA and UNF worked to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF evaluated the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway, where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15-acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3-year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.
- JEA, Miller Electric, and UNF have joined forces under the DOE-backed "Emerge" initiative to train the next generation of energy professionals. Through hands-on training, industry certifications, and expert mentorship, EMERGE equips participants with cutting-edge skills in renewable energy and microgrid technologies. This program is shaping the "Technician of the Future," preparing a workforce capable of building and maintaining resilient, sustainable energy systems to meet the demands of an evolving grid.
- On November 28th, 2023, JEA and UNF commemorated the grand opening of the JEA Sustainable Solutions Lab, a collaboration with UNF's College of Computing, Engineering and Construction, that allows undergraduate and graduate students to research clean energy technologies. JEA has committed to contributing \$100,000 per year, for five years, for a total contribution of \$500,000. The lab will serve as a hub for research to develop sustainable solutions for JEA and a variety of industries.

1.3.3.2 Energy Storage

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

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

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Clean Energy

continue to evaluate the integration of additional storage resources as future studies are conducted.

2. Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peak demands, net energy for load (NEL), interruptible customer demand, demand-side management (DSM), and the impact of plug-in electric vehicles (PEVs). JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

JEA uses National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for the weather parameters, Moody's Analytics (Moody) economic parameters for Duval County, JEA's Data Warehouse to determine the total number of accounts and CBRE Jacksonville for total commercial inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Calendar Year 2026 baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the most recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections.

2.1 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. JEA updates its normal weather every 5 years or more frequently, if needed.

The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy sales, total population, number of households, median household income and total housing starts from Moody's Analytics, JEA's total residential accounts and JEA's residential electric rate.

The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy sales, total commercial employment and gross domestic product from Moody's Analytics, JEA's total commercial accounts, and commercial inventory square footage from the CBRE Jacksonville Office Figures Q3 2025 Report.

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

The lighting energy forecast was developed using the historical actual energy and number of luminaries. JEA developed the forecasted number of luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries.

JEA's forecasted Compounding Annual Growth Rate (CAGR) for net energy for load during the TYSP period is 1.43 percent.

2.2 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 25°F as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA develops the seasonal peak forecasts using normalized historical and forecasted residential, commercial, and industrial energy for winter/summer peak months, and the average load factor based on historical peaks and net energy for winter/summer peak months. JEA's forecasted CAGR for net firm peak demand during the TYSP period is 1.32 percent for summer and 1.36 percent for winter.

2.3 Demand-Side Management (DSM)

2.3.1 Interruptible Load

JEA currently offers Interruptible and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to interruption of their full nominated load during times of system emergencies, including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 120 MW of interruptible peak load for the summer and 107 MW for the winter which remain constant throughout the study period. For 2026, the interruptible load represents 3.7 percent of the forecasted total peak demand in the summer and 3.4 percent of the forecasted total peak demand in the winter.

2.3.2 Demand-Side Management Programs

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

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption**

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

Table 2: DSM Portfolio – Energy Efficiency Programs

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

Table 3: DSM Programs

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

2.4 Customer-Sited Renewables

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

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

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

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

2.5 Plug-in Electric Vehicles Peak Demand and Energy

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

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

The usable battery capacity (85 percent of battery capacity) per vehicle was determined based on the current plug-in electric vehicle models in Duval County. The average usable battery capacity per PEV is calculated using the average usable battery capacity of each vehicle brand and then assumes the annual growth of usable battery capacity per PEV by using the historical 5-year average of 0.001 kWh. Similarly, the peak capacity is determined based on the average

on-board charging rate of each vehicle brand and the forecasted peak capacity per PEV grows by 0.01 kW per year.

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

JEA forecasts Average Annual Growth Rate (AAGR) for PEVs summer and winter coincidental peak demand of 41.18 percent and 35.39 percent, respectively, and total energy of 34.86 percent during the TYSP period.

2.6 Electrification

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

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

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

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Class**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Calendar Year	Rural and Residential			Commercial			Industrial		
	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,692	202	13,322,934
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,777	202	13,717,349
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,765	196	14,081,384
2019	5,479	420,831	13,019	4,060	53,153	76,389	2,733	194	14,085,278
2020	5,679	429,575	13,220	3,886	53,701	72,363	2,698	196	13,759,522
2021	5,551	438,470	12,660	3,848	54,374	70,767	2,612	196	13,348,772
2022	5,723	447,308	12,795	4,005	55,082	72,717	2,708	199	13,641,119
2023	5,658	458,764	12,334	3,968	55,946	70,922	2,614	199	13,151,607
2024	6,022	470,564	12,797	4,104	56,724	72,359	2,691	203	13,254,576
2025	6,081	479,288	12,641	4,194	57,376	73,096	2,648	198	13,389,674
2026	6,075	485,840	12,504	4,022	58,168	69,136	2,754	211	13,054,071
2027	6,174	492,159	12,546	4,027	58,935	68,335	3,033	215	14,107,857
2028	6,262	498,274	12,568	4,035	59,713	67,577	3,285	219	15,001,436
2029	6,351	504,171	12,597	4,046	60,504	66,865	3,357	222	15,120,763
2030	6,441	509,869	12,633	4,057	61,311	66,176	3,427	224	15,297,656
2031	6,531	515,323	12,674	4,070	62,134	65,498	3,475	227	15,307,034
2032	6,620	520,487	12,719	4,082	62,969	64,829	3,526	230	15,329,031
2033	6,707	525,330	12,766	4,097	63,813	64,196	3,544	233	15,209,228
2034	6,794	529,885	12,822	4,109	64,666	63,548	3,567	236	15,114,511
2035	6,892	534,234	12,901	4,122	65,527	62,901	3,600	240	14,999,094

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Class**

Calendar Year	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	Street & Highway Lighting	Other Sales to Ultimate Customers	Total Sales to Ultimate Customers	Sales for Resale	Utility Use & Losses	Net Energy for Load	Other Customers	Total Number of Customers
	GWH	GWH	GWH	GWH	GWH	GWH	(Avg. Number)	
2016	77	0	12,184	490	263	12,937	2	450,033
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,793
2019	57	0	12,328	58	411	12,797	0	474,178
2020	56	0	12,319	7	414	12,740	0	483,471
2021	55	0	12,066	25	449	12,540	0	493,039
2022	55	0	12,491	30	408	12,930	0	502,588
2023	55	0	12,295	63	376	12,733	0	514,909
2024	56	0	12,873	60	321	13,255	0	527,491
2025	57	0	12,980	69	431	13,479	0	536,862
2026	57	0	12,908	0	479	13,386	0	544,219
2027	58	0	13,293	0	493	13,785	0	551,309
2028	58	0	13,641	0	506	14,147	0	558,206
2029	59	0	13,812	0	512	14,324	0	564,897
2030	59	0	13,984	0	518	14,503	0	571,404
2031	59	0	14,135	0	524	14,659	0	577,684
2032	60	0	14,288	0	530	14,817	0	583,686
2033	60	0	14,407	0	534	14,941	0	589,376
2034	61	0	14,531	0	539	15,070	0	594,787
2035	61	0	14,675	0	544	15,219	0	600,001

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 3.1: History and Forecast of Summer Peak Demand**

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

Note: All projections coincident at time of peak.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 3.2: History and Forecast of Winter Peak Demand**

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

Note: All projections coincident at time of peak.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 3.3: History and Forecast of Annual Net Energy for Load**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Energy for Load (GWH)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy for Load (GWH)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2016	12,937	0	0	0	0	0	0	12,937
2017	12,672	0	0	0	0	0	0	12,672
2018	12,813	0	0	0	0	0	0	12,813
2019	12,797	0	0	0	0	0	0	12,797
2020	12,740	0	0	0	0	0	0	12,740
2021	12,540	0	0	0	0	0	0	12,540
2022	12,930	0	0	0	0	0	0	12,930
2023	12,733	0	0	0	0	0	0	12,733
2024	13,255	0	0	0	0	0	0	13,255
2025	13,479	0	0	0	0	0	0	13,479
2026	13,409	0	0	0	0	12	11	13,386
2027	13,831	0	0	0	0	24	22	13,785
2028	14,216	0	0	0	0	36	33	14,147
2029	14,416	0	0	0	0	48	44	14,324
2030	14,618	0	0	0	0	60	55	14,503
2031	14,797	0	0	0	0	72	66	14,659
2032	14,978	0	0	0	0	84	77	14,817
2033	15,125	0	0	0	0	96	88	14,941
2034	15,277	0	0	0	0	108	99	15,070
2035	15,449	0	0	0	0	120	110	15,219

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 4:** Previous Year Actual and Two-Year Forecast of Firm Peak Demand and Net Energy for Load by Month

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

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 5: Fuel Requirements**

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

Note:

(a) Coal includes Northside Coal and Petroleum Coke.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 6.1: Energy Sources (GWh)**

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

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

(c) May not add due to rounding.

JEA 2026 Ten-Year Site Plan**Forecast of Electric Power & Energy Consumption****Schedule 6.2: Energy Sources (Percent)**

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

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

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

JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources as well as other planning assumptions.

3.1.1 Resource Planning

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

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

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

during periods of extreme weather and/or when other generating units or purchased power are unavailable.

3.1.2 JEA Planning Reserve Policy

JEA's Planning Reserve Policy establishes a guideline that provides an allowance to meet the 15 percent reserve margin with up to 3 percent of the forecasted firm peak demand in any season from purchases acquired in the operating horizon. If up to 3 percent of firm peak demand in any season is needed, The Energy Authority (TEA), JEA's affiliated energy market services company, will acquire short-term seasonal market purchases for JEA no later than the season prior to the need. TEA actively trades energy with a large number of counterparties throughout the United States and is generally able to acquire capacity and energy from other market participants when any of its members require additional resources.

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

3.2 Resource Plan

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

JEA 2026 Ten-Year Site Plan**Forecast of Facilities Requirements****Table 4a: Resource Needs after Committed Units - Summer**

Summer										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2026	2,782	601	0	0	3,383	2,772	611	22%	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	522	18%
2028	2,782	703	-206	0	3,279	2,930	349	12%	349	12%
2029	2,782	753	-129	0	3,406	2,961	445	15%	445	15%
2030	2,782	753	-103	0	3,432	2,997	435	15%	435	15%
2031	2,782	753	-103	0	3,432	3,023	409	14%	409	14%
2032	2,782	753	-103	0	3,432	3,052	380	12%	380	12%
2033	2,782	553	0	0	3,335	3,070	265	9%	265	9%
2034	2,782	553	0	0	3,335	3,092	243	8%	243	8%
2035	2,258	553	0	0	2,811	3,119	-308	-10%	-308	-10%

Table 4b: Resource Needs after Committed Units - Winter

Winter										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2025/26	2,952	471	0	0	3,423	2,901	522	18%	522	18%
2026/27	2,952	661	-206	0	3,407	2,988	419	14%	419	14%
2027/28	2,952	686	-206	0	3,432	3,077	355	12%	355	12%
2028/29	2,952	736	-129	0	3,559	3,114	445	14%	445	14%
2029/30	2,952	736	-103	0	3,585	3,147	438	14%	438	14%
2030/31	2,952	736	-103	0	3,585	3,180	405	13%	405	13%
2031/32	2,952	736	-103	0	3,585	3,210	375	12%	375	12%
2032/33	2,952	536	0	0	3,488	3,226	262	8%	262	8%
2033/34	2,952	536	0	0	3,488	3,252	236	7%	236	7%
2034/35	2,428	536	0	0	2,964	3,275	-311	-9%	-311	-9%

Table 5: Resource Plan

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

Notes:

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

JEA 2026 Ten-Year Site Plan**Forecast of Facilities Requirements****Schedule 7.1: Summer Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak**

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2026	2,782	601	0	0	3,383	2,772	611	22%	0	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	0	522	18%
2028	2,782	794	-206	0	3,370	2,930	440	15%	0	440	15%
2029	2,782	753	-129	0	3,406	2,961	445	15%	0	445	15%
2030	2,782	768	-103	0	3,447	2,997	450	15%	0	450	15%
2031	3,364	753	-103	0	4,014	3,023	990	33%	0	990	33%
2032	3,364	753	-103	0	4,014	3,052	962	32%	0	962	32%
2033	3,364	553	0	0	3,917	3,070	846	28%	0	846	28%
2034	3,364	553	0	0	3,917	3,092	824	27%	0	824	27%
2035	3,588	553	0	0	4,141	3,119	1,022	33%	0	1,022	33%

JEA 2026 Ten-Year Site Plan**Forecast of Facilities Requirements****Schedule 7.2: Winter Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak**

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

JEA 2026 Ten-Year Site Plan**Forecast of Facilities Requirements****Schedule 8: Planned and Prospective Generating Facility Additions and Changes**

Planned and Prospective Generating Facility and Purchased Power Additions and Changes														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transport		Construction Start Date	Commercial/ In-Service or Change Date	Expected Retirement/ Shutdown Date	Gen Max Nameplate	Net Capability		Status
				Primary	Alternate	Primary	Alternate					Summer	Winter	
				kW	MW	MW								
Northside	Unit 3	Jacksonville, FL	ST	NG	RFO	PL	WA	N/A	Jul-1977	Jan-2035	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Jan-2028	Jan-2031	Unknown	706,000	582	678	P
Advanced-Class 1x0 CT I	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P
Advanced-Class 1x0 CT II	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P

JEA 2026 Ten-Year Site Plan**Forecast of Facilities Requirements****Schedule 9: Status Report and Specifications of Proposed Generating Facilities**

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

Notes:

(1) Data is confidential.

JEA 2026 Ten-Year Site Plan**Forecast of Facilities Requirements**

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

Notes:

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

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

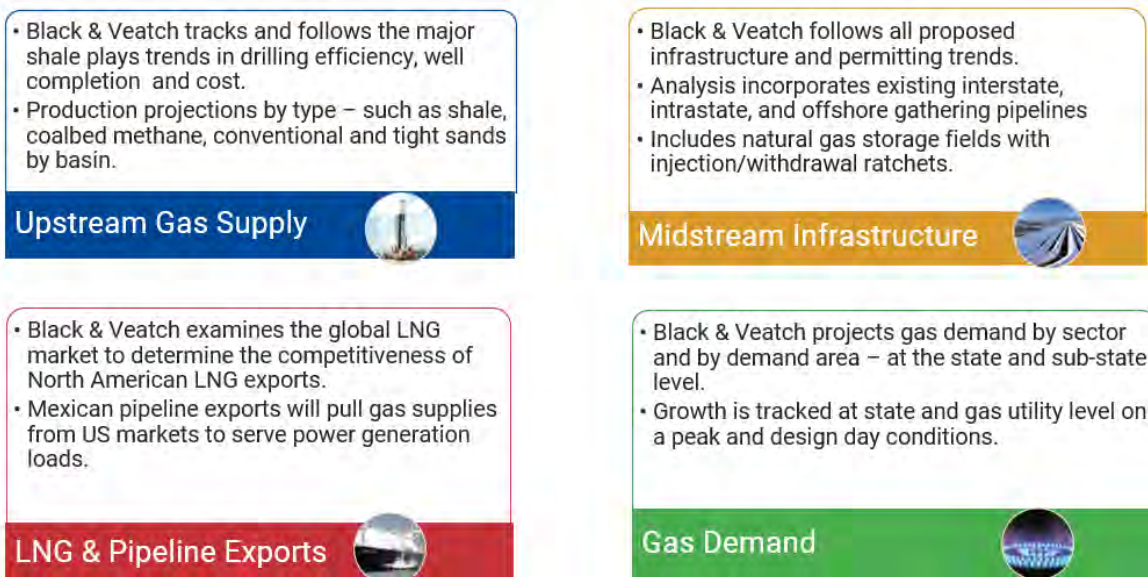
1	Point of Origin and Termination	None to Report
2	Number of Lines	
3	Right of Way	
4	Line Length	
5	Voltage	
6	Anticipated Construction Time	
7	Anticipated Capital Investment	
8	Substations	
9	Participation with Other Utilities	

4. Other Planning Assumptions and Information

4.1 Fuel Price Forecast

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

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



4.2 Economic Parameters

This section presents the economic parameters used by JEA in the evaluations performed to determine JEA's least-cost expansion plan to satisfy forecast capacity requirements as presented in the TYSP period.

4.2.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and non-fuel variable O&M escalation rate are each assumed to be 3.50 percent.

4.2.2 Municipal Bond Interest Rate

JEA performs sensitivity assessments of project cost to test the robustness of JEA's resource plan. Project cost includes forecast of direct cost of construction, indirect cost, and financing cost. Financing cost includes the forecast of long term tax-exempt municipal bond rates, issuance cost, debt service reserve contributions, and insurance cost. For JEA's plan development, the long term tax-exempt municipal bond rate is assumed to be 4.75 percent. This rate is based on JEA's judgment and expectation that the long-term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax-exempt municipal bond interest rate of 4.75 percent.

4.2.4 Interest during Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.75 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR (LFCR) that has the same present value as the year-by-year FCR. Different generating technologies are assumed to have different economic lives and therefore different financing terms. Simple cycle combustion turbines are assumed to have a 20-year financing term, while natural gas-fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different LFCRs were developed. All LFCR calculations assume the 4.75 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.63 percent annual property insurance cost. The resulting 20-year FCR is 8.56 percent and the 25-year FCR is 7.62 percent.

5. Environmental and Land Use Information

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

	Total Net MW due to Large Developments	347	MW	
	Total Net MW due to Residential and Commercial Large Developments	176	MW	50.6%
	Total Net MW due to Industrial Developments	172	MW	49.4%

Solicitation for Long-Term Firm, Dispatchable Capacity and Energy Resources

1. Cover Page

Solicitation
For Participation in
MARKET TEST FOR LONG-TERM FIRM, DISPATCHABLE CAPACITY AND ENERGY RESOURCES
for
JEA
Jacksonville, FL
Solicitation Number 1411846048

Mandatory Pre-Response Meeting via WebEx or Teleconference on December 2, 2024 at 1:30pm EST

Meeting URL: <https://jeameeting.webex.com/>

Meeting Number (Access Code): 2317 234 6279

Meeting Password: ZiA7n7mJ3kK

Dial In: +1-415-655-0001,,23172346279##

Those planning to attend the Webex should send contact information to: MarketTestRFP@JEA.com, 48 hours prior to the Pre-Response Meeting to have contact information documented.

Responses are due on April 21, 2025, by 12:00 PM EST

All Responses shall be submitted through JEA's E-Procurement and Contract Management Portal provided by Zycus Supplier Network at <https://zsn.zycus.com/guest>. Instructions on how to login to Zycus is provided below in this Solicitation. **LATE RESPONSES MAY BE REJECTED.**

JEA will publicly open all Responses received from qualified Respondents¹ on April 21, 2025, at 2:00 PM EST, via WebEx.

For more information please contact the JEA Buyer at:
MarketTestRFP@JEA.com

2. Scope of Solicitation

JEA seeks Responses (the "Solicitation") to provide firm, dispatchable capacity and associated energy to help meet projected customer peak demands (plus reserve margin requirements) and energy requirements beginning in 2030. The Solicitation is supported by JEA's long-term resource planning process, which indicates that JEA's system will benefit from efficient, flexible, intermediate generation through the addition of an advanced-class combined-cycle facility. This addition would allow for the efficient utilization of natural gas while providing the JEA system with operational flexibility and dispatchability to reliably integrate increasing amounts of intermittent solar energy.

In the 2023 Integrated Resource Plan², JEA identified the need for a flexible combined-cycle generation resource. JEA's range for dispatchable net delivered capacity via this RFP is 525MW to 700MW. Though higher capacity options can be proposed, the proposal must include the cost of system upgrades and services needed to meet reliability

¹ *Response* includes the aggregate of the information, documents, and communication provided by the Respondent in connection to an offer to fulfill the requirements of the Product and the Solicitation.

Respondent are 3rd parties submitting a Response(s) to JEA in connection to this Solicitation.

² [JEA | About | Electric Integrated Resource Planning Process](#)

and backup regulatory requirements relative to the loss of a single unit for the capacity exceeding 700MW. For the purpose of this requirement, a unit is defined as either 1) the rating of a single generator supplying the proposed capacity, or 2) the aggregated rating of all generators for interrelated CT(s) and ST(s) that make up a CCCT unit supplying the proposed capacity.

Responses are required to offer resources that provide firm capacity to contribute to meeting JEA's peak demand as well as meeting JEA's requirement for dispatch flexibility. Flexible capacity allows JEA to meet its energy requirements, including the ability to operate the resource as needed to support the integration of intermittent solar energy. Proposed resources are required to be available beginning on or before December 31, 2030.

JEA intends to provide a self-build resource as part of this Solicitation. JEA will evaluate all resource alternatives submitted, that comply with the requirements of this Solicitation, relative to the self-build resource. Unless a preferred resource alternative is identified through this Solicitation, with the terms and conditions of a power supply agreement successfully negotiated with JEA, JEA anticipates pursuing the development of the self-build option. Appendix A - Self-Build Option Information provides additional information regarding JEA's self-build option.

It is anticipated that the generation technology having the highest likelihood of success as an alternative to the self-build option will be an advanced-class combined cycle technology resource, with operating parameters that include the ability to operate in baseload and load-following roles across the full unit load range. As part of any Response, regardless of technology, JEA must have sole rights to unit commitment and de-commitment, that includes dynamic scheduling (e.g., automatic generation control ("AGC")). All Responses must be for a commercially-proven technology, meaning a technology that has a documented track record of being used in one or more commercial power projects (excluding proof-of-concept or prototype-piloting projects), has demonstrated successful operations, and is still in service.

While JEA's resource planning process has identified a dual-fuel, advanced-class combined cycle as the preferred technology, other dispatchable technologies are not prohibited from being proposed in response to this Solicitation.

The following table provides a high-level summary of key scoping items for this Solicitation.

Table 1: Summary Scope

Scope Item	Description
Transaction Type Options	Build-Transfer Agreement ("BTA") transactions: Asset acquisition of a proposed new-build resource and related assets, with Seller assuming construction and financing risk and transfer occurring upon successful achievement of the commercial operation date ("COD"). For any BTA Response outside of JEA's service territory, an O&M Agreement must be contemplated within the Response. Pricing for the O&M agreement is requested through Appendix D – Response Submission Form. Appendix E (ii) - BTA term sheet is expected to model applicable terms for both JEA ownership and a joint ownership arrangement for a new facility.
	Power Purchase Agreement ("PPA") transaction: Purchase of all contract capacity and associated energy, capacity-related benefits, other electric products, and environmental attributes from the proposed new-build or existing resource. Appendix E (i) – PPA term sheet is expected to model applicable terms for a PPA transaction type.

	Asset Purchase Agreement (“APA”): Asset acquisition of an existing resource and related assets. For any APA proposal outside of JEA’s service territory, an O&M Agreement must be contemplated within the Response. Pricing for the O&M agreement is requested through Appendix D – Response Submission Form.
Resource Location	JEA prefers Responses for resources located within the FRCC Reliability Area.
Commercial Operations Date (“COD”) / Delivery Start Date	No later than December 31, 2030
Capacity Range	Responses can be for no less than 525 MW (Average Ambient Conditions), and JEA prefers Responses to be less than or equal to 700 MW (Average Ambient Conditions)
Delivery Term	JEA requires a term of 20-years or more, and any PPA Response with terms less than 30 years or the expected life of the resource (whichever is less) must include options for contract extensions beyond the proposed PPA term. JEA prefers PPA Responses that include a buy-out option at the conclusion of the PPA term.

JEA is committed to exploring opportunities to decrease emissions resulting from its generation portfolio. Additionally, JEA wants to ensure that its generation portfolio provides the flexibility to account for present and potential future environmental regulations that limit or increase the cost of emissions from generation. This includes, but is not limited to, the EPA’s 2024 published greenhouse gas standards (GHG Rule). Any offer must comply with the GHG rule as applicable. To support its customers, JEA also wants to take advantage of opportunities to decrease customer costs that could arise from investing in sustainable infrastructure. See Appendix F: Respondent Questionnaire for details regarding the requested information on compliance with GHG Rule.

Additional details regarding the type and requirements of Respondents and Responses are provided throughout this main body document and in the appendices to this Solicitation. A list of appendices is provided below:

Appendix A - Self-Build Option Information

Appendix B – Transmission Interconnection and Deliverability Considerations

Appendix C - Minimum Requirements Form

Appendix D – Response Submission Form (will be provided in an addendum)

Appendix E(i) – PPA Term Sheet (will be provided in an addendum)

Appendix E(ii) – BTA Term Sheet (will be provided in an addendum)

Appendix F – Respondent Questionnaire

Appendix G – Credit Requirements

Appendix H – Independent Evaluator Scope

Appendix I – JEA 10-Year Site Plan

Appendix J - Evaluation Methodology and Scorecard

Appendix K- Seller Insurance Requirements

Appendix L - Respondent Certification Form

Capitalized terms used in this Solicitation without definition shall have the definitions given to them in Appendix E of this Solicitation.

3. Schedule

The key milestones for the Solicitation and their currently scheduled dates are provided in Table 2 below.

Table 2 – Key Milestones for the Solicitation

Milestone	Date
RFP Issued to Market	October 2, 2024
Required Pre-Response Meeting	December 2, 2024
Response Submissions Due Date	April 21, 2025
Notice to Respondents of Final Selections	August 26, 2025
Definitive Agreement Executed	February 2026
Regulatory Approvals	September 2027
JEA self-build Planned Commercial Operations Date (COD)	September 2030
Guaranteed COD	December 31, 2030

This schedule and the documents associated with the Solicitation are subject to change at JEA’s sole discretion at any time during the Solicitation process and for any reason. JEA will endeavor to notify Respondents of any changes to the Solicitation but shall not be liable for any costs incurred by Respondents or any other party due to a change or for failing to provide notice or acceptable notice of any change. Respondents should factor this schedule and any changes thereto into their project development timelines and Responses.

4. Background

JEA owns, operates, and manages the electric system established by the City of Jacksonville, Florida since 1895. In June 1997, JEA also assumed operation of the water and sewer system previously managed by the City. JEA is located in Jacksonville, Florida, where we proudly serve an estimated 522,469 electric, 396,566 water, 316,441 sewer and 26,902 reuse water customers. JEA is Florida's largest municipal utility and the eighth largest municipal utility in the United States.

JEA owns and operates an electric system with four generating plants, plus transmission and distribution facilities, including over 744 circuit miles of transmission lines and more than 7,408 miles of distribution lines. JEA also currently purchases energy from several solar sites located across the service territory, has contractual arrangements to purchase power from two landfill gas facilities and from a nuclear power plant, Vogtle Units 3 and 4. Additionally, JEA purchases power and energy from conventional resources and solar resources outside of JEA’s service territory.

5. Invitation - Submitting a Response

Respondents that meet the Minimum Requirements stated herein are invited to submit a Response to this Solicitation. A complete copy of this Solicitation, the appendices, forms, and all other documents referenced in this Solicitation are on JEA’s E-Procurement and Contract Management Portal provided by Zycus Supplier Network at <https://zsn.zycus.com/guest/genericRegister/JEA074>. Instructions on how to login to Zycus are provided below in this Solicitation.

All Responses are due at the time indicated on the title page of this Solicitation. Section 6 of this Solicitation has the instructions for submitting a Response for this Solicitation within Zycus.

All documentation submitted with a Response must reference the Solicitation Title and Number identified on the title page of this document. All Responses must be made on the appropriate forms and formats as specified by this Solicitation and uploaded to JEA’s procurement platform.

All Responses should be delivered electronically to JEA via the Zycus platform. An automated, detailed auditing system provides sealed Response integrity. Responses remain sealed on the platform until the Close Date & Time (Due Date & Time).

A Respondent shall be solely responsible for timely delivery of its Response to the Zycus Supplier Network. Respondents are strongly encouraged to acquire log in credentials early as possible. Additionally, Respondents are encouraged to submit Responses early to ensure the uploading process goes smoothly. **If Respondent is unable to access or has issues with the functionality of Zycus, then please contact JEA for assistance.**

Responses are due by the time and on the date stated on the cover page of this Solicitation. **LATE RESPONSES MAY BE REJECTED.**

6. Zycus Instructions

I. How to Log into Zycus

A. New Users – Zycus

1. New Users will need to register to login. Registration will require Company name, address, phone, contact, title, phone and email address. Also, it is recommended users use Google Chrome to access Zycus.
2. Note if the company is already doing business with JEA, you may find the company is already registered in Zycus. To find out if you are registered, try entering your email address in the New User Registration screen. If you receive a message stating “Email ID already registered”, log in as an “Existing User Log-in”. If you don’t know your password, enter your email address and click on “Forgot Password”.

B. Existing Users or New Users with Previously Registered Emails

1. Once the user has a login on the sourcing platform, select “Existing User Log-in”. The user may navigate to the solicitation by selecting the icon for the applicable solicitation.

II. How to Submit a Response Using Zycus

1. Once logged in, users will see all JEA Sourcing Events, then select the applicable event.
2. Once in the Sourcing Event, the Sourcing Event has prompts for actions required to respond to the solicitation.
3. For the user to proceed to submit a Response to JEA using Zycus, the user will be required to provide its acceptance of the of the Zycus iSource Terms & Conditions associated with the work. Such Terms and Conditions may cover non-disclosure, safety, cyber security, Invitation for Bid contract terms, etc.
4. Once all terms are accepted, additional Solicitation information will be available for viewing and submitting a Response by selecting “Confirm Participation”. JEA will then have a record indicating the company intends to submit a Response.
5. A user then can respond to each section of the Solicitation and once completed with each section, can select “Save”. Note each section has a red, yellow, and green light code. Items will turn green once completed. Yellow and red lights mean there is additional action required. Users may also note under each tab, there are multiple questions to respond to, scroll down the list to ensure all questions are answered.
6. In this Solicitation, JEA will provide forms, pricing tables in Excel, and questionnaires which the user will need to download. Additionally, all required documentation outlined in this Solicitation will need to be uploaded once completed as part of the Response. Users can download the required attachments by selecting the “Buyers Attachments” icon.

7. Once the required documentation is uploaded and saved, the section light will turn green. Once all sections are completed and green lighted, the User may select “Submit Response”.
8. Once the user selects “Submit Response”, the user will receive a “Success” pop-up when submitted.
9. Once submitted users may recall and modify submitted documentation and submit information until the Response Due Date and Time.

The Bidder shall be solely responsible for delivery of its Bid response to the electronic Zycus platform.

Bids are due by the time and on the date listed above. Late Bids may not be accepted.

Bidders are strongly encouraged to acquire log in credentials early as possible. Additionally, Bidders are encouraged to submit bids early to ensure uploading process goes smoothly.

Issues in logging in or in submitting documents shall be coordinated through buyer at MarketTestRFP@JEA.com.

7. Questions

All Questions must be submitted in writing electronically on the Zycus eForum to the JEA Buyer listed herein at least five (5) business days prior to the opening date. Questions received within five (5) business days prior to the opening date may not be answered. Bidder Questions may be submitted via the Zycus Chat function in the associated bid under eForum. Group Responses of a material nature shall be issued by addendum and attached to the online procurement on the Zycus platform. JEA reserves the right to provide responses to questions to all bidders that do not refer to specific individual project information in consultation with the Independent Evaluator (“IE”). Refer to Appendix H for a description of the Scope of Work for the IE.

Submitting an inquiry to the eForum section will send a communication to the buyer. Any comments or queries are not Addendums to the Solicitation. Only Addendum(s) issued and attached to the Solicitation under “Buyers Attachments” will be considered to be a formally approved change or clarification.

Additional direct contact may be made directly to the buyer at MarketTestRFP@JEA.com

8. Mandatory Pre-Response Meeting

There will be a mandatory Pre-Response meeting associated with this Solicitation at the date and time listed on the cover page of this Solicitation. All interested Respondents must attend the Pre-Response meeting. Those planning to attend the WebEx or teleconference are encouraged to email their name and contact information to the JEA Buyer listed herein at least 48 hours prior to the Pre-Response meeting to facilitate roll call. A Respondent must only sign in representing one company, unless otherwise agreed to by JEA in writing.

9. Opening of Responses

All Respondents (i.e., company name) and technology included within Responses received shall be publicly announced and recorded via WebEx at the date and time indicated on the cover page of this Solicitation.

The details for the WebEx will be on jea.com at the following website: <https://www.jea.com> approximately 48-hours before the Response opening.

At the opening of Responses, a JEA representative will publicly open each Response that was received prior to the Date and Time, except for those Responses that have been properly withdrawn. Confidential information will not be shared during the opening, and will be limited to Respondent name and technology type. JEA has the right to waive irregularities or informalities in the Responses to the extent allowable under applicable laws.

10. Alternate Provisions and Conditions

Responses that contain provisions that are contrary to requirements found in this Solicitation, including any requirements found in this Solicitation and corresponding appendices, will be reviewed but may not be accepted by JEA. Term sheets for PPAs and BTAs have been provided in Appendix E(i) and Appendix E(ii), respectively. Exceptions to these term sheets should be provided through redlines of the provided term sheets or through Appendix F – Respondent Questionnaire. Respondents shall be deemed to have accepted any terms for which exceptions or

proposed revisions are not provided. JEA reserves the right to negotiate the best terms and conditions if determined to be in the best interests of JEA and negotiate different terms and related price adjustments if JEA determines that it provides the best value to JEA.

11. Minimum Requirements

Respondent must meet the following Minimum Requirements to be considered eligible to have its Response evaluated by JEA. Respondent must complete and submit the Minimum Requirements Form provided in Appendix C of this Solicitation. JEA reserves the right to ask for additional back up documentation or additional reference projects to confirm the Respondent meets the requirements stated below.

JEA will reject Responses from Respondents not meeting all of the following Minimum Requirements:

- Respondents have fully completed all required forms and provided all required information, consistent with the instruction in Section 5, Section 6, and Section 17.
- Responses must have a guaranteed delivery start date or COD of no later than the guaranteed COD date shown in Table 2 of Section 3 - Schedule.
- Responses are for at least 525 MW (Average Ambient Conditions).
- Respondents provided a project development schedule that identifies, at a minimum, the schedule milestones required by JEA, any environmental permitting, transmission interconnection and delivery, and other applicable regulatory processes to facilitate the quoted delivery start date or COD of the proposed resource.
- The Respondent certifies that along with the Response for the generation resource(s), the Respondent has submitted detailed plans and schedules for transmission interconnection, including submission into the interconnection queue, and the implementation of any required transmission upgrades, and the associated transmission service(s) for the power to be delivered to JEA service territory in compliance with all the state and federal regulations. This must be done for any resource regardless of its location (on-system or off-system).
- Respondents satisfy and account for within its Response JEA's credit standards outlined in Appendix G – Credit Requirements
- For resources that JEA will not be operating (e.g., PPAs and off-system BTAs), Respondent acknowledges that the Response is for firm-delivered energy, and Respondent is responsible for providing gas transportation adequate to ensure firm delivery of energy. Respondent to provide the volume of firm gas transport secured from which pipeline provider, the term of the contract, and any other pertinent supply details.
- Responses must include five (5) days of onsite liquid back-up fuel storage and 5 days of on-site demineralized water storage and/or installed production capability.
- Responses include resources with commercially-proven technology. Technologies in the demonstration process are not acceptable.
- The Response must include dynamic scheduling (e.g., automatic generation control ("AGC")) by JEA for the proposed resource.
- The Response must include JEA's ability to commit and decommit the proposed facility at JEA's sole discretion, or the bottom of the dispatch range must be 0MWs.
- Any resulting agreement between the Respondent and JEA will require long-term coordination and approval of scheduled maintenance by JEA.
- For any BTA or APA proposal outside of JEA's service territory, an O&M Agreement must be included within the Response.
- JEA requires a term of 20-years or more, and any PPA Response with terms less than 30 years or the expected life of the resource (whichever is less) must include options for contract extensions beyond the

proposed PPA term to the lesser of 30 years or the expect end-of-life date. Provide details of this option within Appendix F – Respondent Questionnaire.

- The Respondent acknowledges that any study(ies) associated with the system impact must be performed by a transmission consulting engineering firm with experience in the respective (FRCC/ITS) region(s).
- As outlined in Appendix B – Transmission Interconnection and Delivery Considerations, the Respondent acknowledges that all applicable estimated capital cost for any system improvements or new constructions, and the costs of any transmission services through the project life cycle, that will not be estimated by JEA, have been provided along with the Response. The bidder acknowledges that the Respondent price is all inclusive of such costs.
- The Respondent is not on the State of Florida Convicted Vendor List, State of Florida’s Suspended Vendor List, the City of Jacksonville’s Disqualified Vendor List, have their bidding privileges actively suspended by JEA, been debarred by JEA, or have had a contract with JEA was terminated for default within the last two (2) years.
- Respondent acknowledges that immediately following JEA Board approval to negotiate, Respondent will support JEA with all necessary information for filing of petition for Determination of Need, and Site Certification Application, as applicable to the response.
- Respondents must attend the Mandatory Pre-Response Meeting as found in Section 8 of this Solicitation.

12. Insurance Requirements

Prior to JEA issuing a notice to proceed to the Company to begin executing obligations under an executed contract, the Respondent shall submit a certificate of insurance (COI) that is in compliance with amounts and requirements as indicated in this Solicitation (see Appendix K – Seller Insurance Requirements). Note, where applicable, that the COI shall specifically indicate JEA as additional insured on all required insurance except Worker's Compensation and Professional Liability (if applicable). Furthermore, waiver of subrogation must be provided for all required insurance in favor of JEA, including its board members, officers, employees, agents, successors, and assigns.

13. Optional Use of Small and Emerging Business Program

It is at the Respondent's option as to whether it chooses to subcontract with a JSEB firm. JEA encourages the use of JSEB firms; however, the Respondent is not required to utilize a JSEB to be awarded a Contract under this Solicitation.

For more information regarding the JSEB program, please contact Rita Scott, JEA, JSEB Manager, scotrl@jea.com.

14. Basis of Selection - Highest Evaluated

JEA may select and enter contract negotiations to the Respondent whose Response meets or exceeds the Minimum Requirements set forth in this Solicitation, and whose Response receives the highest number of points based upon JEA’s evaluation of the Selection Criteria stated herein. JEA will not select a Response on a price only basis but will make a selection based on an evaluation of how well each Respondent meets the “Selection Criteria” stated herein. Selections and execution of any contracts resulting from this Solicitation is subject to approval from JEA senior leadership and JEA’s Board of Directors.

15. Evaluation Methodology

Responses will be scored and ranked by a committee of 3 to 5 evaluators consisting of JEA’s staff. Each evaluator will individually score the Responses using an evaluation matrix outlined below and in Appendix J – Evaluation Methodology and Scorecard. Evaluators will be supported by a team of subject matter experts (SMEs) consisting of JEA staff and consultants.

JEA will use the “Selection Criteria” listed below to evaluate the Responses. JEA will make its selection decision based solely upon the information submitted in the Responses and any follow-up information requests or questions and answers submitted by JEA’s SME team. JEA may also choose, at JEA’s sole discretion, to have one or more Respondents make presentations to representatives of JEA prior to selections to support JEA Response evaluations. It is always in the best interest of the Respondent to provide informative, concise, well-organized technical and business information relative to the Response, in both the initial submittal of its Response and in any subsequent submittals.

Economic Assessment

Respondent shall provide a firm, best-and-final price through the completion of Appendix D – Response Submission Form. The prices quoted must include all applicable transmission interconnection and delivery cost (as outlined in Appendix B), applicable fuel delivery cost, profit, taxes, benefits, travel, percent mark-up, contingency, and all other overhead items. The prices quoted by Respondent on the Response Form must be firm prices, not estimates.

However, a Respondent is able to propose an escalation rate or methodology to apply to a Response's base Capacity Rate or Acquisition Purchase Price, for a PPA or BTA, respectively, to support changes to cost drivers between Response submission and the receipt of a full notice to proceed ("Response Price Adjustment"). The Response Price Adjustment must be laid out clearly within Appendix D - Response Submission Form and Appendix F – Respondent Questionnaire. As part of a Response Price Adjustment, the Respondent must include a maximum price (or "Price Cap") that the Capacity Rate or Acquisition Purchase Price will not exceed. The economic assessment will be based on the proposed Price Cap.

The economic assessment consists of an economic analysis that measures the total system cost impact to JEA over the JEA planning horizon when the proposed resource is added as compared to a resource plan including the Self-Build Option, with the JEA system optimized around the proposed resource. The economic analysis will utilize information in the Response forms to characterize the cost of the proposed resource. The proposed resource will be evaluated using the PLEXOS model.

To the extent JEA receives robust participation in the Solicitation, the economic evaluation may include a preliminary economic screening analysis and, for those Responses that do not pass the screening, JEA may reject those Responses in its sole and absolute discretion.

Qualitative Evaluation

The qualitative evaluation will include assessments of Respondents capabilities, resource flexibility, project development experience (if applicable), transmission interconnection and delivery, fuel procurement (including transportation), environmental compliance risks, and other factors that JEA determines may be relevant to a Response's risk and viability. A score will be developed for the Response by rating the Respondent and Response over multiple weighted metrics in several risk categories, using defined scoring criteria. The weighted sum of each metric will be totaled to determine the overall score for the proposal. This assessment will be based on the information provided within Appendix D – Response Submission Form, Appendix F – Respondent Questionnaire, and any additional information requested of the Respondent through discussions and clarifying questions from JEA.

Transmission Assessment

Respondents must provide known or estimated interconnection and transmission delivery costs to support the requirements of this Solicitation. If this information is not available, Respondents must provide a summary of any known issue related to power delivery and discuss the status of determining the network upgrade costs. This information is requested through Appendix F – Respondent Questionnaire. JEA has the option to model Responses with an estimated upgrade cost based on the location of the interconnection point and engineering judgment.

The existing capacity of JEA for power import and export over its existing ties is required to support system operation and must not be negatively impacted. JEA will analyze each proposal for impacts to JEA's current capabilities, and if remedies are required to preserve current capabilities, JEA will estimate the cost of those remedies and add the appropriate cost to the proposal.

An assessment of cost and risk associated with Transmission interconnection and delivery will be incorporated into the economic and qualitative assessment. More information regarding the contemplated transmission assessment, requirements of the Respondent related to transmission, and allocation of cost is provided in Appendix B – Transmission Interconnection and Delivery Considerations and within Appendix J – Evaluation Methodology and Scorecard.

Evaluation Scoring

Economic Assessment Score (70 Points)

- Lowest Overall Cumulative Present Worth Cost (CPWC), Base Case (with GHG Rule) over 30 years (30 points)
- Lowest CPWC, Base Case (with GHG Rule) at 15-year mark (10 points)
- Lowest Overall CPWC, Base Case (without GHG Rule) over 30 years (15 points)
- Sensitivity Cases CPWC (15 points)

Qualitative Evaluation (Risk Assessment) Score (30 Points)

- System Reliability (Flexibility) (6 points)
- Experience and Commercial (6 points)
- Transmission Status (6 points)
- Project Status and Technical Design (3 points)
- Environmental (3 points)
- Fuel Supply (6 points)

JEA reserves the right to adjust the qualitative criteria and point assignment prior to receipt of offers.

Independent Evaluator

The Market Test RFP process and procedures and the RFP evaluation process and procedures have been approved by and will be monitored by the Independent Evaluator, Merrimack Energy. For more details, please see Appendix H – IE Scope.

While evaluating Responses, JEA may request clarification or additional information from the Respondent about any item in its Response. Such requests will be sent consistent with the protocols outlined in this Solicitation and the Respondent must provide a response back to JEA within five (5) business days unless otherwise specified by JEA, or JEA, at its sole discretion, may deem the Respondent to be non-responsive and either suspend or terminate further evaluation of its Responses.

Once the evaluation is complete, Respondents and their corresponding Responses may be selected for commercial negotiations. After the selection process has been completed, JEA will notify each Respondent as to whether JEA is moving forward with their Responses or has been eliminated from further consideration for this Solicitation.

16. Tie

In the event of a tie score, the tie shall be resolved in accordance with JEA's Procurement Code and Operational Procedures.

17. Required Forms to be Submitted

The following forms and associated documentation must be completed and submitted to JEA at the timeframes stated above:

- Appendix C - Minimum Requirements Form
- Appendix D – Response Submission Form
- Redlines of Appendix E Term Sheets
- Appendix F – Respondent Questionnaire
- Appendix L – Respondent Certification Form
- Proposed Terms and Conditions for O&M Agreement, if applicable

If the above listed forms are not submitted with the Response by the Response Due Time and Date, JEA may reject the Response.

JEA also requests the following documents to be submitted prior to Contract execution. A Response will not be rejected if these forms are not submitted at the Response Due Date and Time. However, failure to submit these documents prior to Contract execution could result in Response rejection, unless waived by JEA.

- I. Conflict of Interest Certificate Form - This form can be found at JEA.com
- II. Certificate of Insurance
- III. W-9

IV. Evidence of active registration with the State of Florida Division of Corporations (www.sunbiz.org)

V. Subcontractor Form, if applicable

18. Addenda

An addenda is defined as a written change or changes to the Solicitation issued by JEA Procurement Services and is incorporated into the Solicitation as a modification, revision and/or further clarification of the intent of the Solicitation. JEA will submit an Addenda as needed and will notify Respondents through the contemplated communication process described in Sections 5 & 6 above.

19. Contract Execution

Within 30 days from the date of selections, JEA will present the successful Respondent with the Contract. The parties shall negotiate in good faith to execute the definitive Agreement by the date provided in Table 2 above. Such date may be extended at JEA's discretion. If the parties are unable to agree to terms for the definitive Agreement by the date provided in Table 2, as such date may be extended by JEA, JEA may cancel the award with no further liability to the Respondent and retain any bid security or bond.

20. Ex Parte Communication

Ex Parte Communication is defined as any inappropriate communication concerning a Solicitation between any officers, employees or other representatives of Respondent and a JEA representative during the time in which the Solicitation is being advertised through the time of selections. Examples of inappropriate communications include: private communications concerning the details of the Solicitation in which a company becomes privy to information not available to the other Respondents. Social contact between companies and JEA Representatives should be kept to an absolute minimum during the Solicitation process.

Ex Parte Communication is strictly prohibited. Failure to adhere to this policy will disqualify the noncompliant Respondent. Any questions or clarifications concerning this Solicitation must be sent in writing through Zycus to the JEA Buyer at least five business days prior to the opening date. If JEA determines that a question should be answered or a requirement should be clarified, JEA will issue an Addendum to the Solicitation.

21. Certifications and Representations of the Company

By signing and submitting its Response, the Respondent certifies and represents as follows:

A. That the individual signing the Response is duly authorized to contractually bind the Respondent to the terms and conditions of this Solicitation and the Contract. Respondent shall provide satisfactory evidence of such authority within three days of JEA's request.

B. That every aspect of the Response is based on its own knowledge and judgment of the conditions and hazards involved, and not upon any representation of JEA. JEA assumes no responsibility for any understanding or representation made by any of its representatives during or prior to execution of the Contract unless such understandings or representations are expressly stated in the Contract and the Contract expressly provides that JEA assumes the responsibility.

C. That, if successful, the Respondent will be registered to conduct business in the State of Florida and in active status with the Florida Division of Corporations at the time of execution of a Contract.

D. That the Respondent maintains in active status of any and all licenses, permits, certifications, insurance, bonds and other credentials including, but not limited to, all licenses necessary to perform its obligations under the Definitive Agreement. The Respondent also certifies that, upon the prospect of any change in the status of applicable licenses, permits, certifications, insurances, bonds or other credentials, the Respondent shall immediately notify JEA of the status change.

22. Ethics

By submitting a Response, the Respondent certifies that its Response is made without any previous understanding, agreement or connection with any other person, firm, or corporation submitting a Response under this Solicitation other than as a Subcontractor or supplier, and that the Response is made without outside control, collusion, fraud, or

other illegal or unethical actions. The Respondent shall comply with all JEA and City of Jacksonville ordinances, policies and procedures regarding ethics.

The Respondent shall disclose the name(s) of any public officials who have any financial position, directly or indirectly, in Respondent or its Response by completing and submitting the Conflict of Interest Certificate Form available at jea.com. Failure to fully complete and submit the Conflict of Interest Certificate will disqualify the Response. If JEA has reason to believe that collusion exists among the Respondents, JEA shall reject any and all Responses from such Respondents and will proceed to debar the Respondents from future JEA Awards in accordance with the JEA Procurement Code.

JEA is prohibited by its Charter from awarding contracts to JEA board members, officers or employees, and is prohibited from awarding contracts in which a JEA officer or employee has a financial interest. JEA shall reject all Responses from JEA board members, officers or employees, as well as, all Responses in which a JEA officer or employee has a financial interest.

In accordance with Florida Statutes Sec. 287.133, JEA shall reject Responses from any persons or affiliates convicted of a public entity crime as listed on the Convicted Vendor list maintained by the Florida Department of Management Services. JEA shall not make an Award to any officer, director, executive, partner, shareholder, employee, member, or agent active in management of the Respondent listed on the Convicted Vendor list for any transaction exceeding \$35,000 for a period of 36 months from the date of being placed on the Convicted Vendor list.

23. JEA Publications

Applicable JEA publications are available at jea.com.

24. Modification or Withdrawal of Responses

The Respondent may modify or withdraw its Response at any time prior to the Response Due Date and Time by giving written notice to JEA through the established communication protocols outlined in this Solicitation by submitting an updated Response. JEA will not accept modifications submitted by telephone, telegraph, email, or facsimile, or those submitted after the Response Due Date and Time. The Respondent may not modify or withdraw its Response for a period of 12 months following the Response Due Date.

25. Notice of Prohibition Against Considering Social, Political, or Ideological Interests

Pursuant to Section 287.0501, Florida Statutes, JEA may not:

- (i) Request documentation of or consider a vendor's social, political, or ideological interests when determining whether a vendor is a responsible vendor; or
- (ii) Give preference to a vendor based on the vendor's social, political, or ideological interests.

26. Prohibition Against Contingent Fees

The Respondent warrants that it has not employed or retained any company or person, other than a bona fide employee working for the Respondent, or an independent sales representative under contract with the Respondent, to solicit or secure a contract with JEA, and that it has not paid or agreed to pay any person, company, corporation, or other individual, other than a bona fide employee working solely for the Respondent, or an independent sale representative under contract with the Respondent, any fee, commission, percentage, gift, or any other consideration, contingent upon or resulting from the Award or the Contract. If a breach or violation of the provisions occurs, JEA shall have the right to terminate the Contract without liability, and at its discretion, to deduct from the Contract Price, or otherwise recover, the full amount of such fee, commission, percentage, gift or consideration.

27. Protest of Solicitation and Selection Process

Any protests regarding this Solicitation must be filed in writing and in accordance with the JEA Procurement Code, as amended from time to time. The JEA Procurement Code is available online at www.jea.com.

28. Availability Of Response After Opening

In accordance with the Florida Public Records Law, Florida Statutes, Chapter 119, copies of all Responses are available for public inspection thirty (30) days after the opening of Responses or on the date selections are announced, whichever is earlier. Release of documents will be performed in accordance with Section 30 Sunshine Law below. Respondents may review opened Responses once they are available for public inspection by contacting the designated

JEA Buyer or JEA's Public Records custodian whose contact information can be found at jea.com. JEA will post a summary of the Response results immediately after the Response opening.

Pursuant to Section 119.0713(4), Florida Statutes, if the Response contains proprietary confidential business information, such information shall remain confidential for one year after JEA has either completed its due diligence review or has decided not to participate in the project. For the purposes of this section, "proprietary confidential business information" is defined as follows:

- (i) Trade secrets, as defined in Section 688.002, Florida Statutes;
- (ii) Internal auditing controls and reports of internal auditors;
- (iii) Security measures, systems, or procedures;
- (iv) Information concerning bids or contractual data, the disclosure of which would impair the efforts of JEA to contract for goods or services on favorable terms; and
- (v) Information relating to competitive interests, the disclosure of which would impair the competitive business of the provider of the information.

There may be additional public records exemptions that apply to information contained in the Response. It is the responsibility of Respondent to identify information in the Response that may be considered confidential or exempt from production, as provided in Section 30 below.

29. Reservation of Rights of JEA

This Solicitation provides potential Respondents with information to enable the submission of written offers. This Solicitation is not a contractual offer or commitment by JEA to purchase products or services.

JEA reserves the right to reject all Responses, and to waive informalities if JEA deems such action to be in its best interest. JEA may reject any Responses that it deems incomplete or irregular.

JEA reserves the right to cancel, postpone, modify, reissue and amend this Solicitation at its discretion.

JEA reserves the right to cancel or change the date and time announced for opening of Responses at any time prior to the time announced for the opening of Responses. JEA may Award the Contract in whole or in part. JEA may award multiple Contracts if it is deemed to be in JEA's best interest.

30. Sunshine Law

Article I, Section 24, Florida Constitution, guarantees every person access to all public records and Chapter 119, Florida Statutes, provides a broad definition of public records. JEA is subject to these laws and related statutes ("Florida's Public Records Laws"). All responses to this Solicitation are public record and available for public inspection unless specifically exempt by law.

If a Respondent believes that any portion of the documents, data or records submitted in response to this Solicitation are exempt from Florida's Public Records Law, Respondent must (1) clearly segregate and mark the specific sections of the document, data or records as "Confidential," (2) cite the specific Florida Statute or other legal authority for the asserted exemption, and (3) provide JEA with a separate redacted copy of its Response (the "Redacted Copy"). The cover of the Redacted Copy shall contain JEA's title and number for this Solicitation and Respondent's name, and shall be clearly labeled "Redacted Copy." Respondent should only redact those portions of records that Respondent claims are specifically exempt from the Florida Public Records Laws. If Respondent fails to submit a redacted copy of information it claims is confidential, JEA is authorized to produce all documents, data and other records submitted to JEA in answer to a public records request for such information.

In the event of a request for public records to which documents that are marked as confidential are responsive, JEA will provide the Redacted Copy to the requestor. If a requestor asserts a right to any redacted information, JEA will notify Respondent that such an assertion has been made. It is Respondent's responsibility to respond to the requestor to assert that the information in question is exempt from disclosure under applicable law. If JEA becomes subject to a demand for discovery or disclosure of Respondent's redacted information under legal process. JEA shall give Respondent prompt notice of the demand prior to releasing the information (unless otherwise prohibited by applicable law.) Respondent shall be responsible for defending its determination that the redacted portions of its response are not subject to disclosure.

By submitting a Response to this Solicitation, Respondent agrees to protect, defend, and indemnify JEA from and against all claims, demands, actions, suits, damages, losses, settlements, costs and expenses (including but not limited to reasonable attorney fees and costs) arising from it relating to Respondent's determination that the redacted portions of its response to this Solicitation are not subject to disclosure.

IF THE COMPANY HAS QUESTIONS REGARDING THE APPLICATION OF CHAPTER 119, FLORIDA STATUTES, TO THE COMPANY'S DUTY TO PROVIDE PUBLIC RECORDS RELATING TO THIS CONTRACT, CONTACT THE CUSTODIAN OF PUBLIC RECORDS AT:

JEA

**Attn: Public Records
225 North Pearl Street
Jacksonville, FL 32202
Ph: 904-665-8606
publicrecords@jea.com**

31. Scrutinized Companies

Pursuant to Section 287.135(2), Florida Statutes, a company is ineligible to, and may not, bid on, submit a proposal for, or enter into or renew a contract with an agency or local government entity for goods or services of:

- 1) Any amount if, at the time of bidding on, submitting a proposal for, or entering into or renewing such contract, contractor is on the Scrutinized Companies that Boycott Israel List, created pursuant to Section 215.4725, Florida Statutes, or is engaged in a boycott of Israel; or
- 2) One million dollars or more if, at the time of bidding on, submitting a proposal for, or entering into or renewing such contract, contractor:
 - i. Is on the Scrutinized Companies with Activities in Sudan List or the Scrutinized Companies with Activities in the Iran Petroleum Energy Sector List created pursuant to Section 215.473, Florida Statutes; or
 - ii. Is engaged in business operations in Cuba or Syria.

Pursuant to Section 287.135(3)(a)4, Florida Statutes, JEA may terminate this Contract at JEA's option if this Contract is for goods or services in an amount of one million dollars or more and the Company:

- 1) Is found to have submitted a false certification under Section 287.135(5), Florida Statutes;
- 2) Has been placed on the Scrutinized Companies with Activities in Sudan List or the Scrutinized Companies with Activities in the Iran Petroleum Energy Sector List created pursuant to Section 215.473, Florida Statutes;
- 3) Is engaged in business operations in Cuba or Syria.

Pursuant to Section 287.135(3)(b), Florida Statutes, JEA may terminate this Contract at JEA'S option if this Contract is for goods and services of any amount and Company:

- 1) Is found to have been placed on the Scrutinized Companies that Boycott Israel List; or
- 2) Is engaged in a boycott of Israel.

32. Safety Qualification Requirement

As applicable, Respondent shall be approved as JEA Safety Qualified. A Respondent will not be allowed to work onsite of a project without the appropriate safety qualifications.

JEA Safety Qualification information is available online at http://www.jea.com/About/Procurement/Contractor_Safety under Contractor Safety Reference Materials. A Respondent must have a three-year average Experience Modification Rating (EMR) of 1.0 or less and agree to the provisions of the Contractor Safety Management Process (CSMP) in order to become JEA Safety Qualified. It is the Respondent's responsibility to ensure it is JEA Safety Qualified. A list of the JEA's Safety Qualified vendors can be found on https://www.jea.com/About/Procurement/Contractor_Safety/. For additional information, contact Jim Fisher at (904) 226-5045 or Curtis Stothers at (904) 665-7736.

Contractors that have attained JEA Safety Qualification but have experienced incidents that result in their three-year average EMR to raise above 1.0 shall not be permitted to continue to perform work, be prevented from bidding on

other JEA projects and/or sites, and their company name shall be removed from the list of JEA Safety Qualified Contractors. If JEA determines that it is in the best interest of JEA that the contractor be permitted to complete the contract, the contractor shall provide an acceptable Safety Action Plan to the contractor sponsor. The contractor sponsor shall provide that Safety Action Plan to their director and the director of safety and health services or their designees. If it is determined that the contractor has adequately addressed the safety concerns of the worksite, it may complete that contract only. Until written acceptance of the Safety Action Plan is received, the contractor may not go back to work and shall not work on other projects not specifically addressed in the Safety Action Plan.

Each Company once awarded a JEA Contract is required to provide regular and continuing training for their employees. Such training shall not be charged to JEA as a separate billable fee. Company (including General / Prime Contractors) will also monitor the training activities of Subcontractors under their direction. All training outside of JEA specific training must meet OSHA requirements. Company employees working on JEA projects or sites shall receive JEA Safety Orientation and JEA Site-Specific Training before beginning work.

Appendix A – Self-Build Option Information

JEA intends to evaluate Responses to this Solicitation against a JEA Self-Build Option, which is summarized as follows and is current as of the time of the issuance of this RFP:

Self-Build Option will consist of a 1x1 natural gas-fired advanced class combined cycle combustion turbine (CCGT) facility located at JEA's former St. Johns River Power Park site, a JEA owned property in Duval County. The winter capacity of the Self-Build resource is anticipated to be approximately 670MW with an anticipated in-service date within the fourth quarter of calendar year 2030. The guaranteed COD for the proposed project is December 31, 2030.

Key attributes of the proposed CCGT include the following:

-
- High availability.
- 40-60+ MW / min ramp rate
- Capable of turndown to approximately 25 percent of full load (ambient temperature dependent).
- Dual fuel capable, with 5 days (full load) of on-site liquid fuel storage and 5 days demineralized water storage and/or production capability.
- DLN combustion with CTG NOx emissions of 25 ppm on natural gas.
- Planned Outage Factor (POF) – 6%
- Forced Outage Factor (FOF) – 3%
- Equivalent Availability Factor (EAF) - 91%
- Average Net Operating Heat Rate (ANOHR) – 6,380 - 6,750 Btu/kWh
- Book life – 25 years
- Total Installed Cost (\$/kW (winter rating)) – \$1,050 - \$1,220
- Fixed O&M (2023 \$/kW-yr (winter rating)) - \$6.23 - \$7.33
- Variable O&M (2023 \$/MWh) - \$2.28 - \$2.68

The Self-Build Option will utilize existing infrastructure and resources, including existing fuel infrastructure and interconnection facilities.

Appendix B – Transmission Interconnection and Deliverability Considerations

1. Overview

This Solicitation is driven by the need for firm, dispatchable capacity and associated energy to support the reliability of JEA's system, and to serve its customers. This Solicitation is issued at a time when JEA is proactively planning for additional capacity and energy as JEA's generation approaches retirement, and JEA is including the integration of additional renewable generation into its resource portfolio. The diverse mix of future generation resources requires significant attention to reliability impacts to JEA's transmission system that could result from a resource proposed through this Solicitation.

Generally, and detailed more fully within this appendix, any Response to supply firm, dispatchable capacity and energy must account for the full incremental transmission and interconnection costs to deliver the proposed capacity and energy on a firm basis into the JEA system. Proposed resources must interconnect at a location and deliver energy in a manner that does not compromise or diminish the reliability of the present JEA system or adversely affect any other utility's transmission system. Consistent with the description provided within this appendix, costs associated with alleviating any reliability impacts must be accounted for either through the pricing provided in the Response, or through an estimate developed by JEA and applied through the evaluation process. A summary of responsibilities between the parties are outlined in Table 1 and Table 2 below.

The proposed generation resource is expected to be in service by December 31 of 2030. Consequently, the required transmission pathway must be in-service with adequate lead time to support construction completion, testing, and commissioning of the proposed generation resource. The Respondent is responsible for complying with all applicable state and federal transmission regulations.

JEA reserves the right to review and study all Responses and request further clarifications or reject the Responses with insufficient transmission service information. JEA also reserves the right to reject Responses that have an excessively high risk of not being able to meet JEA's proposed project schedule.

2. Existing Transmission System

JEA's transmission system consists of bulk power facilities operated at 69 kV, 138 kV and 230 kV. The 69 kV system basically serves the urban core in Jacksonville. The 138 kV and 230 kV transmission systems provide a backbone around the service territory. JEA has several Transmission ties at 230 kV and 138 kV with its neighboring utilities for power transfers. JEA also jointly owns two 500 kV transmission lines to the north to interconnect with Georgia Integrated Transmission System (ITS). These transmission ties facilitate the power import into JEA for the current long-term firm power purchases that JEA has, as well as any other occasional power purchases and sales.

JEA's import allocation is about 1,200 MW over these lines through FPL's substation but gets significantly reduced under planned or unplanned transmission outage conditions.

3. Transmission Interconnection & Delivery Requirements

3.1. On-System Resources

Table 2 below summarizes what costs should be assumed and incorporated within the Response pricing and who will be responsible for the cost and the implementation of any necessary upgrades resulting from the interconnection and delivery of a resource located on the JEA System. The Response project schedule should account for transmission queue entry requirements or required studies across the impacted transmission systems, and the implementation of any and all required transmission upgrades.

Table 1: Summary of Transmission Responsibility for On-System Resources

Transmission Cost Type	Respondent to Include within Proposal Pricing	JEA to Estimate and Include Within Evaluation	Financial Responsibility of Solution	Responsible Party to Implement
Transmission from Facility to Interconnecting Substation	Yes	No	Seller	Seller
Interconnection Upgrade Costs at the Substation (existing or new)	No	Yes	Seller	JEA
Transmission Impact on JEA's System (including export power, if applicable)	No	Yes	Seller	JEA
Impact to Reserve Requirements (>700MW Response from a single unit)	No	Yes	JEA	JEA
Transmission Impact External to JEA's System (export power only)	Yes	No	Seller	Seller

Details below provide additional information regarding the transmission cost type and the requirements outlined above. In order for JEA to effectively estimate potential transmission upgrade requirements, within Appendix F – Respondent Questionnaire of the Response, the Respondent must clearly identify the intended point of interconnection on JEA's transmission system.

Transmission from Facility to Interconnecting Substation

For any Response that will use an on-system generation resource (generation inside of or adjacent to JEA's service footprint with a transmission line connecting directly with JEA's Transmission system), it will be the responsibility of the Respondent to build and maintain any required facilities to facilitate transmission interconnection up to the interconnecting substation, along with all the associated activities such as regulatory and environmental permitting, acquiring the real estate for the transmission right-of-

way, etc. All costs and the timeline associated with the building and maintaining these facilities should be included within the Response pricing.

Interconnection Upgrade Costs at the Substation (existing or new)

The Respondent will be responsible for all cost to JEA's transmission system to facilitate interconnection and delivery of power, including, but not limited to, the cost of the interconnecting substation or existing substation upgrades for interconnection. JEA reserves the right to either self-perform substation work at the Proposer's cost, or to approve a suitable contractor to perform that work under JEA's construction standard and at the Respondent's cost.

Transmission Impact on JEA's System (including export power, if applicable)

The Respondent will be responsible for all cost to JEA's transmission system to facilitate interconnection and delivery of power, including, but not limited to JEA's existing transmission infrastructure and JEA's existing import and export capability. It is not necessary to include any costs for impacts to the JEA transmission system, as these impacts and costs will be evaluated by JEA during the Response evaluation and added to the Response price as needed.

The existing capacity of JEA for power import and export over its existing ties is required to support system operation and must not be adversely impacted by the interconnection and delivery of the proposed facility. This includes the preservation of JEA's full use of its allocation over the 500 kV ties with Georgia ITS (i.e., utilization of JEA's existing transmission allocation for this new transaction is not acceptable). JEA will analyze each Response for impacts to JEA's current capabilities, and if remedies are required to preserve current capabilities, JEA will estimate the cost of those remedies and add the appropriate cost to the Response.

For clarity, if, in addition to the proposed capacity and energy allocated to JEA, the Respondent's proposal includes export of capacity and energy from a unit interconnected within the JEA system, the Respondent will be responsible for all upgrades necessary to facilitate that export without impacting JEA's present import or export capabilities or reliability, and must secure the necessary transmission service with JEA including ancillary services and accounting for transmission losses.

Impact to Reserve Requirements (>700 MW Response from a single unit)

If the Response is for capacity and energy that exceeds 700 MW for JEA from a single unit, JEA will incorporate within the evaluation of the Response the cost of any system upgrades and services needed to meet reliability and backup regulatory requirements relative to the loss of a single unit for the capacity exceeding 700 MW. For the purpose of this requirement, a unit is defined as either 1) the rating of a single generator supplying the proposed capacity, or 2) the aggregated rating of all generators for interrelated combustion turbine(s) and steam turbine(s) that make up a combined cycle combustion turbine resource supplying the proposed capacity. Reserve requirements for any capacity allocated to the Seller or separate off-taker, would be the supplier's responsibility.

Transmission Impact External to JEA's System (export power only)

If the Response includes export of capacity and energy from the proposed resource the Respondent will be responsible for all upgrades necessary to facilitate that export including all upgrades outside the JEA system. The Respondent must also secure the necessary transmission service, including ancillary service and accounting for transmission losses, with the third party/parties, if required. All costs associated with this transmission service should be accounted for within the Response pricing.

The Respondent is expected to account in the Response the pricing and timeline for the cost of any transmission upgrades or additions outside the JEA system required for delivery of energy and attributes from the proposed project. The Response, within Appendix F – Response Questionnaire, shall include a breakout of the assumed cost of these upgrades to facilitate JEA’s assessment of risk associated with the proposed upgrades or construction.

The Respondent is encouraged to include within the Response a price contingency that the Respondent feels is reasonable and responsible for mitigating any impacts to non-JEA party owned transmission facilities resulting from any transmission upgrades or additions detailed in the Respondent’s Response. The contingency cost shall be identified as a breakout to facilitate JEA’s assessment of risk associated with the potential impacts to non-JEA parties from the proposed upgrades or construction.

Notes on Process Requirements for On-System Resources

- 1) If any new transmission line(s) is/are required for the interconnection, the Respondent shall accommodate all applicable state and federal transmission regulations and procedures (Florida’s Transmission Line Siting Act – TLSA, Order No. 1000 as applicable to FRCC etc.).
- 2) It is the responsibility of the Respondent at Respondent’s cost to address all the associated activities such as regulatory and environmental permitting, acquisition of real estate for the development, permitting and construction of the transmission line(s).
- 3) The impact of interconnection shall be studied through ***JEA Procedures for Generator Interconnection to Transmission System (JPGITS)*** as available at JEA’s OASIS site under JEA Business Practices.
 - a) As part of JPGITS, a system impact study, which will also incorporate FRCC’s¹ Transmission Service Request (TSR)/Generation Interconnection Service Request (GISR) process, must be performed. This study must be completed by a transmission consulting engineering firm with experience in the FRCC region, and at the Respondent’s expense. It is the responsibility of the Respondent to provide all the modeling data pertaining to the generation resource and transmission configuration (as applicable) required for the study.
 - b) The proposed resource could impact non-JEA party owned Transmission facilities as well. To address this potential, the TSR/GISR procedure of FRCC with the associated study(ies) must be followed. The Respondent is responsible for any cost of 3rd-party impacts for interconnection and delivery resulting from these studies.
- 4) If the Response includes the construction of a new transmission line, its impact must be studied through FRCC’s TSR/GISR process. Also, all the regulatory and environmental permitting, and processes for transmission construction as applicable (e.g. Florida Transmission Line Siting Act – TLSA, Order 1000 process as applicable to FRCC etc.) must be followed by the Respondent.
- 5) JEA’s Transmission Planning team can facilitate a public webinar for more information on JPGITS as well as FRCC’s TSR/GISR processes prior to the Response submittal deadline.

¹ FRCC = Florida Reliability Coordinating Council, Inc. is a not-for-profit company in Florida with a mission to coordinate a safe, reliable, and secure bulk power system in the state. FRCC is registered for the Reliability Coordinator and Planning Authority functions with NERC. It has established many procedures to achieve these functions and mission, which its members (like JEA) must follow.

- 6) The Respondent will be responsible for ensuring that all required processes associated with interconnection and delivery of power from the facility is initiated according to the required development timeline to meet the proposed commercial operation date.

3.2. Off-System Resources

Table 2 below summarizes what costs should be assumed and incorporated within the Response pricing and who will be responsible for the cost and the implementation of any necessary upgrades resulting from the interconnection and delivery of a resource located outside the JEA System. The Response project schedule should account for transmission queue entry requirements or required studies across the impacted transmission systems, and the implementation of any and all required transmission upgrades.

Table 2: Summary of Transmission Responsibility for Off-System Resources

Transmission Cost Type	Respondent to Include within Proposal Pricing	JEA to Estimate and Include Within Evaluation	Financial Responsibility of Solution	Responsible Party to Implement
All interconnection costs	Yes	No	Seller	Seller
Required Transmission Cost for Service between Facility and Delivery Point on JEA's system	Yes	No	Seller	Seller
Impacts to other utility transmission systems	Yes	No	Seller	Seller
Impact to JEA Transmission System	No	Yes	Seller	JEA
Impact to JEA Import/Export Capability	No	Yes	Seller	JEA
Impact to Reserve Requirements (>700MW Response from a single unit)	No	Yes	JEA	JEA

Details below provide additional information regarding the transmission cost type and the requirements outlined above. In order for JEA to effectively estimate potential transmission upgrade requirements, within Appendix F – Respondent Questionnaire of the Response, the Respondent must clearly identify the intended point of delivery on JEA's transmission system.

All Interconnection Costs

The Respondent will be responsible for the process and cost of interconnection to a 3rd-party system. Any cost associated with interconnection service on a 3rd-party system must be included within the Response pricing. Additionally, within Appendix F – Respondent Questionnaire, it is requested that the Respondent provide the estimated cost of interconnection service, as applicable.

The Respondent will be responsible for all cost to JEA's transmission system to facilitate interconnection and delivery of power, including, but not limited to JEA's existing transmission infrastructure and JEA's existing import and export capability. It is not necessary to include any costs for impacts to JEA's transmission system, as these impacts and costs will be evaluated by JEA during the Response evaluation and added to the Response price as needed.

Required Transmission Cost for Service between Facility and Delivery Point on JEA's System

For any Response that will use an off-system generation resource (existing or a new generating resource physically located outside of JEA's service territory), it must include sufficient transmission services, including ancillary services and the transmission losses, to transport the full proposed power (MW) into JEA. As this will involve wheeling through 3rd party-owned transmission facilities, it is the responsibility of the Respondent to facilitate all such transmission transactions with that/those party/parties. Any cost associated with transmission service must be included within the Response pricing. Additionally, within Appendix F – Respondent Questionnaire, it is requested that the Respondent provide the estimated cost of transmission services for the life of the project, as applicable.

If the off-system generation resource is located outside of Florida, it is the responsibility of the Respondent to facilitate the associated transmission services with Georgia ITS as well. However, due to the limited inter-state power transfer capacity from Georgia into Florida under planned and unplanned transmission outage conditions, **the Response must clearly state, within the submission of Appendix F- Respondents Questionnaire, the methods for which the power transfer under such contingency situations will be seamlessly maintained for JEA.**

Impacts to Other Utilities' Transmission Systems

The proposed resource could impact a 3rd-party transmission system (i.e., not JEA or the interconnecting transmission owner) The Respondent will be responsible for all upgrades necessary to alleviate the impacts to the 3rd-party transmission owner.

The Respondent is expected to account in the Response pricing and timeline for the cost of any transmission upgrades or additions identified on the 3rd-party system. The Response, within Appendix F – Response Questionnaire, shall include a breakout of the assumed cost of these upgrades to facilitate JEA's assessment of risk associated with the proposed upgrades or construction.

The Respondent is encouraged to include within the Response price a contingency that the Respondent feels is reasonable and responsible for mitigating any impacts to non-JEA party owned transmission facilities resulting from any transmission upgrades or additions detailed in the Respondent's Response. The contingency cost shall be identified as a breakout to facilitate JEA's assessment of risk associated with the potential impacts to non-JEA parties from the proposed upgrades or construction.

Impact to JEA Transmission System

The Respondent will be responsible for all cost associated with the impact to JEA's transmission system to facilitate the delivery of power from the proposed resource. This includes, but is not limited to, JEA's existing transmission infrastructure and JEA's existing import and export capability. It is not necessary to

include any costs for impacts to JEA's transmission system, as these impacts and costs will be evaluated by JEA during the Response evaluation and added to the Response price as needed.

Impact to Reserve Requirements (>700 MW Response from a single unit)

If the Response is for capacity and energy that exceeds 700 MW for JEA from a single unit, the JEA will incorporate within the evaluation of the Response the cost of any system upgrades and services needed to meet reliability and backup regulatory requirements relative to the loss of a single unit for the capacity exceeding 700 MW. For the purpose of this requirement, a unit is defined as either 1) the rating of a single generator supplying the proposed capacity, or 2) the aggregated rating of all generators for interrelated CT(s) and ST(s) that make up a CCCT unit supplying the proposed capacity.

Notes on Process Requirements for Off-System Resources

1) Generation resource located within Florida -

- The Respondent should clearly state where the resource will be located and how it will be delivered to JEA. Depending upon the physical location as well as electric proximity, such resource may need to be wheeled through a single entity's transmission system or through multiple entities' systems. It is the responsibility of the Respondent to take all the necessary steps with any related transmission services; including the ancillary services; for the delivery into JEA's transmission system. The Respondent must submit a request for transmission service and the associated study (TSR/GISR study process of FRCC) to be in the transmission provider's queue consistent with the requirements of the proposed project schedule. This study must be completed by a transmission consulting engineering firm with experience in FRCC region, and at the Respondent's expense. It is the responsibility of the Respondent to provide all modeling data pertaining to the generation resource and transmission configuration (as applicable) required for the study.

2) Generation Resource located outside of Florida

- The Respondent should clearly state where the resource will be located outside of Florida and how it will be delivered/wheeled to JEA. The wheeling of such resource will involve utilizing transmission resources inside Florida as well as that of Georgia ITS, and any other parties if the resource is located outside of Georgia ITS. As stated earlier, JEA's import allocation cannot be utilized for this option and the Respondent must clearly specify how the power import under planned and unplanned outage situations will be seamlessly maintained for JEA. In addition to going through FRCC's TSR/GISR process, this will also involve transmission service request and study for Georgia ITS, and any other parties if the resource is located outside of Georgia ITS.
 - Any such studies (for FRCC, Georgia ITS, and outside of Georgia ITS transmission impacts) must be completed by a transmission consulting engineering firm with experience in both FRCC and ITS regions, and outside of Georgia ITS system if applicable, at the Respondent's expense. It is the responsibility of the Respondent to provide all modeling data pertaining to the generation resource and transmission configuration (as applicable) required for the system impact studies.
- 3) If the Response includes the construction of a new transmission line, its impact must be studied through FRCC's TSR/GISR process. Also, all the regulatory and environmental permitting, and processes for transmission construction as applicable (e.g. TLSA, Order 1000 process as applicable to FRCC etc.) must be followed by the Respondent. Similarly, the impact of the construction of any new

transmission line in Georgia ITS or outside of Georgia ITS must be studied with all appropriate procedure, if applicable.

- 4) The Respondent will be responsible for ensuring that all required processes associated with interconnection and delivery of power from the facility is initiated according to the required development timeline to meet the proposed commercial operation date.



Appendix C - Minimum Requirements Form

THE MINIMUM QUALIFICATIONS SHALL BE SUBMITTED ON THIS FORM. IN ORDER TO BE CONSIDERED A QUALIFIED RESPONDENT BY JEA YOU MUST MEET THE MINIMUM QUALIFICATIONS LISTED BELOW, AND BE ABLE TO PROVIDE ALL THE SERVICES LISTED IN THIS SOLICITATION/TECHNICAL SPECIFICATION.

THE RESPONDENT MUST COMPLETE THE RESPONSE INFORMATION SECTION BELOW AND PROVIDE ANY OTHER INFORMATION OR REFERENCE REQUESTED. THE RESPONDENT MUST ALSO PROVIDE ANY ATTACHMENTS REQUESTED WITH THIS MINIMUM QUALIFICATIONS FORM.

BY SIGNING THIS FORM, THIS IS YOUR CONCURRENCE THAT YOU MEET MINIMUM QUALIFICATIONS FOR SUBMISSION OF A RESPONSE.

RESPONDENT INFORMATION

COMPANY NAME:
BUSINESS ADDRESS:
CITY, STATE, ZIP CODE:
TELEPHONE:
E-MAIL:
PRINT NAME OF AUTHORIZED REPRESENTATIVE:
SIGNATURE OF AUTHORIZED REPRESENTATIVE:
NAME AND TITLE OF AUTHORIZED REPRESENTATIVE:

Respondent must meet the following Minimum Qualifications to be considered eligible to have its Response evaluated by JEA. The Minimum Requirements Form is to be completed by each Respondent in connection with the Solicitation. Respondents must enter the information requested in the left column in the adjacent blank cell in the "Response" column. In the "Documentation Column", Respondent is to provide the name of the file that provides the information/evidence needed to confirm Respondent's response. *A Minimum Requirements Form must be completed for each Response in order to be considered conforming and evaluated further.*

Assessment Criteria	Response Description	Response	Documentation
Summary Information			
Respondent Name	[Name]		
Facility Name	[Name]		
Proposal Transaction Type	[PPA/BTA/Acquisition]		
Resource Location	[City/County]		
Configuration (if applicable)	[e.g., 2x1]		
COD, delivery start date, or acquisition date	9/30/2031		
Provide PPA Term Length, if applicable	[Years/NA]		
Minimum Criteria			
1 Confirm that the Respondent has fully completed all required forms and provided all required information, consistent with the instruction in Section 5 and Section 17 of the Main Body of this Solicitation.	[Yes/No]		
2 Confirm Response has a guaranteed delivery start date, commercial operation date ("COD"), or acquisition date of no later than December 31, 2030.	[Yes/No]		
3 Confirm that the Response is for at least 525 MW (Average Ambient Conditions).	[Yes/No]		
4 Confirm that the Response includes a project development schedule that identifies, at a minimum, the schedule milestones required by JEA, any environmental permitting, transmission interconnection and delivery, and other applicable regulatory processes to facilitate the quoted delivery start date or COD of the proposed resource.	[Yes/No]		
5 The Respondent certifies that the Response includes detailed plans and schedules for transmission interconnection, including submission into the interconnection queue, the implementation of any required transmission upgrades, and the associated transmission service(s) for the power to be delivered to JEA service territory in compliance with all the state and federal regulations.	[Yes/No]		
6 Confirm that the Respondent satisfies and accounts for within its Response JEA's credit standards outlined in Appendix G – Credit Requirements.	[Yes/No]		
7 For resources that JEA will not be operating (e.g., PPAs and off-system BTAs), Respondent acknowledges that the Response is for firm-delivered energy, and Respondent is responsible for providing gas transportation adequate to ensure firm delivery of energy.	[Yes/No/NA]		
8 Confirm that the Response includes five (5) days of onsite, liquid back-up fuel storage and 5 days of on-site demineralized water storage and/or installed production capability.	[Yes/No]		
9 Confirm that the Response includes a resource with commercially-proven technology.	[Yes/No]		
10 Confirm that the Response includes JEA's ability to dynamically schedule (e.g., automatic generation control ("AGC")) the proposed resource.	[Yes/No]		
11 Confirm that the Response includes JEA's ability to commit and decommit the proposed facility at JEA's sole discretion, or the bottom of the dispatch range must be 0MWs.	[Yes/No]		
12 Confirm that the Respondent acknowledges that any resulting agreement between the Respondent and JEA will require long-term coordination and approval of scheduled maintenance by JEA.	[Yes/No/NA]		
13 To the extent the Response is for a BTA or APA proposal outside of JEA's service territory, confirm an O&M Agreement is included within the Response.	[Yes/No/NA]		
14 Confirm that, for a PPA Response, the term is for at least for 20-years.	[Yes/No/NA]		
15 Confirm that, for any PPA Response with terms less than 30 years or the expected life of the resource (whichever is less), the Response includes an option for a contract extension beyond the proposed PPA term to the lesser of 30 years or the expect end-of-life date.	[Yes/No/NA]		

16	Confirm that the Respondent acknowledges that any study(ies) associated with the system impact must be performed by a transmission consulting engineering firm with experience in the respective (FRCC/ITS) region(s).	[Yes/No]		
17	As outlined in Appendix B – Transmission Interconnection and Delivery Considerations, the Respondent acknowledges that all applicable estimated capital cost for any system improvements or new constructions, and the costs of any transmission services through the project life cycle, that will not be estimated by JEA, have been provided along with the Response. The bidder acknowledges that the Respondent price is all inclusive of such costs.	[Yes/No]		
18	Confirm that the Respondent is not on the State of Florida Convicted Vendor List, State of Florida's Suspended Vendor List, the City of Jacksonville's Disqualified Vendor List, have their bidding privileges actively suspended by JEA, been debarred by JEA, or have had a contract with JEA was terminated for default within the last two (2) years.	[Yes/No]		
19	Respondent acknowledges that immediately following JEA Board approval to negotiate, Respondent will support JEA with all necessary information for filing of petition for Determination of Need, and Site Certification Application, as applicable to the response.	[Yes/No]		
20	Attended Mandatory Pre-Response Meeting as found in Section 8 of this Solicitation.	[Yes/No]		



Appendix D - Response Submission Form

Instructions:

Respondents must fill out all fields for each Response in the applicable tab corresponding to the Response type. All Responses must have its own individual column and all fields must be filled out by Respondents for each of the Responses to meet the Solicitation's Minimum Requirements. Additionally, each Response must provide information for a guaranteed heat rate curve in the "Heat Rate Inputs" tab in the corresponding Response Number input section.

Response Input Sheet - PPAs

Respondent Name

Response Number
Facility Name
Resource Type
Expected Commercial Operations Date
Guaranteed Commercial Operations Date
Delivery Term (Years)
Primary Fuel
Secondary Fuel (if applicable)
Generation Configuration
Energy Delivery Point
Interconnection Location

PPA Response 1	PPA Response 2	PPA Response 3	PPA Response 4

Operational Input

Facility Description

1	Project Design Life	Years				
2	Net Maximum Capacity of Facility	MW				
3	Net Maximum Capacity Allocated to Buyer	%				
4	Interconnection Capacity	MW				
5	Expected Contract Capacity	MW				
6	Guaranteed Contract Capacity	MW				
7	MECL Dependable Capacity (allocated to Buyer)	MW				

Facility Operations

8	Minimum Run Time	Hours				
9	Minimum Down Time	Hours				
10	Maximum Ramp-up Rate	MW/minute				
11	Maximum Ramp-down rate	MW/minute				
12	Maximum number of Complete Starts per day	#				
13	Maximum number of Complete Starts per year	#				
14	Hot Start-up Time	Minutes				
15	Duration of Shut Down to Hot Start	Hours				
16	Warm Start-up Time	Minutes				
17	Duration of Shut Down to Warm Start	Hours				
18	Cold Start-up Time	Minutes				
19	Hot Start Fuel Quantity	MMBtu/MW/CT				
20	Warm Start Fuel Quantity	MMBtu/MW/CT				
21	Cold Start Fuel Quantity	MMBtu/MW/CT				

Outage Information

22	Planned Outage Rate	%				
23	Forced Outage Rate	%				
24	Availability Rate	%				

Emissions

25	CO2 emission rate	lbs/Mwh				
26	NOx emission rate	lbs/MWh				
27	SOx emission rate	lbs/MWh				

Pricing Input

PPA Price Components

Capacity Rate

28	Year 1	\$/kW-mo				
29	Annual Escalation	%/year				
30	Response Price Adjustment (Defined in Section 15 of Solicitation)	Text				
31	Capacity Rate Price Cap	\$/kW-mo				

Fixed O&M

32	Fixed O&M - Year 1	\$/kW-mo				
33	FOM - Annual Escalation	%/year				

Energy Charges

34	Variable O&M - Year 1	\$/MWh				
35	VOM - Annual Escalation	%/year				
36	Start Charge - Year 1	(\$/Completed Start/CT)				
37	Start Charge - Annual Escalation	%/year				

38	Notes, If Any	Text				

Response Input Sheet - BTAs and Acquisitions

Respondent Name	Response Number	BTA/APA Response 1	BTA/APA Response 2	BTA/APA Response 3	BTA/APA Response 4
	Facility Name				
	Resource Type				
	Expected Commercial Operations Date				
	Guaranteed Commercial Operations Date				
	Primary Fuel				
	Secondary Fuel (if applicable)				
	Generation Configuration				
	Energy Delivery Point				
	Interconnection Location				

Operational Input

Facility Description

1	Project Design Life	Years				
2	Guaranteed Net Electrical Output	MW				
3	Net Maximum Capacity Allocated to Buyer	%				
4	Interconnection Capacity	MW				
5	Guaranteed MECL Dependable Capacity (allocated to Buyer)	MW				

Facility Operations

6	Minimum Run Time	Hours				
7	Minimum Down Time	Hours				
8	Maximum Ramp-up Rate	MW/minute				
9	Maximum Ramp-down rate	MW/minute				
10	Maximum number of Complete Starts per day	#				
11	Maximum number of Complete Starts per year	#				
12	Hot Start-up Time	Minutes				
13	Duration of Shut Down to Hot Start	Hours				
14	Warm Start-up Time	Minutes				
15	Duration of Shut Down to Warm Start	Hours				
16	Cold Start-up Time	Minutes				
17	Hot Start Fuel Quantity	MMBtu/MW/CT				
18	Warm Start Fuel Quantity	MMBtu/MW/CT				
19	Cold Start Fuel Quantity	MMBtu/MW/CT				

Outage Information

20	Planned Outage Rate	%				
21	Forced Outage Rate	%				
22	Availability Rate	%				

Emissions

23	CO2 emission rate	lbs/MWh				
24	NOx emission rate	lbs/MWh				
25	SOx emission rate	lbs/MWh				

Pricing Input

Acquisition Price Components

26	Acquisition Purchase Price	\$				
	Response Price Adjustment (Defined in Section 15 of Solicitation)	Text				
	Acquisition Purchase Price Cap	\$				
27	Notes, If Any	Text				

Response Input Sheet - BTAs and Acquisitions

Respondent Name

PPA Guaranteed Heat Rate Information Request		PPA Response 1		PPA Response 2		PPA Response 3		PPA Response 4	
		Heat Rate	Capacity	Heat Rate	Capacity	Heat Rate	Capacity	Heat Rate	Capacity
		Btu/kWh	MW	Btu/kWh	MW	Btu/kWh	MW	Btu/kWh	MW
Summer Guaranteed Heat Rate									
1	Maximum Dependable with Supplemental Capacity								
2	Maximum Dependable Base Capacity								
3	75% of Base Dependable Capacity								
4	50% of Base Dependable Capacity								
5	MECL Dependable Capacity								
Winter Guaranteed Heat Rate									
6	Maximum Dependable with Supplemental Capacity								
7	Maximum Dependable Base Capacity								
8	75% of Base Dependable Capacity								
9	50% of Base Dependable Capacity								
10	MECL Dependable Capacity								

BTA/APA Guaranteed Heat Rate Information Request		BTA/APA Response 1		BTA/APA Response 2		BTA/APA Response 3		BTA/APA Response 4	
		Heat Rate	Capacity	Heat Rate	Capacity	Heat Rate	Capacity	Heat Rate	Capacity
		Btu/kWh	MW	Btu/kWh	MW	Btu/kWh	MW	Btu/kWh	MW
Guaranteed Heat Rate for Summer Ambient Conditions									
1	Maximum Dependable with Supplemental Capacity								
2	Maximum Dependable Base Capacity								
3	75% of Base Dependable Capacity								
4	50% of Base Dependable Capacity								
5	MECL Dependable Capacity								
Guaranteed Heat Rate for Winter Ambient Conditions									
6	Maximum Dependable with Supplemental Capacity								
7	Maximum Dependable Base Capacity								
8	75% of Base Dependable Capacity								
9	50% of Base Dependable Capacity								
10	MECL Dependable Capacity								
Guaranteed Heat Rate for Average Ambient Conditions									
11	Maximum Dependable with Supplemental Capacity								
12	Maximum Dependable Base Capacity								
13	75% of Base Dependable Capacity								
14	50% of Base Dependable Capacity								
15	MECL Dependable Capacity								

Appendix E(i) – Power Purchase Agreement (PPA) Term Sheet

The following terms and conditions shall apply to any Agreement between JEA and Respondent for the purchase by JEA of long-term capacity, energy, and ancillary services from a combined cycle combustion turbine (CCCT) resource in connection with the Solicitation. The terms set forth in this Term Sheet will establish the basis for the negotiation and execution of a Definitive Agreement between JEA and any Respondent whose Response is selected by JEA for contract negotiations in connection with the Solicitation. Any changes or special considerations provided in the Respondents Response may only be accepted by JEA in its sole and absolute discretion. JEA shall provide the initial draft of the contract to the selected Respondent at the beginning of contract negotiations.

If Respondent is unable or unwilling to accept one or more of the terms and conditions set forth in this Term Sheet or wishes to propose any alternative or additional terms or conditions (e.g., a buy-out option during or at the conclusion of the Delivery Term), Respondent should indicate in its Response (i) the terms and conditions to which Respondent takes exception, describing with specificity any terms and conditions that Respondent proposes in substitution, and/or (ii) the additional terms and conditions that Respondent proposes as a supplement to the terms and conditions in this Term Sheet. The Respondent may utilize **Appendix F – Respondent Questionnaire** to provide a description of the proposed edits or additional conditions or provide redlines to this Term Sheet.

Response Term		Description of Response Term
1	Product Description	The product described in this Term Sheet is designated as the “Product” or “PPA Product.” The referenced Product provides for delivered capacity, energy, and ancillary services from flexible generation with an Expected Contract Capacity at Summer Conditions no lower than 525 MW and up to a preferred maximum of 700 MW at base load including duct-firing, from a designated CCCT resource capable of meeting the requirements of this Product (the “Facility”). Buyer will be entitled to all delivered capacity, energy, and ancillary services from the Facility (or, in the event Respondent proposes to allocate to Buyer a portion of the net maximum capacity of the Facility, the corresponding portion thereof). Buyer will be entitled to dynamic scheduling of the Product, and Buyer shall have sole right to commit and decommit the Facility or schedule the Product to zero (0) MW at Buyer’s sole discretion.
2	Buyer	“ Buyer ” shall mean JEA, a body politic and corporate.
3	Seller	“ Seller ” will be the party specified by Respondent in the applicable Response.
4	Facility	The “ Facility ” includes the net maximum capacity and major

		equipment as specified by Respondent in the applicable Response. Net maximum capacity is measured at the Interconnection Location.
5	Energy Delivery Point	The point on the JEA Transmission System at which deliveries of capacity, energy, and ancillary services from Seller to Buyer are required to be made and scheduled. The Energy Delivery Point will be as specified by Respondent in the applicable Response, will be on the JEA bulk power system at voltages of 138kV or 230kV (depending on proposed location), and consistent with the details and requirements set forth in Appendix B – Transmission Interconnection and Delivery Considerations.
6	Interconnection Location	The Interconnection Location is the location on the transmission system to which the Facility is interconnected. The Interconnection Location is on the high-voltage side of the generator step-up transformer, at the location where net output is measured directly or where gross output is measured and auxiliary load is measured then subtracted from gross output to calculate net output.
7	Electric Interconnection and Transmission	Seller will be responsible for the interconnection of the Facility at the Interconnection Location and the transmission or transfer of power dispatched by Buyer to the Energy Delivery Point located on the JEA Transmission System. Without limiting the foregoing, (i) all costs are assigned to the interconnection customer under the interconnection agreement for the Facility, (ii) all costs of any transmission service, (iii) any required ancillary costs, and (iv) any transmission system additions or modifications required for the interconnection of the Facility or the transmission or transfer of power to the Energy Delivery Point will be borne by Seller. Additional details and requirements regarding the interconnection and delivery of power to the JEA Transmission System can be found in Appendix B- Transmission Interconnection and Delivery Considerations.
8	Delivery Term	The Delivery Term (in years) and Seller's Conditions Precedent is expected to be specified by the Respondent in the applicable Response. The Delivery Term will commence once the last of the Conditions Precedent (see item 33) have been satisfied or waived by the applicable party. JEA prefers a Delivery Term of 20-years or more, and any Response for a PPA Product with terms less than 30 years or the expected life of the resource (whichever is less) must include priced options for contract extensions beyond the proposed PPA term.

9	Transmission Losses (TL)	The estimated amount of the decrease in electrical power between the Interconnection Location and the Energy Delivery Point (“Transmission Losses”) will be accounted for in the measurement of delivered Contract Capacity, energy, and ancillary services. In other words, any compensation from Buyer to Seller as a result of the obligations under the Agreement will be measured at the Energy Delivery Point accounting for Transmission Losses. The Response shall include a schedule of Transmission Losses (as applicable) for delivery of the Product from the Interconnection Location to the Energy Delivery Point.
10	Pricing	Pricing for this Product will be composed of: (i) a Capacity Rate expressed in \$/kW-mo specified in item 18 below; (ii) an Energy Price expressed in \$/MWh specified in item 21 below; (iii) a Fixed O&M Rate expressed in \$/kW-mo specified in item 22 below, (iv) a Variable O&M Rate expressed in \$/MWh specified in item 23 below; (v) a Start-up Charge expressed in \$ per Completed Start specified in item 24 below; and (vi) if applicable, a Start Fuel Charge calculated as specified in item 25 below. Except to the extent otherwise expressly provided in this Term Sheet, Buyer will not be required to pay any amounts to Seller other than the Capacity Payment, Fixed O&M Payment, the Energy Payment, the Start-up Payment, and, if applicable, the Start Fuel Payment derived from the pricing described above.
11	Average Ambient Condition (AA)	The Average Ambient Condition (AA) for Jacksonville, FL is 69F, 81.8% RH and Barometric pressure of 14.86 psia. (Referenced at Jacksonville International Airport (JIA) from 2018-2023) If the Facility is located elsewhere, and the Average Ambient conditions are notably different, then local Average Ambient conditions should be used, and conditions must be stated.
12	Summer Ambient Condition (SA)	The peak Summer Ambient Condition (SA) for Jacksonville, FL is 98F, 38.2% RH and Barometric pressure of 14.67 psia. (Referenced at JIA from 2018-2023) If the Facility is located elsewhere, and the Summer Ambient conditions are notably different, then local Summer Ambient conditions should be used, and conditions must be stated.
13	Winter Ambient Condition (WA)	The peak Winter Ambient Condition (WA) for Jacksonville, FL is 24F, 67.8% RH and Barometric pressure of 14.86 psia. (Referenced at JIA from 2018-2023) If the facility is located elsewhere, and the Winter Ambient conditions are notably different, then local Winter Ambient

		conditions should be used, and conditions must be stated.
14	Facility Ambient Condition (FA)	Facility Ambient Conditions are the hourly ambient conditions at Facility in the hour being evaluated. This will be defined by the Respondent within the Response.
15	Net maximum Capacity Allocated to Buyer	The portion of the net maximum capacity of the Facility allocated to Buyer (expressed in %) is expected to be specified by the Respondent within the Response.
16	Contract Capacity	The Contract Capacity means the Net Dependable Capacity (MW) that the Facility (or, in the event Respondent proposes to allocate to Buyer a portion of the net maximum capacity of the Facility, the corresponding portion thereof) is capable of delivering reliably to Buyer at the Energy Delivery Point accounting for Transmission Losses under Summer Ambient Conditions. The Contract Capacity will be established and adjusted consistent with Performance Testing described in item 28 below shortly before the Commercial Operation Date or the start of the Delivery Term and at the request of the Buyer from time to time. The Respondent shall provide within its Response the Expected Contract Capacity under Summer Ambient Conditions and Guaranteed Contract Capacity under Summer Ambient Conditions. The Guaranteed Contract Capacity can be no less than 95% of the Expected Contract Capacity. Expected Contract Capacity should be the estimated Contract Capacity based on the proposed design and expected performance of the Facility. The Guaranteed Contract Capacity establishes minimum performance requirements as described in item 17 below. The Contract Capacity may be no more than 3% above Expected Contract Capacity.
17	Initial Capacity Shortfall Liquidated Damages	Prior to the start of the Delivery Term, the Contract Capacity must meet the Guaranteed Contract Capacity provided within the Response. If Performance Test results show that the Contract Capacity is less than the Guaranteed Contract Capacity, then a capacity shortfall exists. The Respondent shall be given 180 days from the Guaranteed COD to meet the Guaranteed Contract Capacity. If the Respondent cannot make right the Contract Capacity but is able to achieve at least 85% of the Expected Contract Capacity, then the Respondent may reset the Guaranteed Contract Capacity (the “Revised Guaranteed Contract Capacity”) but shall be subject to the Initial Capacity Shortfall Liquidated Damages. The Delivery Term shall not commence until the Initial Capacity Shortfall is rectified as described herein. Calculation of the Initial Capacity Shortfall

		Liquidated Damages shall be as follows: Sum of [(Guaranteed Contract Capacity – Revised Guaranteed Contract Capacity) * 1000 kW/MW * Replacement Capacity Cost Rate (\$/kW-Yr) escalated at the Respondent’s capacity escalation rate for each year of the Delivery Term and discounted back to the COD year at 3%. The Replacement Capacity Cost Rate shall be \$115 /kW-Yr) To the extent the Seller is unable to meet 85% of the Guaranteed Net Dependable Capacity, the Seller will be in Default of the Agreement, and the Buyer will have the right to terminate the agreement.
18	Capacity Rate	The Capacity Rate (expressed in \$/kW-month) for the Contract Capacity in each year of the Delivery Term will be based upon the rate specified by Respondent in the applicable Response. The Capacity Rate can be fixed for the Delivery Term or can be escalated annually via a proposed escalation rate.
19	Monthly Availability Requirement	Monthly Availability Requirement will be 98% for Summer (including the months of June through August) and Winter (including the months of December through February) and 96% for all other months of the Delivery Term. The Facility’s Monthly Availability shall be developed and negotiated in connection with the Definitive Agreement. The Respondent may provide proposed terms for calculating the Facility’s Monthly Availability. The Definitive Agreement will use and account for the following in determining the Facility’s Monthly Availability: • Will be based on Contract Capacity and calculated on a MWh basis accounting for derations and/or unavailability of the Facility during the applicable month. • Will be measured at the Energy Delivery Point and shall include any unavailability or deration resulting from the Facility, Force Majeure, fuel delivery, or due to transmission constraints between the Interconnection Location and the Energy Delivery Point. • Will include an allowance for Planned Maintenance hours. There will be a maximum number of Planned Maintenance hours for each year, informed by industry best practices and guidance from the Original Equipment Manufacturer (OEM). Additional information regarding Planned Maintenance is provided in item 29 below. • Will be impacted to the extent the resource is unable to reach the Minimum Emissions Compliant Load (MECL), or zero (0) MW if Buyer does not have the right to commit and decommit the facility at Buyer’s sole discretion (“Minimum Dispatch Level”).

		Will include the potential for Seller to offer replacement capacity to offset impacts to the Facility's Monthly Availability, with the acceptance of the replacement capacity being in Buyer's sole discretion.
20	Capacity Payment and Capacity Payment Discount	Capacity Payment will equal the Capacity Rate multiplied by the Contract Capacity, subject to the Capacity Payment Discount described below. Capacity Payment Discount - If the Facility's Monthly Availability for a month is below the applicable Monthly Availability Requirement, a discount will apply to the Capacity Payment. The Capacity Payment Discount will be two percent (2%) of the Capacity Payment for the applicable month for each one percent (1%) shortfall to the Monthly Availability Requirement. However, to the extent the unavailability is due solely to Force Majeure, the Capacity Payment Discount will be one percent (1%) of the Capacity Payment for the applicable month for each one percent (1%) shortfall to the Monthly Availability Requirement. In no event will the Capacity Payment Discount exceed one hundred percent (100%) of the Capacity Payment for the applicable month.
21	Energy Price and Energy Payment	The Energy Price will be equal to the Actual Heat Rate of the Facility (expressed in MMBtu (HHV)/MWh) multiplied by the applicable Fuel Price (expressed in \$/MMBtu (HHV)). The "Actual Heat Rate" of the Facility is the actual operating performance in such hour with respect to the energy deliveries at the Energy Delivery Point during such hour, expressed in actual MMBtu of gas consumed per MWh of delivered energy (HHV) at the Energy Delivery Point, unless modified per the terms outlined below. However, if, as a result of a unit contingency or other limitation, Buyer's dispatch level was limited during such hour and such limitation resulted in a higher applicable heat rate, the Actual Heat Rate will be the heat rate corresponding to Buyer's dispatch that would have occurred during such hour absent such limitation. The "Guaranteed Heat Rate" means, with respect to any hour of energy delivery, the heat rate (expressed in \$/MMBtu (HHV)) (which will be based on the Guaranteed Heat Rate curve specified within the Response) corresponding to Buyer's dispatch level during such hour. The Guaranteed Heat Rate curve provided in the Response will include, but is not limited to, the following dispatch levels:

- Base Load + DF = Base load plus 100% Duct (or Supplemental) Firing
- Base Load = 100% Maximum Capacity with 0% Duct Firing
- 75% of Base Load
- 50% of Base Load
- Minimum Dispatch Level (i.e., Minimum Emissions Compliant Load (MECL) or (0) MW)

The Guaranteed Heat Rate curve may be provided on a seasonal basis.

If, in any hour, the Facility's Actual Heat Rate is at a heat rate that is:

- greater than 103% of the Guaranteed Heat Rate, the Actual Heat Rate will be the Guaranteed Heat Rate multiplied by 103%; or
- lower than 97% of the Guaranteed Heat Rate, the Actual Heat Rate will be the Guaranteed Heat Rate multiplied by 97%.

To the extent the Response is based on providing a portion of a larger Facility, the Actual Heat Rate will equal to the Guaranteed Heat Rate provided within the Response.

The Fuel Price is expected to account for fuel commodity cost, and any variable cost for fuel delivery. Operationally, fuel commodity cost and transportation cost shall be addressed as follows:

1. Hourly Fuel Commodity Price shall be the real-time average price for 100% of the fuel commodity supplied to the facility in the subject hour on a \$/mmBtu basis.
 - a. Hourly Fuel Commodity Price shall be the weighted cost of the fuel, (natural gas or diesel), expected to be burned in the hour.
 - b. In the case of a delivered product, it may include the variable delivery cost provided that same delivery cost is not also included in the Hourly Fuel Variable Delivery Cost.
 - c. Price shall be weighted average by expected percentage or quantity used from each source.
2. Hourly Fuel Variable Delivery Cost shall be the real-time average price for any non-firm fuel transportation charges to be added to the Hourly Fuel Commodity Price.
 - a. Hourly Fuel Variable Delivery Cost shall be the weighted variable delivery cost of the fuel, natural gas or diesel, that was not accounted for in delivered fuel cost, for the fuel expected to be burned in the hour.
 - b. It may include any variable (non-firm) interstate delivery

		cost identified in the fuel supply plan or any per mmBtu O&M cost associated with firm transportation (interstate or local), but shall not include the cost of Firm Interstate Transportation Reservation Charges or Firm Local Delivery Reservation Charges c. Price shall be weighted average of variable transportation cost by expected percentage or quantity used from each source. 3. Firm Transportation Reservation Charges shall be the annual fixed cost of all Firm Interstate Transportation Reservation Charges and Firm Local Delivery Reservation Charges. a. Annual Firm Transportation Reservation Charges (Interstate and local delivery separately) shall be provided as information for Response evaluation purposes b. Charges shall be recovered via the Capacity Rate in \$/kW-Mo, but must also be shown as a breakout to the Capacity Rate for evaluation purposes. 4. The following formula shall be used to calculate the Energy Price on an hourly basis: Hourly Energy Price (\$/MWh) = (Hourly Fuel Commodity Price + Hourly Fuel Variable Delivery Cost)* Actual Heat Rate (HR))*(1000kWh/MWh)*1mmBtu/ 1,000,000Btu 5. Energy Payment = monthly sum((hourly Energy Price (\$/MWh) + VOM (\$/MWh)) * hourly MWh) The Response will be evaluated based on the use of gas sourced at Henry Hub prices. For PPA evaluation gas commodity prices for Henry Hub will be as forecasted by buyer. Response shall include any necessary variable interstate transportation costs and/or firm fuel transportation (\$/mmBtu) O&M costs for the duration of the Delivery Term. Response shall include any necessary fixed adders (or deducts) to Henry Hub fuel commodity price for the duration of the Delivery term. Response shall also include separately the Firm Interstate and Firm Local delivery reservation charges for the duration of the delivery term. These costs shall be lumped into the capacity payment, but must be identified separately for evaluation purposes.

22	Fixed O&M (FOM) Rate	A Fixed O&M Rate (\$/kW-Mo) shall be proposed with Response. FOM Rate can be fixed for the Delivery Term or can be escalated annually via a proposed escalation rate. FOM Payment will equal the FOM Rate multiplied by the Contract Capacity.
23	Variable O&M (VOM) Rate	For each MWh of energy dispatched by Buyer and delivered to Buyer from the Facility (or portion thereof allocated to Buyer) at the Energy Delivery Point, Buyer will pay the “Variable O&M Rate.” The Variable O&M Rate (expressed in \$/MWh) can be fixed for the Delivery Term or can be escalated annually via a proposed escalation rate. Notwithstanding the foregoing, the Variable O&M Rate will not apply to ramp energy delivered by Seller to Buyer during any start-up or shutdown.
24	Start-Up Charge	For each Completed Start, Buyer will pay the “Start-up Charge.” The Start-up Charge (expressed in \$ per Completed Start) for each year of the Delivery Term will be based upon the amount specified by Respondent in the applicable Response. The Start-Up Charge can be fixed for the Delivery Term or can be escalated annually via a proposed escalation rate. “Completed Start” means a start-up of a combustion turbine at the Facility (i) required to be undertaken solely as a result of an increase in dispatch by Buyer either from 0 MW to positive MW or from less than the Minimum Dispatch Level for a multiple combustion turbine operating configuration to greater than or equal to the Minimum Dispatch Level for such multiple combustion turbine operating configuration and (ii) during which (a) an output level to Buyer at the Energy Delivery Point equal to the Minimum Dispatch Level for the dispatched operating configuration is achieved for at least thirty (30) consecutive minutes and (b) the Facility is released unconditionally for ramping to, and the attainment of, any higher output level dispatched by Buyer, but excluding any such start-up that follows any shutdown that is not scheduled by Buyer (such as a shutdown resulting from the occurrence of a unit contingency or other limitation on the availability of the capacity of the Facility).
25	Start Fuel Charge	To the extent specified by Respondent in the applicable Response, for each Completed Start, Buyer will pay the “Start Fuel Charge” equal to the applicable gas price (expressed in \$/MMBtu) multiplied by the applicable start fuel amount (expressed in MMBtu), which gas price and start fuel amount will be based upon the amount specified by Respondent in the applicable Response. Response shall specify the mmBtu required for a cold, warm and hot startup.
26	Dispatch Rights	Throughout the Delivery Term, Buyer shall have sole rights to dynamically schedule Buyer’s allocated portion of all attributes resulting from the operation of the proposed Facility. Buyer’s ability to dispatch the Facility shall be consistent with the design capabilities of the Facility, and those restrictions laid out in the Response (“Operating Restrictions

and Capabilities”).

Operating Restrictions and Capabilities shall include the Contract Capacity, Minimum Dispatch Level for Summer and Winter months, minimum run time and down time, maximum number of Completed Starts per year, minimum start times, and maximum ramp rates. These restrictions should be substantially equivalent to the operating restrictions that would apply to the owner of the Facility. Buyer shall have sole right to commit and decommit the Facility or schedule the Facility to zero (0) MW at Buyer’s sole discretion.

As described in item 19 above, the Facility’s Monthly Availability may be impacted due to deviations from the proposed Operating Restrictions and Capabilities, specifically the Contract Capacity and the Minimum Dispatch Level, preventing the Buyer from operating the Facility consistent with Dispatch Rights defined in the Definitive Agreement.

Seller will make available to Buyer all capacity of the Facility (or, in the event Respondent proposes to allocate to Buyer a portion of the Facility, the corresponding portion thereof) and will deliver to Buyer all associated capacity, energy, and ancillary services at the Energy Delivery Point in accordance with Buyer’s dispatch notices. Without limiting the foregoing, Seller will be required to make available to Buyer, for delivery to Buyer at the Energy Delivery Point, any capacity of the Facility (or, in the event Respondent proposes to allocate to Buyer a portion of the Facility, the corresponding portion thereof) in excess of the Contract Capacity allocated to Buyer that the Facility is capable of delivering (as a result of prevailing ambient conditions or otherwise) (“Excess Capacity”) to the Energy Delivery Point, and, to the extent dispatched by Buyer (in its sole and absolute discretion), Seller will deliver to Buyer at the Energy Delivery Point the capacity, energy, and ancillary services associated with such excess capacity. Except to the extent required by a unit contingency, Seller will not interrupt, curtail or otherwise reduce the availability or deliveries of the capacity allocated to Buyer or any associated energy, and ancillary services, even if Seller is otherwise above the availability requirements of the Definitive Agreement. In addition, to the extent the Facility is capable, from time to time, of reduced operating restrictions (including reduced minimum permitted dispatch levels and start times and increased ramp rates) and, as a result, allows Buyer greater dispatch flexibility, Seller will make available such capability to Buyer.

Buyer’s rights to the capacity, energy, and ancillary services from the Facility (or, in the event Respondent proposes to allocate to Buyer a portion of the Facility, the corresponding portion thereof) are exclusive, and Seller may not offer, sell, deliver or make available during the

		Delivery Term any of such capacity, , energy, or ancillary services to any person other than Buyer (whether or not Buyer dispatches the Facility).
27	Real-Time Data	The Definitive Agreement shall require transmission of real-time Facility data, including but not limited to the following: 1. Real time available Contract Capacity or Excess Capacity 2. Real-time Actual Heat Rate 3. Real-time Fuel Price
28	Performance Testing	Performance Testing shall be performed shortly before the Commercial Operation Date (for Developmental Resources) of the start of the Delivery Term, and thereafter at the request of the Buyer from time to time, at Seller's expense, to demonstrate compliance with the various contract guarantees. Performance Testing schedule shall be as agreed upon by Buyer and Seller. Performance Testing shall be performed in accordance with all applicable ASME Performance Test Codes (PTCs). Procedures shall be mutually agreed upon by Buyer and Seller within the Agreement. Buyer and Buyer's engineer shall have the right to witness all Performance Tests. Pre-Test Calibrations shall be performed as required by Seller at Seller's expense. As part of performance test, custody transfer gas meters shall also be calibrated. Following test completion and calculation of results, Seller will deliver to Buyer via acceptable electronic means 100% of test input data, calculations and results. Performance tests shall be performed by a qualified independent contractor at Seller's expense, unless Buyer agrees at Buyer's sole discretion for Seller to self-perform. Performance Testing shall include a capacity, heat rate, and emission demonstration tests.
29	Planned Maintenance	All maintenance of the Facility (or any portion thereof) that has a pre-determined start date and duration and includes a reduction in the availability of the capacity of the Facility allocated to Buyer is required to be coordinated and scheduled in accordance with the Definitive Agreement as Planned Maintenance. Seller will have the right to schedule and conduct Planned Maintenance only during the months that Buyer agrees to schedule outages during. During the Delivery Term, Seller will deliver to Buyer its proposed schedule for Planned Maintenance at least 90 days ahead of the contract anniversary date. Changes in outage schedule will require different lead time depending on the outage duration.

		• Scheduled maintenance durations less than 2 day duration require 24 hours notice • Scheduled maintenance duration from 2 to 5 days require 7 days notice • Schedule maintenance durations over 5 days require 90 days notice Because Buyer's dispatch profile for Facility is not expected to be constant due to the evolving percentage of solar generation, and could be influenced by compliance requirements of the GHG Rule Buyer has requested a Milestone-Based Major Maintenance Plan. This plan should echo OEM Long-term Service Agreement (LTSA) recommendations for Major Maintenance Milestones. The plan should be detailed enough to determine outage schedules and costs based on both starts and hours-based maintenance. Each Major Maintenance Milestone activity shall have an outage duration attached to the activity. Major maintenance shall be performed at OEM recommended intervals, and shall overlap activities to the maximum amount possible. Planned Maintenance hours shall be accounted for within the Facility's Monthly Availability in determining any applicable Capacity Payment Discount. Response shall include all necessary OEM based data and information to schedule and estimate cost of Planned Maintenance activities for all major equipment (ST, STG, CT, CTG), including the following: 1. A list of Major Maintenance Milestone outages with the order they shall be performed, the means to determine, whether starts or hours based, when to schedule each milestone, the duration for each Milestone outage; 2. Days proposed for annual scheduled minor maintenance activities such as inspections; and 3. For Response evaluation Respondent shall supply a proposed major maintenance schedule for the facility lifecycle assuming 200 starts and 7000 hours per year, and a second schedule assuming 200 starts and 5400 hours per year.
30	Force Majeure	Neither party shall be liable for any default or delay in the performance of its obligations under the Agreement due to an act of God or other event to the extent that: (a) the non-performing party is without fault in causing such default or relay; (b) such default or delay could not have been prevented by reasonable precautions; and (c) such default or delay could not have been reasonably circumvented by the non-performing party through the use of alternate sources, work-around plans, or other means. Such causes include acts of civil or military authority (including but not

		limited to courts or administrative agencies); acts of God; war; terrorist attacks; riots; insurrection; inability of Buyer to secure approval, validation, or sale of bonds; inability of either party to obtain any required permits, licenses, or zoning; blockades; embargo; sabotage; epidemics or pandemics declared by public health authorities; fires; hurricanes; tornadoes; floods; or strikes. In the case of epidemic or pandemic, the parties stipulate that a Force Majeure event shall not include any epidemic or pandemic that is ongoing as of the date of execution of the Agreement. For the avoidance of doubt, a Force Majeure event shall not include (x) financial distress nor the inability of either party to make a profit or avoid a financial loss, (y) changes in market prices or conditions, or (z) a party's financial inability to perform its obligations hereunder. In the event of any delay resulting from such causes, the time for performance of each of the parties hereunder (including the payment of monies if such event prevents payment) shall be extended for a period of time reasonably necessary to overcome the effect of such delay, except as provided for elsewhere in the Agreement. In the event of any delay or nonperformance resulting from such causes, the party affected shall promptly notify the other in writing of the nature, cause, date of commencement and the anticipated impact of such delay or nonperformance. Such written notice shall indicate the extent to which it is anticipated that any delivery or completion dates will be thereby affected within seven (7) calendar days.
31	Transfer Restrictions	Seller will not (and will not permit any direct or indirect parent or affiliate of Seller to) sell or transfer the Facility (or its direct or indirect equity interests in Seller), including by merger, consolidation or sale of all or substantially all of its assets, without Buyer's prior written consent, which will not be unreasonably withheld or delayed, provided that it will be deemed reasonable for Buyer to withhold its consent if (a) the proposed transferee is not a qualified operator, (b) the proposed transferee has a creditworthiness below that of Seller, (c) any credit support provided by Seller prior to such sale or transfer would not remain in effect or be substituted with credit support acceptable to Buyer, (d) in the case of a direct transfer of the Facility, Seller does not concurrently assign its rights and obligations under the Agreement according to the assignment provisions thereof, or (e) the proposed transfer would create a prohibited conflict of interest on the part of Buyer or would otherwise be prohibited under Applicable Law.
32	Change in Law	The parties acknowledge the possibility that a Change in Law may occur that requires or will require one or both of the parties to incur additional costs (including environmental costs) during the Delivery Term beyond those projected to be incurred by such party as of the date of execution of the Definitive Agreement. Notwithstanding the foregoing, if such a change in law occurs, the other party will not be required to share in,

		reimburse, or otherwise pay all or any portion of such additional costs, except as expressly provided in the Agreement. Subject to the other terms herein, Buyer shall pay the net increase or decrease in the reasonable, actual, direct, and verifiable out-of-pocket costs, without mark-up, to the extent such costs are actually incurred by Seller in the provision to Buyer of PPA Product as a direct and proximate result of, and only to the extent required by, a Change in Law. Such costs shall exclude, without limitation, any costs that would not have been incurred but for other uses of the Facility. If more than one commercially reasonable option is available to comply with a Change in Law, the least cost option will serve as and establish the basis for determining the costs payable by Buyer irrespective of the option actually selected. Buyer's share of the payment of increased costs associated with a Change in Law shall be based on the percentage of the Facility's capacity that is dedicated to providing PPA Product to Buyer under the Agreement. Buyer shall have at least one hundred eighty (180) days after the receipt of notice from Seller of a Change in Law to conduct due diligence with respect to the Change in Law and associated costs. Seller shall cooperate with Buyer during the due diligence period. <i>Respondent shall propose a cap for expenditures by Buyer and Seller associated with a Change in Law.</i> Once the above caps are reached, Seller shall have a period of sixty (60) days to elect to terminate the Agreement and notify Buyer of such election. If Buyer does not receive notice within such sixty (60)-day period, Seller will be deemed to have waived such termination right with respect to all Changes In Law to date. If Buyer receives such notice within such sixty (60)-day period, Buyer may notify Seller within thirty (30) days either (i) that it accepts Seller's termination or (ii) that it wishes to engage in negotiations with Seller to amend the Agreement in light of the Change in Law. In the event Buyer elects to engage in negotiations, the parties shall negotiate in good faith to amend the Agreement. In the event the parties are unable to agree to and execute an amendment within sixty (60) days of commencing negotiations, Seller may terminate the Agreement by submitting a written notice of termination to Buyer.
33	Conditions Precedent	Buyer's obligations under the Definitive Agreement will be conditioned upon the fulfillment, or express waiver, by Buyer of the following conditions: 1) Buyer has obtained all Governmental Approvals deemed necessary or advisable by Buyer in order for Buyer to enter into the Definitive Agreement and perform its obligations thereunder;

		2) Buyer has obtained all third-party consents, approvals, and authorizations deemed necessary or advisable by Buyer to enter into the Definitive Agreement and perform its obligations thereunder; 3) All credit support requirements detailed in the Solicitation, as more fully developed in the Definitive Agreement have been posted by Seller and remain in full force and effect; 4) Seller has obtained all required Certificates of Insurance evidencing the coverages detailed in the Solicitation and has submitted such Certificates of Insurance to Buyer, and the required insurance remains in full force and effect; and 5) The Facility has achieved Commercial Operations (for developmental resources only).
34	Commercial Operation Date	The date by which it is expected that the Facility will have achieved Commercial Operations, as defined herein, is the date specified as such by Respondent in the Response (as such date may be extended to the extent Commercial Operations is delayed by an event of Force Majeure). Such date shall be referred to herein as the “Commercial Operation Date” or “COD”. Seller will notify Buyer immediately when the COD has occurred, including in such notice reasonable evidence to Buyer of the satisfaction of all of the conditions set forth in the Agreement and a certification to that effect by an officer of Seller familiar with the Facility after due inquiry of Seller. The Definitive Agreement will require Seller to provide periodic progress reports to Buyer and will grant to Buyer inspection and other rights applicable during the pre-commercial operation phase of the Definitive Agreement. If the COD does not occur on or before the Guaranteed COD specified by Respondent, which shall be no later than December 31, 2030, Seller will pay to Buyer liquidated damages of \$115 per MW of proposed Contract Capacity, for each day after the Guaranteed COD that COD is not achieved until the earliest of (i) the date Seller achieves COD, (ii) the date the Definitive Agreement is validly terminated, and (iii) one hundred eighty (180) days after the Guaranteed COD. Seller’s aggregate liability for liquidated damages pursuant to this paragraph will be capped at the product of (x) \$100 per MW of proposed Contract Capacity per day multiplied by (y) one hundred eighty (180) days. If the COD does not occur on or before the date after the Guaranteed COD on which the delay liquidated damages cap is reached Buyer will have the right, at any time thereafter until the COD occurs, to terminate the Definitive Agreement upon notice to Seller (and to receive termination damages arising out of any such termination).

35	Credit Support	Seller will be expected to meet the credit support requirements detailed in this Solicitation, including Appendix G, all of which will be more fully developed in the Definitive Agreement.
36	Seller Default	The Agreement shall include the following events of Seller Default: • Failure to pay amounts due; • Breach of representations and warranties; • Failure to provide or maintain required credit support; • Breach of covenants; • Assignment by Seller of the Agreement or sale or transfer of the Facility, directly or indirectly, except as permitted by the terms of the Agreement; • Bankruptcy, dissolution, or liquidation of Seller; • Default of Seller under any agreements relating to indebtedness for borrowed money in excess of a specified aggregate amount; • Seller makes any material intentional misrepresentation or omission in any metering report, invoice, estimate of intra-day gas cost, or availability notice required to be made or furnished by Seller pursuant to the Agreement or Seller's actual fraud, tampering with Buyer- owned facilities, or material intentional misrepresentation or misconduct in connection with the Definitive Agreement or operation of the Facility; • Except as expressly provided by the Agreement, Seller sells, assigns, or otherwise transfers, or commits to sell, assign, or otherwise transfer, the capacity, energy, or ancillary services that are subject to the Definitive Agreement, or any portion thereof, to any person other than Buyer; • The average of the Facility's Monthly Availability during any Rolling 12 Month Period is less than the Rolling 12 Month Availability Requirement of eighty-five percent (85%), where "Rolling 12 Month Period" means, as of the end of any month during the Delivery Term, the twelve (12)- month period that includes such month and the preceding eleven (11) months that occurred during the Delivery Term; • Default of Seller under, or failure to maintain in effect, any project document (including any interconnection agreement or other service-related agreement); • The commencement of the Delivery Term has not occurred by 180 days after the Guaranteed COD; Other events of default may be included in the Definitive Agreement as

		appropriate.
37	Termination Rights	The Definitive Agreement will contain provisions entitling a party the right to terminate the Definitive Agreement upon the occurrence and continuation of an event of default by the other party and to calculate termination damages based on the costs, gains, or losses incurred by the non-defaulting party arising out of termination of the Definitive Agreement. If the termination damages are negative, the non-defaulting party will not be obligated to pay such amount to the defaulting party.
38	Indemnification	To the extent permitted by law, and within the limitations provided herein, each party shall hold harmless and indemnify the other party, its governing board, officers, employees, and agents against any claim, action, loss, damage, injury, liability, cost and expense of whatsoever kind or nature (including, but not by way of limitation, reasonable attorney's fees and court costs) arising out of injury to persons, including death, or damage to property, arising out of the negligence, recklessness or intentional wrongful misconduct of the party and any person or entity used by either party in the performance of the obligations required by the Agreement. This indemnification shall survive the term of the Agreement for events that occurred during the term of the Agreement. This indemnification shall be separate and apart from, and in addition to, any other indemnification provisions set forth elsewhere in the Agreement. Buyer's indemnification of Seller shall be subject to and within the limitations set forth in Section 768.28, Florida Statutes. Buyer shall not agree to a waiver of such limitations or of its sovereign immunity. Notwithstanding the foregoing, in accordance with Section 768.28(5)(a), Florida Statutes, Buyer may agree to settle claims or judgements against it within the limitations of its insurance coverage without having been deemed to have waived any defense of sovereign immunity or to have increased its limits of liability as a result of obtaining such insurance coverage.
39	Confidentiality	Subject to Buyer's obligations under Chapter 119, Florida Statutes, and Section 21.09(c)(4) of the Charter of the City of Jacksonville, the parties will safeguard Confidential Information against disclosure by employing the same means to protect such Confidential Information as that party uses to protect its own non-public, confidential, or proprietary information. Specifically, no receiving party shall itself, or permit its employees, consultants, or agents to disclose to any person the Confidential Information of the other Party without the prior written consent of the party disclosing the Confidential Information, except a receiving party may distribute the Confidential Information to its board members, officers, employees, agents, consultants, contractors, potential investors and lenders who are confidentially bound to the receiving party and have a need for

		such Confidential Information. In the event that Buyer receives a request from a third party to disclose Confidential Information, or any information reasonably determined to be Confidential Information, Buyer shall, prior to the disclosure of the Confidential Information, promptly notify the Seller of such request. Seller may thereafter, at its sole cost and expense, seek a protective order or other appropriate remedy and/or waive compliance with the terms of the Agreement. Seller shall notify Buyer within five (5) business days of receiving notification of a request whether it intends to seek a protective order or other appropriate remedy. Buyer may not disclose any Confidential Information until (i) such time as it is legally compelled to do so by court order (providing that all appellate remedies have been exhausted); (ii) Seller provides its written consent to Buyer; or (iii) Seller fails to notify Buyer of its intent to seek a protective order or other appropriate remedy within five (5) business days of receiving notice of a request to disclose Confidential Information. Seller shall be solely responsible for all fines, fees, and reasonable costs incurred by Buyer in complying with this item, including attorney's fees, provided that Seller shall not be responsible for any such fines, fees, or costs incurred by Buyer by reason of its failure to adhere to a court order or failing to comply with the terms of the Agreement. Each party acknowledges that the unauthorized disclosure of Confidential Information may cause irreparable harm and significant injury that may be difficult to ascertain. Each party therefore agrees that specific performance or injunctive relief, in addition to other legal and equitable relief, are appropriate remedies for any actual or threatened violations of this confidentiality and non-disclosure commitment, neither party shall be entitled to any special, consequential, indirect, or punitive damages as a result of a breach of this item or any other term or provision of the Agreement, regardless of whether such claim is based in contract, tort, or otherwise.
40	Audit Rights	Each party has the right, during normal working hours, to examine the records of the other party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to the Agreement. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly. By entering into an Agreement Seller agrees that it shall be subject to audit by the Council Auditor of the City of Jacksonville pursuant to Article 5 of the Charter of the City of Jacksonville. The auditing party shall bear the costs associated with an audit conducted pursuant to this item, except that if an audit identifies overpricing or overcharges of any nature in excess of one half of one percent (0.5%) of total contract billings, or otherwise discovers substantive findings of fraud, misrepresentation, or nonperformance, the auditing party shall be entitled to reimbursement for the reasonable costs of the audit.

41	Governing Law and Venue	The Agreement and any dispute, claim, or controversy arising hereunder or in relation hereto shall be governed by and interpreted in accordance with the laws of the state of Florida. Venue for any action arising hereunder or in relation hereto shall lie exclusively in Duval County, Florida.
42	Appropriations	Buyer's obligations under the Agreement shall be subject to the appropriation of sufficient funds for such purposes by its Board of Directors and the Jacksonville City Council. While Buyer will make every reasonable effort to provide the funds needed to perform its obligations under the Agreement, Buyer makes no express commitment to provide such funds in any given fiscal year.
43	Taxes	Except as otherwise provided in the Agreement, Seller shall pay or cause to be paid all taxes levied or assessed by governmental authorities associated with the PPA Product that arise prior to the Energy Delivery Point, including, but not limited to (i) any real property taxes levied against land or interests in land associated with the Facility; or (ii) any tangible personal property taxes assessed against goods, chattels, or other articles of value owned by Seller that are necessary for the operation of the Facility. Seller's obligations under this item shall not apply to any taxes that arise at or after the Energy Delivery Point or to any real or personal property owned by JEA.
44	Definitions	Capitalized words and terms used in this Term Sheet shall have the meaning given to them in this Section 20. Unless otherwise specified, words importing the singular include the plural and vice versa and words importing gender include all genders. The term "including" means "including without limitation", and the terms "include", "includes" and "included" have similar meanings. Any reference in the Contract to any other agreement is deemed to include a reference to that other agreement, as amended, supplemented or restated from time to time. <i>Actual Heat Rate</i> is the actual operating performance in such hour with respect to the energy deliveries at the Energy Delivery Point during such hour, expressed in actual MMBtu of gas consumed per MWh of delivered energy (HHV) at the Energy Delivery Point, unless modified per the terms in item 21. <i>Agreement</i> or <i>Definitive Agreement</i> means the Agreement entered into between Buyer and Seller for the purchase of the PPA Product as a result of the Solicitation. <i>Applicable Laws</i> means all federal, state, and local laws, rules, regulations, ordinances, statutes, codes, and practices that apply to any

	party with respect to the party's performance under the Definitive Agreement. <i>Average Ambient Condition</i> is defined in item 11 of this Term Sheet. <i>Buyer</i> means JEA, a body politic and corporate organized under Article 21 of the Charter of the City of Jacksonville. <i>Contract Capacity</i> as defined in item 16 of this Term Sheet. <i>Capacity Payment</i> means the payment made to Seller by Buyer as compensation for all capacity-related benefits allocated to the Facility. The Capacity Payment is calculated as the total of the Capacity Rate multiplied by the Contract Capacity, subject to a discount as provided in Section 20 herein. <i>Capacity Payment Discount</i> means the discount applied to payments from Buyer to Seller in a month where the Monthly Availability is below the applicable Monthly Availability Requirements. <i>Capacity Rate</i> is a rate, defined by the Respondent, expressed in \$/kW-month, applied to the Contract Capacity to determine the Capacity Payment. <i>Certificates of Insurance</i> is a document that verifies the existence of an insurance policy and summarizes its key details. <i>Change in Law</i> means any change in Applicable Laws after the execution of the Definitive Agreement. <i>Commercial Operations</i> means that all of the following have occurred: • Final Completion of the Facility, as defined in the Agreement for construction of the Facility; • The Facility (i) has successfully completed its Performance Test and has demonstrated a Contract Capacity equal to at least 95% of Expected Contract Capacity, or has remedied any Initial Capacity Shortfall consistent with the terms laid out in item 17. • Has successfully achieved tested heat rates equal to or less than the corresponding maximum Guaranteed Heat Rates without producing emissions in excess of the levels set forth in the Definitive Agreement • Has successfully completed an emission demonstration test at emissions levels and rates below the levels and rates set forth in the Definitive Agreement or permitted under (1) air permit(s) for the Facility or (2) Applicable Laws for emissions.

- Interconnection of the Facility to Buyer's transmission system as provided in Appendix B;
- All required permits and consents for the construction, operation, and maintenance of the Facility have been obtained by Seller and are in full force and effect;
- The Facility is capable of safe, reliable, and continuous commercial operation for its intended use and purpose, and without injury to persons or property, in compliance with applicable laws, permits, and generally accepted industry practices; and
- Seller has delivered to Buyer a report with the results of all required performance testing conducted by Seller to demonstrate that the Facility is capable of commercial operations.

Commercial Operations Date or *COD* means the date that the Facility meets all conditions for Commercial Operations, except to the extent such conditions may be waived by Buyer.

Completed Start is defined in item 24 of this Term Sheet

Confidential Information means proprietary information, regardless of form or characteristics, that (i) is the subject of efforts that are reasonable under the circumstances to maintain its secrecy; (ii) the disclosure of which would cause harm to the entity providing the information or its business operations; and (iii) that has not been disclosed unless disclosed pursuant to a statutory provision, an order of a court or administrative body, or a private agreement that provides that the information will not be released to the public. For the purposes of this Solicitation and resulting Agreement, Confidential Information must be designated as "confidential" or "proprietary" at the time it is disclosed.

Delivery Term means the term for deliveries of capacity, energy, and ancillary services from Seller to Buyer under a Definitive Agreement.

Energy Delivery Point means the point on the JEA Transmission System (at 138kV or 230kV depending on location) at which deliveries of capacity, energy, and ancillary services from Seller to Buyer are required to be made and scheduled.

Energy Price is equal to the Actual Heat Rate of the Facility (expressed in MMBtu (HHV)/MWh) multiplied by the applicable Fuel Price (expressed in \$/MMBtu (HHV)) as described in item 21.

Energy Payment means the sum of the Energy Price and the Variable O&M Rate, multiplied by the energy that is dispatched by Buyer and delivered to Buyer from the Facility at the Energy Delivery Point.

	<i>Excess Capacity</i> is any capacity of the Facility (or, in the event Respondent proposes to allocate to Buyer a portion of the Facility, the corresponding portion thereof) in excess of the Contract Capacity allocated to Buyer that the Facility is capable of delivering as a result of prevailing ambient conditions or otherwise. <i>Expected Contract Capacity</i> is the estimated Contract Capacity based on the proposed design and expected performance of the Facility. <i>Facility</i> means the electric generation facility specified as such in a Response. <i>Facility Ambient Condition</i> is defined in item 14 of this Term Sheet <i>Firm Transportation Reservation Charges</i> are the annual fixed cost of all Firm Interstate Transportation Reservation Charges and Firm Local Delivery Reservation Charges <i>Force Majeure</i> is defined in item 30 of this Term Sheet. <i>Fuel Price</i> is the price applied to the energy produced and delivered to the Energy Delivery Point that will account fuel commodity cost, and any variable cost for fuel delivery. <i>GHG Rule</i> is the EPA's 2024 published greenhouse gas standards. <i>Governmental Approvals</i> means all authorizations, consents, approvals, waivers, exceptions, variances, filings, notices, permits, orders, licenses, exemptions, and declarations of any federal, state, or local government agency having jurisdiction over either party, the Facility, the JEA Transmission System, any Interconnection Facilities, or the generation, delivery, and sale of the Product. <i>Guaranteed COD</i> is the date that the Facility must reach COD to avoid paying liquidated damages. The Guaranteed COD will be provided by the Respondent in the Response and must be on or before December 31, 2030. <i>Guaranteed Contract Capacity</i> is the capacity amount the Facility must meet (under Summer Ambient Conditions) to avoid paying liquidated damages. The Guaranteed Contract Capacity must be at least 95% of the Expected Contract Capacity. <i>Guaranteed Heat Rate</i> means, for a new unit, the proposed heat rate plus unrecoverable losses averaged over a major maintenance cycle.

		<i>Hourly Fuel Commodity Price</i> is the real-time average price for 100% of the fuel commodity supplied to the facility in the subject hour on a \$/mmBtu basis. <i>Hourly Fuel Variable Delivery Cost</i> is the real-time average price for any non-firm fuel transportation charges. <i>Interconnection Location</i> is the location on the transmission system to which the Facility is interconnected. <i>Initial Capacity Shortfall Liquidated Damages</i> is defined in item 17 of this Term Sheet. <i>Major Maintenance Milestone</i> and <i>Major Maintenance Milestone Plan</i> is defined in item 29 of this Term Sheet. <i>Minimum Dispatch Level</i> is the Minimum Emissions Compliant Load (MECL), or zero (0) MW if Buyer does not have the right to commit and decommit the facility at Buyer's sole discretion. <i>Minimum Emissions Compliant Load (MECL)</i> is the lowest output at which a gas turbine power plant can operate while still meeting environmental limits for nitrogen oxides (NOx) and carbon monoxide (CO) emissions. <i>Monthly Availability</i> and <i>Monthly Availability Requirement</i> is defined in item 19 of this Term Sheet. <i>Net Dependable Capacity (NDC)</i> is defined per NERC definitions for NDC and is the net capacity modified for the subject ambient conditions. <i>Operating Restrictions and Capabilities</i> are the Buyer's restrictions and capabilities, provided in the Response, when exercising Buyer's dispatch rights under the Agreement. Operating Restrictions and Capabilities shall include the Contract Capacity, Minimum Dispatch Level for Summer and Winter months, minimum run time and down time, maximum number of Completed Starts per year, minimum start times, and maximum ramp rates. <i>Original Equipment Manufacturer (OEM)</i> is the manufacture of the major parts and equipment of the Facility. <i>Performance Test</i> as described in item 28 of this Term Sheet.

	<i>Planned Maintenance</i> means maintenance of the Facility that (i) is scheduled in advance with Buyer in accordance with the terms of the Definitive Agreement and included in a Planned Maintenance schedule and has a predetermined start date and expected duration (including but not limited to annual overhaul, inspections, and testing) and (ii) includes a reduction in the availability of the capacity of the Facility allocated to Buyer. <i>Product or PPA Product</i> provides for delivered capacity, energy, and ancillary services from flexible generation through a Power Purchase Agreement. <i>Respondent</i> are parties submitting a Response in connection to the Solicitation. <i>Response</i> includes the aggregate of the information, documents, and communication provided by the Respondent in connection to an offer to fulfill the requirements of the Product and the Solicitation. <i>Revised Guaranteed Contract Capacity</i> is the revised Guaranteed Contract Capacity in the event of an Initial Capacity Shortfall, conditioned on the terms laid out in item 17. <i>Seller</i> is the party specified by Respondent in the applicable Response as the party responsible for the execution of requirements of the “Seller” under the Agreement. <i>Start Fuel Payment</i> means the applicable Start Fuel Charge multiplied by the number of Completed Starts. <i>Start-Up Payment</i> means the Start-up Charge multiplied by the number of Completed Starts. <i>Summer</i> includes the months of June, July, and August. <i>Summer Ambient Condition</i> is defined in item 12 of this Term Sheet. <i>Transmission Losses</i> are the estimated amount of the decrease in electrical power between the Interconnection Location and the Energy Delivery Point. <i>Winter</i> includes the months of January, February, and December. <i>Winter Ambient Condition</i> is defined in item 13 of this Term Sheet.

Appendix E(ii) – Build Transfer Agreement (BTA) Term Sheet

The following terms and conditions shall apply to any agreement between JEA and Respondent for the acquisition of a proposed new-build resource and related assets (collectively, “the Facility”) with Seller assuming construction and financing risk and transfer occurring upon successful achievement of the Commercial Operation Date in connection with the Solicitation. The terms set forth in this Term Sheet will establish the basis for the negotiation and execution of a definitive agreement between JEA and any Respondent whose proposal is selected by JEA for contract negotiations in connection with the Solicitation, with necessary changes to accurately reflect any special considerations in Respondent’s proposal that are accepted by JEA in its sole and absolute discretion. JEA shall provide the initial draft of the contract to the selected Respondent at the beginning of contract negotiations.

If Respondent is unable or unwilling to accept one or more of the terms and conditions set forth in this Term Sheet or wishes to propose any alternative or additional terms or conditions, Respondent should indicate in its Response (i) the terms and conditions to which Respondent takes exception, describing with specificity any terms and conditions that Respondent proposes in substitution, and/or (ii) the additional terms and conditions that Respondent proposes as a supplement to the terms and conditions in this Term Sheet. The Respondent may utilize **Appendix F – Respondent Questionnaire** to provide a description of the proposed edits or additional conditions or provide redlines to this Term Sheet.

Response Term		Description of Response Term
1	Product Description:	The product described in this Term Sheet is designated as the “Product” or “BTA Product.” The Product provides for flexible generation with a generation capacity that is at least 525 MW and up to a preferred maximum of 700 MW at base load including duct-firing, under summer conditions from a designated CCCT resource capable of meeting the requirements of this Product.
2	Buyer:	“Buyer” shall mean JEA, a body politic and corporate.
3	Seller:	“Seller” will be the party specified by Respondent in the applicable Response.
4	Facility:	The “Facility” includes the nameplate capacity and major equipment as specified by Respondent in the applicable Response.
5	Interconnection Location	The Interconnection Location is the location on the transmission system to which the Facility is interconnected. The Interconnection Location is on the high-voltage side of the generator step-up transformer, at the location where net output is measured directly or where gross output is measured and auxiliary load is measured then subtracted from gross output to calculate net output.

6	Electric Interconnection and Transmission	Seller will be responsible for the interconnection of the Facility at the Interconnection Location and the transmission or transfer of power dispatched by Buyer to the JEA Transmission System. Details and requirements regarding the interconnection and delivery of power to the JEA Transmission System can be found in Appendix B - Transmission Interconnection and Delivery Considerations.
7	Purchased Assets and Payment Terms:	Buyer shall purchase and acquire all of Seller's assets, properties, and rights of any kind comprising the Facility, including without limitation all contracts, permits, reports, tangible assets, rights to environmental attributes and incentives, and all other intangible assets and rights related to the Facility. Seller shall specifically identify any excluded assets within the Definitive Agreement. The Purchase Price for acquisition of the Facility by the Buyer shall be provided within the Response. The purchase price shall be inclusive of all Project Costs and shall not require Buyer to assume any debt of Seller. For the purposes of this Solicitation and the resulting Agreement, the term "Project Costs" shall mean the aggregate of any and all amounts payable under any contract or permit or any other costs, obligations, or liabilities incurred or payable in connection with the siting, design, development, engineering, procurement, supply, construction, interconnection, permitting, start-up, commissioning or testing of, the Facility or any parts or components thereof or materials used therein, including all amounts owed under contracts entered into in order for the Facility to achieve Commercial Operations. <i>Seller shall propose the Purchase Price and the timing and structure of payments, including payment milestones.</i>
8	Independent Engineer	Seller shall select, subject to Buyer's approval, which shall not be unreasonably withheld, an independent engineer for the project. The independent engineer shall work with the parties to develop Design Criteria to be utilized by Seller's contract to meet the needs of the parties as detailed herein.
9	Approval of Design Documents:	Prior to commencement of the construction of the Facility, Seller shall submit to Buyer for its review and approval the design documents based on the Design Criteria for the Facility and shall obtain final approval from all governmental authorities pursuant to all Applicable Laws. Buyer shall approve such design documents to ensure compatibility of the construction design with construction standards utilized by Buyer for similar infrastructure owned or operated by Buyer. During construction, Buyer retains the right to inspect construction of the Facility to ensure compliance with the design documents at all reasonable times, after reasonable advance notice to Seller.
10	Projects Outside Buyer's Service Area; Projects for	For any project that is (i) located outside Buyer's service area, or (ii) for which Buyer will not be the sole owner and offtaker, regardless of the Facility's location, the following terms shall apply:

	Which Buyer Is Not Sole Owner and Offtaker	• Seller's response must supply guaranteed firm capacity and energy. • Buyer shall have the right to commit or decommit the resource at Buyer's sole discretion, or the resource minimum offtake must be zero (0) MW. • Unit loading must be controlled via dynamic scheduling from maximum load down to Minimum Emissions Compliant Load (MECL) or down to zero (0) MW if Buyer does not have sole right to commit and decommit unit ("Minimum Dispatch Level"). • Respondent must propose within its Response an O&M Agreement that addresses the following: items: ○ Plan for fuel transportation and delivery ○ Transmission plan consistent with the requirements of Appendix B ○ Plan to address the GHG Rule ○ Description for major planned maintenance (if applicable) ○ The intent of the terms and conditions for an O&M Agreement shall be consistent with those laid out in Appendix E(i) - PPA Term Sheet
11	Project Construction	Professional services for construction of the Facility shall be selected and secured in accordance with all applicable laws, including but not limited to Sections 255.20 and 287.055, Florida Statutes. Contractor selection shall be subject to the prior approval of Buyer, which shall not be unreasonably withheld. Seller shall be responsible for the management of the construction of the Facility and will appoint a qualified professional engineer licensed in the State of Florida as its project representative during the construction period. Seller's representative shall make visits to the site at intervals appropriate to the various stages of construction as deemed necessary in order to observe as an experienced and qualified design professional the progress that has been made and the quality of various aspects of the contractor's work. Based on information obtained during such visits, Seller's representative shall endeavor on behalf of Seller to determine in general if the work is proceeding in accordance with the design documents and the construction contract for the Facility. Seller shall prepare and regularly update a project schedule, which shall include phasing of construction, times of commencement and completion required of each contractor, ordering and delivery of products requiring long lead times, and activities of each contractor, such as activity sequences and duration. Seller shall keep Buyer advised of the progress of construction through progress reports in form and substance reasonably acceptable to Buyer, which shall include percentages of completion and costs and expenses, if applicable, incurred therewith.

		Seller shall not begin construction on the Facility until it has provided performance security consistent with the requirements of Section 255.05 Florida Statutes. Seller shall ensure that the Facility is constructed in accordance with the requirements of the agreed upon design documents, Buyer's standards, and all Applicable Laws, regulations, and permit requirements. Seller shall be responsible for the means, methods, techniques, sequences, procedures, and safety requirements with respect to construction of the Facility. Notwithstanding anything to the contrary herein, Seller acknowledges that Buyer has no obligation to oversee, supervise, inspect, or otherwise perform any activities that may be construed to mean that Buyer has assumed responsibility for the actions of Seller or its contractors or subcontractors. If Buyer should determine that Seller has not fulfilled a responsibility under the Agreement and Buyer notifies Seller of same, such action shall not shift any responsibility for Seller's actions or inactions to Buyer in any way, including for all construction means, methods, techniques, sequences, procedures, or safety requirements.
12	Permits and Approvals	Except as otherwise provided herein, Seller shall be responsible for obtaining all permits and approvals required for the construction and operation of the Facility. Buyer shall coordinate the submission of the applications to the Florida Public Service Commission for the Determination of Need and to the Florida Department of Environmental Protection for the Site Certification Application. Buyer and Seller shall coordinate with one another to provide any information necessary for the responsible party to obtain required governmental authorizations and permits.
13	Warranties	Seller shall provide the following warranties to Buyer: • Materials Warranty: All materials, equipment, and systems incorporated into the Facility shall be new, unused, and undamaged when installed; shall be free of defects and deficiencies in materials, assembly, and workmanship, suitable for use under normal operating conditions, and otherwise consistent with the Design Criteria. In addition, Seller shall cause all equipment installed at the Facility to have Equipment Warranties, which warranties shall be transferred to Buyer at Closing. • Workmanship Warranty: The construction, procurement, and installation services included in the project shall be performed in a good and workmanlike manner, in compliance with the requirements of the Definitive Agreement, the construction contracts, and all Applicable Laws, and shall be consistent with and in compliance with the specifications set forth in the Solicitation and the Response. • Design Warranty: The design and engineering of the Facility shall be performed in accordance with the standards of care, skill and diligence as would be provided by an engineering firm experienced in supplying

		similar services nationally in the United States of America to entities owning projects of technology, complexity and size similar to that of the Facility, and otherwise in compliance with the specifications set forth in the Solicitation and the Response.
14	Changes in Scope of Work	Buyer shall have the right to propose change orders clarifying or modifying the scope of work defined by the Agreement and design documents. In the event of a Buyer-requested change order, the Purchase Price, Commercial Operations Date, applicable Performance Guarantees, and Minimum Performance Levels may be subject to equitable adjustment.
15	Closing Conditions:	The Parties shall close the transaction if Seller achieves Commercial Operations and the parties satisfy the following Conditions Precedent to Closing: Conditions Precedent as to Buyer: • Buyer has received all approvals required to complete the transaction; • Buyer has performed its obligations under all relevant project agreements in all material respects. • Buyer receives Certificate of Need Conditions Precedent as to Seller: • Seller has performed its obligations under all relevant project agreements in all material respects, including, but not limited to, the following: ○ Interconnection to the JEA Transmission System consistent with the details and requirements set forth in Appendix B – Transmission Interconnection and Delivery Considerations; ○ Achieving all Minimum Performance Levels that will be negotiated and defined within the Definitive Agreement; and ○ Satisfied Performance Guarantees as provided in item 20 below; • All of Seller's Closing Deliverables have been provided; • Any objections to title and survey matters have been resolved to Buyer's reasonable satisfaction; • All required project permits have been issued, and Seller has assigned to Buyer all permits necessary for Buyer to own, operate, and maintain the Facility and has notified all governmental agencies of such assignment; • To the best of Seller's knowledge, the following representations and warranties are true and correct: ○ There are no contracts or agreements outstanding that will affect any portion of the Facility or its operation; ○ There is no action, suit, proceeding, or claim affecting the Facility or any portion thereof being asserted in any federal, state, or local court, department, commission, board, bureau, agency, or other government instrumentality, nor, to the

		knowledge of Seller, is any such action, suit, proceeding, or claim threatened or being asserted; - o Seller is not prohibited from consummating the transaction contemplated herein by any law, regulation, agreement, restriction, order, or judgment; - o There are no attachments, executions, assignments for the benefit of creditors, receiverships, conservatorships, or voluntary or involuntary proceedings in bankruptcy or pursuant to any other debtor relief laws contemplated by Seller or filed by Seller or pending against Seller or the Facility; - o The Facility is free and clear of all liens or encumbrances Seller and Buyer each agree to exercise commercially reasonable efforts to satisfy all of their respective Conditions Precedent to Closing. The Closing shall occur within [] business days after all Conditions Precedent to Closing have been satisfied or waived by the applicable party. At the Closing, Seller shall transfer the Facility to Buyer free and clear of all encumbrances and liabilities except for the liabilities that will be assumed by Buyer as described in item 17.
16	Closing Deliverables	Seller shall provide the following deliverables to Buyer at the Closing: • A Warranty Deed conveying to Buyer fee simple title to the Facility, free and clear of any and all liens or encumbrances; • Transfer of LTSA to Buyer; • O&M Agreement, if applicable; • As-built survey of the Facility in compliance with Buyer's survey requirements; • All documents or instruments necessary to convey any tangible personal property or other improvements necessary for the operation of the Facility, including but not limited to bills of sale, waivers, or releases of lien, in a form acceptable to Buyer; and • Documentation of assignment to Buyer of all certificates, licenses, permits, and warranties associated with the Facility. Buyer shall provide the following deliverables to Seller at the Closing: • Payment of the Purchase Price in accordance with the terms and conditions of the Definitive Agreement; • Any and all consents and authorizations as Seller may reasonably deem necessary to evidence the authority of Buyer to purchase the Facility and to consummate all other actions required to be taken by Buyer under the Definitive Agreement. At the Closing, Buyer and Seller shall execute such further documents and agreements as are reasonably appropriate or reasonably necessary to consummate the transaction as herein contemplated.

17	Assumed and Excluded Liabilities:	Buyer shall only assume liabilities in respect of assigned contracts and permits that (i) arise from the ownership, operation, maintenance, repair, or use of the Facility after the Closing and are paid, performed or discharged after the Closing, and (ii) do not relate to any breach or failure on the part of Seller or any person or entity acting on Seller's behalf to comply with any law, permit, contract or other requirement. All liabilities other than those specified above shall be excluded liabilities and shall be expressly retained and discharged by Seller. All Project Costs shall be excluded liabilities.						
18	Plant Performance Testing:	Prior to achieving Commercial Operations, Seller shall conduct or cause to be conducted performance tests to confirm the Facilities ability to meet Minimum Performance Levels and Performance Guarantees as defined by items 19 and 20 below. Performance testing shall be executed in accordance with all American Society of Mechanical Engineers (ASME) Performance Test Codes (PTCs) applicable to the proposed power generating equipment and technology. Testing shall be performed by an independent contractor approved by Buyer. Buyer and buyer's engineer shall have the right to witness all performance tests. Following performance testing, Buyer shall receive all performance testing input data, calculations, and output data via electronic means in formats suitable to Buyer. Buyer shall have the right to challenge results prior to acceptance if Buyer deems it necessary.						
19	Minimum Performance Levels	In order to reach Commercial Operations and meet the Conditions Precedent for Closing, the Facility must demonstrate the ability to meet defined performance specification ("Minimum Performance Levels"). If, pursuant to the most recent performance tests before Commercial Operations the Facility does not achieve all of the Minimum Performance Levels required by the Definitive Agreement, Seller will be required to retest and will not achieve Commercial Operations until the Facility has achieved all Minimum Performance Levels. If the Facility does not achieve Minimum Performance Levels and, correspondingly, Commercial Operations by the Guaranteed Commercial Operations Date, then Buyer's remedies described in item 21 will apply. The Minimum Performance Levels required to achieve Commercial Operations are as follows: <table border="1" data-bbox="565 1604 1458 1860"> <thead> <tr> <th><u>Performance Specifications</u></th><th>Average Ambient Conditions</th><th>Summer Ambient Conditions</th></tr> </thead> <tbody> <tr> <td>Guaranteed Net Electrical Output</td><td>[97%] of the Guaranteed Equipment Net Electrical Output</td><td>[97%] of the Guaranteed Equipment Net Electrical Output</td></tr> </tbody> </table>	<u>Performance Specifications</u>	Average Ambient Conditions	Summer Ambient Conditions	Guaranteed Net Electrical Output	[97%] of the Guaranteed Equipment Net Electrical Output	[97%] of the Guaranteed Equipment Net Electrical Output
<u>Performance Specifications</u>	Average Ambient Conditions	Summer Ambient Conditions						
Guaranteed Net Electrical Output	[97%] of the Guaranteed Equipment Net Electrical Output	[97%] of the Guaranteed Equipment Net Electrical Output						

			Guaranteed Net Heat Rate	[103%] of the Guaranteed Equipment Net Heat Rate	[103%] of the Guaranteed Equipment Net Heat Rate
			Guaranteed Ammonia Consumption	[120%] of the Guaranteed Equipment Ammonia Consumption	[120%] of the Guaranteed Equipment Ammonia Consumption
			Guaranteed Minimum Emissions Compliant Load (MECL)	[103%] of the Guaranteed Equipment MECL	[103%] of the Guaranteed Equipment MECL
			Guaranteed MECL Heat Rate	[103%] of the Guaranteed Equipment MECL Heat Rate	[103%] of the Guaranteed Equipment MECL Heat Rate
			Guaranteed CTG Demineralized Water Injection Rate	[110%] of the Guaranteed CTG Demineralized Water Injection Rate	[110%] of the Guaranteed CTG Demineralized Water Injection Rate
			Guaranteed CTG Inlet Air Chiller Duty (if applicable)	[110%] of the Guaranteed CTG Inlet Air Chiller Duty	[110%] of the Guaranteed CTG Inlet Air Chiller Duty
			Guaranteed Chilled Water Flowrate (if applicable)	[110%] of the Guaranteed Chilled Water Flowrate	[110%] of the Guaranteed Chilled Water Flowrate
			Guaranteed Ramp Rate	Must Meet	Must Meet
			Guaranteed Steady State Emissions	Must Meet	Must Meet
			Startup and Shutdown Emissions Guarantees	Must Meet	Must Meet

		<table border="1"> <tr> <td>Near Field Noise Levels</td><td>Must Meet</td><td>Must Meet</td></tr> <tr> <td>Reliability Guarantee</td><td>Must Meet</td><td>Must Meet</td></tr> </table> Note: The Minimum Performance Levels above apply for both natural gas and fuel oil, where applicable. Subject to Sellers obligations and Buyers rights under item 21 below, if Seller fails to meet any or all of the Minimum Performance Levels then Seller shall, with Buyer's approval and at Seller's sole cost and expense, immediately do all things necessary or appropriate to achieve the Minimum Performance Levels including, without limitation, exercise each and every repair or replacement alternative, regardless of cost to Seller or difficulties associated therewith. Seller shall be responsible for expenses in connection with the removal and reinstallation of any equipment and/or materials and/or structures not provided by Seller so as to allow Seller to perform corrective measures. Buyer will repeat the Performance Tests after Seller notifies Buyer in writing that the cause of the failure has been corrected. Seller will be responsible for all costs associated with each retest.	Near Field Noise Levels	Must Meet	Must Meet	Reliability Guarantee	Must Meet	Must Meet
Near Field Noise Levels	Must Meet	Must Meet						
Reliability Guarantee	Must Meet	Must Meet						
20	Performance Guarantees and Performance Liquidated Damages	Within the Response, Respondent shall provide proposed guarantees for all performance specifications outlined herein ("Performance Guarantees") unless already specified in the table below. The Respondent shall include within its Response Performance Guarantees for the following specifications for both Average Ambient Conditions and Summer Ambient Conditions: • Guaranteed Net Electrical Output • Guaranteed Net Heat Rate • Guaranteed Equipment Ammonia Consumption • Guaranteed Minimum Emissions Compliant Load (MECL) • Guaranteed MECL Heat Rate • Guaranteed CTG Demineralized Water Injection Rate • Guaranteed CTG Inlet Air Chiller Duty, if applicable • Guaranteed Chilled Water Flowrate, if applicable • Guaranteed Ramp Rate • Startup and Shutdown Emissions Guarantees						

Additionally, the following Performance Guarantees will apply to the following performance specifications:

- Guaranteed Steady State Emissions

Site Emissions Guarantees – Natural Gas Fuel	
NOx (nitrous oxide)	2 ppmvd @ 15% O ₂
Ammonia Slip	5.0 ppmvd @ 15% O ₂
CO (carbon monoxide)	7.2 ppmvd @ 15% O ₂
VOC	1.0 ppmvd @ 15% O ₂
Opacity	10%
Noise Level	Refer to section 01100.5.3
Vibration Levels	Refer to sections 15561 and 15562.
Notes:	
1. The emissions are guaranteed for all ambient conditions (17°F to 106°F, RH 0-100%) and loads between CTG MECL and CTG Base Load, except during initial commissioning and periods of startup and shutdown.	

Site Emissions Guarantees – Fuel Oil	
NOx (nitrous oxide)	8 ppmvd @ 15% O ₂
Ammonia Slip	5.0 ppmvd @ 15% O ₂
CO (carbon monoxide)	14.6 ppmvd @ 15% O ₂
VOC	2 ppmvd @ 15% O ₂
Opacity	10%
Noise Level	Refer to section 01100.5.3
Vibration Levels	Refer to sections 15561 and 15562.
Notes:	
1. The emissions are guaranteed for all ambient conditions and loads between CTG MECL and CTG Base Load, except during initial commissioning and periods of startup and shutdown.	

- Near Field Noise Levels

The near-field noise emissions shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet (1.5 meters) above floor/ground level and any personnel platform during normal operation.

During intermittent operations such as start-up and shutdown, as well as all emergency conditions, the A-weighted sound pressure levels (referenced to 20 micropascals) shall not exceed 110 dBA at all locations accessible by Site personnel including locations on elevated platforms and walkways.

- **Reliability Guarantee**

The Facility must generate power for a continuous test duration of seven hundred and twenty (720) hours with 100% reliability.

If Seller has achieved Minimum Performance Levels, but fails to achieve Performance Guarantees, Seller may elect to retest (subject to Buyer's rights under item 21 below, or Seller shall pay Buyer liquidated damages for the respective performance shortfall with respect to the Performance Guarantees, at the following rates ("Performance Liquidated Damages"):

Performance Specifications Subject to Liquidated Damages	LD Rates (Natural Gas)	LDs Rates (Fuel Oil)
Equipment Net Electrical Output	[\$1,600]/kW	[\$1,600]/kW
Equipment Net Heat Rate	[\$290,000]/Btu/kWh (HHV)	[\$170,000]/Btu/kWh (HHV)
Equipment Ammonia Consumption	[\$11,100] per lbm/hr	[\$11,100] per lbm/hr
Equipment Minimum Emission Compliant Load (MECL)	[\$1,600]/kW	[\$1,600]/kW
MECL Heat Rate	[\$140,000]/Btu/kWh (HHV)	[\$85,000]/Btu/kWh (HHV)
CTG Demineralized Water Injection Rate	N/A	[\$45,000] per lbm/hr
CTG Inlet Air Chiller Duty	[\$371,000] per MMBtu/hr	N/A
CTG Chilled Water Flowrate	[\$272,000] per kpph	N/A

21**Commercial Operations Date:**

Seller shall provide conditions precedent to include within the Definitive Agreement to commence construction of the Facility, the expected Commercial Operations Date, and the Guaranteed Commercial Operations Date. The Guaranteed Commercial Operations Date shall be no later than December 31, 2031.

		The Commercial Operations Date shall be defined as the date when all of the following (collectively referred to herein as “Commercial Operations”) have occurred: • Final Completion of the Facility, as defined in the Agreement for construction of the Facility; • Interconnection of the Facility to Buyer’s transmission system as provided in Exhibit B of this Solicitation; • All required permits and consents for the construction, operation, and maintenance of the Facility have been obtained by Seller and are in full force and effect; • The Facility is capable of safe, reliable, and continuous commercial operation for its intended use and purpose, and without injury to persons or property, in compliance with applicable laws, permits, and generally accepted industry practices; • The Facility has achieved all Minimum Performance Levels as provided in item 19; and • Seller has delivered to Buyer a report with the results of all required performance testing conducted by Seller to demonstrate that the Facility is capable of commercial operations. If Seller does not achieve Commercial Operations by the Guaranteed Commercial Operations Date, Seller shall pay liquidated damages equal to two hundred thousand dollars (\$200,000.00) per day for each date that Commercial Operations is not achieved after the Guaranteed Commercial Operations Date. If Seller does not achieve Commercial Operations by 180 days after the Guaranteed Commercial Operations Date (or prior to such date if it is evident that Seller will be unable to achieve Commercial Operations by such date), Buyer shall be entitled to terminate the Agreement. Upon such termination, Seller shall pay Buyer all accrued liquidated damages as of the date of termination, and Buyer shall have the right to purchase the Facility from Seller at an amount equal to Seller’s documented project costs. If Seller is unable to achieve Commercial Operations by the Guaranteed Commercial Operations Date due to an event of Force Majeure, Seller shall be entitled to a day-for-day extension of the deadlines provided in this item, provided that the Guaranteed Commercial Operations Date shall not be extended more than one hundred eighty (180) days.
22	Project Financing	Seller may finance or refinance all or a portion of the costs to develop, construct, equip, operate, maintain, repair, expand, alter, or replace the Facility. Seller may assign or pledge the Definitive Agreement to any financing party in connection with such financing or refinancing. Buyer shall, upon request by Seller, execute and deliver certificates, opinions, and other documents reasonably requested by the financing party from time to time. The rights and obligations of the Buyer, Seller, and any financing party shall be as set forth in the contract documents.

23	Seller Default	The Agreement shall include the following events of Seller Default: • Failure to pay amounts due; • Breach of representations and warranties; • Failure to provide or maintain required credit support; • Breach of covenants; • Assignment by Seller of the Agreement or sale or transfer of the Facility, directly or indirectly, except as permitted by the terms of the Agreement; • Bankruptcy, dissolution, or liquidation of Seller; • Default of Seller under any agreements relating to indebtedness for borrowed money in excess of a specified aggregate amount; • Seller makes any material intentional misrepresentation or omission in any metering report, invoice, estimate of intra-day gas cost, or availability notice required to be made or furnished by Seller pursuant to the Agreement or Seller's actual fraud, tampering with Buyer- owned facilities, or material intentional misrepresentation or misconduct in connection with the Definitive Agreement or operation of the Facility; • Except as expressly provided by the Agreement, Seller sells, assigns, or otherwise transfers, or commits to sell, assign, or otherwise transfer, the Facility and any associated assets contemplated by the Definitive Agreement, or any portion thereof, to any person other than Buyer; • Default of Seller under, or failure to maintain in effect, any project document (including any Interconnection Agreement or other service-related agreement); • The Commercial Operations has not occurred by 180 days after the Guaranteed Commercial Operation Date; Other events of default may be included in the Definitive Agreement as appropriate.
24	Force Majeure	Neither party shall be liable for any default or delay in the performance of its obligations under the Agreement due to an act of God or other event to the extent that: (a) the non-performing party is without fault in causing such default or delay; (b) such default or delay could not have been prevented by reasonable precautions; and (c) such default or delay could not have been reasonably circumvented by the non-performing party through the use of alternate sources, work-around plans, or other means. Such causes include acts of civil or military authority (including but not limited to courts or administrative agencies); acts of God; war; terrorist attacks; riots; insurrection; inability of Buyer to secure approval, validation, or sale of bonds; inability of either party to obtain any required permits, licenses, or zoning; blockades; embargo; sabotage; epidemics or pandemics declared by public health authorities; fires; hurricanes; tornadoes;

		floods; or strikes. In the case of epidemic or pandemic, the parties stipulate that a Force Majeure event shall not include any epidemic or pandemic that is ongoing as of the date of execution of the Agreement. For the avoidance of doubt, a Force Majeure event shall not include (x) financial distress nor the inability of either party to make a profit or avoid a financial loss, (y) changes in market prices or conditions, or (z) a party's financial inability to perform its obligations hereunder. In the event of any delay resulting from such causes, the time for performance of each of the parties hereunder (including the payment of monies if such event prevents payment) shall be extended for a period of time reasonably necessary to overcome the effect of such delay, except as provided for elsewhere in the Agreement. In the event of any delay or nonperformance resulting from such causes, the party affected shall promptly notify the other in writing of the nature, cause, date of commencement and the anticipated impact of such delay or nonperformance. Such written notice shall indicate the extent to which it is anticipated that any delivery or completion dates will be thereby affected within seven (7) calendar days.
25	Change in Law	The Parties acknowledge the possibility that a change in law may occur that requires or will require one or both of the Parties to incur additional costs (including environmental costs) during the Delivery Term beyond those projected to be incurred by such party as of the date of execution of the Definitive Agreement. Notwithstanding the foregoing, if such a change in law occurs, the other party will not be required to share in, reimburse, or otherwise pay all or any portion of such additional costs, except as expressly provided in the Agreement. Subject to the other terms herein, Buyer shall pay the net increase or decrease in the reasonable, actual, direct, and verifiable out-of-pocket costs, without mark-up, to the extent such costs are actually incurred by Seller in the provision to Buyer of PPA Product as a direct and proximate result of, and only to the extent required by, a Change in Law. Such costs shall exclude, without limitation, any costs that would not have been incurred but for other uses of the Facility. If more than one commercially reasonable option is available to comply with a Change in Law, the least cost option will serve as and establish the basis for determining the costs payable by Buyer irrespective of the option actually selected. Buyer's share of the payment of increased costs associated with a Change in Law shall be based on the percentage of the Facility's capacity that is dedicated to providing PPA Product to Buyer under the Agreement. Buyer shall have at least one hundred eighty (180) days after the receipt of notice from Seller of a Change in Law to conduct due diligence with respect to the Change in Law and associated costs. Seller shall cooperate with Buyer during the due diligence period.

		<i>Respondent shall propose a cap for expenditures by Buyer and Seller associated with a Change in Law.</i> Once the above caps are reached, Seller shall have a period of sixty (60) days to elect to terminate the Agreement and notify Buyer of such election. If Buyer does not receive notice within such sixty (60)-day period, Seller will be deemed to have waived such termination right with respect to all Changes In Law to date. If Buyer receives such notice within such sixty (60)-day period, Buyer may notify Seller within thirty (30) days either (i) that it accepts Seller's termination or (ii) that it wishes to engage in negotiations with Seller to amend the Agreement in light of the Change in Law. In the event Buyer elects to engage in negotiations, the parties shall negotiate in good faith to amend the Agreement. In the event the parties are unable to agree to and execute an amendment within sixty (60) days of commencing negotiations, Seller may terminate the Agreement by submitting a written notice of termination to Buyer.
26	Credit Support	Seller will be expected to meet the credit support requirements detailed in this Solicitation, including Appendix G, all of which will be more fully developed in the Definitive Agreement.
27	Indemnification	To the extent permitted by law, and within the limitations provided herein, each party shall hold harmless and indemnify the other party, its governing board, officers, employees, and agents against any claim, action, loss, damage, injury, liability, cost and expense of whatsoever kind or nature (including, but not by way of limitation, reasonable attorney's fees and court costs) arising out of injury to persons, including death, or damage to property, arising out of the negligence, recklessness or intentional wrongful misconduct of the party and any person or entity used by either party in the performance of obligations required by the Agreement. This indemnification shall survive the term of the Agreement for events that occurred during the term of the Agreement. This indemnification shall be separate and apart from, and in addition to, any other indemnification provisions set forth elsewhere in the Agreement. Buyer's indemnification of Seller shall be subject to and within the limitations set forth in Section 768.28, Florida Statutes. Buyer shall not agree to a waiver of such limitations or of its sovereign immunity. Notwithstanding the foregoing, in accordance with Section 768.28(5)(a), Florida Statutes, Buyer may agree to settle claims or judgments against it within the limitations of its insurance coverage without having been deemed to have waived any defense of sovereign immunity or to have increased its limits of liability as a result of obtaining such insurance coverage.

28	Confidentiality	Subject to Buyer's obligations under Chapter 119, Florida Statutes, and Section 21.09I(4) of the Charter of the City of Jacksonville, the parties will safeguard Confidential Information against disclosure by employing the same means to protect such Confidential Information as that party uses to protect its own non-public, confidential, or proprietary information. Specifically, no receiving party shall itself, or permit its employees, consultants, or agents to disclose to any Person the Confidential Information of the other Party without the prior written consent of the party disclosing the Confidential Information, except a receiving party may distribute the Confidential Information to its board members, officers, employees, agents, consultants, contractors, potential investors and lenders who are confidentially bound to the receiving party and have a need for such Confidential Information. In the event that Buyer receives a request from a third party to disclose Confidential Information, or any information reasonably determined to be Confidential Information, Buyer shall, prior to the disclosure of the Confidential Information, promptly notify the Seller of such request. Seller may thereafter, at its sole cost and expense, seek a protective order or other appropriate remedy and/or waive compliance with the terms of this Agreement. Seller shall notify Buyer within five (5) business days of receiving notification of a request whether it intends to seek a protective order or other appropriate remedy. Buyer may not disclose any Confidential Information until (i) such time as it is legally compelled to do so by court order (providing that all appellate remedies have been exhausted); (ii) Seller provides its written consent to Buyer; or (iii) Seller fails to notify Buyer of its intent to seek a protective order or other appropriate remedy within five (5) business days of receiving notice of a request to disclose Confidential Information. Seller shall be solely responsible for all fines, fees, and reasonable costs incurred by Buyer in complying with this item, including attorney's fees, provided that Seller shall not be responsible for any such fines, fees, or costs incurred by Buyer by reason of its failure to adhere to a court order or failing to comply with the terms of the Agreement. Each party acknowledges that the unauthorized disclosure of Confidential Information may cause irreparable harm and significant injury that may be difficult to ascertain. Each party therefore agrees that specific performance or injunctive relief, in addition to other legal and equitable relief, are appropriate remedies for any actual or threatened violations of this confidentiality and non-disclosure commitment. Neither party shall be entitled to any special, consequential, indirect, or punitive damages as a result of a breach of this item or any other term or provision of the Agreement, regardless of whether such claim is based in contract, tort, or otherwise.
29	Audit Rights	Each party has the right, during normal working hours, to examine the records of the other party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to the Agreement. If any

		such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly. By entering into an Agreement Seller agrees that it shall be subject to audit by the Council Auditor of the City of Jacksonville pursuant to Article 5 of the Charter of the City of Jacksonville. The auditing party shall bear the costs associated with an audit conducted pursuant to this item, except that if an audit identifies overpricing or overcharges of any nature in excess of one half of one percent (0.5%) of total contract billings, or otherwise discovers substantive findings of fraud, misrepresentation, or nonperformance, the auditing party shall be entitled to reimbursement for the reasonable costs of the audit.
30	Governing Law and Venue	The Agreement and any dispute, claim, or controversy arising hereunder or in relation hereto shall be governed by and interpreted in accordance with the laws of the state of Florida. Venue for any action arising hereunder or in relation hereto shall lie exclusively in Duval County, Florida.
31	Appropriations	Buyer's obligations under the Agreement shall be subject to the appropriation of sufficient funds for such purposes by its Board of Directors and the Jacksonville City Council. While Buyer will make every reasonable effort to provide the funds needed to perform its obligations under the Agreement, Buyer makes no express commitment to provide such funds in any given fiscal year.
32	Taxes	Except as otherwise provided in the Agreement, Seller shall pay or cause to be paid all taxes levied or assessed by governmental authorities against the Facility, including, but not limited to, any tangible personal property taxes assessed against goods, chattels, or other articles of value owned by Seller that are necessary for the operation of the Facility. Seller's obligations under this item shall cease upon Closing except with respect to any real or personal property for which Seller retains ownership.
33	Definitions	Capitalized words and terms used in this Term Sheet shall have the meaning given to them in this item 20. Unless otherwise specified, words importing the singular include the plural and vice versa and words importing gender include all genders. The term "including" means "including without limitation", and the terms "include", "includes" and "included" have similar meanings. Any reference in the Definitive Agreement to any other agreement is deemed to include a reference to that other agreement, as amended, supplemented or restated from time to time. <i>Agreement or Definitive Agreement</i> means the Agreement entered into between Buyer and Seller for the construction and purchase of the Facility.

	<i>Applicable Laws</i> means all federal, state, and local laws, rules, regulations, ordinances, statutes, codes, and practices that apply to any party with respect to the party's performance under the Definitive Agreement. <i>Average Ambient Conditions</i> for Jacksonville, FL is 69F, 81.8% RH and Barometric pressure of 14.86 psia. (Referenced at Jacksonville International Airport (JIA) from 2018-2023) If the Facility is located elsewhere, and the Average Ambient conditions are notably different, then local Average Ambient conditions should be used, and conditions must be stated. <i>BTA Product</i> or <i>Product</i> provides for the construction and transfer of ownership of a CCCT under a Build Transfer Agreement. <i>Buyer</i> means JEA, a body politic and corporate organized under Article 21 of the Charter of the City of Jacksonville. <i>Change in Law</i> means any change in Applicable Laws after the execution of the Definitive Agreement. <i>Closing</i> means the closing of the sale of the Facility to Buyer. <i>Closing Deliverables</i> is defined in item 16 of this Term Sheet. <i>Commercial Operations</i> and <i>Commercial Operations Date</i> is defined in item 21 of this Term Sheet. <i>Conditions Precedent to Closing</i> means the conditions set forth in item 15 herein. <i>Confidential Information</i> means information provided by one party to the other party in connection with the negotiation or performance of the Definitive Agreement that is clearly labeled or designated by the disclosing party at the time of disclosure as "confidential", "proprietary", or "trade secret" or with words of like meaning or, if disclosed orally, clearly identified as confidential with that status promptly confirmed thereafter in writing. However, if determined by a court of competent jurisdiction to be a public record subject to disclosure, no confidentiality shall be enforced. <i>Design Criteria</i> addresses, among other things, the scope of the Seller's engineering, procurement, and construction ("EPC") work on the proposed project, the project execution plan, EPC standards and processes to be followed, and other technical information about the project. <i>Facility</i> means the electric generation facility specified as such in a Response.

	<i>Force Majeure</i> means the conditions set forth in item 24 herein. <i>Net Equipment Electrical Output</i> is equal to the gross electrical outputs measured at the generator terminals less the auxiliary power consumption and generator excitation power consumption. <i>Guaranteed Commercial Operations Date</i> is the date that the Facility must reach COD to avoid paying liquidated damages. The Guaranteed COD will be provided by the Respondent in the Response and must be on or before December 31, 2030. <i>Interconnection Location</i> is the location on the transmission system to which the Facility is interconnected. <i>Minimum Emissions Compliant Load (MECL)</i> is the lowest output at which a gas turbine power plant can operate while still meeting environmental limits for nitrogen oxides (NO_x) and carbon monoxide (CO) emissions. <i>Minimum Performance Levels</i> the performance specifications, as described in item 19 above, that must be met through performance testing to meet Commercial Operations. <i>Performance Guarantees</i> the performance specifications, as described in item 20 above, that must be met through performance testing to avoid liquidated damages. <i>Project Costs</i> is the aggregate of any and all amounts payable under any contract or permit or any other costs, obligations, or liabilities incurred or payable in connection with the siting, design, development, engineering, procurement, supply, construction, interconnection, permitting, start-up, commissioning or testing of, the Facility or any parts or components thereof or materials used therein, including all amounts owed under contracts entered into in order for the Facility to achieve Commercial Operations. <i>Seller</i> means the party specified by Respondent in the applicable Response. <i>Summer Ambient Conditions</i> for Jacksonville, FL is 98F, 38.2% RH and Barometric pressure of 14.67 psia. (Referenced at JIA from 2018-2023) If the Facility is located elsewhere, and the Summer Ambient conditions are notably different, then local Summer Ambient conditions should be used, and conditions must be stated.

Appendix F – Respondent Questionnaire

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Project Overview

Provide a reasonably thorough summary description of the proposed project, including, but not limited to,

1. The proposed location,
2. Site description,
3. Generation technology,
4. Original COD of facility (existing only)
5. Nameplate capacity and the capacity of the proposed Facility at Summer Conditions,
6. Water source(s),
7. Fuel supply and transportation source(s),
8. Backup fuel storage
9. Plan for engineering/procurement/construction,
10. Environmental compliance and permitting,
11. Status of electric and other utility interconnection,
12. Financing plan,
13. O&M plan,
14. Any tax incentives utilized,
15. Current or future ownership or joint ownership of the resource,
16. Non-standard project components/considerations, and
17. The minimum PPA term is 20 years. If the Response is for a term of less than the expected life of the resource or 30 years, whichever is less, then provide terms (e.g., pricing details) associated with a contract extension that provides the option to extend the term to the lesser of 30 years or the expected end-of-life date.

Operations

1. Describe the anticipated operations and maintenance expectations and philosophy for the project after project completion, including, without limitation, the use of any third-party operator and any long-term service agreement with respect to any of the plant equipment. As part of this response provide:
 - o Staffing plan for the facility, and
 - o O&M plan including major maintenance.
2. For an existing facility, provide:
(If the proposed facility is a CCGT, provide data in the aggregate along with individual combustion turbine(s) statistics)
 - o Five years of historical operations and maintenance cost data
 - o Seasonal (summer/winter) net output rating (MW),
 - o Five years of historical capacity factor data,
 - o Five years of historical equivalent availability data,

- o Five years of historical forced outage rate data,
 - o Scheduled outage rate,
 - o Deratings,
 - o Seasonal net plant heat rate, and
 - o Forecasted five-year scheduled maintenance cycle
- 3. Discuss the on-site spare part inventory strategy and major parts list that exists or, if a future project, that is anticipated.
- 4. Confirm that the proposed operational range of the unit is under Automatic Generation Control (AGC).
- 5. Does the proposed facility include Black Start capability?
- 6. Outline considerations associated with potential economic and reliability curtailments as directed by JEA.
- 7. For a PPA, provide details regarding the fixed and variable O&M costs included within the Response pricing.
- 8. Provide the ambient conditions for the proposed Facility under the following conditions:
 - o Average Ambient Conditions
 - o Summer Ambient Conditions
 - o Winter Ambient Conditions

Respondent's Experience

1. Provide a description of Respondent's and all relevant Affiliates' background and experience, including the key project team members.
2. Provide list of relevant projects that key project team members have had direct responsibility for development (development Responses only). Provide both individual experience and experience with the Respondent company.
3. Provide a list of sites and description of the project where Respondent has developed (development only), built (development only), operated, and/or maintained a project with the generation technology included in Respondent's Response.

Project Development (Development Project Only)

1. Has a preliminary or detailed engineering design study been performed for the proposed facility? If so, please provide the study. If not, when is this activity expected to be completed?
2. Provide a detailed project schedule that includes major milestone events and critical path activities to achieve the successful completion of the project, including:
 - o Initiation and completion of environmental site studies
 - o Execution of site control

- o Receipt of major permits (including air permit).
 - o Execution of major project contracts (e.g., interconnection or deliverability contracts, EPC contract, site purchase)
 - o Financial Closing
 - o Full Notice to Proceed (“FNTTP”)
 - o Receipt of Buyer’s regulatory approvals
 - o Delivery of major equipment
 - o Transmission queue entry requirements or required studies.
 - o Major milestone schedule for any transmission upgrades.
 - o Expected Mechanical Completion date
 - o Commercial Operation Date
 - o Delivery Term commencement date (PPA Responses)
3. How much contingency is included within the proposed schedule?
4. Indicate the accuracy of the estimate used in the development of the Response (for example, Class 1 through Class 5)
5. For an BTA or APA, provide a compensation and custody transfer plan for BTA proposals (if sole ownership will transfer to JEA).
6. Provide Respondent’s commissioning plan.
7. For a BTA or APA, provide Respondent’s plan for acceptance and testing of the facility (if sole ownership transfers to JEA).
8. In reasonable detail, describe the contracting plan for this proposed resource.
9. Confirm whether the Respondent has:
- o Made a technology selection,
 - o Made a reservation agreement, and
 - o Have a signed power island contract.
- If a power island contract is not signed, provide the planned execution date for that contract.
10. Is there an EPC contract in place for the facility? If so, identify the EPC contractor and the EPC pricing structure. If not, provide the following information and answer the following questions:
- o When is such an EPC contract expected to be executed?
 - o Is there a letter of intent in place with an EPC provider?
 - o If no such letter of intent is in place, have proposals been requested from possible EPC providers?
11. Are contracts in place for the following matters:
- o Design engineering
 - o Support of permitting

- o Major equipment purchase
- o Subcontracting plan
- o Long-term service agreements
- o Third-Party operators
- o Other.

If so, provide supporting information, such as a summary description of those contracts. If not, provide a procurement plan for each of these activities.

Insurance

Define the assumed insurances and levels for the project included within the Response, including:

- o Workers' compensation,
- o Commercial general,
- o Employer's and automobile liability, and umbrella excess liability,
- o Builder's Risk
- o All-Risk Property, and
- o any additional insurance coverage.

Site Control

Please describe the status of the proposed project site, including the following:

1. Confirm whether the project site (including required easements) is under the legal control of the Respondent and provide evidence of such control.
2. Confirm that the site control covers the entire term of the Response or the anticipated life of the asset.
3. If the site or needed easements is not currently under the legal control of Respondent, describe the process required to gain control and provide an assessment of the risk related to gaining control of the site.
4. Provide a site map indicating the expected boundary of the full project site, indicating which parcels are currently under Respondent's control and which are not.
5. Provide evidence that the project site is properly zoned for the project and the use contemplated by this RFP.
6. Is the proposed project site within a floodplain? If so, identify the FEMA zone and the corresponding level of exposure.

Safety

1. Provide a copy of Respondent's corporate safety policies applicable to the project and the work, including safety and security policies utilized at project sites.
2. Provide metrics for safety for the last three (3) years for the Respondent and any of Respondent's proposed or expected prime contractors and subcontractors, including:
 - o Total recordable incident rate (TRIR),
 - o Days Away Restricted or Transferred (DART),
 - o OSHA willful or serious citations,
 - o Near-miss incidents, and
 - o Fatalities
3. Confirm that Respondent has read and understands the JEA Safety Qualification Requirement and confirms they will comply, if selected.

Interconnection and Deliverability

1. Provide the proposed resources point of interconnection to the transmission system.
2. Provide the proposed point of delivery to the JEA transmission system.
3. Provide any interconnection studies completed to date. If none, what is the status of the interconnection process for the project.
4. Describe the Respondent's experience and/or the Respondent's transmission consultant's experience (if applicable) with performance of transmission studies and transmission/interconnection construction in the FRCC and ITS regions. Name any consultant to be used.
5. Provide schedule of Transmission Losses assumed for the Response, if applicable, and confirm that Transmission Losses are included in the determination of Contract Capacity.
6. ***On-System Resources Only***
 - Provide estimated costs of transmission facilities from the proposed resource to the interconnecting substation.
 - o Confirm that these costs are accounted for within Response pricing.
 - o Include a detailed description of the scope and state whether or not the scope is expected to trigger the Florida TLSA or FERC Order No. 1000
 - Confirm whether interconnection upgrade costs at the substation have been included within the Response pricing.
 - o If included, provide any estimates of these costs available from any completed or ongoing studies and include a detailed description of the scope.
 - o If not included these costs will be estimated by JEA based on analysis of JEA's system and the proposed addition.
 - Confirm whether costs associated with impacts to the JEA System have been included within the Response pricing.

- If included, provide any estimates of these costs available from any completed or ongoing studies and include a detailed description of the scope.
- If not included, these costs will be estimated by JEA based on analysis of JEA's system and the proposed addition.
- Provide estimated costs to mitigate any impact to 3rd party transmission system due to export power, if applicable.
 - Confirm that these costs are accounted for within Response pricing.
 - Include a detailed description of the scope and state whether or not the scope is expected to trigger the Florida TLISA or FERC Order No. 1000.
 - If impacts include transformers, note the size and voltage of the transformers and include the expected procurement and delivery timeline(s).
- Provide estimated costs for any required 3rd party transmission service, due to export power, for full duration of the proposed contract, if applicable.
 - Confirm that these costs are accounted for within Response pricing.
- Provide estimated costs for the generator step-up transformer (GSU).
 - Confirm that these costs are accounted for within Response pricing and note if they are already reflected in the transmission facilities cost above or not.
 - Include the expected procurement and delivery timeline for the GSU.

7. Off-System Resources Only

- Provide estimated costs of all interconnection facilities associated with the proposed resource.
 - Confirm that these costs are accounted for within Response pricing.
 - Include a detailed description of the scope and state whether or not the scope triggers the Florida TLISA or FERC Order No. 1000.
 - If impacts include transformers other than the GSU, note the size and voltage of the transformers and include the expected procurement and delivery timeline(s).
- Provide estimated costs for the generator step-up transformer (GSU).
 - Confirm that these costs are accounted for within Response pricing and note if they are already reflected in the interconnection cost above or not.
 - Include the expected procurement and delivery timeline for the GSU.
- Provide estimated costs associated with all required transmission service, for the full duration of the proposed contract, between the proposed resource and Delivery Point on JEA's system.
 - Confirm that these costs are accounted for within Response pricing.
- Provide estimated costs associated with all impacts to other utility transmission systems for interconnection and delivery of energy to JEA.
 - Confirm that these costs are accounted for within Response pricing.
 - Include a detailed description of the scope and state whether or not the scope is expected to trigger the Florida TLISA or FERC Order No. 1000.

- Confirm whether costs associated with impacts to the JEA System have been included within the Response pricing.
 - If included, provide any estimates of these costs available from any completed or ongoing studies and include a detailed description of the scope.
 - If not included, these costs will be estimated by JEA based on analysis of JEA's system and the proposed addition.
- Confirm whether costs associated with impacts to the JEA's import and export capabilities have been included within the Response pricing.
 - If included, provide any estimates of these costs available from any completed or ongoing studies and include a detailed description of the scope.
 - If not included, these costs will be estimated by JEA based on analysis of JEA's system and the proposed addition.
- For all costs provided above, provide a narrative on how these costs were developed, including the types of studies completed, and whether contingency and escalation (including magnitude) were accounted for within the estimates.
- For all costs provided above, indicate the accuracy of the estimate used in the development of the estimated costs (for example, Class 1 through Class 5).
- Provide the estimated timeline for completion of each estimated upgrade provided above. Confirm that Response accounts for the timeline required for interconnection and delivery of the resource to the JEA transmission system. Within the timeline include:
 - Transmission queue entry requirements or required studies.
 - Major milestone schedule for any transmission upgrades.
- Other than costs to be estimated by JEA, confirm that Respondent has agreed to accept the risk that the final interconnection and transmission costs may exceed the costs included in the Response pricing and that the interconnection and transmission upgrades may be completed later (or earlier) than scheduled or expected.
- To the extent the proposed facility is located outside of Florida, provide the methods for which the power transfer under contingency conditions will be seamlessly maintained for JEA.
- Confirm that the Respondent understands and has accounted for the process requirements outlined in Appendix B - Transmission Interconnection and Deliverability Considerations.

Environmental

- Provide an Environmental permit matrix showing all required permits, schedule for acquiring permits and any predecessor activities needed to proceed with them. This should be in spreadsheet format like Excel. An example template can be provided if requested.
 - Include all permits required for the proposed facility. Include the status of each of those permits at the time of proposal submission.
 - For major processes such as PPSA, FERC Order 1000, TLISA, NGPSA, Consumptive use permits, Wastewater/industrial pre-treatment and disposal permits and any other such regulated

permitting processes also include a brief description of the methodology that will be applied to obtain each permit, the name of any contractors expected to be involved, and major schedule milestones including the start of the preparation process and the planned filing date of the full application, and the planned date for the granting of the permit or order.

- The referenced consents and authorizations in terms and conditions may include but are not limited to all applicable Federal, State and local standards or permits of any nature as applicable to the proposed project. This may include but is not limited to the Florida Power Plant Siting Act (PPSA) (Determination of Need and Site Certification Application processes), the Florida Transmission Line Siting Act (TLSA), FERC Order 1000, Local zoning and land-use regulations including noise, construction permits, stormwater management designs/permits, consumptive use water permits, fuel storage permits, wastewater/industrial pre-treatment and disposal permits, the Florida Natural Gas Pipeline Siting Act (NGPSA) and Federal permits or regulations on gas line construction or upgrades, environmental remediation, wetlands mitigation and/or buffer requirements, etc. on an as-applicable basis.
- Please provide a copy of any permits received for the project to date.
- Provide a description of the status of environmental studies completed, underway, or planned.
- (Development Resource) Provide evidence that Respondent has completed all permitting due diligence necessary to prepare to apply for all required permits (e.g., a copy of the draft permit application(s) or a summary of the permit application requirements including how those requirements will be met).
- How have you addressed cooling water needs and sources and disposal options of blowdown?
- Discuss Respondent's strategy to provide sufficient annual emission allowance allocations issued under federal, state or local law and applicable rules, regulations, and orders as necessary to meet the unconstrained scheduling of energy from the proposed unit or units. Discuss the how these costs are included in the Response and how future changes in such costs would impact the sales price.
- (Existing Resource) Does the resource have an Environmental Management System in place? If so, please describe the system in detail.
- (Existing Resource) Describe any pending permit-renewal proceedings, any pending requests for modification, and any expected hurdles to re-issuance.
- (Existing Resource) Provide copies of any facility or site environmental audit reports, including results and corrective actions (including audits conducted internally and externally by federal or state agencies).
- (Existing Resource) Have there been any compliance actions as a result of prior environmental audit findings?

Fuel Supply and Transportation

1. Identify what natural gas pipelines are available to or are currently interconnected to the facility.
2. (Development only) Have the Precedent, Firm Transportation, and interconnect agreements been completed? If so, please provide a copy of the contract(s). If not, when is this activity expected to be completed?

3. (Development only) For each pipeline that's expected to be utilized, provide an estimated timeline to the project, with key milestones for approvals to completion. If existing assets are to be considered, describe any modifications that might be necessary for this project.
4. (Development only) Identify the cost estimate to interconnect the resource with each natural gas pipeline that would be directly interconnected to the project.
5. (Existing only) Provide the projected delivered fuel costs, for the next five years, broken out by commodity and transportation.
6. (Existing only) Provide a list and summary of all commodity, transportation and storage tariffs and/or agreements. At a minimum, include counterparty name, execution date, contract term, transportation type, and cost for each that will be utilized to serve this facility.
7. (Existing only) Provide the current pipeline infrastructure, design capacity and contractual arrangements for all pipelines interconnected to the facility.
8. Provide evidence that the natural gas pipeline(s) that would serve the project can provide firm capacity as well as necessary flexible flow parameters that would meet the operating design parameters of the unit, such as gas quality, and identify any additional services offered by the pipeline (e.g., non-ratable service, swing capability, imbalance provisions) and level of firm deliverability (e.g., primary firm, secondary firm, any access to storage) and any other aspects that could meet the appropriate level of reliability.
9. Provide an assessment of liquidity and basis to Henry Hub for all receipt points included in firm transportation arrangements.
10. Provide details regarding plan to meet backup fuel requirements including availability of fuel, storage, etc., as well as Respondent's plan for replenishment of supply during an extended extreme event.
11. Describe in detail the means Respondent has proposed to achieve reliable fuel supply to enable firm reliable energy and capacity delivery. Include details regarding firm interstate transportation options, non-firm transportation options, firm delivered commodity agreements, and any other supply-side options that Respondent has available. Also provide any measures that Respondent might use to optimize transportation assets as well as commodity supply agreements when not required to serve load.
12. Provide details regarding all gas source basins serving the project, all existing gas line capacity used (interstate and local) by name including origin and delivery points, any proposed gas lines required for project (interstate and local) including a description of origin and delivery point, any commodity or transportation agreements including reservation quantity, cost, terms and status of contracts (existing, in negotiation, proposed, estimated, etc), and any other information required for JEA to evaluate the risk, reliability and cost of Respondent's fuel plan.
13. Provide a breakout of gas transportation costs and quantities accounted for within the Response.
14. Provide detailed information for JEA to fully understand and evaluate fuel related charges associated with the Response if it has not been addressed within the applicable term sheet or Appendix D of this Solicitation.
15. Confirm that 5 days of full-load on-site backup fuel storage and 5 days of demineralized water storage and/or installed demineralized water production capacity are included. Describe fuel storage and unloading facility capability and capacity and demineralized water production/storage capability and capacity in some detail.

Financing

Provide a complete financing plan that covers the total project costs of the facility being proposed. If the Response involves an existing facility financed on a limited recourse basis and not in a utility rate base, the section must include, if accurate, adequate justification that the owning project company (if it exists) and the parent company are in good financial health and at the time the Response is made, is in no danger of default on project loans.

Include all data required to assess creditworthiness per the specifications included in Appendix G, including the following:

- o Provide an overview of the financing plan for the project including proposed debt and equity percentages and the expected sources of debt and equity.
- o Confirm the methodology of which the Respondent will meet credit requirements outlined in Appendix G.
- o Provide audited financial statements of the Respondent from the last three full fiscal years.
- o Provide evidence of an investment grade long-term, senior unsecured debt rating meeting the requirements in Appendix G, if available.
- o If the Respondent plans on using a Parent Guarantee to meet credit requirements, provide 1) evidence of the guarantor's relationship to the Respondent, 2) audited financial statements from the last three full fiscal years of the guarantor, and 3) evidence of an investment grade long-term, senior unsecured debt rating meeting the requirements in Appendix G, if available.
- o If the Respondent plans on using a Letter of Credit to meet requirements laid out in Appendix G, confirm that the Response includes the cost associated with such Letter of Credit.

GHG Rule Compliance

1. Provide a description as to how the Response complies with EPA's current GHG rule.
2. Does the Response include any options for alternative compliance measures for the GHG Rule?
 - a. If the Respondent is including GHG Rule options (e.g., carbon capture and sequestration, hydrogen) provide detailed information to allow JEA to comprehensively assess this option, including:

For APAs or BTAs, provide detailed implications of burning hydrogen to the following economic terms:

- o Capacity Rating (MW) (Summer/Winter)
- o Heat Rate
- o Purchase price
- o Capital or O&M expectations
- o Fuel mix
- o Other

For PPAs, provide detailed implications of burning hydrogen to the following economic terms:

- o Capacity Rating (MW) (Summer/Winter)

- o Capacity Rate (\$/kW-yr)
 - o Energy Rate
 - o Variable O&M Rate
 - o Start Charge
 - o Start Fuel
 - o Fuel Mix
 - o Other
3. Does the project site provide for the possibility for hydrogen storage, onsite production, or hydrogen/natural gas blending equipment?
 - a. Does the proposed facility include the possibility of future conversion to hydrogen fuel?
 4. Does the project site provide for the possibility for carbon capture and transport (CCT), or carbon capture and sequestration (CCS)?
 - a. Does the proposed facility include the possibility of future conversion to CCT/CCS?
 5. Provide any additional detail that would help JEA consider optionality for options to address the GHG Rule in the context of the Respondent's Response.
 6. To the extent the proposed facility is expected to be impacted by the GHG Rule as it stands today, provide details of the impact to the Response if the proposed facility is no longer impacted by the GHG Rule. This should include details regarding both pricing and non-pricing considerations.

Commercial Terms

PPA Product

1. For resources with Delivery Terms of less than 30 years, provide detailed information, including all pricing terms that would be applicable under the PPA, and for a contract extension beyond the proposed Delivery Term through at least 30 years total or the expected life of the generator.
2. To the extent the proposal for a PPA Product includes a buy-out option, provide detailed information regarding the terms and conditions associated with this option, including the determination of price and the triggering event for the option to occur (e.g., after the 10th year of the Delivery Term).
3. Provide a list of Seller's Conditions Precedent for the start of the Delivery Term.
4. Provide proposed terms for calculating the Facility's Monthly Availability associated with meeting the Monthly Availability Requirement outlined in Appendix E(i) – PPA Term Sheet.
5. Provide all necessary OEM based data and information to schedule and estimate cost of Planned Maintenance activities for all major equipment (ST, STG, CT, CTG), including the following:

- o A list of Major Maintenance Milestone outages with the order they shall be performed, the means to determine, whether starts or hours based, when to schedule each milestone, the duration for each Milestone outage;
 - o Days proposed for annual scheduled minor maintenance activities such as inspections; and
 - o For Response evaluation, provide a proposed major maintenance schedule for the facility lifecycle assuming 200 starts and 7000 hours per year, and a second schedule assuming 200 starts and 5400 hours per year.
6. To the extent a Response Price Adjustment, as defined in Section 15 – Evaluation Methodology of the Solicitation, is included as part of the Response, provide a detailed explanation of how the Capacity Price would be modified based on changes to cost drivers of the Response. The Response Price Adjustment would apply from the Response submission to the receipt of a full notice to proceed. Include within the description a maximum Capacity Rate applicable to the Response (i.e., a Price Cap).

BTA Product

1. Provide the timing and structure of payments for the proposed, including payment milestones.
2. For Off-System BTA or APA proposals, provide scope and terms of a proposed O&M Agreement. It must include:
 - a. Information regarding a fuel plan
 - b. Information regarding a transmission plan (if applicable) per rules in Appendix B
 - c. Plan to address EPA's current Greenhouse Gas rule (GHG Rule)
 - d. Details regarding major planned maintenance
 - e. Details regarding annual performance testing
3. Provide a list of Seller's Conditions Precedent to commence construction and for Closing.
4. Provide Performance Guarantee levels for the following specifications for both Average Ambient Conditions and Summer Ambient Conditions:
 - o Guaranteed Net Electrical Output
 - o Guaranteed Net Heat Rate
 - o Guaranteed Equipment Ammonia Consumption
 - o Guaranteed Minimum Emissions Compliant Load (MECL)
 - o Guaranteed MECL Heat Rate
 - o Guaranteed CTG Demineralized Water Injection Rate
 - o Guaranteed CTG Inlet Air Chiller Duty, if applicable
 - o Guaranteed Chilled Water Flowrate, if applicable

- o Guaranteed Ramp Rate
 - o Startup and Shutdown Emissions Guarantees
5. To the extent a Response Price Adjustment, as defined in Section 15 – Evaluation Methodology of the Solicitation, is included as part of the Response, provide a detailed explanation of how the Acquisition Purchase Price would be modified based on changes to cost drivers of the Response. The Response Price Adjustment would apply from the Response submission to the receipt of a full notice to proceed. Include within the description a maximum Acquisition Purchase Price applicable to the Response (i.e., a Price Cap).

All Proposals

1. Provide the terms and conditions to which Respondent takes exception, describing with specificity any terms and conditions that Respondent proposes in substitution, and/or (ii) the additional terms and conditions that Respondent proposes as a supplement to the terms and conditions in Appendix E(i) - PPA Term Sheet and/or Appendix E(ii) – BTA Term Sheet.
2. Provide a propose a cap for expenditures by Buyer and Seller associated with a Change in Law.

Appendix G - Credit Requirements

The Respondent must be able to satisfy JEA's credit standards to ensure the Respondent has adequate financial capability. JEA requires qualified Respondents to possess either an investment grade long term, senior unsecured debt rating (S&P / Fitch BBB- or above; Moody's Baa3 or above) or sufficient equity security to cover their anticipated delivery obligations under any agreement, as defined below, entered into as a result of this Solicitation process. If the Respondent is unable to satisfy the foregoing credit standards, they may designate a credit support provider/guarantor. If the credit support provider/guarantor is satisfactory to JEA, the Respondent will be deemed to have satisfied JEA's credit standards. The quality of credit of the proposed credit support provider/guarantor will be evaluated under the same standards as that of the Respondent.

Execution of an agreement under this Solicitation is conditional upon full satisfaction of any JEA credit support requirements. JEA reserves the right to require additional credit standards and to review and evaluate the quality of credit of each Respondent and credit support provider/guarantor in addition to adjusting, as necessary, in the application of the foregoing standards.

This document contains a brief overview of credit requirements of the Respondent for a selected Response of the Solicitation. The purpose of this document is to assure (1) that a counterparty's credit quality, when considered in the context of a Respondent's Response, complies with JEA expectations and requirements, and (2) that any requirement for credit support associated with the Response is considered by the Respondent in preparation and submission of a Response.

Information requests associated with these requirements are included within Appendix F- Respondents Questionnaire of this Solicitation.

Credit Quality and Forms of Credit Support

The Seller shall provide JEA with commercially reasonable security instruments such as cash, cash escrow security, parent guarantee, or letter of credit from a credible financial institution to support credit assurance requirements.

JEA will perform a credit analysis to determine whether the issuing entities are creditworthy to support the Seller's credit assurance obligations. The creditworthiness of the entity providing the applicable instrument will be based on the reasonable judgment of JEA, provided that any entity with a short-term or long-term investment grade credit rating by S&P, Fitch, or Moody's shall be deemed to have acceptable financial creditworthiness.

Credit Support Requirements

Negotiating Period

For any Respondent with whom negotiations begin, an irrevocable letter of credit or bank guarantee in favor of JEA, issued by a reputable financial institution or commercial bank satisfactory to JEA, in the amount of \$200,000 (Bid Security). This Bid Security must remain in full force and effect for the lesser of: A) a period lasting 90 days from the start of negotiations, or B) until a governing agreement is executed. The Bid Security can be called upon by JEA up to the full amount if negotiations are not completed within 90 days and if, in JEA's sole judgment, the Respondent has not negotiated in good faith or in accordance with the pricing parameters and risk sharing conceptual framework set forth in its Response. The 90-day negotiating period may be extended by JEA at its discretion and upon consent of the Respondent; if the negotiating period is so extended, the Bid Security must be likewise extended.

Post-Contract Execution

Seller will be required to provide credit support within five (5) business days after the execution of an applicable agreement. The amount of credit support that Seller must provide will be adjusted at various milestone dates during the term of the agreement. The tables below show key milestones and the corresponding amount of the credit support required to be in effect.

Table 1: PPA Letter of Credit Requirements

Project Milestone	Credit Assurance Amount
Execution of PPA	\$1,500,000 plus \$15,000/MW
Issuance of Full Notice to Proceed	\$75,000/MW
One-year Anniversary of Full Notice to Proceed	\$100,000/MW
Two-year Anniversary of Full Notice to Proceed	\$125,000/MW
Commencement of the PPA delivery term	\$150,000/MW
PPA Expiration	Letter of credit will return to Seller unless there are pending claims of Buyer, which then the letter of credit will remain outstanding and in effect until the final resolution of such claims.

Table 2: Build-Transfer Agreement (BTA) Letter of Credit Requirements

Project Milestone	Credit Assurance Amount
Execution of BTA	\$1,500,000 plus \$15,000/MW
Issuance of Full Notice to Proceed (FNTTP)	\$75,000/MW
One-year Anniversary of FNTTP	\$100,000/MW
Two-year Anniversary of FNTTP	\$125,000/MW

Additional credit requirements may be required and negotiated through the BTA for the period after closing and/or substantial completion of the facility to address outstanding obligations of the Seller and potential indemnity claims.

Table 3: Acquisition Agreement (Existing Resource)

Project Milestone	Credit Assurance Amount
Execution of Acquisition Agreement	\$1,500,000 plus \$15,000/MW

Additional credit requirements may be required and negotiated through the Acquisition Agreement for the period after closing to address outstanding obligations of the Seller and potential indemnity claims.

Appendix H – Independent Evaluator Scope

Merrimack Energy Group Inc. has been selected and has agreed to serve as the Independent Evaluator (“IE”) for this Solicitation. This document outlines the scope of the IE’s responsibilities and activities for the Solicitation. The IE is being engaged to help ensure that the Solicitation design, processes, and reviews are impartial and objective, and that all Responses submitted in the Solicitation are treated in a consistent fashion, and no undue preference is given to any Responses or Respondents in the Solicitation.

These responsibilities and activities include oversight, review, monitoring, and reporting on the implementation of the solicitation process throughout the various phases of the Solicitation, including:

1. Design and Development of the Solicitation;
2. Issuance of the Solicitation and Response Development;
3. Submission of Responses, Response Evaluation and Selection Process;
4. Contract Negotiations with the Selected Responses;
5. Regulatory Approval Process

The scope of the IE’s role and engagement in each phase of the Solicitation process is summarized below.

Stage 1 includes the period from the development of the Solicitation documents and processes through issuance of the final Solicitation. Table 1 below provides a general description of the anticipated tasks for Stage 1.

Table 1: Stage 1 - Design and Development of the Solicitation

Task	Description
Review and comments on Draft Solicitation by IE	IE reviews and provides comments on Draft Solicitation documents to ensure that the documents are clear and concise with regard to the definition of the product sought, information required of Respondents, and overall solicitation process.
Development of Safeguards	Work with the utility to ensure that procedures and processes are in place to ensure that any utility generation options do not have any undue preferential treatment and to ensure any concerns regarding fairness are reasonably addressed and eliminated to the degree possible.
Website/portal for Communications with Respondents	Discuss process for receipt of Responses and interaction with Respondents.
Discussion Regarding Evaluation Criteria and Methodologies	IE review, comment, and discussions with JEA project team and consultants regarding proposed evaluation criteria, evaluation process, and methodology for initial review, evaluation, ranking, and selection process.

Review and comment on Solicitation related documents	IE reviews and comments on final Solicitation prior to final completion and posting of documents on the Website. Documents for review by the IE will include all appendices and Response forms associated with the Solicitation. IE will generally review and comment on all the above-mentioned Solicitation documents and provide final feedback.
Development of Final Solicitation documents	Merrimack Energy will work with the JEA team to complete a final review on any updates to documents in preparation of the final Solicitation documents.

As IE, one of Merrimack Energy's functions will be to review documents with an eye toward ensuring the information required from the Respondents is linked closely to the evaluation criteria and methodology and to ensure that the Solicitation is requesting information that will be utilized in both the quantitative and non-cost evaluations. The IE also will review the Solicitation specifications developed by the JEA team to ensure the risk profile for the utility ownership option and third-party Responses are reasonably aligned and fairly consistent.

Stage 2 includes the time period from issuance of the Solicitation to submission of Responses from Respondents. Table 2 below provides a general description of the anticipated tasks for Stage 2.

Table 2: Stage 2 - Issuance of the Solicitation and Response Development

Task	Description
Question and Answer Process	As IE, as part of the Q&A process, Merrimack will interact closely with the JEA team to determine which questions may be specific to an individual Respondent and which should be provided to all Respondents. The IE will review responses to questions before they are posted to the Solicitation website.
Lock-down Input Assumptions and Forecasts	An important task during this stage of the process is to lock-down the input assumptions and forecasts (i.e., gas prices, inflation, other fuels, O&M costs, etc.) prior to receipt of Responses. These are the input assumptions and forecasts upon which all Responses will be evaluated. The IE will review and comment on the input assumptions and meets with the JEA team and consultants to review.
Lock down evaluation criteria, evaluation methodology, evaluation matrix (non-price) and scorecard, as applicable	The primary task during Stage 2 is to lock down the evaluation criteria, models and methodologies, and evaluation and scoring forms that will be used by the evaluation team for its internal review of all Responses. The evaluation and scoring forms are also useful as documentation of the results of the evaluation. The IE will meet with JEA's team and consultants to discuss the criteria, methodology and evaluation process leading up to lockdown and the development and review of documentation.

Potential Revisions to Solicitation documents	Based on Respondent questions or comments, JEA and IE may consider whether revisions or redline changes should be made to Solicitation documents prior to submission of Responses. Revisions would be posted at a minimum of two weeks before Response submittal.
Preparation for Receipt of Responses	Prep for receipt of Responses to ensure the company and IE have access to all Responses submitted.

The third stage of the process is the evaluation and selection phase which is generally the most detailed and time- consuming part of the solicitation process. Table 3 below provides a general description of the anticipated tasks for Stage 3.

Table 3: Stage 3 - Submission of Responses, Response Evaluation, and Selection Process

Task	Description
Review and Summary of Responses Submitted	Once the Responses are submitted, the IE's initial task along with the JEA team is to conduct a high-level review of the Responses and prepare a summary of the key characteristics of each Response including Respondent and project name, project size, location, operational characteristics, pricing, and any notes on the Responses based on the initial review. The IE and JEA will compare lists to ensure that both parties have a complete record of the Responses submitted.
Conformance Review/Minimum Requirements and Threshold Evaluation	The initial step in the evaluation process is the conformance review. In this stage of the evaluation, the JEA team will review Responses to ensure the Responses conform to minimum requirements. The IE will review JEA's results as to whether or not Responses are conforming or non-conforming. Conforming Responses are then moved into the evaluation phase.
Market Test Response Evaluation	Conforming Responses will be evaluated from a quantitative and non-cost perspective by the JEA team. In this stage of the process, the IE will review the evaluation results, including quantitative and qualitative evaluation results, meet with the JEA team to review and discuss the results, and raise any questions or issues for resolution.
Finalize Results	At this stage in the process, all the quantitative and qualitative evaluation results will be compiled and validated. The IE will review and comment on the model results and may ask for additional analysis, if appropriate. The IE may also meet with JEA and its management to discuss the results and recommendation for Response selection.

As IE, Merrimack will prepare a final report on the entire solicitation process. The report is provided to JEA who may provide the report to the regulator. The final report will also be included as an Exhibit to the IE's testimony, if needed.



Building Community®

TEN-YEAR SITE PLAN

April 2024

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List of Abbreviations

Type of Generation Units

CA	Combined Cycle – Steam Turbine Portion, Waste Heat Boiler (only)
CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
GT	Combustion Turbine
FC	Fluidized Bed Combustion
IC	Internal Combustion
ST	Steam Turbine, Boiler, Non-Nuclear

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Under construction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
DFO	No. 2 Fuel Oil
RFO	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke
WH	Waste Heat

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Introduction

The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities, the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.

The Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. The 2024 TYSP provides information related to JEA's power supply strategy to adequately meet the forecasted needs of our customers for the planning period from January 1st, 2024 to December 31st, 2033. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

1. Description of Existing Facilities and Resources

1.1 Power Supply System Description

1.1.1 JEA Electric System

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 510,000 customers.

1.1.1.1 Existing Generation System

The JEA Electric System consists of generating facilities located on four plant sites within the City of Jacksonville (The City); the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), the Brandy Branch Generating Station (Brandy Branch), and the Greenland Energy Center (GEC).

Collectively, these plants consist of two multifuel-fired (coal/petroleum coke/natural gas/biomass) Circulating Fluidized Bed (CFB) steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2 and Brandy Branch GT1); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle system that comprises of two gas-fired combustion turbine-generator units and one combined cycle heat recovery steam generator unit (Brandy Branch CT2 and CT3 and Brandy Branch steam Unit 4). Details of the existing facilities are displayed in Schedule 1.

Schedule 1: Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	FYI	(12)	(13)	(14)	(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate (b)	Gen Max Turbine	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Year	Mo/Year	kW	kW	Summer	Winter		
Kennedy										<u>427,800</u>	<u>346,400</u>	<u>357</u>	<u>382</u>		
	7	12-031	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	173,200	179	191	Utility	
	8	12-031	GT	NG	DFO	PL	WA	06/2009	(a)	224,000	173,200	179	191	Utility	
Northside										<u>1,601,856</u>	<u>1,407,100</u>	<u>1,310</u>	<u>1,356</u>		
	1	12-031	ST	PC	BIT	WA		05/2003	(a)	350,000	297,500	293	293	Utility	
	2	12-031	ST	PC	BIT	WA		04/2003	(a)	350,000	297,500	293	293	Utility	
	3	12-031	ST	NG	RFO	PL	WA	07/1977	01/2030	626,300	563,700	524	524	Utility	
	33-36	12-031	GT	DFO		TK		01/1975	(a)	275,556	248,400	200	246	Utility	
Brandy Branch										<u>946,200</u>	<u>745,100</u>	<u>758</u>	<u>831</u>		
	1	12-031	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	173,200	179	191	Utility	
	2	12-031	CT	NG		PL		05/2001	(a)	237,000	173,200	190	212	Utility	
	3	12-031	CT	NG		PL		10/2001	(a)	237,000	173,200	190	212	Utility	
	4	12-031	CA	WH				01/2005	(a)	268,400	225,500	200	216	Utility	
Greenland Energy Center										<u>448,000</u>	<u>346,400</u>	<u>357</u>	<u>382</u>		
	1	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	
	2	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	
JEA System Total												2,782	2,952		(c)

Notes:

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

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

(c) Numbers may not add due to rounding.

1.1.2 Power Purchases

1.1.2.1 FPL Natural Gas Power Purchase Agreement

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

1.1.3 Clean Energy Power Purchases

1.1.3.1 Trail Ridge Landfill Power Purchase Agreement

In 2006, JEA entered into a PPA with Trail Ridge Energy, LLC (TRE) to purchase energy and environmental attributes from up to 9 net MW of firm renewable generation capacity utilizing the methane gas from The City's Trail Ridge landfill located in western Duval County (the "Phase One Purchase"). The facility was one of the largest landfill gas-to-energy facilities in the Southeast when it began commercial operation on December 6th, 2008.

JEA and TRE executed an amendment to this PPA on March 9th, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began in February 2015. The contract for Trail Ridge Phase One and Phase Two will expire in December of 2026.

1.1.3.2 Jacksonville Solar Power Purchase Agreement

In May 2009, JEA entered into a PPA with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW_{AC} of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100-acre site. The Jacksonville Solar plant began commercial operation at full designed capacity on September 30th, 2010. The facility was acquired by Rev Renewables, LLC, an LS Power company, on June 15th, 2021. The contract for Jax Solar will expire in September 2040.

1.1.3.3 Small Utility-Scale Solar Power Purchase Agreements

JEA issued two Solar Photovoltaic (PV) Request for Proposals (RFP), one in December 2014 and another in April 2015, and awarded a total of 31.5 MW_{AC} of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements were finalized for a total of 27 MW_{AC}. The last of these seven projects was completed in December 2019.

The following are the seven PPAs that are installed within JEA's service territory of which JEA pays for the energy and has rights to the associated environmental attributes produced by the facilities:

- Northwest Jacksonville Solar Partners, LLC: 7 MW_{AC} / 25-year PPA. The NW Jax facility consists of 28,000 single-axis tracking photovoltaic panels on a vendor-leased site, owned by American Electric Power (AEP). The facility became operational on May 30th, 2017.
- Old Plank Road Solar Farm, LLC: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility consists of 12,800 single-axis tracking photovoltaic panels on a vendor-leased 40-acre site, owned by Southeast Solar Farm Fund, a partnership between PEC Velo & Cox Communications. The site attained commercial operation on October 13th, 2017.
- C2 Starratt Solar, LLC: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility, on a vendor-leased site, is now owned by EDPR DR (acquired C2 Starratt Solar, LLC) and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20th, 2017.
- Inman Solar Holdings 2, LLC: 2 MW_{AC} / 20-year PPA. The Simmons Solar facility, on a vendor-leased site, is owned by Inman Solar Holdings 2, LLC and was constructed by Inman Solar, Inc. The site attained commercial operation on January 17th, 2018.
- Hecate Energy Blair Road, LLC: 4 MW_{AC} / 20-year PPA. The Blair Road facility, on a vendor-leased site, is owned by Hecate Energy Blair Road, LLC and was constructed by Hecate Energy, LLC. The site attained commercial operation on January 23rd, 2018.
- JAX Solar Developers, a wholly-owned subsidiary of Mirasol Fafco Solar, Inc.: 1 MW_{AC} / 20-year PPA. The Old Kings Rd Solar facility is owned by EcoPower Development, LLC and was constructed by Mirasol Fafco Solar, Inc. The site attained commercial operation on October 15th, 2018.
- Imeson Solar, LLC: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The primary function of the BESS is to smooth the solar generation. It is the first utility scale solar plus storage facility interconnected to the JEA grid. The site, labeled SunPort Solar, was constructed by 174 Power Global and attained commercial operation on December 4th, 2019.

1.1.3.4 FPL Solar Power Purchase Agreements

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

1.1.3.5 Planned Solar Power Purchase Agreements

JEA sought bids for the development of approximately 300 MW_{AC} of solar or solar plus energy storage system on JEA-owned parcels. The solicitation, released on January 31st, 2023 and

facilitated through TEA, sourced full attribute solar, or solar plus storage resource solutions formatted in multiple blocks, not to exceed 74.9 MW_{AC} each. Fifteen companies responded to the solicitation, providing an array of options. Responses were evaluated in a two-phase process, narrowing those fifteen respondents down to a shortlist of five, before award. On November 7th, 2023, JEA Board of Directors approved the award for 280 MW_{AC} of solar and energy storage system to Florida Renewable Partners (FRP). Contracts are currently in negotiation for four facilities. One 50 MW_{AC} facility, Forest Trail Solar, and two 74.9 MW_{AC} facilities, Miller Solar and Caldwell Solar, are expected to commission by December 31st, 2026. The final 74.9 MW_{AC} facility, Peterson Solar, is expected to attain commercial operation by September 30th, 2027.

JEA has also entered into a 20-year solar agreement with the Florida Municipal Power Agency (FMPPA) to purchase approximately 140 MW_{AC} from two facilities located in Florida, both set to commission by December 31st, 2026.

1.1.3.6 MEAG Nuclear Power Purchase Agreement

In June 2008, JEA entered into a 20-year PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4. These two new nuclear units are located at the existing Plant Vogtle in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity. After accounting for transmission losses, JEA is anticipating to receive a total of approximately 200 MW of net firm capacity from these units.

Vogtle Unit 3, commissioned on July 31st, 2023, is supplying approximately 100 MW of net firm capacity to JEA. Vogtle Unit 4, currently under construction with a projected commercial operation date of Q2 2024, is anticipated to supply approximately 100 MW of net firm capacity to JEA.

1.1.4 Cogeneration

Cogeneration facilities help meet the energy needs of JEA's system on an as-available, non-firm basis. Since these facilities are considered energy only resources, they are not forecasted to contribute towards firm capacity to JEA's reserve margin requirements.

Currently, JEA has contracts with one customer-owned qualifying facility (QF), as defined in the Public Utilities Regulatory Policy Act of 1978. Anheuser Busch has a total installed summer rated capacity of 8 MW and winter rated capacity of 9 MW.

Table 1a: JEA Existing Power Purchase Agreement Schedule

Contract		Start Date	End Date	MW_{AC}	Product Type
LES Trail Ridge	I	12/06/08	12/31/26	9	Annual
	II	02/01/14	12/31/26	6	Annual
MEAG Plant Vogtle	Unit 3⁽¹⁾	07/31/2023	07/31/2043	100	Annual
	Unit 4⁽¹⁾	Q2 2024	Q2 2044	100	Annual
FPL PPA		01/01/22	01/01/42	200	Annual
FPL Solar PPA		04/01/23	04/01/28	150	Annual
Jacksonville Solar		09/30/10	09/30/40	12	Annual
NW Jacksonville Solar		05/30/17	05/30/42	7	Annual
Old Plank Road Solar		10/13/17	10/13/37	3	Annual
Starratt Solar		12/20/17	12/20/37	5	Annual
Simmons Road Solar		01/17/18	01/17/38	2	Annual
Blair Site Solar		01/23/18	01/23/38	4	Annual
Old Kings Solar		10/15/18	10/15/38	1	Annual
SunPort Solar		12/04/19	12/04/39	5	Annual

(1) After accounting for transmission losses, JEA expects to receive approximately 100 MW from Vogtle Unit 3 and 100 MW from Vogtle Unit 4.

Table 1.1b: JEA Future Solar Power Purchase Agreement Schedule

Contract	Start Date	End Date	MW_{AC}	Product Type
Forest Trail Solar PPA	December 2026	December 2061	50	Annual
Caldwell Solar PPA	December 2026	December 2061	74.9	Annual
Miller Solar PPA	December 2026	December 2061	74.9	Annual
FMPA Solar PPA	December 2026	December 2046	139.8	Annual
Peterson Solar PPA	September 2027	September 2062	74.9	Annual
Two (2) 74.9 MW Solar PPA	Q1 2028	Q1 2053	149.8	Annual
150 MW Solar PPA	Q2 2028	Q2 2053	150	Annual
Seven (7) 74.9 MW Solar PPA	Q1 2030	Q1 2055	524.3	Annual
One (1) 35 MW Solar PPA	Q1 2030	Q1 2055	35	Annual

(1) Refer to section 1.1.3.5 and section 1.3.3 for details about the planned and future solar PPAs.

(2) All dates are subjected to change upon finalization of the agreements.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

JEA's transmission system consists of 744 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL, completing the path from FPL's Duval substation (located in the westerly portion of JEA's system) to the north to interconnect with the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Duke Energy Florida and the City of Tallahassee each own transmission interconnections with the Georgia ITS. JEA's import capacity is 1,228 MW over the 500 kV transmission lines through Duval substation.

The 230 kV and 138 kV transmission systems provide a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest; covering the area not covered by the 230 kV and 138 kV transmission backbone.

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

JEA has a 138 kV tie with Beaches Energy Services at JEA's Neptune substation. JEA owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to JEA's Nassau substation. This substation serves as a 138 kV transmission interconnection point for FPL's O'Neil substation and Florida Public Utilities Company's (FPU) Step Down substation. JEA's ownership of these two 138 kV interconnections end at the first transmission structure outside of the Nassau substation.

1.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. In compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, JEA continually assesses the needs and options for increasing the capability of the transmission system.

Since the FRCC region became the FL-Peninsula sub-region of SERC in July 2019, JEA has been following additional guidelines and actively participating in the SERC activities towards the reliability and security of the bulk electric system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process. FRCC's published Regional Transmission Planning Process facilitates coordinated planning by all transmission providers, owners, and stakeholders within the FRCC Region.

FRCC's members include investor-owned utilities, municipal utilities, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Technical Subcommittee in conjunction with the FRCC Staff to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 for: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

1.2.3 Transmission Service Requirements

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

The following existing transmission service contract is set to expire in the future during this Ten-Year Site Plan period:

- FPL purchased Cedar Bay plant and retired the generation in December 2016. The transmission service for the delivery of Cedar Bay generation has been converted to JEA's Open Access Transmission service and will remain with FPL through 2024.

1.2.4 Distribution

The JEA distribution system operates at three primary voltage levels (4.16 kV, 13.2 kV, and 26.4 kV). The 4.16 kV system serves a permanently defined area in older residential neighborhoods. The 13 kV system serves a permanently defined area in the urban downtown area. These two distribution systems serve any new customers that are located within their defined areas, but there are no plans to expand these two systems beyond their present boundaries. The 26.4 kV system serves approximately 90 percent of JEA's load, including 75 percent of the 4.16 kV substations. The current standard is to expand the 26.4 kV system as required to serve all new distribution loads, except loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,408 miles of distribution circuits of which approximately 60 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

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

JEA continues to investigate economic opportunities to incorporate clean energy into JEA's power supply portfolio.

1.3.2 Renewable Energy

1.3.2.1 JEA Distributed Energy

JEA has installed 35 solar PV systems, totaling 222 kW, on public high schools in Duval County, some of JEA's facilities and the Jacksonville International Airport.

1.3.2.2 Customer-Owned Distributed Energy

In addition to the solar thermal system incentive program, JEA established a residential net metering program to encourage the use of customer-sited solar PV systems. The policy has since evolved with several revisions:

- 2009: Tier 1 & 2 Net Metering policy launched to include all customer-owned renewable generation systems less than or equal to 100 kW
- 2011: Tier 3 Net Metering policy established for customer-owned renewable generation systems greater than 100 kW up to 2 MW
- 2014: Policy updated to define Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as 100 kW – 2 MW. This policy was capped at 10 MW for total generation. All customer-owned generation in excess of 2 MW would be addressed in JEA's Distributed Generation (DG) Policy.
- 2017: In October, the JEA Board of Directors approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1st, the comprehensive DG Policy qualified renewable and non-renewable customer-owned generation systems under the following ranges:
 - o DG-1 – Less than or equal to 2 MW
 - o DG-2D – Over 2 MW with distribution level connection

- o DG-2T – Over 2 MW with transmission level connection

This DG policy acts in concert with the JEA Battery Incentive Program and allows existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years. JEA's residential Battery Incentive Program pilot, enacted on April 1st, 2018, provided financial incentive towards the cost of an energy storage system, subject to lawfully appropriated funds. The pilot, used in concert with the 2018 DG Policy, is intended to assist customers in being efficient energy users. Customers who elect to collect the rebate were able to offset electricity consumption from JEA up to the limits of their storage devices. Funds allotted to each customer under the pilot is subject to review and change to optimize adoption. Since its inception until July 2022 when the pilot ended, over 700 residential storage systems have been installed.

1.3.2.3 Renewable Energy Credits (REC)

JEA acquires environmental attributes through its series of renewable PPAs and made those available to sell in order to lower rates for JEA customers. JEA had sold these environmental credits for specified periods. To maximize our clean energy efforts and meet our 2030 goals, a portion of those attributes have been inventoried. In 2023, JEA certified over 150,000 Solar RECs under the Green-e certification structure and tracked over 80,000 landfill gas RECs through the North America Renewables (NAR) registry.

1.3.2.4 SolarSmart and SolarMax

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

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

1.3.2.5 Landfill Gas and Biogas

JEA owned three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997 and was fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, methane gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and the remaining Girvin landfill generation facilities were decommissioned in 2014.

JEA's Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using three anaerobic digesters and one sludge dryer to produce a pelletized fertilizer product. The methane gas from the digesters can be used as a fuel for the sludge dryer and the digester heaters.

1.3.2.6 Biomass

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

In 2011, JEA co-fired biomass in Northside units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. They produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. At that time, JEA received bids from local sources to provide biomass for potential continued use.

In 2021, JEA began co-firing up to 10 percent of biomass (approximately up to 240 Tons per Day) in Northside Unit 2 due to the high price of petcoke. In early 2022, JEA submitted a request and was granted an air construction permit with the Florida Department of Environment Protection (FDEP), to burn up to 1000 tons per day of biomass in Northside units 1 and 2. At present, the price of petroleum coke continues to be volatile, and biomass is typically co-fired when available and economically beneficial.

1.3.3 Future Utility-Scale Renewable Energy

JEA Clean Energy Goals were approved by the JEA Board of Directors, which calls for 35 percent clean energy by 2030. To achieve the goal, JEA will need a total of 1,275 MW_{AC} of solar generation by 2030. JEA has identified that it can source two 74.9 MW solar facilities on JEA-owned parcels. JEA is expected to seek bids for the two solar facilities in 2024, with anticipated

commercial operation in 2028. JEA will continue to plan and identify the addition of the remaining 709 MW_{AC} of solar generation to be in-service between 2028 to 2030. For the purpose of this TYSP, JEA has considered all new solar generation as PPAs, as summarized in Table 1.1b.

1.3.4 Clean Energy Research Efforts

1.3.4.1 Collaboration with University of North Florida

JEA's clean energy research efforts have focused on the development of these technologies through a partnership with the University of North Florida's (UNF) Engineering Department. In the past, UNF and JEA have worked on the following projects:

- JEA and UNF worked to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF evaluated the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway, where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15-acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3-year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

On November 28th, 2023, JEA and UNF commemorated the grand opening of the JEA Sustainable Solutions Lab, a collaboration with UNF's College of Computing, Engineering and Construction, that allows undergraduate and graduate students to research clean energy technologies. JEA has committed to \$100,000 per year, for five years, for a total contribution of \$500,000. The lab will serve as a hub for research to develop sustainable solutions for JEA and a variety of industries.

1.3.4.2 Energy Storage

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

JEA welcomed the first utility-scale BESS to its grid with the addition of the SunPort Solar facility's 4 MWh battery; the storage system levels the solar PV output. The Florida Renewable Partner (FRP) projects will also host BESS alongside the 280 MW_{AC} of solar PV. As JEA continues to seek additional solar generation, JEA will be looking for opportunities to pair the new solar facilities with storage systems.

2. Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peak demands, net energy for load (NEL), interruptible customer demand, DSM, and the impact of plug-in electric vehicles (PEVs). JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

JEA uses National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for the weather parameters, Moody's Analytics (Moody) economic parameters for Duval County, JEA's Data Warehouse to determine the total number of Residential accounts and CBRE Jacksonville for Commercial total inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Calendar Year 2024 baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the more recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections.

2.1 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. JEA updates its normal weather every 5 years or more frequently, if needed.

The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy, 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 2023 Report.

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

The lighting energy forecast was developed using the historical actual energy, number of luminaries and JEA's estimated High Pressure Sodium (HPS) to Light-Emitting Diode (LED)

streetlight conversion schedule. The LEDs are estimated to use 45 percent less energy than the HPS streetlights. JEA developed the forecasted number of luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries, applied with the remaining HPS to LED streetlight conversions with all new streetlight additions as LED only.

JEA's forecasted Average Annual Growth Rate (AAGR) net energy for load during the TYSP period is 0.82 percent.

2.2 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 25°F as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA develops the seasonal peak forecasts using normalized historical and forecasted residential, commercial, and industrial energy for winter/summer peak months, and the average load factor based on historical peaks and net energy for winter/summer peak months. JEA's forecasted AAGR for net firm peak demand during the TYSP period is 0.58 percent for summer and 0.65 percent for winter.

2.3 Demand-Side Management (DSM)

2.3.1 Interruptible Load

JEA currently offers Interruptible and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to interruption of their full nominated load during times of system emergencies, including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 107 MW of interruptible peak load for the summer and 102 MW for the winter which remain constant throughout the study period. For 2024, the interruptible load represents 3.9 percent of the forecasted total peak demand in the summer and 3.6 percent of the forecasted total peak demand in the winter.

2.3.2 Demand-Side Management Programs

JEA continues to implement DSM programs that are economically beneficial and meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's programs focus on improving the efficiency of customer end use equipment, as well as, improving the system load factor through behavioral education and technology incentives.

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

Table 2: DSM Portfolio – Energy Efficiency Programs

ANNUAL INCREMENTAL		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Annual Energy	Residential	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
	Commercial	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
(GWh)	Total	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
Summer Peak	Residential	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
	Commercial	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
(MW)	Total	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Winter Peak	Residential	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	Commercial	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
(MW)	Total	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1

Table 3: DSM Programs

Commercial Programs	Residential Programs
Commercial Energy Assessment Program	Residential Energy Assessment Program
Commercial Prescriptive Program	Residential Energy Efficiency Products
Commercial Custom Program	Residential Solar Water Heating
Small Business Direct Install Program	Neighborhood Energy Efficiency Program
	Residential Energy Upgrades

2.4 Customer-Sited Renewables

A customer-sited renewables analysis on rooftop solar PV and battery storage installation was conducted by Black & Veatch Consulting group for JEA. The solar PV analysis accounted for available roof space (including pitched vs. 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 a 30-year 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, discount rates, and other costs using the extensive sensitivity analysis capabilities of the modeling software.

The battery storage analysis focused primarily on technical 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 stand-alone or solar-paired storage systems, accounting for electric rate structure, system characteristics, customer load profile, and solar PV generation profile.

2.5 Plug-in Electric Vehicles Peak Demand and Energy

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

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

The usable battery capacity (85 percent of battery capacity) per vehicle was determined based on the current plug-in electric vehicle models in Duval County. The average usable battery capacity per PEV is calculated using the average usable battery capacity of each vehicle brand and then assumes the annual growth of usable battery capacity per PEV by using the historical 5-year average of 0.001 kWh. Similarly, the peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecast peak capacity per PEV grows by 0.01 kW per year.

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

JEA forecasts AAGRs for PEVs winter and summer coincidental peak demand of 19.02 percent and 19.02 percent, respectively, and total energy of 19.0 percent during the TYSP period.

2.6 Electrification

JEA's electrification load growth assumptions align with the annual program goals for JEA's Electrification Rebates Program (ERP) through CY25 with the final year's goal projected forward to the end of the ten-year period. These goals were established for the program following a market potential study performed by ICF in June 2019. This study determined there were 803,465 MWh of existing convertible load in JEA's service territory at that time and made high/medium/low goal recommendations for the electrification program based on a prescriptive list of electrification measures for each scenario. JEA chose the medium scenario for the program which resulted in the electrification targets used for the program as well as projected load growth from electrification for the TYSP.

ERP is currently contracted through CY25 and will capture 22.5 percent of the market potential above when the contract expires. Following CY25, it is assumed that the program will be renewed resulting in continued load growth at least equal to the final contractual year of the current program. Assuming the goals are achieved, the resulting kWh of new load will be 46.8 percent of the market potential which is reasonable for a program in market for greater than 10 years.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Calendar Year	Rural and Residential			Commercial			Industrial		
	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer
2014	5,162	383,998	13,443	3,882	49,364	78,642	2,785	215	12,984,365
2015	5,197	391,219	13,285	4,001	50,821	78,733	2,806	207	13,531,924
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,692	202	13,322,934
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,777	202	13,717,349
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,765	196	14,081,384
2019	5,479	420,831	13,019	4,060	53,153	76,389	2,733	194	14,085,278
2020	5,679	429,575	13,220	3,886	53,701	72,363	2,698	196	13,759,522
2021	5,551	438,470	12,660	3,848	54,374	70,767	2,612	196	13,348,722
2022	5,723	447,308	12,795	4,005	55,082	72,717	2,708	199	13,641,119
2023	5,658	458,764	12,334	3,968	55,946	70,922	2,614	199	13,151,607
2024	5,738	464,202	12,360	3,976	56,705	70,115	2,702	200	13,508,157
2025	5,824	470,100	12,389	4,004	57,460	69,686	2,718	201	13,521,706
2026	5,904	476,433	12,393	4,040	58,213	69,395	2,722	201	13,542,903
2027	5,972	482,695	12,372	4,078	58,964	69,164	2,742	202	13,574,253
2028	6,032	488,640	12,345	4,118	59,711	68,958	2,748	202	13,604,039
2029	6,091	494,249	12,323	4,155	60,455	68,726	2,766	203	13,627,834
2030	6,146	499,480	12,305	4,190	61,194	68,479	2,769	203	13,641,554
2031	6,196	504,323	12,285	4,226	61,930	68,236	2,785	204	13,650,781
2032	6,240	508,813	12,264	4,262	62,662	68,021	2,785	204	13,654,261
2033	6,280	512,980	12,243	4,297	63,391	67,787	2,785	204	13,652,068

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

Calendar Year	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	Street & Highway Lighting	Other Sales to Ultimate Customers	Total Sales to Ultimate Customers	Sales for Resale	Utility Use & Losses	Net Energy for Load	Other Customers	Total Number of Customers
	GWH	GWH	GWH	GWH	GWH	GWH	(Avg. Number)	
2014	105	0	11,934	472	252	12,658	2	433,578
2015	87	0	12,091	392	385	12,868	2	442,249
2016	77	0	12,184	490	263	12,937	2	450,033
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,793
2019	57	0	12,328	58	411	12,797	0	474,178
2020	56	0	12,319	7	414	12,740	0	483,471
2021	55	0	12,066	25	449	12,540	0	493,039
2022	55	0	12,491	30	408	12,930	0	502,588
2023	55	0	12,295	63	376	12,733	0	514,909
2024	55	0	12,470	0	429	12,899	0	521,107
2025	56	0	12,602	0	434	13,036	0	527,761
2026	57	0	12,723	0	438	13,161	0	534,848
2027	57	0	12,849	0	442	13,291	0	541,861
2028	58	0	12,956	0	446	13,401	0	548,554
2029	58	0	13,070	0	450	13,520	0	554,907
2030	59	0	13,165	0	453	13,618	0	560,878
2031	59	0	13,266	0	456	13,722	0	566,458
2032	60	0	13,348	0	459	13,807	0	571,679
2033	60	0	13,423	0	462	13,885	0	576,574

Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Net Demand (MW)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand (MW)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2014	2,591	0	0	0	0	0	0	2,591
2015	2,618	0	0	0	0	0	0	2,618
2016	2,689	0	0	0	0	0	0	2,689
2017	2,631	0	0	0	0	0	0	2,631
2018	2,495	0	0	0	0	0	0	2,495
2019	2,591	0	0	0	0	0	0	2,591
2020	2,582	0	0	0	0	0	0	2,582
2021	2,511	0	0	0	0	0	0	2,511
2022	2,728	0	0	0	0	0	0	2,728
2023	2,756	0	0	0	0	0	0	2,756
2024	2,713	107	0	0	0	3	3	2,600
2025	2,742	107	0	0	0	6	5	2,624
2026	2,768	107	0	0	0	13	9	2,639
2027	2,794	107	0	0	0	17	11	2,659
2028	2,817	107	0	0	0	20	13	2,677
2029	2,840	107	0	0	0	23	16	2,694
2030	2,858	107	0	0	0	23	16	2,712
2031	2,879	107	0	0	0	25	17	2,730
2032	2,895	107	0	0	0	37	26	2,725
2033	2,910	107	0	0	0	38	26	2,739

Note: All projections coincident at time of peak.

Schedule 3.2: History and Forecast of Winter Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Net Demand (MW)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand (MW)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2013/14	2,754	0	0	0	0	0	0	2,754
2014/15	2,791	0	0	0	0	0	0	2,791
2015/16	2,600	0	0	0	0	0	0	2,600
2016/17	2,433	0	0	0	0	0	0	2,433
2017/18	3,011	0	0	0	0	0	0	3,011
2018/19	2,410	0	0	0	0	0	0	2,410
2019/20	2,445	0	0	0	0	0	0	2,445
2020/21	2,532	0	0	0	0	0	0	2,532
2021/22	2,529	0	0	0	0	0	0	2,529
2022/23	2,599	0	0	0	0	0	0	2,599
2023/24	2,853	102	0	0	0	2	2	2,747
2024/25	2,883	102	0	0	0	4	3	2,774
2025/26	2,908	102	0	0	0	5	4	2,797
2026/27	2,935	102	0	0	0	8	5	2,820
2027/28	2,957	102	0	0	0	12	8	2,835
2028/29	2,981	102	0	0	0	17	11	2,851
2029/30	3,000	102	0	0	0	19	12	2,867
2030/31	3,021	102	0	0	0	19	12	2,888
2031/32	3,038	102	0	0	0	18	12	2,906
2032/33	3,054	102	0	0	0	24	16	2,912

Note: All projections coincident at time of peak.

Schedule 3.3: History and Forecast of Annual Net Energy for Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Energy for Load (GWH)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy for Load (GWH)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2014	12,658	0	0	0	0	0	0	12,658
2015	12,868	0	0	0	0	0	0	12,868
2016	12,937	0	0	0	0	0	0	12,937
2017	12,672	0	0	0	0	0	0	12,672
2018	12,813	0	0	0	0	0	0	12,813
2019	12,797	0	0	0	0	0	0	12,797
2020	12,740	0	0	0	0	0	0	12,740
2021	12,540	0	0	0	0	0	0	12,540
2022	12,930	0	0	0	0	0	0	12,930
2023	12,733	0	0	0	0	0	0	12,733
2024	12,933	0	0	0	0	17	17	12,899
2025	13,104	0	0	0	0	34	34	13,036
2026	13,263	0	0	0	0	51	51	13,161
2027	13,427	0	0	0	0	68	68	13,291
2028	13,571	0	0	0	0	85	85	13,401
2029	13,724	0	0	0	0	102	102	13,520
2030	13,856	0	0	0	0	119	119	13,618
2031	13,994	0	0	0	0	136	136	13,722
2032	14,113	0	0	0	0	153	153	13,807
2033	14,225	0	0	0	0	170	170	13,885

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Actual 2023		Forecast 2024		Forecast 2025		Forecast 2026	
	Firm Peak Demand (MW)	Net Energy for load (GWH)	Firm Peak Demand (MW)	Net Energy for load (GWH)	Firm Peak Demand (MW)	Net Energy for load (GWH)	Firm Peak Demand (MW)	Net Energy for load (GWH)
January	2,326	977	2,747	1,043	2,774	1,054	2,797	1,065
February	1,813	844	2,422	906	2,448	916	2,470	925
March	2,049	948	1,963	953	1,984	964	2,002	973
April	2,080	963	2,080	931	2,102	941	2,123	951
May	2,230	1,064	2,346	1,087	2,372	1,098	2,395	1,109
June	2,598	1,168	2,555	1,218	2,583	1,231	2,608	1,242
July	2,699	1,353	2,563	1,317	2,591	1,330	2,617	1,342
August	2,756	1,418	2,600	1,300	2,624	1,312	2,639	1,324
September	2,461	1,149	2,460	1,167	2,486	1,179	2,511	1,190
October	2,057	993	2,180	1,044	2,204	1,055	2,224	1,065
November	2,043	887	1,961	939	1,983	949	2,000	959
December	2,016	969	2,329	995	2,354	1,006	2,375	1,016
Annual Peak/ Total Energy	2,756	12,733	2,747	12,899	2,774	13,036	2,797	13,161

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	NUCLEAR													
		TOTAL	TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL^(a)													
		TOTAL	1000 TON	515	220	430	489	534	422	389	92	69	46	142
(3)	RESIDUAL													
		STEAM	1000 BBL	20	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL	1000 BBL	20	0	0	0	0	0	0	0	0	0	0
(7)	DISTILLATE													
		STEAM	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	9	78	32	46	22	27	33	22	21	22	20
(10)		TOTAL	1000 BBL	9	78	32	46	22	27	33	22	21	22	20
(12)	NATURAL GAS													
		STEAM	1000 MCF	20,647	20,199	19,132	18,097	14,593	12,116	12,850	36	48	24	72
(13)		CC	1000 MCF	27,446	30,181	30,221	29,878	27,749	30,673	30,811	46,793	47,948	47,957	47,363
(14)		CT/GT	1000 MCF	12,429	19,435	12,831	14,104	13,994	11,699	11,777	6,824	6,743	7,022	6,876
(15)		TOTAL	1000 MCF	60,522	69,815	62,184	62,079	56,335	54,488	55,438	53,654	54,739	55,003	54,311
(17)	OTHER (BIOMASS)													
		TOTAL	TRILLION BTU	45	88	172	195	213	168	155	37	28	18	57

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	Firm Inter-Region Interchange		GWH	3,385	1,434	1,332	1,354	1,483	1,352	1,397	489	474	484	484
(2)	Firm Inter-Region Intchg. - Nuclear		GWH	378	1,272	1,634	1,594	1,603	1,613	1,706	1,578	1,597	1,709	1,596
(3)	NUCLEAR		GWH	0	0	0	0	0	0	0	0	0	0	0
(4)	COAL^(a)		GWH	1,231	630	1,216	1,378	1,527	1,196	1,104	254	189	129	397
(5)	RESIDUAL	STEAM	GWH	11	0	0	0	0	0	0	0	0	0	0
(6)		CC		0	0	0	0	0	0	0	0	0	0	0
(7)		CT		0	0	0	0	0	0	0	0	0	0	0
(8)		TOTAL		11	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CC		0	0	0	0	0	0	0	0	0	0	0
(11)		CT		3	26	9	15	5	7	10	6	5	5	5
(12)		TOTAL		3	26	9	15	5	7	10	6	5	5	5
(13)	NATURAL GAS	STEAM	GWH	1,903	2,055	1,920	1,811	1,426	1,159	1,229	0	0	0	0
(14)		CC		4,147	4,887	4,890	4,834	4,494	4,961	4,987	7,421	7,608	7,610	7,518
(15)		CT		1,219	1,909	1,233	1,347	1,380	1,135	1,147	668	661	683	674
(16)		TOTAL		7,268	8,851	8,043	7,992	7,300	7,254	7,362	8,088	8,269	8,293	8,192
(17)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	RENEWABLES	LANDFILL GAS	GWH	53	128	129	129	0	0	0	0	0	0	0
(19)		SOLAR PPA		335	432	449	449	1,096	1,759	1,735	3,138	3,134	3,142	3,122
(20)		SOLARSMART/ SOLARMAX ^(b)		24	24	24	24	24	24	24	24	24	24	24
(22)		TOTAL		412	584	601	601	1,120	1,782	1,759	3,161	3,158	3,166	3,146
(23)	OTHER (BIOMASS)		GWH	46	104	200	227	252	197	182	42	31	21	65
(24)	NET ENERGY FOR LOAD^(c)		GWH	12,733	12,899	13,036	13,161	13,291	13,401	13,520	13,618	13,722	13,807	13,885

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

(c) May not add due to rounding.

Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	Inter-Region Interchange		%	26.6	11.1	10.2	10.3	11.2	10.1	10.3	3.6	3.5	3.5	3.5
(2)	Firm Inter-Region Intchg. - Nuclear		%	3.0	9.9	12.5	12.1	12.1	12.0	12.6	11.6	11.6	12.4	11.5
(3)	NUCLEAR		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4)	COAL ^(a)		%	9.7	4.9	9.3	10.5	11.5	8.9	8.2	1.9	1.4	0.9	2.9
(5)	RESIDUAL	STEAM	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		TOTAL		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	DISTILLATE	STEAM	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CT		0.0	0.2	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0
(12)		TOTAL		0.0	0.2	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0
(13)	NATURAL GAS	STEAM	%	14.9	15.9	14.7	13.8	10.7	8.6	9.1	0.0	0.0	0.0	0.0
(14)		CC		32.6	37.9	37.5	36.7	33.8	37.0	36.9	54.5	55.4	55.1	54.1
(15)		CT		9.6	14.8	9.5	10.2	10.4	8.5	8.5	4.9	4.8	4.9	4.9
(16)		TOTAL		57.1	68.6	61.7	60.7	54.9	54.1	54.5	59.4	60.3	60.1	59.0
(17)	NUG		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(18)	RENEWABLES	LANDFILL GAS	%	0.4	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)		SOLAR PPA		2.6	3.3	3.4	3.4	8.2	13.1	12.8	23.0	22.8	22.8	22.5
(20)		SOLARSMART/ SOLARMAX ^(b)		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(22)		TOTAL		3.2	4.5	4.6	4.6	8.4	13.3	13.0	23.2	23.0	22.9	22.7
(23)	OTHER (BIOMASS)		%	0.4	0.8	1.5	1.7	1.9	1.5	1.3	0.3	0.2	0.2	0.5
(24)	NET ENERGY FOR LOAD		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.

(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

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

JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources as well as other planning assumptions.

3.1.1 Integrated Resource Planning Study

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

- Environmental Legislative and Regulatory Action
 - o Cost for emissions of CO₂
 - o Specific goals or targets for percentages of energy from sources that do not emit carbon dioxide (CO₂)
 - o Retirement of solid fuel and/or natural gas-fired generation
 - o 316(b) regulations
- Load Growth Forecasts
 - o Energy
 - o Peak demand
 - o Demand-side management and energy efficiency
 - o Plug-in electric vehicles
 - o Electrification
 - o Customer-sited renewables
- Fuel Costs
- Cost of New Generation
- Continued Operation of Existing Generating Units
- Other Considerations
 - o Affordability
 - o Reliability
 - o Environmental
 - o Economic development
 - o CO₂ emissions reductions

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

The IRP was developed reflecting consideration of JEA's existing 524 MW Northside Unit 3 being removed from service in 2030. Removal of this unit from service is influenced by multiple factors, including the need for capital upgrades to remain reliable and as a means of compliance with potential 316(b) surface water withdrawal regulations.

The IRP results consistently identified a 1x1 advanced-class combined cycle combustion turbine (CCCT) configuration in the 2030 timeframe as part of the least-cost resource plan across the majority of scenarios and sensitivities. Modeling results show that the retirement and replacement of JEA's Northside Unit 3 with an efficient, advanced-class CCCT provides JEA with a new cost-effective resource. This new resource will provide reliable dispatchable power, allow for more efficient use of natural gas, reduces system CO₂, NO_x and SO₂ emissions, provides support to reliably integrate more renewable energy into the JEA system and will also avoid costly upgrades that would otherwise be necessary to extend the life of the 46-year-old unit. It should be noted that in order to maintain reliable operation of JEA's system, Northside Unit 3 unit cannot be retired until a replacement unit has achieved commercial operation. Due to permitting requirements associated with the Florida Power Plant Siting Act (PPSA), specifically Determination of Need and Site Certification (environmental permitting) for a CCCT, Northside Unit 3 may need to continue to operate until the earliest commercial operation date of a new CCCT resource, which is estimated to be in the 2030 timeframe. Development considerations, such as permitting delays, supply chain difficulties, or construction delays, could impact the earliest commercial operation date.

The results from the IRP also helped identify that a total of 1,275 MW_{AC} of Solar PV will enable JEA to achieve part of its Clean Energy Goals by 2030. JEA is currently in negotiation for a total of approximately 415 MW_{AC} of solar PPAs. The details on these solar PPAs can be found in section 1.1.3.5. JEA will continue to seek for additions of solar PV and perform studies to determine potential reliability considerations for the JEA system associated with the integration of 1,275 MW_{AC} of solar.

3.1.2 JEA Planning Reserve Policy

JEA's Planning Reserve Policy establishes a guideline that provides an allowance to meet the 15 percent reserve margin with up to 3 percent of the forecasted firm peak demand in any season from purchases acquired in the operating horizon. If up to 3 percent of firm peak demand in any season is needed, The Energy Authority (TEA), JEA's affiliated energy market services company, will acquire short-term seasonal market purchases for JEA no later than the season prior to the

need. TEA actively trades energy with a large number of counterparties throughout the United States and is generally able to acquire capacity and energy from other market participants when any of its members require additional resources.

No short-term seasonal market purchases are required in this TYSP period.

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA included a review of existing electric supply resources, forecast of customer energy requirements and peak demand, forecast of fuel prices and fuel availability, committed unit additions, existing capacity changes and annual and seasonal capacity purchase additions. All of these factors considered collectively provide JEA with sufficient capacity to cover customer demand and reserves during this ten-year period. Table 4 presents the ten-year resource addition plan, which meets JEA's strategic goals. TYSP Schedules 7-10 provide further detail of this plan.

Table 4: Resource Plan

Year	Resource Plan
2024	MEAG Plant Vogtle 4 Purchase (100 MW) ⁽²⁾
2025	
2026	Trail Ridge Contract Expires (-15 MW) ⁽³⁾ Forest Trail Solar PPA (50 MW _{AC}) ⁽⁴⁾ Caldwell Solar PPA (~75 MW _{AC}) ⁽⁴⁾ Miller Solar PPA (~75 MW _{AC}) ⁽⁴⁾ FMPA Solar PPAs (~140 MW _{AC}) ⁽⁴⁾
2027	Peterson Solar PPA (~75 MW _{AC}) ⁽⁴⁾
2028	Two (2) 74.9 MW _{AC} Solar PPAs (~150 MW _{AC}) ⁽⁵⁾ FPL Solar PPA Expires (-150 MW) Future Solar PPA (150 MW) ⁽⁵⁾
2029	
2030	Future Solar PPAs (~560 MW _{AC}) ⁽⁵⁾ Northside 3 Retires (-524 MW) ⁽⁶⁾ 1x1 CCCT (669.8 MW) ⁽⁶⁾
2031	
2032	
2033	

Notes:

- (1) All dates are subjected to change.
- (2) After accounting for transmission losses, JEA expects to receive approximately 100 MW from Vogtle Unit 4. Vogtle Unit 4 in-service date is expected to be Q2 2024.
- (3) Trail Ridge contract ends December 31, 2026.
- (4) Please refer to section 1.1.3.5 for details about the Planned Solar PPAs.
- (5) Please refer to section 1.3.3 for details about Future Solar PPAs.
- (6) Please refer to section 3.1.1 for more details.

Schedule 7.1: Summer Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2024	2,782	514	0	0	3,296	2,600	695	27%	0	695	27%
2025	2,782	517	0	0	3,299	2,624	675	26%	0	675	26%
2026	2,782	516	0	0	3,298	2,639	659	25%	0	659	25%
2027	2,782	568	0	0	3,350	2,659	692	26%	0	692	26%
2028	2,782	550	0	0	3,332	2,677	656	24%	0	656	24%
2029	2,782	550	0	0	3,332	2,694	638	24%	0	638	24%
2030	2,834	661	0	0	3,495	2,712	783	29%	0	783	29%
2031	2,834	661	0	0	3,495	2,730	765	28%	0	765	28%
2032	2,834	659	0	0	3,493	2,725	768	28%	0	768	28%
2033	2,834	658	0	0	3,492	2,739	753	27%	0	753	27%

Schedule 7.2: Winter Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2023/24	2,952	315	0	0	3,267	2,747	520	19%	0	520	19%
2024/25	2,952	415	0	0	3,367	2,774	593	21%	0	593	21%
2025/26	2,952	415	0	0	3,367	2,797	570	20%	0	570	20%
2026/27	2,952	400	0	0	3,352	2,820	532	19%	0	532	19%
2027/28	2,952	400	0	0	3,352	2,835	517	18%	0	517	18%
2028/29	2,952	400	0	0	3,352	2,851	501	18%	0	501	18%
2029/30	2,952	400	0	0	3,352	2,867	485	17%	0	485	17%
2030/31	3,098	400	0	0	3,498	2,888	610	21%	0	610	21%
2031/32	3,098	400	0	0	3,498	2,906	591	20%	0	591	20%
2032/33	3,098	400	0	0	3,498	2,912	586	20%	0	586	20%

Schedule 8: Planned and Prospective Generating Facility Additions and Changes

Planned and Prospective Generating Facility and Purchased Power Additions and Changes														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transport		Construction Start Date	Commercial/ In-Service or Change Date	Expected Retirement/ Shutdown Date	Gen Max Nameplate	Net Capability		Status
				Primary	Alternate	Primary	Alternate					Summer	Winter	
												kW	MW	MW
Northside	Unit 3	12-031	ST	NG	RFO	PL	WA	N/A	Jul-77	Jan-30	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Apr-27	Jan-30	Unknown	TBD	576	669.8	P

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

1	Plant Name and Unit Number:	Advanced-Class 1x1 CC
2	Capacity:	
3	Summer MW:	576
4	Winter MW:	669.8
5	Technology Type:	CCCT
6	Anticipated Construction Timing:	
7	Field Construction Start-date:	Apr-27
8	Commercial In-Service date:	Jan-30
9	Fuel:	
10	Primary:	NG
11	Alternate:	DFO
12	Air Pollution Control Strategy:	As required by new source Performance Standards
13	Cooling Method:	Wet mechanical draft cooling tower
14	Total Site Area:	Block approximately 30 acres
15	Construction Status:	Not started
16	Certification Status:	Not started
17	Status with Federal Agencies:	Permitting not started
18	Projected Unit Performance Data:	
19	Planned Outage Factor (POF):	6%
20	Forced Outage Factor (FOF):	3%
21	Equivalent Availability Factor (EAF):	91%
22	Resulting Capacity Factor (%):	50%
23	Average Net Operating Heat Rate (ANOHR):	6,702 Btu/kWh
24	Projected Unit Financial Data:	
25	Book Life:	25 years
26	Total Installed Cost (In-Service year \$/kW) ⁽¹⁾ :	1,220 \$/kW All-in
27	Direct Construction Cost (\$/kW):	Included above
28	AFUDC Amount (\$/kW):	IDC included above
29	Escalation (\$/kW):	Included above
30	Fixed O&M (2023 \$/kW-yr) ⁽¹⁾ :	7.33
31	Variable O&M (\$/MWh):	2.68

Note:

(1) Total installed cost and fixed O&M are based on winter capacity.

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

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

4. Other Planning Assumptions and Information

4.1 Fuel Price Forecast

The fuel price projections used in this forecast were developed based on long-term price forecasts from the Annual Energy Outlook 2023 (AEO2023 issued by the EIA). A new Annual Energy Outlook will not be available in 2024 because the EIA's model requires substantial updates to better model hydrogen, carbon capture, and other emerging technologies. The AEO2023 presents projections of energy supply, demand, and prices through 2050. AEO2023 projections are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based energy-economy modeling system of U.S. energy markets. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.

On January 1st, 2022, JEA began receiving energy from FPL through a PPA that provides 200 MW of natural gas combined cycle power. The natural gas price projection was based on a six-month average of NYMEX natural gas futures over the short-term and then escalated using the AEO2023 Henry Hub price forecast. The transportation costs are based on the PPA contract terms, and the total cost is escalated by an inflation rate of 3 percent thereafter.

Northside Units 1 and 2 burn a blend of petroleum coke, coal, biomass, and natural gas. The blends of these four fuel types vary during the forecast period based on the projected costs of the fuels and other constraints. The Northside coal price projections are based on a six-month average of NYMEX API2 Argus-McCloskey coal futures over the short-term and then escalated using AEO2023 projections for Interior coal. Freight rates for waterborne delivery of Colombian coal were based on the historical average over the last three years and escalated using a 3 percent inflation rate to project transportation costs beyond 2024. A ratio of historical delivered petroleum coke and coal prices over the past ten years was applied to the delivered Northside coal price projections to derive the projected petroleum coke price.

JEA currently operates eight units utilizing natural gas as a primary fuel. These units are GEC GT1 and GT2, Brandy Branch GT1, CT2 and CT3, Northside 3, and Kennedy GT7 and GT8. The natural gas price projection was based on a six-month average of NYMEX natural gas futures over the short-term and then escalated using the AEO2023 Henry Hub price forecast. The transportation costs are a combination of historical Florida city gate market costs on Florida Gas Transmission and local distribution fees.

The 1970's-vintage combustion turbine units at Northside (GT3, GT4, GT5, and GT6) burn diesel fuel as the primary fuel type. Five JEA units utilize diesel fuel as an alternative to natural gas: Kennedy GT7 and GT8, GEC GT1 and GT2, and Brandy Branch GT1. Projections for the price

of diesel fuel are based on a six-month average of NYMEX ultra-low sulfur diesel futures pricing over the short-term and then escalated using AEO2023 projections for ultra-low sulfur diesel.

JEA has a PPA with MEAG for 200 MW from Vogtle Units 3 and 4. Unit 3 commenced service in July 2023 and Unit 4 is currently under construction with in-service expected in 2024. The fuel price forecast accounts for the costs of mine-mouth uranium, enrichment, and fabrication.

4.2 Economic Parameters

This section presents the parameters and methodology used for economic evaluations as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the TYSP period.

4.2.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and non-fuel variable O&M escalation rate are each assumed to be 3.00 percent.

4.2.2 Municipal Bond Interest Rate

JEA performs sensitivity assessments of project cost to test the robustness of JEA's resource plan. Project cost includes forecast of direct cost of construction, indirect cost, and financing cost. Financing cost includes the forecast of long term tax-exempt municipal bond rates, issuance cost, and insurance cost. For JEA's plan development, the long term tax-exempt municipal bond rate is assumed to be 4.00 percent. This rate is based on JEA's judgment and expectation that the long-term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax-exempt municipal bond interest rate of 4.00 percent.

4.2.4 Interest during Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.00 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR (LFCR) that has the same present value as the year-by-year FCR. Different generating technologies are assumed to have different economic lives and therefore

different financing terms. Simple cycle combustion turbines are assumed to have a 20-year financing term, while natural gas-fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different LFCRs were developed. All LFCR calculations assume the 4.00 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.57 percent annual property insurance cost. The resulting 20-year FCR is 8.00 percent and the 25-year FCR is 7.00 percent.

5. Environmental and Land Use Information

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.

Appendix J – Evaluation Methodology and Scorecard

JEA reserves the right to adjust evaluation criteria or weighting before the response due date. Any modification of response evaluation criteria will be posted via an addendum.

Economic Evaluation

The quantitative assessment is inclusive of economic analysis that measures the cumulative present worth cost (CPWC) over a 30-year horizon, consistent with the expected life of a new-build CCGT. The economic analysis will utilize information in the Responses to characterize the cost of the proposed resource. The proposed resource will be evaluated using the PLEXOS capacity expansion and production cost models.

The PLEXOS model inputs will be fixed prior to opening Responses within the Solicitation and will be used consistently throughout the evaluation of the Responses and the self-build option, including fuel price forecasts, load forecast, existing unit characteristics, candidate (new) unit characteristics, clean energy requirements, and required reserve margin.

JEA will use the PLEXOS LT model to develop an optimal capacity expansion plan for each proposed resource for under each of these scenarios and sensitivities listed below.

- a. Reference case which assumes the EPA's Greenhouse Gas Rule is in place and effective (across 30 years and 15 years)
- b. Sensitivity without the EPA's Greenhouse Gas Rule in place
- c. High load forecast sensitivity
- d. Low load forecast sensitivity
- e. High gas price sensitivity

Under each of these sensitivities and scenarios the JEA system will be optimized around the proposed resource. Through this process, planning objectives will be met within reason, including clean energy goals, dump energy levels, unserved energy, unit capacity factors, starts, operating hours, unit costs.

In the economic evaluation, Responses will be ranked based on minimizing the CPWC of serving JEA load over the planning horizon. Responses with a low CPWC will receive a higher score than Responses with a higher CPWC.

Credit Evaluation

JEA has included detailed credit requirements in Appendix G – Credit Requirements and has specified the information required to evaluate credit requirements in Section 11- Financing of Appendix F – Respondent Questionnaire.

JEA will perform a credit analysis to determine whether the issuing entities are creditworthy to support the Seller's credit assurance obligations. The creditworthiness of the entity providing the applicable instrument will be based on the reasonable judgment of JEA, provided that any entity with a short-term or long-term investment grade credit rating by S&P, Fitch, or Moody's shall be deemed to have acceptable financial creditworthiness.

Transmission Evaluation

All applicable Response requirements relative to Transmission and Interconnection are contained in Appendix B – Transmission Interconnection and Deliverability Considerations, and identified narratives and information for Responses are in Section 8 – Interconnection and Delivery of Appendix F – Respondent Questionnaire. Each Response will be evaluated based on the narrative descriptions and data requested in the subject appendices. The evaluation process is described as follows:

- JEA will review all the transmission system impact studies, results and narrative descriptions submitted as part of the Response. If insufficient information is provided, JEA will request further clarifications or initiate its own study as needed to evaluate the Response. JEA also reserves the right to reject significantly incomplete or non-compliant Responses.
- Categories to be evaluated include the following:
 - Reliability and Risk of proposed transmission / interconnection
 - Transmission company and/or consulting engineering contractor's experience level;
 - Complexity, Cost and Schedule Reasonableness of required upgrades.
 - Risks and Mitigation of impacts to JEA's existing import and export capability and to reliability and performance of the JEA system
- The criteria for the basis of JEA's present import/export capability will be analyzed (by JEA) according to standard methods and furnished to the IE prior to receipt of Market RFP Responses. JEA's current system with and without JEA's self-build resource will be analyzed for 2030/2031 Winter and 2031 summer peak load conditions to determine these values. The same planned system for the above years and seasons with the resource proposed by the Respondents substituted for the JEA self-build resource will also be analyzed for transmission impacts to determine how JEA's import/export capacity may be impacted.
- Note that any network resource must be evaluated at the same queue position as JEA's proposed self-build option.

Fuel Supply Evaluation

JEA will evaluate fuel supply information provided in Section 10 – Fuel Supply and Transportation of Appendix F - Respondent Questionnaire. JEA's primary focus for this evaluation includes:

- Reliability –JEA will evaluate the potential reliability, cost risk and construction risk of the Respondent's fuel plan by looking at the following:
 - Existing pipelines serving facility will be viewed as providing less risk than new pipelines.
 - Where new pipelines are required, risk will be assessed by how well Respondent demonstrates that there is a reasonable possibility of successful permitting and construction.
 - Source(s) of natural gas transportation should be a liquid and accessible location.
- Optionality – Firm transportation and/or firm delivered commodity contracts should be designed to cost effectively deliver fuel with primary firm reliability, in order to meet firm energy delivery requirements. The coverage needed to achieve this is left to the Respondent to propose, and might include means of firming gas supply such as firm interstate gas transportation contracts and/or firm delivered commodity contracts or equivalent arrangements. Responses including options that will allow for optimization of

transportation assets as well as any gas commodity supply deals when not required to serve load will achieve a higher rating.

- Diversity – Consideration will be given for fuel supply sources that expand the current supply basins that JEA accesses. For example, options to move further upstream with transportation assets that access more liquid supply basins and receipt points. JEA is typically accessing Texas/Gulf and Appalachian shale basins at present.

JEA Solicitation Scorecard

JEA reserves the right to adjust the qualitative criteria and point assignment prior to receipt of offers.

Total Scoring Methodology

Metric	Max Points	Max Score	If not least cost
Economic Assessment Scoring	70		
Lowest Overall CPWC, Base Case (with GHG Rule) 30 Years	30	Lowest cost CPWC over 30 year planning period	30 Points less plan's percentage above least cost CPWC plan
Lowest CPWC, Base Case (with GHG Rule) at 15 year mark	10	Lowest cost CPWC after 15 year planning period	15 Points less plan's percentage above least cost CPWC plan
Lowest Overall CPWC, Base Case (without GHG Rule) 30 Year	15	Lowest cost CPWC over 30 year planning period	15 Points less plan's percentage above least cost CPWC plan
Sensitivity Cases CPWC	15	Lowest average cost CPWC across sensitivities	15 Points less plan's percentage above least cost CPWC plan
Risk Assessment	30	Criteria outlined below in scorecard	
System Reliability (Flexibility)	6		
Experience and Commercial	4.5		
Transmission Status	6		
Project Status and Technical Design	3		
Environmental	4.5		
Fuel Supply	6		
Total Score	100		

Risk Assessment Scorecard

Metric	Weighting	Score Definition: 0-5	Score Definition: 6-10	Score Definition: 11-15
System Reliability (Flexibility)	20%			
Start Time (cold start) to MECL (hours)	15%	Over 8 hours	6-8 hours	6 hours or less
Start Time (Warm) to MECL (minutes)	20%	Over 85 minutes	75-85 minutes	75 minutes or less
Maximum Hours Qualifying to Full Load as Warm Start	15%	Over 4.5 hours	4 - 4.5 hours	4 hours or less
Starts Per year limitation	15%	Less than 50	>=50 but less than 150	>=150
CT Ramp Rate (CT Only, with steam cycle in service if CC)	15%	<40MW/Min MECL to MCR	>=40MW/Min, <60MW/Min MECL to MCR	>= 60MW/Min MECL to MCR
Continuous Minimum Dispatch Level (MECL)	20%	>35% of unfired MCR	<=35%, >25% of unfired MCR	<=25% of unfired MCR
Total Score	100%			

Metric	Weighting	Score Definition: 0-5	Score Definition: 6-10	Score Definition: 11-15
Experience and Commercial	15%			
Commercial Terms	20%	Did not provide proposed terms, or the terms allocated significant risk to Buyer	Proposed term sheet reflects a balanced allocation of risk between Buyer and Seller	Proposed term sheet is consistent with JEA preferred contract terms.
Respondent's Development Experience	30%	Respondent has completed zero projects of the same proposed technology (i.e. CCGT) and that is at least 75% of the proposed capacity (for a single unit)	Respondent has completed at least 1 project, but less than 3 projects, of the same proposed technology and that are at least 75% of the proposed capacity (for a single unit)	Respondent has completed 3 or more projects of the same proposed technology that are at least 75% of the proposed capacity (for a single unit), or the Response is for an existing resource.
Company's Operational Experience	30%	Respondent has owned and operated less than 3 facilities with the proposed fuel-types.	Respondent has owned and operated at least 3 but less than 6 facilities with the same fuel type as the proposes resource.	Respondent has owned and operated at least 6 facilities with the same fuel-type as proposed, or the proposed resource will be operated by JEA.
Safety and Performance of Similar Units	20%	Respondent has no Safety Standards or has not provided adequate documentation, or their standards have significant deficiencies. Or Respondent has a total recordable incident (TRI) level higher than the TRI for their industry as determined by the U.S. Occupational Health and Safety Administration (OSHA).	Respondent has provided Safety Standards, but they have some deficiencies in the standards. And Respondent has a total recordable incident (TRI) level lower than or equal to the TRI for their industry as determined by the U.S. Occupational Health and Safety Administration (OSHA).	Respondent has provided Safety Standards consistent with expectations, and these standards will be applicable to any contractors. And Respondent has a total recordable incident (TRI) level lower than or equal to the TRI for their industry as determined by the U.S. Occupational Health and Safety Administration (OSHA).
Total Score	100%			

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Metric	Weighting	Score Definition: 0-5	Score Definition: 6-10	Score Definition: 11-15
Transmission Status	20%			
Reliability and Risk of transmission solution compared with proposed self-build project	35%	Power delivery via transmission service with multiple transmission providers, or interconnection within JEA system with significant negative impacts to JEA system	Power delivery via transmission service with one service provider, or interconnection within JEA system with some negative impacts	Directly interconnected within JEA system, no negative impacts to JEA system, reliability and risk equivalent to self-build project
Quality of Proposer's and/or Proposer's engineering contractor's experience with developing, evaluating and executing transmission upgrades in the respective (FRCC/ITS) region(s) as applicable	20%	Minimal to no experience with developing, evaluating and executing transmission upgrades	Experienced with developing, evaluating and executing transmission upgrades, but in only one (FRCC or ITS) region	No upgrades required, or very experienced with developing, evaluating and executing transmission upgrades in the applicable (FRCC/ITS) region(s)
Project Upgrades Cost & Complexity (Total Project Cost = Transmission + Interconnection + 3rd Party Impacts + JEA impacts (as determined by JEA study))	15%	Significant projects were identified (Total Project Cost >\$50M) or projects are not expected to be in-service by COD, or proposal failed to adequately address necessary transmission/interconnection, 3rd party upgrades	Some projects (\$25M< Total Project Cost <=\$50M) were identified with no expected impact to project schedule	Total Project Cost <= \$25M and no expected impact to COD
Risk of Transmisison construction project(s) not meeting the PPA In-Service Date	15%	Identified projects contain significant risks, or trigger regulation under the Florida TLSA or FERC Order No. 1000	Identified projects are more extensive (Total Project Cost > \$25M, or some impact expected on the COD) but do not trigger regulation under Florida TLSA or FERC Order No. 1000	Total Project Cost <= \$25M, No TLSA/FERC Order No. 1000 and no expected impact to COD
Risk of 3rd party impacts	15%	Major 3rd party impact projects (>\$20M required, or no assessment of 3rd party impacts, or inadequate methodology for assessment of 3rd party impacts at any cost level	Minor 3rd party impact projects identified with adequate assessment of projects	No 3rd party impacts, adequate assessment shows zero 3rd party impact cost
Total Score	100%			

Metric	Weighting	Score Definition: 0-5	Score Definition: 6-10	Score Definition: 11-15
Project Status and Technical Design	10%			
Project Design and Cost Estimate Status	25%	Response based on a planning estimate, or did not provide enough information to assess.	Response is based on a Class 4 or 5 estimate	Response is based on a level 3 estimate, or the Response is for an existing resource.
Project Development Schedule	20%	Timeline provides only a high level of detail or timeline does not support the proposed COD.	Timeline provides sufficient detail to confirm achievable milestone dates, the critical path, and any owner-furnished obligations that support the stated COD.	Timeline provides additional detail beyond critical path items and key milestone dates, and supports the stated COD, or the Response is for an existing resource.
EPC Contract Status	10%	Documentation indicates that no long-lead time equipment (e.g., transformers) and EPC contracts have been established and/or suppliers have not been identified	Documentation indicates that long-lead time equipment (e.g., transformers) and EPC contracts have been identified.	Documentation indicates that long-lead time equipment (e.g., transformers) and EPC contracts are have been idenitified and are in negotiations, or master supply arrangements/ agreements exist, or the Response is for an existing resource.
Site Control	25%	Respondent provided no documentation to support site control	Respondent is in negotiations (e.g., has an LOI) for all or a portion of the site and required easements, or has site control for only a portion of the required site plan.	Respondent has full site control with an executed agreement, or the Response is for an existing resource.
Financing Plan	10%	Respondent has not provided a comprehensive financing plan, or has not indicate engagement with financing entities.	Respondent has made progress in financing project, including engagement with applicable financing entities.	A detailed financing plan has been provided as part of the Response and it is determined to be realistic to keep project development on track, or the Response is for an existing resource, or the resource is owned by JEA.
Staffing and O&M Plan	10%	Respondent did not provide a comprehensive O&M and staffing plan	Respondent provided an O&M & staffing plan consistent with development stage of the project	Respondent provided a comprehensive staffing & O&M plan, or the resource will be operated by JEA.
Total Score	100%			

Metric	Weighting	Score Definition: 0-5	Score Definition: 6-10	Score Definition: 11-15
Environmental		15%		
Permit Matrix	10%	Respondent has not provided a permit matrix and associated schedule for permitting.	Respondent provided a permit matrix but did not include all appropriate permits and/or a realistic schedule for obtaining the permits.	Respondent provided a permit matrix outlining all of the appropriate permits needed and a realistic schedule for obtaining the permits.
Regulatory, Permitting and Environmental Studies and Plans Impact Severity	40%	Studies and Plans reflect significant undue permitting, schedule, remediation or cost risks or schedule challenges, or the Response is for an existing resource.	Studies and Plans reflect minor undue permitting, schedule, remediation or cost risks or schedule challenges, or the Response is for an existing resource.	Studies and Plans reflect no undue permitting, schedule, remediation or cost, risks or schedule challenges, or the Response is for an existing resource.
Greenhouse Gas Rule Compliance	50%	Proposed asset is subject to the GHG rule, but not in compliance with the rule, or no compliance strategy mentioned.	Proposed asset is subject to GHG rule and in compliance with the rule via proposed CCS included in pricing and schedule.	Proposed asset is subject to the GHG rule and compliance via specified capacity factor limitation and emission rate cap are proposed without impacting flexibility requirements, or proposed asset is not subject to the GHG rule.
Total Score		100%		

Metric	Weighting	Score Definition: 0-5	Score Definition: 6-10	Score Definition: 11-15
Fuel Supply		20%		
Maturity of fuel supply plan	25%	Respondent has not engaged with gas companies/pipelines for fuel supply.	Respondent has developed a fuel supply plan, and has had preliminary discussions with pipelines.	Respondent has formal engagements with pipelines to provide fuel to proposed facility, or the Response is for an existing resource.
Number of fuel sources (Available pipelines from different supply basings) for primary fuel (natural gas)	25%	There is a single fuel source for the facility.	There are two fuel sources for the facility.	There are more than 2 fuel sources for the facility.
Firm Fuel Transportation Availability	25%	Firm gas supply is not adequate to limit use of backup fuel to extreme winter peaks or during gas supply emergencies.	Firm gas supply is adequate to limit use of backup fuel to extreme winter peaks or during gas supply emergencies	Firm gas supply is adequate to require no backup fuel use to meet system peaks except during gas supply emergencies.
Flexibility in fuel scheduling	25%	Terms of fuel contracts are unknown.	Fuel contracts require day-ahead scheduling.	Fuel contracts allow for intra-day scheduling and options for re-delivery.
Total Score		100%		

Appendix K – Seller Insurance Requirements

Before the Commercial Operation Date, Seller shall procure and maintain the following minimum insurance, with (i) insurance carriers having an A.M. Best rating of “A-” or better, or (ii) insurance carriers having a Standard & Poor’s Global rating of “A” or better, or (iii) insurance carriers having an equivalent rating by another nationally recognized insurance rating agency, or (iv) such other insurance carriers of recognized responsibility (which, solely in the case of insurance carriers described in this clause (iv), shall require the consent of Buyer), in each case, that are authorized to do business in the State where the Services are performed or to be performed:

(a) Workers’ Compensation Insurance for statutory obligations imposed by applicable laws, including, where applicable, the Alternate Employer Endorsement, the United States Longshoremen’s and Harbor Workers’ Act, the Maritime Coverage and the Jones Act;

(b) Employers’ Liability Insurance, including Occupational Disease, shall be provided with a limit of (i) One Million Dollars (\$1,000,000) for bodily injury per accident, (ii) One Million Dollars (\$1,000,000) for bodily injury by disease per policy, and (iii) One Million Dollars (\$1,000,000) for bodily injury by disease per employee;

(c) Business Automobile Liability Insurance which shall apply to all owned, non-owned, leased, and hired automobiles with a limit of One Million Dollars (\$1,000,000) combined single limit per accident for bodily injury and property damage;

(d) Commercial General Liability Insurance which shall apply to liability arising out of premises, operations, bodily injury, property damage, products and completed operations and liability insured under and insured contract (contractual liability), with a limit of One Million Dollars (\$1,000,000) per occurrence, Two Million Dollars (\$2,000,000) aggregate. The products and completed operations coverage insurance shall be provided for the duration of any applicable warranty period;

(e) Excess Liability Insurance which shall apply to Employers Liability, Commercial General Liability and Business Automobile Liability Insurance, required in (b), (c), and (d) above, with a limit of Five Million Dollars (\$5,000,000) per occurrence and Five Million Dollars (\$5,000,000) aggregate;

(f) Upon commencement of construction of the Project, Builder's Risk Insurance with limits of insurance written on a probable maximum loss basis, including sub-limits for wind, earthquakes and flood exposure;

(g) Following the Commercial Operation Date, All-Risk Property Insurance with limits of insurance written on a probable maximum loss basis, including sublimits for wind, earthquake, and flood exposures.

Except for Workers’ Compensation Insurance, Buyer shall be endorsed as an additional insured on Seller’s insurance policies required to be maintained under the Agreement and such policies shall

provide for a waiver of subrogation in favor of Buyer. All policies of insurance required to be maintained by Seller hereunder shall provide for a severability of interests clause and include a provision that Sellers's insurance policies are to be primary and non-contributory to any insurance that may be maintained by or on behalf of Buyer.

In the event that any policy furnished by Seller provides for coverage on a "claims made" basis, the retroactive date of the policy shall be the same as the effective date of the Agreement, or such other date, as to protect the interest of Buyer. Furthermore, for all policies furnished on a "claims made" basis, Seller's providing of such coverage shall survive the termination of the Agreement and the expiration of any applicable warranty period, until the expiration of the maximum statutory period of limitations in the State of Florida for actions based in contract or in tort. If coverage is on "occurrence" basis, Seller shall maintain such insurance during the entire term of the Agreement.

Following execution of this Agreement and annually thereafter, Seller shall promptly provide evidence of the minimum insurance coverage required under the Agreement in the form of an ACORD certificate or other certificate of insurance. If any of the required insurance is cancelled or non-renewed, Seller shall within thirty (30) days provide written notice to Buyer and file a new certificate of insurance with Buyer, demonstrating that the required insurance coverage to be maintained hereunder has been extended or replaced. Neither Seller's failure to provide evidence of minimum coverage of insurance following Buyer's request, nor Buyer's decision to not make such request, shall release Seller from its obligation to maintain the minimum coverage provided for in this Appendix K. Additionally, Seller is responsible for ensuring that Subcontractors are adequately insured. If Subcontractors are not adequately insured, then it is the responsibility of the Seller to "bridge the gap" and procure insurance consistent with the expectations outlined in this Appendix K.

Seller shall be responsible for covering all deductibles associated with the foregoing insurance coverage.

1411846048 APPENDIX L – RESPONDENT CERTIFICATION FORM
MARKET TEST FOR LONG-TERM FIRM, DISPATCHABLE CAPACITY AND ENERGY
RESOURCES

Company Name: _____

Company's Address: _____

Phone Number: _____ Email Address: _____

BID SECURITY REQUIREMENTS

- ☒ **None required**
☐ Certified Check or Bond (Five Percent (5%))

TERM OF CONTRACT

- ☐ One Time Purchase
☐ Annual Requirements
☒ **Other, Specify - Project Completion**

SAMPLE REQUIREMENTS

- ☒ **None required**
☐ Samples required prior to Bid Opening
☐ Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND

- ☐ None required
☐ Bond required 100% of Bid Award
☒ **Letter of Credit or Bank Guarantee**

QUANTITIES

- ☐ **Quantities indicated are exacting**
☒ Quantities indicated reflect the approximate quantities to be purchased Throughout the Contract period and are subject to fluctuation in accordance with actual requirements.

INSURANCE REQUIREMENTS**Insurance required**

☐ **I have read and understood the Sunshine Law/Public Records clauses contained within this solicitation. I understand that in the absence of a redacted copy my proposal will be disclosed to the public "as-is".**

RESPONDENT CERTIFICATION

By submitting this Response, the Respondent certifies that it has read and reviewed all of the documents pertaining to this Solicitation, agrees to abide by the terms and conditions set forth therein, that the person signing below is an authorized representative of the Responding Company, that the Company is legally authorized to do business in the State of Florida, and that the Company maintains in active status an appropriate contractor's license for the work (if applicable).

The Company certifies, under penalty of perjury, that it holds all licenses, permits, certifications, insurances, bonds and other credentials required by law, Contract or practice to perform the Work. The Company also certifies that, upon the prospect of any change in the status of applicable licenses, permits, certifications, insurances, bonds or other credentials, the Company shall immediately notify JEA of status change.

We have received addenda

_____ through _____

Handwritten Signature of Authorized Officer of Company or Agent Date_____
Printed Name and Title



October 30, 2024

ADDENDUM NUMBER: One (1)TITLE: (RFP) Long-Term Firm, Dispatchable Capacity and Energy ResourcesJEA ITN NUMBER: 1411846048RESPONSE DUE DATE: **March 4, 2025**TIME DUE: 12:00 PM (noon)

THIS ADDENDUM IS FOR THE PURPOSE OF MAKING THE FOLLOWING CHANGES OR CLARIFICATIONS:

1. The Mandatory Pre-Response Meeting via WebEx or Teleconference on ~~November 4, 2024~~ at 1:30pm EST has been changed to **November 18, 2024** at 1:30pm EST

Meeting URL: <https://jeameeting.webex.com/>

Meeting Number (Access Code): 2317 234 6279

Meeting Password: ZiA7n7mJ3kK

Dial In: [+1-415-655-0001](tel:+1-415-655-0001),,23172346279##

Those planning to attend the Webex should send contact information to: MarketTestRFP@JEA.com, 48 hours prior to the Pre-Response Meeting to have contact information documented.



November 06, 2024

ADDENDUM NUMBER: Two (2)TITLE: (RFP) Market Test for Long-Term Firm Dispatchable Capacity and Energy ResourcesJEA RFP NUMBER: 1411846048RESPONSE DUE DATE: **March 4, 2025**TIME DUE: 12:00 PM (noon)**THIS ADDENDUM IS FOR THE PURPOSE OF MAKING THE FOLLOWING CHANGES OR CLARIFICATIONS:**

1. The Mandatory Pre-Response Meeting via WebEx or Teleconference on ~~November 4, 2024, November 18, 2024~~ at 1:30pm EST has been changed to **December 02, 2024** at 1:30pm EST

Meeting URL: <https://jeameeting.webex.com/>

Meeting Number (Access Code): 2317 234 6279

Meeting Password: ZiA7n7mJ3kK

Dial In: [+1-415-655-0001](tel:+1-415-655-0001), [23172346279##](tel:+1-415-655-2317)

Those planning to attend the Webex should send contact information to: MarketTestRFP@JEA.com, 48 hours prior to the Pre-Response Meeting to have contact information documented.



November 15, 2024

ADDENDUM NUMBER: Three (3)TITLE: (RFP) Market Test for Long-Term Firm Dispatchable Capacity and Energy ResourcesJEA RFP NUMBER: 1411846048RESPONSE DUE DATE: March 4, 2025TIME DUE: 12:00 PM EST (noon)**THIS ADDENDUM IS FOR THE PURPOSE OF MAKING THE FOLLOWING CHANGES OR CLARIFICATIONS:**

1. **The Solicitation Terms and Conditions with document labelled as 1411846048 Market Test for Long-Term Firm Dispatchable Capacity and Energy Resources RFP has been replaced in its entirety with 1411846048 Market Test for Long-Term Firm Dispatchable Capacity and Energy Resources RFP Solicitation - Addendum 3 to incorporate changes with regards to:**

- **Mandatory Pre-Response Meeting**

Mandatory Pre-Response Meeting via WebEx or Teleconference on December 2, 2024 at 1:30pm EST

Meeting URL: <https://jeameeting.webex.com/>

Meeting Number (Access Code): 2317 234 6279

Meeting Password: ZiA7n7mJ3kK

Dial In: +1-415-655-0001,,23172346279##

2. **"1411846048 Appendix E(i) - PPA Term Sheet – Blank" has been replaced in its entirety with "1411846048 Appendix E(i) - PPA Term Sheet - Addendum 3"**
3. **"1411846048 Appendix E(ii) - BTA Term Sheet – Blank" has been replaced in its entirety with "1411846048 Appendix E(ii) - BTA Term Sheet - Addendum 3"**
4. **"1411846048 Appendix D - Response Submission Form – Blank" has been replaced in its entirety with "1411846048 Appendix D - Response Submission Form - Addendum 3"**
5. **"1411846048 Appendix F - Respondent Questionnaire" has been replaced in its entirety with "1411846048 Appendix F - Respondent Questionnaire - Addendum 3" to incorporate changes with regards to:**
 - **Operations – Section 8**
 - **Interconnection and Deliverability – Section 4**
 - **GHG Rule Compliance – Section 6**
 - **Commercial Terms**



January 07, 2025

ADDENDUM NUMBER: Four (4)

TITLE: (RFP) Market Test for Long-Term Firm Dispatchable Capacity and Energy Resources

JEA RFP NUMBER: 1411846048

RESPONSE DUE DATE: March 4, 2025

TIME DUE: 12:00 PM EST (noon)

THIS ADDENDUM IS FOR THE PURPOSE OF MAKING THE FOLLOWING CHANGES OR CLARIFICATIONS:

1. **Question:** What transmission upgrades are planned for JEA between now and 2030 that a potential respondent would need to be aware of? Should the projects outlined in JEA's Capital Projects Meetings (i.e. 5-year transmission plan) be assumed to be completed in the respondents bid?

Answer: The publicly listed projects can be considered as complete in the timeline communicated to the Board.

2. **Question:** In the minimum requirements, the RFP states "The Respondent certifies that along with the Response for the generation resource(s), the Respondent has submitted detailed plans and schedules for transmission interconnection, including submission into the interconnection queue, and the implementation of any required transmission upgrades, and the associated transmission service(s) for the power to be delivered to JEA service territory in compliance with all the state and federal regulations." How should respondents document their response to satisfy this requirement. Will it be sufficient to document the submission of a pending TSR to satisfy this minimum requirement?

Answer: Yes, it is sufficient to document the submission of a pending TSR to satisfy this minimum requirement at the time of RFP submission.

3. **Question:** With respect to JEA's transmission import capacity, the transmission addendum states "JEA will analyze each Response for impacts to JEA's current capabilities, and if remedies are required to preserve current capabilities, JEA will estimate the cost of those remedies and add the appropriate cost to the Response". How will JEA determine the necessary project, relevant capacity thresholds and project costs? And when will JEA do so.

Answer: JEA will estimate costs associated with transmission upgrades, consistent with the description provided in Appendix B – Transmission Interconnection and Delivery Considerations, necessary for delivery of power based on Responses received within this Solicitation, as applicable. Such costs will be incorporated into the economic evaluations performed to evaluate the Responses prior to Final Selections. JEA's assessment of transmission system capabilities, improvements, and associated costs will be studied on a case-by-case basis and completed during the Market RFP evaluation period.

4. **Question:** Will emissions from any new gas compression required to serve a build/own/transfer be included in the environmental assessment?

Answer: For purposes of this Solicitation, the environmental-related assessment is laid out in Appendix J – Evaluation Methodology and Scorecard. Any new gas compressors required to operate a proposed facility will be expected to comply with all applicable regulatory requirements.

5. **Question:** If JEA fulfills its needs with a Power Purchase Agreement (PPA) from the market, how much upstream/interstate/PGS system gas would be avoided? Would such an avoided cost be factored into the present value of the self-build versus proposed alternatives?

Answer: JEA will reflect all costs associated with natural gas delivery for the self-build option in the analysis of its self-build option. Any resulting cost or avoided cost identified during analysis of Responses received in response to the Solicitation shall be analyzed and applied based on the specific natural gas delivery requirements for the self-build option and proposed projects.

6. **Question:** When the evaluator compares power supply proposals to JEA's self-build option, will it be assumed that the self-build unit will be restricted to a 40% capacity factor to meet EPA carbon reduction rules? Or will there be a scenario with and without the EPA rules? If multiple scenarios, how will the present value of these be combined for comparison to the proposed market alternatives?

Answer: As indicated in Appendix J – Evaluation Methodology and Scorecard, evaluations of the self-build option and Responses received in response to the Solicitation will be performed for two scenarios related to emissions of carbon dioxide – one which reflects compliance with the EPA's May 2024 guidelines for greenhouse gas emissions from electric generating units, and one scenario in which such regulations are not in place. To the extent the EPA Rule is adjusted, vacated, or otherwise not applicable, the scoring may be adjusted to reflect the new circumstances. For purposes of the evaluation within this Solicitation, JEA's compliance strategy for its self-build resource will be to limit the capacity factor to 40%.

7. **Question:** To the extent JEA determines that a response fails to meet one of the minimum requirements, will respondents be given an opportunity to cure any such deficiency? How long will such a cure period be?

Answer: It is JEA's intent that to submit a response, a Respondent must meet all minimum requirements at the time of submitting a response. In cases where there is ambiguity in how a Respondent meets a minimum requirements, Respondents will be given [5] days to clarify their response to cure a deficiency in their Response from the date which the Respondent is notified of such deficiency. Since Respondents are required to meet all minimum requirements, JEA reserves the right to classify a proposal as non-conforming if the Respondent does not meet a number of minimum requirements.

8. **Question:** Can JEA provide a forecast of the self-build dispatch profile on an hourly basis for the first five years of service (2031-2035)?

Answer: Please see file titled "1411846048 Self Build Dispatch_2031-2035 - Addendum 4.xlsx" for JEA's estimate of annual dispatch information for JEA's self-build option, including annual hours of operation, annual number of starts, and annual capacity factor. Information is included for two scenarios – one which reflects compliance with the EPA's May 2024 guidelines for greenhouse gas emissions from electric generating units, and one scenario in which such regulations are not in place. Note that the referenced results were for demand and energy forecasts and fuel forecasts current at the time of prior analysis, and will be updated for evaluation of the JEA Reference project and all Responses from this RFP.

9. **Question:** Based on the latest version of Appendix D (the response input sheet), it appears that if sellers were to submit multiple offers, they would do so here. Is this the proper format for submitting multiple offers or should those be submitted separately?

Answer: If Respondents are submitting multiple Responses, each Response must include the requested information outlined in Section 17 of the Solicitation..

- Appendix C - Minimum Requirements Form
- Appendix D – Response Submission Form
- Redlines of Appendix E Term Sheets
- Appendix F – Respondent Questionnaire
- Appendix L – Respondent Certification Form
- Proposed Terms and Conditions for O&M Agreement, if applicable

Appendix D is structured in a manner that the information associated with multiple Responses can be included within a single Appendix D submission. Each Response must include all required information requested within this Solicitation.

- 10. Question:** What is the process and timeline for JEA to assess and incorporate its own transmission upgrade costs into market alternatives?

Answer: JEA will estimate costs associated with transmission upgrades, consistent with the description provided in Appendix B – Transmission Interconnection and Delivery Considerations, necessary for delivery of power based on Responses received within this Solicitation, as applicable. Such costs will be incorporated into the economic evaluations performed to evaluate the Responses prior to Final Selections. JEA's assessment of transmission system capabilities, improvements, and associated costs will be studied on a case-by-case basis and completed during the Market RFP evaluation period.

- 11. Question:** Are there added benefits or evaluation points for proposals that can deliver earlier than the specified Commercial Operation Date?

Answer: JEA's evaluation will consider potential economic benefits for Responses that propose to deliver power earlier than the required Guaranteed Commercial Operation Date by evaluating the Response based on when power delivery will begin.

- 12. Question:** If a proposal includes assets that would be constructed inside City of Jacksonville / Duval County limits, will the benefit of incremental property taxes be factored into the bid evaluation process?

Answer: JEA's evaluation will be performed from the perspective of JEA's system economics and will not include consideration of incremental property taxes that the City/County may realize.



February 06, 2025

ADDENDUM NUMBER: Five (5)TITLE: (RFP) Market Test for Long-Term Firm Dispatchable Capacity and Energy ResourcesJEA RFP NUMBER: 1411846048RESPONSE DUE DATE: ~~March 4, 2025~~, April 21, 2025TIME DUE: 12:00 PM EST (noon)**THIS ADDENDUM IS FOR THE PURPOSE OF MAKING THE FOLLOWING CHANGES OR CLARIFICATIONS:**

1. **Change:** The response due date has been changed from ~~March 4, 2025~~ to **April 21, 2025** at 12:00PM EST
2. **Note:** There will be a project schedule update in an upcoming addendum.



March 26, 2025

ADDENDUM NUMBER: Six (6)TITLE: (RFP) Market Test for Long-Term Firm Dispatchable Capacity and Energy ResourcesJEA RFP NUMBER: 1411846048RESPONSE DUE DATE: April 21, 2025TIME DUE: 12:00 PM EST (noon)**THIS ADDENDUM IS FOR THE PURPOSE OF MAKING THE FOLLOWING CHANGES OR CLARIFICATIONS:**

1. **Question:** In the draft PPA term sheet Appendix E(i), the following two items are listed in the definitive agreement section. Can you please describe what governmental and 3rd party approvals/consents/authorizations are anticipated by the Buyer?

-- Buyer has obtained all Governmental Approvals deemed necessary or advisable by Buyer in order for Buyer to enter into the Definitive Agreement and perform its obligations thereunder;

-- Buyer has obtained all third-party consents, approvals, and authorizations deemed necessary or advisable by Buyer to enter into the Definitive Agreement and perform its obligations thereunder;

Answer: It is anticipated that the required consents, approvals and authorizations may include but are not limited to the following:

The referenced consents and authorizations may include but are not limited to all applicable Federal, State and local standards or permits of any nature as applicable to the proposed project. This may include but is not limited to the Florida Power Plant Siting Act (PPSA) (Determination of Need and Site Certification Application processes), the Florida Transmission Line Siting Act (TLSA), FERC Order 1000, Local zoning and land-use regulations including noise, construction permits, stormwater management designs/permits, consumptive use water permits, fuel storage permits, wastewater/industrial pre-treatment and disposal permits, the Florida Natural Gas Pipeline Siting Act (NGPSA) and Federal permits or regulations on gas line construction or upgrades, environmental remediation, wetlands mitigation and/or buffer requirements, etc. on an as-applicable basis.

The language in Appendix F has been amended as follows to address this:

- Provide an Environmental permit matrix showing all required permits, schedule for acquiring permits and any predecessor activities needed to proceed with them. This should be in spreadsheet format like Excel. An example template can be provided if requested.
 - o Include all permits required for the proposed facility. Include the status of each of those permits at the time of proposal submission.
 - o For major processes such as PPSA, FERC Order 1000, TLSA, NGPSA, Consumptive use permits, Wastewater/industrial pre-treatment and disposal permits and any other such regulated permitting processes also include a brief description of the methodology that will be applied to obtain each permit, the name of any contractors expected to be involved, and major schedule milestones including the start of the preparation

process and the planned filing date of the full application, and the planned date for the granting of the permit or order.

- o The referenced consents and authorizations in terms and conditions may include but are not limited to all applicable Federal, State and local standards or permits of any nature as applicable to the proposed project. This may include but is not limited to the Florida Power Plant Siting Act (PPSA) (Determination of Need and Site Certification Application processes), the Florida Transmission Line Siting Act (TLSA), FERC Order 1000, Local zoning and land-use regulations including noise, construction permits, stormwater management designs/permits, consumptive use water permits, fuel storage permits, wastewater/industrial pre-treatment and disposal permits, the Florida Natural Gas Pipeline Siting Act (NGPSA) and Federal permits or regulations on gas line construction or upgrades, environmental remediation, wetlands mitigation and/or buffer requirements, etc. on an as-applicable basis.

2. **Question:** On the Response Submission Form, we do not see a section for fuel charges in the PPA tab. Should we work those into the form in some way?

Answer: Please provide detailed information within the Fuel Supply and Transportation section of Appendix F and within the redlines of the applicable term sheets for JEA to fully understand and evaluate the Response.

3. **“1411846048 Market Test for Long-Term Firm Dispatchable Capacity and Energy Resources RFP Solicitation - Addendum 5” has been replaced in it’s entirety with “1411846048 Market Test for Long-Term Firm Dispatchable Capacity and Energy Resources RFP Solicitation - Addendum 6”**
4. **“1411846048 Appendix D - Response Submission Form - Addendum 3” has been replaced in it’s entirety with “1411846048 Appendix D - Response Submission Form - Addendum 6”**
5. **“1411846048 Appendix F - Respondent Questionnaire - Addendum 3” has been replaced in it’s entirety with “1411846048 Appendix F - Respondent Questionnaire - Addendum 6”**
6. **“1411846048 Appendix J - Evaluation Methodology and Scorecard” has been replaced in it’s entirety with “1411846048 Appendix J - Evaluation Methodology and Scorecard - Addendum 6”**

**Market Test RFP Economic Evaluation Results
(in \$1,000) for Each Case (CPWC - \$1,000)**

Cases	Self-Build	PPA 1	PPA 2	PPA 3
Base Case – GHG – 30 years	\$29,957,888	\$30, 089,810	\$30,130,087	\$30,400,698
Base Case – GHG – 15 years	\$17,614,693	\$17,513,343	\$17,490,429	\$17,454,803
No GHG – 30 years	\$28,499,845	\$29,362,428	\$29,347,207	\$29,493,687
Average of Sensitivity Cases	\$32,006, 963	\$31,766,258	\$31,703,323	\$32,030,254

Market Test RFP Quantitative Scores

Quantitative Scoring	Maximum Points	FPL Response 1	FPL Response 2	FPL Response 3	Self-Build Option
Evaluator 1	70	65.9991	66.2479	64.0035	68.1262
Lowest Overall CPWC, Base Case (With GHG Rule) 30 years	30	29.5596	29.4252	28.5219	30.0000
Lowest CPWC, Base Case (with GHG Rule) 15 years	10	9.6646	9.7959	10.0000	9.0840
Lowest Overall CPWC Base Case (Without GHG Rule) 30 years	15	11.9734	12.0268	11.5128	15.0000
Sensitivity Cases CPWC	15	14.8015	15.0000	13.9688	14.0423
Evaluator 2	70	65.9991	66.2479	64.0035	68.1262
Lowest Overall CPWC, Base Case (With GHG Rule) 30 years	30	29.5596	29.4252	28.5219	30.0000
Lowest CPWC, Base Case (with GHG Rule) 15 years	10	9.6646	9.7959	10.0000	9.0840
Lowest Overall CPWC Base Case (Without GHG Rule) 30 years	15	11.9734	12.0268	11.5128	15.0000
Sensitivity Cases CPWC	15	14.8015	15.0000	13.9688	14.0423
Evaluator 3	70	65.9991	66.2479	64.0035	68.1262
Lowest Overall CPWC, Base Case (With GHG Rule) 30 years	30	29.5596	29.4252	28.5219	30.0000
Lowest CPWC, Base Case (with GHG Rule) 15 years	10	9.6646	9.7959	10.0000	9.0840
Lowest Overall CPWC Base Case (Without GHG Rule) 30 years	15	11.9734	12.0268	11.5128	15.0000
Sensitivity Cases CPWC	15	14.8015	15.0000	13.9688	14.0423

Market Test RFP Qualitative Scores

Qualitative Scoring	Maximum Points	PPA 1	PPA 2	PPA 3	Self-Build Option
Evaluator 1	30	16.4100	16.4100	16.4100	26.3700
System Reliability (Flexibility)	6.0	1.6400	1.6400	1.6400	5.1200
Experience and Commercial	4.5	2.3100	2.3100	2.3100	3.7200
Transmission Status	6.0	1.2800	1.2800	1.2800	5.7800
Project Status and Technical Design	3.0	1.4000	1.4000	1.4000	2.7700
Environmental	4.5	3.7800	3.7800	3.7800	4.0800
Fuel Supply	6.0	6.0000	6.0000	6.0000	4.9000
Evaluator 2	30	22.1800	22.1800	22.1800	28.8400
System Reliability (Flexibility)	6.0	2.1600	2.1600	2.1600	5.2600
Experience and Commercial	4.5	3.6600	3.6600	3.6600	4.5000
Transmission Status	6.0	2.8600	2.8600	2.8600	5.8800
Project Status and Technical Design	3.0	3.0000	3.0000	3.0000	3.0000
Environmental	4.5	4.5000	4.5000	4.5000	4.5000
Fuel Supply	6.0	6.0000	6.0000	6.0000	5.7000
Evaluator 3	30	21.5700	21.5700	21.5700	27.5700
System Reliability (Flexibility)	6.0	2.6000	2.6000	2.6000	4.9200
Experience and Commercial	4.5	3.4800	3.4800	3.4800	4.0500
Transmission Status	6.0	3.0040	3.0040	3.0040	6.0000
Project Status and Technical Design	3.0	2.2500	2.2500	2.2500	2.9000
Environmental	4.5	4.5000	4.5000	4.5000	3.9000
Fuel Supply	6.0	5.7000	5.7000	5.7000	5.8000

Market Test RFP Total Scores

Total Scores	Maximum Points	PPA 1	PPA 2	PPA 3	Self-Build Resource
Evaluator 1	100	82.4091	82.6579	80.4135	94.4962
Evaluator 2	100	88.1791	88.4279	86.1835	96.9662
Evaluator 3	100	87.5691	87.8179	85.5735	95.6962

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

HUA FANG

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF HUA FANG

DOCKET NO. _____

June 4, 2026

I. INTRODUCT AND QUALIFICATION

Q. Please state your name and address.

A. My name is Hua Fang. My business address is 11720 Katy Freeway, Suite 400, Houston, Texas 77079.

Q. By whom are you employed and in what capacity?

A. I am a Managing Director with Black & Veatch’s Transactions and M&A Solution.

Q. What is Black & Veatch’s Transactions and M&A Solution?

A. Black & Veatch’s M&A Solution is a specialized advisory service for infrastructure investors, lenders, and developers in the energy, water, and telecommunications sectors. We focus on conducting rigorous technical due diligence and identifying risks prior to high-stakes investment decisions and mergers and acquisitions. We also provide customized market advisory services to support energy asset investment and long-term planning studies.

1 **Q. Please describe your responsibilities in your current position.**

2 A. I advise industry and financial clients on the outlook of key energy markets; I
3 develop commercial strategies and perform due diligence and asset valuation.
4 My specific areas of focus include natural gas, electricity, renewable fuels and
5 carbon credit markets, and I develop fuel commodity forecasts. I have
6 expertise in stochastic simulations, derivative asset pricing, financial and
7 economic modeling, and cost benefit analysis.

8

9 **Q. Please state your professional experience and educational background.**

10 A. I have more than 20 years' experience advising industry and financial clients
11 on energy markets. I have been in my current position at Black & Veatch
12 since 2016. I have both a Bachelor of Arts and Masters of Arts in International
13 Finance. I also hold a Master of Arts and Doctor of Philosophy in Economics
14 from the University of Virginia.

15

16 **Q. Have you previously testified before state regulatory commissions?**

17 A. Yes. I have testified before the South Carolina Public Service Commission on
18 matters related to natural gas hedging.

19

20 **Q. Is Exhibit No. ____ (HF-1) a true and correct copy of your resume?**

21 A. It is.

22

23 **Q. Please more specifically describe your fuel supply forecasting experience.**

24 A. I have led Black & Veatch's development of natural gas price forecasts
25 utilizing a fundamental natural gas supply and demand model - Gas Pipeline

1 Competition Model GPCM® for nearly two decades. Price forecasts developed
2 by my team are reflected in management consulting engagements related to
3 valuation and commercial strategies of natural gas and electric assets,
4 including integrated resource planning work for electric utilities. Most
5 recently, I led our data center strategy consulting services with data center
6 developers assessing natural gas availability and costs to support proposed data
7 center projects around the country.

8
9 The GPCM® provides important inputs into the Black & Veatch Energy
10 Market Perspective (EMP), a comprehensive, long-term energy market outlook
11 for North America. The EMP incorporates the latest developments and trends
12 in load growth, public policy, federal and state energy initiatives, generation
13 technology availability and costs, generation capacity retirements and
14 additions, transmission improvements as well as fuel prices, such as natural
15 gas, coal and petroleum fuels. The EMP is used to project market prices and
16 the revenue earned by generation assets. I direct the fuel price forecast and
17 oversee the annual update of the EMP.

18
19 **Q. What is the purpose of your testimony in this proceeding?**

20 A. My testimony describes the fuel price forecast utilized by JEA in performing
21 the economic modeling associated with the analysis and evaluation of St. Johns
22 River Power Park Unit 3 (SJRPP Unit 3) and generation alternatives.

23
24 **Q. Are you sponsoring any exhibits in the case?**

1 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
2 under my supervision and are attached to this pre-filed testimony:

- 3 • Exhibit No. ____ (HF-1) - Professional Resume of Hua Fang
- 4 • Exhibit No. ____ (HF-2) - Base Fuel Price Assumptions
- 5 • Exhibit No. ____ (HF-3) - High and Low Fuel Price Assumptions

6 I also am sponsoring Section 6.4.5 and Table 6-2 of the Need Study (Exhibit
7 No. __ JB-2).

8

9 **Q. Could you please explain what a fuel price forecast is?**

10 A. In this context, a fuel price forecast represents the projection of future costs for
11 the fuels used in electrical generation, including natural gas, coal, and oil. Fuel
12 costs are a significant component of a utility's total cost to serve load and
13 therefore constitute a critical input to the long-term planning models used to
14 develop integrated resource plans and associated need studies.

15

16 **Q. Did you prepare the fuel price forecast reflected in the Need Study in Ex.**
17 **No. ____ (JLB-2)?**

18 A. Yes. I prepared the fuel price forecast for JEA's 2026 Ten Year Site Plan
19 (TYSP), which is consistent with that described in the Need Study.

20

21 **Q. For what fuels did you develop forecasts?**

22 A. I developed fuel price forecasts for natural gas, diesel, and the mix of solid fuel
23 used at JEA's Northside Generating Station (NGS) Units 1 and 2.

24

25 **Q. What methodology did you use in developing the fuel price forecast?**

1 A. The price of natural gas was forecasted utilizing GPCM®, a network
2 simulation model developed by RBAC, Inc. GPCM® models the North
3 America natural gas value chain, including production basins, demand centers,
4 transportation pipelines, storage facilities, and liquefied natural gas (LNG)
5 export facilities. The model applies an optimization algorithm to solve for
6 market-clearing, equilibrium gas prices at all natural gas pricing hubs. These
7 long-term price projections produced by GPCM® were calibrated and blended
8 with near-term price signals observed in the natural gas futures market to
9 develop the long-term gas price forecasts used in our planning studies.

10
11 Diesel and coal prices were forecasted from the short-term pricing trends
12 observed in the New York Mercantile Exchange (NYMEX) futures market and
13 the year-over-year growth rate of the projected prices published in the U.S.
14 Energy Information Administration (EIA)'s Annual Energy Outlook (AEO).

15
16 **Q. Please describe the specific steps you used in developing the fuel price**
17 **forecasts?**

18 A. In projecting future natural gas prices, I started with Black & Veatch's
19 proprietary EMP forecast. I then combined the long-term fundamental
20 forecasts developed through the EMP process with the six-month average
21 NYMEX Henry Hub futures using a structured blending approach. Under this
22 approach, the forecast relies entirely on Henry Hub futures in 2025, transitions
23 to a reduced reliance of 15% Henry Hub futures in 2029, and shifts to a purely
24 fundamental-based projection beginning in 2030 and continuing thereafter.

25

1 Near-term diesel and coal price forecasts were developed using the six-month
2 average NYMEX settlement prices observed between July and December
3 2024. Prices beyond the NYMEX settlement horizon were projected using the
4 price growth rates derived from the AEO.

5

6 **Q. Are competing future demands for natural gas factored into your fuel**
7 **price forecast?**

8 A. Yes, as described above, the GPCM® model takes as inputs projected natural
9 gas demand from all sectors, including residential, commercial, industrial and
10 power sectors for the US Lower 48 states. The model also represents exports to
11 Mexico and LNG export facilities as sources of demand for US natural gas
12 productions, which together determine equilibrium price outcomes across the
13 market. For example, Henry Hub natural gas prices are expected to increase
14 from current levels primarily due to rising LNG demand among the Gulf Coast
15 and increased natural gas consumption in the power sector, including demand
16 growth associated with data center development. These increased demand
17 drivers are explicitly incorporated into the natural gas price forecast through
18 the GPCM® modeling framework.

19

20 **Q. Is Exhibit No. ____ (HF-2) reflective of your fuel forecasts?**

21 A. Yes. Exhibit No. ____ (HF-2) reflects the base case fuel forecasts I developed.
22 These were utilized for the economic modeling associated with the analysis
23 and evaluation of SJRPP Unit 3 and generation alternatives as described in the
24 Need Study and are consistent with JEA's 2026 TYSP.

25

1 **Q. Did you develop any alternative fuel forecasts for sensitivity analyses?**

2 A. Yes, I also developed high- and low-case forecasts for natural gas. The high-

3 case Henry Hub natural gas price forecast assumed, depending on the year,

4 approximately 10 to 15 percent higher demand from the power sector, with

5 prices developed through a blending approach that incorporates NYMEX

6 futures. The low-case Henry Hub price forecasts were mainly developed with

7 the EIA AEO 2025 side cases – specifically “high oil and gas supply, high oil

8 prices, low economic growth” – which were used to derive appropriate

9 downward price scalars relative to the AEO 2025 reference case.

10

11 **Q. Have you prepared an exhibit showing the results of your alternative fuel**

12 **forecasts?**

13 A. Yes. Exhibit No. ____ (HF-3) presents the alternative fuel forecasts utilized in

14 the updated economic modeling described in the pre-filed testimony of Mr.

15 Kushner.

16

17 **Q. Were the fuel forecasts depicted on Exhibit No. ____ (HF-2) and Exhibit**

18 **No. ____ (HF-3) also used for the evaluation of alternate technologies and**

19 **the economic modeling of market test alternatives?**

20 A. No. The evaluation of alternate technologies and economic modeling of

21 market test alternatives were conducted in 2025 utilizing fuel forecasts

22 consistent with JEA’s 2025 TYSP. Those fuel forecasts were updated for the

23 2026 TYSP and economic modeling of SJRPP Unit 3.

24

- 1 **Q.** **Are the fuel price forecasts reflected on Ex. No. __ (HF-2) and Ex. No. __**
2 **(HF-3) consistent with current market conditions and projections?**
- 3 **A.** Yes.
- 4
- 5 **Q.** **Do you have any reason to believe that other market demands, such as**
6 **LNG or data centers, will increase costs beyond these forecasts?**
- 7 **A.** No. As I mentioned, competing demands are factored into the forecast. I also
8 developed a high gas sensitivity to capture potential cost increases.
- 9
- 10 **Q.** **Do you have any reason to believe JEA will be unable to acquire sufficient**
11 **gas to operate SJRPP Unit 3?**
- 12 **A.** No. The United States is one of the largest natural gas producers in the world
13 with 584 trillion cubic feet (Tcf) of economically recoverable reserves at year-
14 end 2024. The existing pipeline network allows JEA to access gas supplies
15 from the largest natural gas production basins, such as Permian, Haynesville
16 Shale and Marcellus/Utica Shale.
- 17
- 18 **Q.** **Does this complete your testimony?**
- 19 **A.** Yes.



Hua Fang, Ph.D.

Managing Director

Dr. Hua Fang is a Managing Director with Black & Veatch's Transactions and M&A solution. Dr. Fang has more than 20 years' experience advising industry and financial clients on the developments and outlook of key energy markets, commercial strategy, due diligence and asset valuation. Dr. Fang's expertise spans the natural gas, electricity, renewable fuels and carbon credits markets.

Dr. Fang has also led multiple engagements advising data center and power asset developers on site screening, site due diligence, project planning, power access strategies and utility negotiation support. She also leads Black & Veatch's economic and market assessments for emerging zero carbon technologies, such as carbon capture and storage, green hydrogen and ammonia.

She is an expert in stochastic simulations, derivative asset pricing, financial and economic modeling, cost benefits analysis and has developed sophisticated tools to simulate price, weather and market uncertainties, quantify risks and value real options and hedging strategies.

Expertise

Energy Asset Valuation;
Energy Market Analysis;
Financial Risk Analysis; Fuel
Market Analysis; Gas-Power
Interdependency; Price
Forecasting Econometric
Analysis

Education

- Doctor of Philosophy, Economics, University of Virginia, 2002
- Master of Arts, Economics, University of Virginia, 1998
- Master of Arts, International Finance, People's University of China, 1996, China
- Bachelor of Arts, International Finance, People's University of China, 1993, China

Years experience

26

Languages

- Chinese (Mandarin)
- English

Location

Houston, TX USA

PROJECT EXPERIENCE

Multiple Clients; Data Center Power and Natural Gas Strategy, 2024-Current

Project Director. Black & Veatch has supported multiple clients developing data centers or power shells to supply data centers in site screening, development planning, due diligence, power and natural gas strategies as well as negotiation with utilities. Sample clients: Google, AWS, QTS, Aligned, SoftBank, Stack Infrastructure, Total Energies, Eolian Energy.

Confidential Client; Carbon Capture and Storage Power Strategy, 2024-2025

Project Director. Black & Veatch has been engaged to provide guidance in supporting Client's strategy in deploying direct air capture projects in Texas and California. Black & Veatch provided overview of the regional power market developments near proposed sites, projected total capacity additions and generation mix of grid power and compare the costs/benefits, schedule and operational difference in contracting for grid power or build Behind the Meter (BTM) solutions.

Chugach Electric Association; Gas Supply Strategy 2021 – Ongoing

Project Director. Black & Veatch has been engaged to support the strategy related to secure natural gas supply to replace the declining gas production from Cookinlet.

Hawaii Gas; Integrated Resource Planning (IRP); 2022 – 2026

Project Director. Black & Veatch supported Hawaii Gas in its April 2023 filing of IRP to meet the requirements of Public Utility Commission order No. 38189. Black & Veatch's scope of work includes demand forecasting, supply potential evaluations and supply portfolio optimization. Black & Veatch also actively leads the communication and progress review meetings with various stake holders in this process.

Dominion Energy South Carolina | Natural Gas Hedging Review for Gas and Electric Customers; United States; 2023 – 2024

Project Director - Black & Veatch. Black & Veatch was engaged by Dominion Energy South Carolina, Inc (DESC) to provide an independent review and assessment of the feasibility, costs, and benefits to the Company's natural gas electric utility customers of a natural gas hedging program.

Multiple Clients | Technical Due Diligence, United States; 2016-Current

Project Director - Black & Veatch. Led due diligence assessment of various midstream oil and gas assets and power assets in North America. Key clients include Goldman Sachs, StonePeak Energy Partners, Morgan Stanley, Blackstone, FICA, OMERS, I-Squared Capital, etc. The assets include gathering systems, storage facilities, processing facilities, transportation pipelines and LNG export terminals for natural gas, crude oil and natural gas liquids infrastructure assets.

Multiple Clients | Market Assessment and Commercial Due Diligence, United States; 2016-Current

Project Director - Black & Veatch. Multiple market assessment and due diligence on natural gas and other energy assets in North America. Key asset covered include:

- LNG terminals
- Natural gas storage facilities
- Ammonia facilities
- Gas distribution companies
- Gas turbines

East Coast Natural Gas Utility | Pre-feasibility Study of a Green Hydrogen Hub; United States; 2022 – 2023

Project Director - Black & Veatch. Black & Veatch is designing a small green hydrogen hub for an East Coast natural gas utility.

Mid-West Natural Gas Utility | Hydrogen Blending Evaluation; United States; 2021 – 2022

Project Director - Black & Veatch. Black & Veatch is currently advising the client achieving a hydrogen blending goal as part of its decarbonization plan. Black & Veatch evaluated the Client's current system conditions and identified engineering, operational and other system requirements for blending hydrogen into its system. Black & Veatch developed a feasible roadmap for the successful implementation of its hydrogen blending strategy.

Renewable Portfolio Asset Owner | Pre-feasibility Study of a Green Hydrogen Hub; Texas, United States; 2021 – 2022

Economic and Optimization SME. Black & Veatch is advising a developer for a green hydrogen and ammonia hub utilizing renewable energy from Texas. Ms. Fang provides a comprehensive analysis to explore the optimal portfolio to support the stable operation of the hydrogen and ammonia production facility.

Proposed Hydrogen Production Facility Developer | Pre-feasibility Study of a Hydrogen Production/Transportation/Storage Facility; Texas, United States; 2021.

Economic and Optimization SME. Black & Veatch provided a feasibility study to the owner of a Texas wind facility to investing in hydrogen production, transportation and distribution infrastructure assets.

West Coast Utility | Zero-Carbon Future Strategy; United States; 2021 – 2022

Project Director - Black & Veatch. Black & Veatch is supporting a West coast utility understanding the impact of a zero-carbon future – on utilization and operation of their assets, rate and regulatory processes, customer bills; and identify any zero carbon investments opportunities.

New England Utility | Energy Portfolio and Procurement Review; New Hampshire, United States; 2021 - 2022

Project Director - Black & Veatch. Black & Veatch successfully supported the client to review its current procurement practice and hedging programs and to recommend any improvements and additional considerations based on the load requirement trends and energy market developments in its service territory. Black & Veatch presented the results to client's Board of Directors.

Black Hills Energy | Gas IRP; Colorado, United States, 2021 – 2022

Project Director - Black & Veatch. Black & Veatch was engaged by the client to develop the first natural gas integrated resource plan in Black Hills Colorado. As part of the Gas IRP, Black & Veatch conducted an independent review of the current methodologies used to develop forecasts of gas customers, usage under peak and design day conditions and also reviewed the client's gas supply portfolio by rate area and the gas supply hedging program and benchmarked against other utilities in the region.

Wabash Valley Power Association | Electric Market and Price Forecast; Indiana, United States; 2020-2021

Testifying Expert - Black & Veatch. Ms. Fang provided expert testimony regarding the economic value of power contracts upon a member's exit of the cooperative. Ms. Fang provided direct testimony, rebuttal testimony and testified in the FERC hearing.

SoCalGas | CPUC Gas OIR; California, United States; 2019-Ongoing

Project Director - Black & Veatch. Ms. Fang led the Black & Veatch team to support client in the gas OIR proceeding, understanding the implications on reliability standards, asset utilization patterns and rate impacts from the State's various decarbonization strategies.

Confidential West Utility | Infrastructure Assessment for Electric Reliability; California, United States; 2016-2021

Project Director - Black & Veatch. For an integrated gas and electric utility in the West region, Dr. Fang led a team assessing the adequacy of natural gas infrastructure to support the electric grid reliability under various weather conditions and solar and wind profiles. Energy and capacity market prices in various California load zones were projected for the next 25 years.

Confidential Integrated Utility | SB 100 Implementation & Implications; United States; 2016-2019

Project Director - Black & Veatch. Led the study of the logical paths and economic and consumer implications for California to implement SB 100, which requires 100% of California's energy comes from carbon-free resources by 2045.

Eversource | Regulatory Support in Gas Capacity Cost Recovery; Massachusetts; 2015-2016

Project Manager - ICF International. Dr. Fang led the analysis to support Eversource in obtaining cost recovery from the commission on contracting for firm capacity on the proposed Access Northeast Pipeline. The benefits were estimated in an integrated modeling framework using the fundamental demand and supply model for the gas market (GMM) and power market (IPM) to estimate the project's reduction in natural gas price and wholesale power prices in the region. In addition, the benefits from reduced natural gas and electric volatility are also estimated using an econometric approach. Dr. Fang led the development of the report and supported the testifying expert.

Spectra Energy | The Market and Economic Impact of Access Northeast; Texas; 2015

Project Lead - ICF International. Dr. Fang led the analysis to estimate the natural gas, power and economic impact of the Access Northeast Pipeline proposed by Spectra Energy. The benefits were estimated in an integrated modeling framework using the fundamental demand and supply model for the gas market (GMM) and power market (IPM) to estimate the project's reduction in natural gas price and wholesale power prices in the region. In addition, the benefits from reduced natural gas and electric volatility are also estimated using an econometric approach. Dr. Fang led the development of the report that was utilized as part of public outreach program engaged by the client.

Kinder Morgan | Gas and Electric Market Impact of the Northeast Energy Direct; Texas; 2014

Project Director - ICF International. Dr. Fang led a study for Kinder Morgan to estimate the economic and reliability benefits to New England electric consumers from the proposed Northeast Energy Direct pipeline and Access Northeast Pipeline. The benefits were estimated in an integrated modeling framework using the fundamental demand and supply model for the gas market (GMM) and power market (IPM) to estimate the project's reduction in natural gas price and wholesale power prices in the region. In addition, the benefits from reduced natural gas and electric volatility are also estimated using an econometric approach. Dr. Fang authored a report for each client that was utilized by both pipeline sponsors in their public outreach efforts.

NESCO Infrastructure Assessment | Massachusetts; 2012-2013

Project Lead. The New England States Committee on Electricity (NESCOE) engaged Black & Veatch to assess the adequacy of the natural gas infrastructure to support power generation in New England. In Phase I, Black & Veatch surveyed the existing studies that touched upon the interaction between the natural gas and electric sectors in New England market and concluded that no study had quantified the adequacy in a meaningful way that could provide insights into whether the infrastructure is adequate to meet New England's future needs.

In Phase II, our analysis assessed the gas demand growth in different sub-regions of New England and compared it against physical and contracted pipeline capacity on a daily and hourly basis during the study period to identify the location of potential constraint points in the New England regional infrastructure. Black & Veatch examined 14 sub-regions in New England and identified that 10 of them would face capacity constraints lasting longer than 30 days by 2023. As part of this phase, Black & Veatch projected daily gas demand by sector and by local distribution service territory, taking into account the location of new incremental gas-fired generation builds in each sub-region.

In Phase III, Black & Veatch evaluated numerous potential gas and electric infrastructure solutions across a Base Case, and several stress-test cases (High Demand, Low Demand) to identify the solution that would yield the highest net benefits to gas and electric consumers. Black & Veatch presented our net benefits assessment to NESCOE's New England Gas-Electric Focus Group as well as the Chairmen of New England state commissions, which led the New England electric utilities to develop a strategy to encourage incremental pipeline development into the region.

OG&E | Gas Transportation and Storage Contracts Review; Oklahoma; 2011-2012

Analysis Lead. Black & Veatch was engaged by the state regulatory body of Oklahoma, the OCC, to review the natural gas transportation and storage capacity held by OG&E to serve the needs of its gas-fired electric generation fleet. Dr. Fang led Black & Veatch's assessment of projected load in OG&E's market given projected dispatch in the current SPP as well as the proposed SPP MarketPlace expected to take effect in 2014. The assessment identified the level of no-notice, firm and interruptible natural gas capacity that would be required to meet the annual, seasonal, daily and hourly needs of OG&E's generation fleet. The trade-offs between reduced capacity costs and increased risk of curtailment were quantified and

incorporated in the assessment and recommendations to OG&E and the OCC. The findings of the assessment were presented to stakeholders including OCC Staff, OG&E, Attorney General's Staff and the Oklahoma Industrial Energy Consumers.

Presentations & Publications

"Creating the Long-Term Energy Mix," S&P Global Power Markets™ Conference Americas Conference. April 2022.

"Outlook for Hydrogen – What is Driving Growth in the Market," S&P Global Hydrogen Markets Americas Conference. March 2022.

"California's SB 100 Law: Opportunities and Challenges of Moving to 100% Clean Energy." Black & Veatch Webinar. March 2019.

"California Goes All In On Renewables." Solar Power Finance & Investment. March 2019.

"ERCOT – Opportunities and Challenges for Energy Projects." Black & Veatch Webinar. April 2019.

"Texas vs. California – Renewable Strategy and Implications." 8th Annual Renewable Energy Summit. April 2019.

"Storage Procurement in California." CA Renewable Energy Procurement Summit. September 2019.

"PJM Capacity Price – What Happens Next." New York Power Market Briefing. September 2019.

"ERCOT Outlook: Fuel, Generation, Transmission, and Recent Market Volatility." Black & Veatch Webinar. May 2020.

"WECC & CAISO Market Outlook 2020." Black & Veatch Webinar. October 2020.

"Gas and Electric Interdependency: Implications for New England." EUEC conference proceedings. February 2014.

"Gas and Electric Interdependency: Case Studies of Two Regions." EUEC Proceedings. February 2015.

Base Case Fuel Price Forecasts (\$2025/MMBtu)

Year	Natural Gas (\$/MMBtu)	Northside Units 1 and 2 (\$/MMBtu)	Diesel (\$/MMBtu)
2026	3.91	4.76	16.53
2027	4.12	4.77	15.82
2028	4.54	4.79	14.87
2029	5.03	4.79	14.98
2030	5.56	4.88	15.07
2031	5.61	4.88	15.06
2032	5.59	4.87	15.13
2033	5.63	4.86	15.12
2034	5.62	4.89	15.21
2035	5.66	4.89	15.27
2036	5.59	4.88	15.32
2037	5.54	4.89	15.35
2038	5.54	4.94	15.37
2039	5.49	4.83	15.42
2040	5.41	4.83	15.48
2041	5.47	4.83	15.58
2042	5.48	4.83	15.57
2043	5.47	4.83	15.64
2044	5.51	4.83	15.61
2045	5.56	4.83	15.68
2046	5.62	4.83	15.83
2047	5.78	4.84	15.85
2048	5.98	4.85	15.88
2049	6.20	4.87	15.96
2050	6.25	4.88	15.96
2051	6.38	4.89	16.01
2052	6.52	4.91	16.05
2053	6.67	4.92	16.08

Year	Natural Gas (\$/MMBtu)	Northside Units 1 and 2 (\$/MMBtu)	Diesel (\$/MMBtu)
2054	6.81	4.94	16.13
2055	6.96	4.95	16.16
2056	7.11	4.96	16.20
2057	7.27	4.98	16.24
2058	7.43	4.99	16.27
2059	7.59	5.00	16.31
2060	7.75	5.02	16.35

High and Low Fuel Price Assumptions (\$2025/MMBtu)

Year	High Fuel Price Forecast, \$/MMBtu			Low Fuel Price Forecast, \$/MMBtu		
	Natural Gas	NS CFB	Diesel	Natural Gas	NS CFB	Diesel
2026	4.00	4.76	16.53	3.79	4.76	16.53
2027	4.48	4.77	15.82	3.86	4.77	15.82
2028	5.37	4.79	14.87	4.12	4.79	14.87
2029	5.97	4.79	14.98	4.46	4.79	14.98
2030	6.43	4.88	15.07	4.84	4.88	15.07
2031	6.52	4.88	15.06	4.85	4.88	15.06
2032	6.25	4.87	15.13	4.74	4.87	15.13
2033	6.32	4.86	15.12	4.61	4.86	15.12
2034	6.37	4.89	15.21	4.53	4.89	15.21
2035	6.49	4.89	15.27	4.53	4.89	15.27
2036	6.41	4.88	15.32	4.47	4.88	15.32
2037	6.31	4.89	15.35	4.43	4.89	15.35
2038	6.22	4.94	15.37	4.45	4.94	15.37
2039	6.12	4.83	15.42	4.47	4.83	15.42
2040	6.03	4.83	15.48	4.43	4.83	15.48
2041	6.08	4.83	15.58	4.49	4.83	15.58
2042	6.07	4.83	15.57	4.48	4.83	15.57
2043	6.07	4.83	15.64	4.40	4.83	15.64
2044	6.11	4.83	15.61	4.42	4.83	15.61
2045	6.15	4.83	15.68	4.46	4.83	15.68
2046	6.22	4.83	15.83	4.51	4.83	15.83
2047	6.39	4.84	15.85	4.59	4.84	15.85
2048	6.51	4.85	15.88	4.74	4.85	15.88
2049	6.70	4.87	15.96	4.94	4.87	15.96
2050	6.74	4.88	15.96	4.98	4.88	15.96
2051	6.85	4.89	16.01	5.08	4.89	16.01
2052	6.97	4.91	16.05	5.19	4.91	16.05
2053	7.08	4.92	16.08	5.29	4.92	16.08

Year	High Fuel Price Forecast, \$/MMBtu			Low Fuel Price Forecast, \$/MMBtu		
	Natural Gas	NS CFB	Diesel	Natural Gas	NS CFB	Diesel
2054	7.20	4.94	16.13	5.40	4.94	16.13
2055	7.32	4.95	16.16	5.52	4.95	16.16
2056	7.44	4.96	16.20	5.63	4.96	16.20
2057	7.57	4.98	16.24	5.75	4.98	16.24
2058	7.70	4.99	16.27	5.87	4.99	16.27
2059	7.82	5.00	16.31	5.99	5.00	16.31
2060	7.96	5.02	16.35	6.11	5.02	16.35

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

MATT OAKES

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF MATT M. OAKES

DOCKET NO. _____

June 4, 2026

I. INTRODUCTION AND QUALIFICATION

Q. Please state your name and address.

A. My name is Matt Oakes. My business address is 11401 Lamar Avenue
Overland Park, Kansas.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Thermal Performance and Technologies section and
Gas Turbine Technology Lead at Black & Veatch.

Q. Please describe your responsibilities in your current position.

A. My current duties include preparing specifications and providing review and
negotiations support for the procurement of combustion turbine generators,
steam turbine generators, and long-term service agreements. My
responsibilities also include leading technology assessments, feasibility
studies, and levelized cost of electricity evaluations for new power generation
opportunities.

1 **Q. Please state your professional experience and educational background.**

2 A. I am a Professional Engineer with more than 20 years' experience assisting

3 clients in developing operation and maintenance (O&M) cost estimates,

4 performing due diligence for electrical generating projects, including natural

5 gas-fired combined cycle generation, preparing bid specifications, evaluating

6 bids and providing contract negotiation support for equipment procurement

7 and Long-Term Service Agreements, and supporting technology evaluations for

8 new equipment. I have been employed by Black & Veatch since 2005, and in

9 my current position since 2022. I have a Bachelor of Science in Mechanical

10 Engineering.

11

12 **Q. Is Exhibit No. ____ (MO-1) a true and correct copy of your resume?**

13 A. It is.

14

15 **Q. What is the purpose of your testimony in this proceeding?**

16 A. I will be testifying regarding my role in developing capital, O&M, and

17 performance estimates for the natural gas generating unit alternatives to St.

18 Johns River Power Park Unit 3 (SJRPP Unit 3) considered in the economic

19 modeling associated with selection of the technology for SJRPP Unit 3 as well

20 as the updated economic evaluation of generation alternatives.

21

22 **Q. Are you sponsoring any exhibits in the case?**

23 A. Yes. I am sponsoring my resume attached as Exhibit No. ____ (MO-1). I am

24 also co-sponsoring Exhibit No. ____ (MO-2), Capital and Performance

25 Assumptions for Generating Alternatives, and Section 6.4.4 of the Need Study,

1 which is Exhibit No. ____ (JB-2), as to the natural gas alternatives. Mr. Bradley
2 Kushner is addressing the other generating alternatives in his pre-filed direct
3 testimony.

4
5 **Q. Please describe your role related to the evaluation of generating**
6 **alternatives to SJRPP Unit 3.**

7 A. My role was to develop, or lead the development of, the capital costs, O&M
8 costs and performance estimates for the natural gas alternatives used to
9 compare generating alternatives in the SJRPP Unit 3 economic modeling. I
10 developed, or led the development of, cost estimates for natural gas generating
11 alternatives utilized during the technology selection phase of the project, the
12 economic evaluation of market alternatives, and the updated economic
13 modeling to confirm SJRPP Unit 3 as the least cost alternative.

14
15 **Q. Please describe the methodology utilized to develop the capital cost**
16 **estimates for the natural gas generating alternatives.**

17 A. To prepare the estimates for the natural gas generating alternatives, Black &
18 Veatch started with the Plant Engineering and Cost Estimation (PEACE®)
19 module integrated within the Thermoflow software suite which was also used
20 to develop the performance models. We then made adjustments to those
21 estimates by (1) comparing the PEACE® costs against in-house project data
22 and more detailed estimates that Black & Veatch has recently developed for
23 other projects; (2) evaluating hydrogen co-firing and post-combustion carbon
24 capture; and (3) adjusting capital costs for labor rates and preliminary site-
25 specific project data.

1

2 **Q. Please describe the methodology utilized to develop the O&M cost**
3 **estimates for natural gas generating alternatives.**

4 A. To prepare the estimates for the natural gas generating alternatives, Black &
5 Veatch utilized an Electric Power Research Institute (EPRI) State of the Art
6 Power Plant (SOAPP) cost estimating model as well as in-house cost
7 information from other projects with similar technology options to estimate
8 O&M costs for each gas turbine and reciprocating internal combustion engine
9 (RICE) power generation option.

10

11 **Q. Please describe the methodology utilized to develop the performance**
12 **estimates for the natural gas generating alternatives.**

13 A. Black & Veatch developed plant models in Thermoflow for each of the natural
14 gas generating alternatives considered. Combustion turbine, RICE, or power
15 island performance was based on Thermoflow data or data received from the
16 original equipment manufacturers (OEMs) for JEA use, along with
17 coordination with JEA on ambient and operating conditions.

18

19 **Q. How did the cost estimates change over the course of SJRPP Unit 3**
20 **evaluation?**

21 A. Over the course of JEA's evaluation of technologies, market alternatives, and
22 cost-effectiveness of SJRPP Unit 3, Black & Veatch updated the capital cost
23 estimates to ensure the costs utilized were representative of the current market
24 and of ongoing discussions between JEA and manufacturers.

25

1 **Q. Please identify Exhibit No. ____ (MO-2).**

2 A. Exhibit ____ MO-2 reflects the cost and performance assumptions for
3 generating alternatives utilized in the updated economic modeling performed
4 to confirm SJRPP Unit 3 as the least cost alternative.

5

6 **Q. Does this complete your testimony?**

7 A. Yes.

Matt M. Oakes, P.E.

Matthew M. Oakes is a Mechanical Engineer and Manager of the Thermal Performance and Technologies section within Black & Veatch Energy. His current duties include managing professionals in the TPT section, preparing specifications and providing review and negotiations support for the procurement of combustion turbine generators, steam turbine generators, and long-term service agreements. Other duties include leading technology assessments, feasibility studies, and levelized cost of electricity evaluations for new power generation opportunities as well as supporting proposals. Another current role includes serving as the Gas Turbine Technology Lead for Black & Veatch. Duties of this position include discussing technology updates, technology issues, equipment availability, market conditions, etc. with OEMs of gas fired power generation equipment. It also includes providing technical support for Black & Veatch resources such as project directors, project and engineering managers, proposal managers, and sales representatives.

Past duties have included providing support for due diligence and condition assessment projects, asset evaluation, and O&M costs analysis for various power generation projects.

Key business roles include the following:

- Supervising professionals in the Thermal Performance and Technologies section.
- Providing support for the procurement of Combustion Turbine Generators, Steam Turbine Generators, and Long-Term Service Agreements.
- Reviewing and providing technical support for O&M Agreements and LTSAs.
- Leading technology assessments, feasibility studies, and levelized cost of electricity evaluations for new power generation opportunities.
- Serving as the Black & Veatch Gas Turbine Technology Lead.
- Performing asset evaluation, due diligence, and long-term assessment studies.
- Developing O&M estimates for cogeneration, combined cycle, and simple cycle power plants.
- Providing services for O&M analysis projects.
- Performing reliability, availability, and maintainability (RAM) studies.

PROJECT EXPERIENCE

Tallgrass; Wyoming ILS; Wyoming, United States; 2025-In-Progress

Gas Turbine Technology Lead - Black & Veatch. Supported Tallgrass Energy as their Gas Turbine Technology Lead during their evaluation and procurement of two M501JAC Gas Turbines. Support included a trip to MHI and Toshiba factories in Japan.

JEA; Need for Power project; Florida, United States; 2024-In-Progress

Lead Engineer - Power Island Equipment procurement - Black & Veatch. Supported JEA with selection and procurement of power island equipment for the Need for Power project. Also provided support for LTSA contract.

Sunflower Electric; Clifton Generating Station; Kansas, United States; 2025-2026

Lead Engineer - Black & Veatch. Led an effort to support the Sunflower Energy team in getting to an LTSA with Solar Turbines for 3 Solar Titan 350 gas turbines.

GRDA; Advanced Class Simple Cycle Generating Station; Oklahoma, United States; 2025

LEAD MECHANICAL ENGINEER

EXPERTISE:

Combustion Turbine Generator / Combined Cycle SME; Due Diligence; Feasibility Studies; Green Belt Certified; Long Term Service Agreement SME; O&M Cost Estimation; Operations and Maintenance SME; Reliability, Availability, Maintainability (RAM) Analysis; Thermal Performance

EDUCATION

Bachelor of Science, Mechanical Engineering, Winona State University, 1996, United States

PROFESSIONAL REGISTRATION

CSSGB - Certified Six Sigma Green Belt, Mechanical, Kansas, United States

PE - Professional Engineer, Mechanical, 23768, Kansas, United States

18696, Minnesota, United States

TOTAL YEARS OF EXPERIENCE

20.5

BLACK & VEATCH YEARS OF EXPERIENCE

20.5

LANGUAGE CAPABILITIES

English

OFFICE LOCATION

Overland Park, Kansas, USA: United States

Lead Engineer - Black & Veatch. Supported the procurement of an advanced class simple cycle gas turbine with development of a Gas Turbine technical specification, bid review, and procurement.

Confidential; Gas Turbine Hydrogen Conversion ; Texas, United States; 2024-2025

Lead Engineer - Black & Veatch. Supported Client with a project to convert gas turbine units from gas fired only to be able to fire up to 100% natural gas or 100% hydrogen.

GRDA; Advanced Class Simple Cycle; Oklahoma, United States; 2023

Long Term Service Agreement Support - Black & Veatch. Development of LTSA specification, review of bids from turbine providers, and support of negotiations through execution of final contract for an advanced class simple cycle project.

GRDA; Technology Study; Oklahoma, United States; 2022-2023

Mechanical Engineer - Black & Veatch. Leading study to evaluate potential simple cycle and combined cycle technology options for new power generation.

Confidential; Advanced Class Combined Cycle; Confidential, Canada; 2022-2023

Mechanical Engineer - Black & Veatch. Provided gas turbine and LTSA specifications for a new advanced class CC project. Providing support in evaluating and comparing equipment and LTSA bids and participating in bid negotiation meetings with multiple bidders. Leading an LCOE evaluation to help select a power island equipment supplier.

Confidential; Dual Fuel Study; Missouri, United States; 2021-2022

Mechanical Engineer - Black & Veatch. Provided gas turbine specifications for converting existing frame units from natural gas to dual fuel capability. Providing support in evaluating and comparing equipment bids and participating in bid negotiation meetings with multiple bidders.

JEA; IRP Study; Florida, United States; 2021

Mechanical Engineer - Black & Veatch. Estimated performance, EPC costs, and O&M costs for an IRP study evaluating several simple cycle, combined cycle, and biomass options.

Confidential; Advanced Class Combined Cycle; Confidential, Dominican Republic; 2021

Mechanical Engineer - Black & Veatch. Provided equipment and LTSA specifications for a new advanced class CC project. Provided support in evaluating and comparing equipment and LTSA bids and participating in bid negotiation meetings with multiple bidders. Provided O&M costs and supported an LCOE evaluation to recommend an equipment supplier for the project.

Intermountain Power; Advanced Class Combined Cycle Facility; Utah, United States; 2019-2020

Mechanical Engineer - Black & Veatch. Provided LTSA specifications for a new advanced class CC project. Provided support in evaluating and comparing LTSA bids and participating in bid negotiation meetings with multiple bidders.

PowerSouth; Advanced Technology Combined Cycle Power Plant; Alabama, United States; 2019

Engineer - Black & Veatch. Provided LTSA specifications for a new advanced class CC project. Provided support in evaluating and comparing LTSA bids and participated in bid negotiation meetings with multiple bidders. Developed O&M cost estimates to support the review and comparison of bids.

Confidential Client; Advanced Technology Combined Cycle Power Plant; Ohio, United States; 2018-2019

Mechanical Engineer - Black & Veatch. Provided LTSA specifications for a new advanced class CC project. Provided support in evaluating and comparing LTSA bids and participating in bid negotiation meetings with multiple bidders.

Confidential Client; Advanced Technology Combined Cycle Power Plant; Alberta, Canada; 2017-2018

Mechanical Engineer - Black & Veatch. Provided LTSA specifications for a new CC project. Provided support in evaluating and comparing LTSA bids and participated in bid negotiation meetings with multiple bidders.

Confidential Client; Advanced Technology Combined Cycle Power Plant; Florida, United States; 2016

Mechanical Engineer - Black & Veatch. Developed power island specifications for an advanced technology combined cycle project. Completed technical evaluation of power island proposals and provided support for resolving exceptions and clarifications of OEM proposals with the equipment specifications.

Developed LTSA specification supported evaluation of LTSA proposals.

Participated in bid negotiation meetings for power island equipment and LTSA proposals with multiple bidders.

Tyr Energy; Confidential; New Jersey, United States; 2015

Mechanical Engineer - Black & Veatch. Provided due diligence services for multiple combustion turbines at existing facility.

City of Ames; GT1 Return to Service; United States; 2014-2015

O&M Specialist - Black & Veatch. Provided a combustion turbine specification for the replacement of an existing combustion turbine.

Exelon; O&M Cost Estimates and CSA Negotiations; United States; 2014

O&M Specialist - Black & Veatch. Provided O&M cost estimates and CSA review and negotiation support for Client evaluating multiple bidders.

GRDA; LTSA technical support; Oklahoma, United States; 2013-2014

O&M Specialist - Black & Veatch. Reviewed several LTSAs and provided negotiation support and technical input for the selected LTSA.

KRoad Power, LLC; Solar Photovoltaic (PV) O&M Review; California, United States; 2012

O&M Specialist - Black & Veatch. Reviewed and provided input for O&M cost estimates and, an O&M agreement between KRoad and O&M service provider, SunPower, for a 25 MW solar PV project in California.

Eskom; Strategic Resource Assessment; South Africa; 2011-2012

O&M Specialist - Black & Veatch. Assisted Project Manager and Black & Veatch team in providing a strategic resource assessment for the Eskom Enterprises Division. The strategic resource assessment included estimates of professional and craft labor that will be required to be hired and trained by Eskom to meet the integrated resource plan, as requested by the South African Department of Energy, for the design and construction of nearly 45 GW of new power over the next 20 years.

Black Hills Energy; O&M Cost Estimating; Colorado, United States; 2011-2012

O&M Specialist - Black & Veatch. Responsible for the development of O&M cost estimates for several simple cycle and combined cycle combustion turbine and reciprocating engine configurations as well as conventional coal fired power generating units.

Enbridge, Inc.; Solar Photovoltaic (PV) O&M Review; Sarnia Project; Ontario, Canada; 2010

O&M Specialist - Black & Veatch. Reviewed and provided input on O&M cost estimates, O&M agreement, and O&M manual between Enbridge and O&M service provider, First Solar, for the Sarnia project, the world's largest operating solar PV facility.

Hawaiian Electric Company (HECO); Fuel Inventory Study; Hawaii, United States; 2010

O&M Specialist - Black & Veatch. Performed a study to determine the minimum fuel inventory requirements for HECO on the island of Oahu (on the basis of scheduled fuel delivery quantities and estimated fuel demand) by performing a stochastic analysis of fuel supply interruptions and fuel demand increases caused by various failure modes and probabilities of failure.

Sempra Energy; Gas Cleanup Study; California, United States; 2010

O&M Specialist - Black & Veatch. Researched carbon dioxide (CO₂) and Siloxane removal technologies and contacted several vendors and operators to gather information and provide the client with an estimate of maintenance requirements and reliability of the gas cleanup systems.

PG&E; Solar Power Plant O&M Cost Estimates; United States; 2009

O&M Specialist - Black & Veatch. Developed O&M cost estimates for a 250 MW solar thermal power plant feasibility study.

Ingenco Wholesale Power, LLC; Due Diligence Study; Virginia, United States; 2009

O&M Specialist - Black & Veatch. Performed condition assessment of landfill gas fired reciprocating engines. Conducted a walkdown of units to observe condition of equipment. Reviewed historic and projected CAPEX, O&M costs, and staffing requirements for input to a Proforma model.

Pacific Gas & Electric (PG&E); Renewable Energy O&M Cost Estimates; California, United States; 2009

O&M Specialist - Black & Veatch. Responsibilities included development of O&M cost estimates for multiple renewable resource power generating options including: biomass fired boilers, geothermal, solar, and wind.

Eskom; Asset Information Model Development; South Africa; 2008-2009

O&M Specialist - Black & Veatch. Responsible for the development of an asset information model that will serve as the foundation for the client's SmartPlant database. The database will be maintained for plant equipment design control and procurement purposes.

Los Angeles Department of Public Works (LADPW) / Los Angeles Department of Water and Power (LADWP); Renewable Energy Cogeneration Feasibility Study; California, United States; 2008-2009

O&M Specialist - Black & Veatch. Evaluated multiple options and developed O&M costs for combustion turbine technologies to be used in a combined cycle configuration firing on a digester gas / natural gas blend. Assisted in the coordination of information to be used in a California air permit application process.

Viridis Technologies, Inc.; Condition Assessment; Quebec, Canada; 2007

O&M Specialist - Black & Veatch. Performed a condition assessment of biomass fueled and combined cycle natural gas generating facilities. Provided technical support to assist the client in deciding whether to purchase the available assets.

Shell; Combined Cycle O&M Estimates; United States; 2007

O&M Specialist - Black & Veatch. Provided the client with O&M estimates for several combined cycle combustion turbine generating facilities to compare costs between different vendor-supplied products and combustion turbine technologies.

Alliant Energy Corporation; Ancillary Services Market-Generating Unit Impacts Study; Wisconsin, United States; 2007

O&M Specialist - Black & Veatch. Performed an analysis of issues and impacts associated with the transition of generating stations to the Midcontinent Independent System Operator (MISO) ancillary services market. Coordinated with the client to determine the resulting effect of equipment maintenance by running in automatic generation control.

KCP&L; Long Range Alternatives Assessment; Kansas, United States; 2006

O&M Specialist - Black & Veatch. In a long-term assessment project, evaluated the schedule, feasibility, and O&M costs associated with the addition of AQC equipment to existing generating stations, as well as consideration of the addition of capacity to generating sites at LaCygne, Kansas, and Montrose, Missouri.

Orlando Utilities Commission; O&M Cost Estimates; Florida, United States; 2005

O&M Specialist - Black & Veatch. Provided O&M cost estimates expected to be required for adding availability of several simple cycle and combined cycle combustion turbine power plant options at an existing site.

AmerenUE Corporation; Remote Monitoring Services; Missouri, United States; 2005

O&M Specialist - Black & Veatch. Provided remote performance monitoring services for five coal fired power plants.

Fleet Operations; Missouri, United States; 2000-2004

Fleet Operations and Power Plant Engineer; Repair Development Engineer - Trans World Airlines (TWA) / American Airlines. Fleet Operations and Power Plant Engineer. Evaluated and implemented service bulletins to improve performance, reliability, and safety. Monitored the performance and reliability of aircraft engines and components. Determined engine build standards and maintenance levels required during engine overhaul.

Repair Development Engineer. Coordinated with original equipment manufacturers (OEMs), repair vendors, and other airline power plant engineers to develop repairs for engine components.

Cost (2031\$) and Performance Assumptions for Generating Alternatives

Candidate Option	In-Service Capital Cost (\$M)	In-Service Capital Cost (\$/kW)	Summer Rating (MW)	Winter Rating (MW)	Full Load Net Plant Heat Rate (Btu/kWh; higher heating value)	Fixed O&M Cost (\$/kW-yr)	Variable O&M Cost (\$/MWh)	Start Cost (\$/Start)
GE LM6000 PF SPRINT 2x0	\$401.11	\$4,051.13	76.1	99.5	8,831	\$21.52	\$10.66	N/A
GE 7FA.05 1x0	\$617.95	\$2,621.76	208.7	235.7	10,080	\$12.13	N/A	\$13,214
GE 7HA.03 1x0	\$925.75	\$2,044.13	374.2	452.9	9,031	\$7.06	N/A	\$34,419
Wartsila 18V50DF 5x0	\$322.31	\$3,606.88	83.8	89.4	8,380	\$33.02	\$9.65	N/A
GE 7FA.05 1x1	\$1,501.66	\$3,957.10	342.2	279.5	6,940	\$14.89	\$3.52	N/A
GE 7HA.03 1x1	\$1,570.00	\$2,344.10	581.6	677.6	6,317	\$13.08	\$1.11	\$69,884
Conversion of existing GEC CTGs	\$817.58	\$2,487.03	297.3	328.8	6,832	\$13.78	\$3.38	N/A
Conversion of existing GEC CTGs	\$1,447	\$2,192	597.2	660.3	6,803	\$8.75	\$3.28	N/A
75 MW Photovoltaic Solar Array ⁽¹⁾⁽²⁾	First year PPA cost \$72.81/MWh	N/A	75	75	N/A	N/A	N/A	N/A
50 MW Lithium Ion 4-hour Battery Storage ⁽¹⁾	\$71.17	\$1,423.11	50	50	N/A	\$69.50	N/A	N/A
100 MW Vanadium Redox 10-hour Battery Storage ⁽¹⁾	\$334.23	\$3,342.47	100	100	N/A	\$129.22	N/A	N/A
Small Modular Reactors ⁽²⁾	\$1,480.02	\$19,220.27	77	77	10,400	\$157.55	\$4.12	N/A
GE 7HA.03 1x1 with Carbon Capture and Sequestration	\$3,716.90	\$6,205.77	509.9	598.9	7,162	\$75.24	\$15.33	N/A
GE 7HA.03 1x1 Hydrogen	\$2,364.96	\$3,577.75	583.5	677.8	6,522	\$10.39	\$6.55	N/A
GE LM6000 PF SPRINT 2x0 Hydrogen	\$466.75	\$4,688.38	76.1	99.5	9,477	\$21.52	\$10.66	N/A
1. "Summer Rating" and "Winter Rating" represents nameplate rating; summer and winter ratings are less than nameplate ratings shown. 2. For battery energy storage options and nuclear options, the capital costs shown in this table reflect a 30% investment tax credit (ITC). It has been assumed that beginning in 2034 the ITC is reduced to 22.5% and further reduced to 15% in 2035, with no subsequent ITC.								

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

JIM HERNDON

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF JIM HERNDON

DOCKET NO. _____

June 4, 2026

Q. Please state your name, position of employment, and business address.

A. My name is Jim Herndon. I am a Vice President in the Advisory Services Practice within the Utility Services business unit of Resource Innovations, Inc. (RI). My business address is 2500 Regency Parkway, Suite 218, Cary, North Carolina 27518. A statement of my background and qualifications is attached as Exhibit No. __ (JH-1).

Q. Please describe your responsibilities in your position.

A. I am responsible for providing consulting services for RI clients in the field of Demand-Side Management (DSM) initiatives, which include energy efficiency (EE), demand response (DR), and demand-side renewable energy (DSRE). In this capacity, I primarily focus on DSM planning, including analysis of DSM market impacts, and assisting DSM program initiatives. This includes the development of market baseline and potential studies, cost-benefit analyses, and design of comprehensive DSM programs and portfolios.

Q. What specific projects or studies has RI done to assess DSM potential?

1 A. RI has conducted over 55 Market Potential Studies (MPS) to identify
2 opportunities for DSM in the United States and Canada. RI conducted the
3 MPS for the Florida Energy Efficiency and Conservation Act (FEECA)
4 utilities in the DSM goals proceeding in 2024 before this Commission. In
5 2021, RI merged with Nexant, Inc. (Nexant) – Nexant conducted the MPS for
6 the FEECA utilities in the DSM goals proceeding in 2019.

7
8 **Q. Please summarize your experience with DSM market potential studies.**

9 A. I have been involved in conducting or managing over 35 DSM potential
10 studies over the past 20 years. I have also led the development of numerous
11 DSM programs and portfolios, managed implementation of DSM programs,
12 and conducted third-party assessments of utility DSM programs.

13
14 **Q. Have you previously testified before the Florida Public Service
15 Commission or in other state regulatory proceedings?**

16 A. Yes, I provided testimony in the 2019 and 2024 DSM goals proceeding before
17 this Commission in support of our MPS for each FEECA utility, including
18 JEA. I have also submitted testimony before the Virginia State Corporation
19 Commission, the North Carolina Utilities Commission, the South Carolina
20 Public Service Commission, the Public Utilities Commission of Ohio, and the
21 New Jersey Board of Public Utilities.

22
23 **Q. What is the purpose of your testimony in this proceeding?**

24 A. The purpose of my testimony is to introduce and summarize the methodology
25 and findings of the analysis we performed to update and supplement the MPS

1 we conducted for JEA in the 2024 FEECA DSM proceeding. This updated
2 analysis confirms the absence of cost-effective conservation measures to
3 mitigate JEA's need for St. John River Power Park Unit 3 (SJRPP Unit 3).
4

5 **Q. Please describe your role and responsibilities with respect to RI's work for**
6 **this proceeding.**

7 A. I served as the project manager for RI's work, overseeing all phases of our
8 analysis.
9

10 **Q. Are you sponsoring any exhibits in the case?**

11 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
12 under my supervision and are attached to this pre-filed testimony:

- 13 • Exhibit No. ____ (JH-1) – Professional Resume of Jim Herndon
- 14 • Exhibit No. ____ (JH-2) – MPS for JEA (2024)
- 15 • Exhibit No. ____ (JH-3) – Update to MPS for JEA (2026)

16 I also am sponsoring Section 7.2 of the Need Study which is identified as
17 Exhibit No. ____(JB-2).
18

19 **Q. Please briefly summarize the analysis you conducted for JEA in 2024.**

20 A. In support of the 2024 FEECA proceeding, RI conducted a MPS for each of
21 the six Florida utilities subject to FEECA, including JEA (2024 JEA MPS).
22 More specifically, RI independently analyzed the technical potential for EE,
23 DR, and DSRE across JEA's residential, commercial, and industrial customer
24 classes. This included disaggregation of JEA's load forecast into customer-
25 class and end-use components, development of a comprehensive set of DSM

1 measures and quantification of the measures' impacts, and calculation of
2 potential energy and demand savings at the technology, end-use, customer
3 class, and system levels. For JEA, RI also conducted an economic analysis of
4 EE, DR, and DSRE measures, designed to determine which measures are cost-
5 effective from different test perspectives and to develop estimates of potential
6 impacts if those measures were developed. Finally, we assisted JEA in
7 developing DSM goals.

8
9 **Q. Please explain why you performed the update to the 2024 JEA MPS.**

10 A. RI was retained by JEA to perform an update to the MPS that RI conducted for
11 JEA as part of the 2024 FEECA goal setting proceedings, including DR and
12 EE economic potential and achievable potential results, to assist JEA in
13 determining whether there are sufficient conservation measures available to
14 mitigate the need for new generation. While a review of the DR and EE
15 measures included in the 2024 FEECA study did not show significant changes
16 in available technologies in the market, or savings per measure, JEA's avoided
17 unit cost and load forecast have changed since the 2024 study. Therefore, JEA
18 retained RI to update the 2024 JEA MPS to incorporate the current avoided
19 unit cost and load forecast.

20
21 **Q. Please summarize the methodology you utilized to update and supplement**
22 **the 2024 MPS.**

23 A. The update to the 2024 JEA MPS consisted of two primary tasks: 1)
24 disaggregating and applying current load forecast data; and 2) updating the

1 economic analysis and re-running the achievable potential modeling for both
2 EE and DR opportunities.
3
4 For the first task, RI collected load forecast data from JEA's 2026 Ten Year
5 Site Plan as well as supplemental details on customer categories that contribute
6 to the new load growth. RI compared the forecast for each customer sector:
7 residential, commercial, and industrial, as well as segments and end-uses
8 within each sector, to the load forecast used in the 2024 MPS to assess the
9 similarities and differences. Based on this comparison, RI adjusted the load
10 forecast inputs by customer sector, segment, and end-use from the 2024 JEA
11 MPS.
12
13 For the second task, JEA provided RI with current economic forecast data,
14 including avoided marginal energy cost and avoided capacity cost forecasts. RI
15 incorporated the economic data into our proprietary TEAPot model, which is
16 used in all our MPS analyses, including the 2024 JEA MPS for FEECA. The
17 economic data was used to update the cost-effectiveness screening for all EE
18 and DR measures included in the 2024 JEA MPS. Consistent with the 2024
19 study, this screening included both a Ratepayer Impact Measure (RIM)
20 scenario as the primary analysis, and a Total Resource Cost (TRC) scenario as
21 a sensitivity. The updated screening results for each scenario were applied to
22 the current JEA load forecast in RI's TEAPot model to derive updated
23 achievable potential results.
24

- 1 **Q. Did your analysis include evaluation of all DSM categories from the 2024**
2 **JEA MPS?**
- 3 A. The updated MPS analysis included evaluation of both EE and DR
4 opportunities based on the current economic information and load forecast.
5 The evaluation for both EE and DR included the two primary tasks described
6 above and resulted in updated achievable potential estimates.
- 7
- 8 The 2024 JEA MPS for FEECA also included analysis of DSRE opportunities.
9 The FEECA study found that JEA did not have any DSRE measures or
10 programs that passed the cost-effectiveness screening for the RIM or TRC
11 Scenario. RI conducted a review of the economic screening results from the
12 FEECA study for DSRE measures and found that the updated economic
13 information and load forecasts would have minimal to no impact on the
14 previous DSRE results, and therefore DSRE modeling was not updated.
- 15
- 16 **Q. Did you consider JEA’s existing and forecasted DSM goals and other**
17 **conservation measures?**
- 18 A. Yes. The achievable potential modeling includes estimates of current EE
19 measure market saturation that considers JEA’s historic DSM program
20 accomplishments. However, achievable potential estimates overlap with
21 forecasted DSM goals, therefore the load forecast applied in RI’s TEAPot
22 model removed the impact of JEA’s future DSM goals.
- 23
- 24 **Q. Did you prepare a report summarizing the updated analysis?**

1 A. Yes, Exhibit No. ____ JH-3 includes a summary of our updated DSM MPS for
2 JEA.

3
4 **Q. Please summarize the results of your analysis relative to EE?**

5 A. Our EE analysis based on JEA's updated economic information and load
6 forecast resulted in minor changes to the number of measures that passed the
7 economic screening for both the primary RIM scenario and the TRC
8 sensitivity. The updated set of passing measures resulted in EE cumulative
9 achievable potential of 0.01 MW in 2031, 0.02 MW in 2033, and 0.02 MW in
10 2035 for winter peak savings, and 0.06 MW in 2031, 0.07 MW in 2033, and
11 0.09 MW for summer peak savings.

12
13 These updated results indicate no material change in EE achievable potential
14 when compared with 2024 FEECA results. Detailed results for the EE analysis
15 are provided Exhibit No. ____ (JH-3).

16
17 **Q. Please summarize the results of your analysis for DR?**

18 A. Updating the DR analysis using the current avoided capacity cost forecast
19 resulted in additional DR measures passing the economic screening that
20 previously were not cost-effective in the 2024 JEA MPS. However, several
21 measures that are now cost-effective target the same equipment or end-use and
22 therefore need to be treated as competing rather than additive when calculating
23 aggregated DR achievable potential. In these situations, the measure that
24 contributed the highest demand savings was selected for inclusion in the
25 achievable potential.

1
2 Incorporating the current load forecast and avoided capacity cost assumptions,
3 and accounting for measure competition, three residential DR measures were
4 included in the updated achievable potential: HVAC Load Shed (switches);
5 Bring-Your-Own Smart Thermostats (BYOT); and Critical Peak Pricing. Two
6 small commercial measures were included in the achievable potential: central
7 air conditioning and heating load shed. The four DR measures analyzed for
8 large commercial and industrial customers were all cost-effective in the
9 updated analysis, however because they apply to the same target population
10 and peak loads, each measure is mutually exclusive of the others, and the
11 measure with the highest demand savings was included in the achievable
12 potential. The updated MPS resulted in DR achievable potential of 50.2 MW in
13 2031, 60.2 MW in 2033, and 68.0 MW for winter peak savings, and 49.3 MW
14 in 2031, 59.7 MW in 2033, and 67.9 MW in 2035 for the summer peak
15 savings.

16
17 Detailed results for the DR analysis are provided in Exhibit No. ____ (JH-3).

- 18
- 19 **Q. What were the main factors affecting the increased DR potential?**
- 20 A. The DR potential was impacted by both the increases in JEA's load forecast
21 and the increased avoided capacity cost estimate. Both updates resulted in
22 higher DR achievable potential than the 2024 JEA MPS, through a
23 combination of new load that could be utilized for DR and additional DR
24 measure opportunities that are now economically feasible.

25

1 **Q. In your opinion, is the DR potential shown on Exhibit __ (JH-3) reflective**
2 **of the DR practicably achievable by JEA?**

3 A. No. The DR potential shown on Exhibit No. ____ (JH-3) reflects maximum
4 achievable potential with respect to measure and program selection. It is not
5 reflective of what may be practicably achievable by JEA when taking program
6 delivery strategy into account. To further explain, the DR analysis included
7 several measures competing for the same load, and the achievable potential
8 included the measure in each competition group that contributed the highest
9 savings without regard for the practicality or overall utility strategy for
10 delivering DSM programs. For example, several measures compete for
11 residential space cooling load control. The measure with the highest savings,
12 HVAC load shed, is based on professional installation of a load control switch
13 on each customer's HVAC unit that is controlled by the utility. While these
14 switch programs have historically been implemented by other utilities, these
15 devices were more prevalent when other control technologies, such as smart
16 thermostats, were not in existence. Current DR programs offered by other
17 utilities have typically transitioned to leveraging newer and more advanced
18 technologies, such as smart thermostats, which are already installed in many
19 homes, can be installed by customers, and provide other customer benefits
20 such as improved comfort and energy efficiency savings throughout the year.
21 Therefore, while HVAC load shed provides the highest achievable potential,
22 there are likely practical reasons for JEA to select another DR measure for
23 program delivery that better aligns with customer preferences and overall DSM
24 program strategy.

25

1 **Q. In your opinion, are there conservation measures available to mitigate**
2 **JEA's need for SJRPP Unit 3?**

3 A. No. My understanding is that JEA's need is 72 MW beginning in 2031,
4 increasing to 222 MW in 2033, and 802 MW in 2035. Even assuming JEA
5 could practicably and cost-effectively realize the full achievable potential
6 shown on Exhibit No. ____ (JH-3), it falls well short of mitigating the need for
7 SJRPP Unit 3.

8

9 **Q. Does this complete your testimony?**

10 A. Yes.

Jim Herndon

Vice President

Jim Herndon is a Vice President in the Advisory Services group, focusing on strategic planning and program design to more effectively implement demand-side management (DSM) programs. His work is informed by 24 years of experience performing market assessments, planning portfolios, managing program design and implementation, conducting technical project reviews and analyses, and delivering third-party program evaluations across a variety of sectors. Jim leads potential and market characterization studies, program portfolio development and cost-effectiveness analyses, and provides regulatory support and expert witness testimony for program filings and integrated resource planning (IRP) activities. In these capacities, he serves many electric and natural gas utilities, including Duke Energy, Dominion Energy, Florida Power and Light, JEA, Santee Cooper, Columbia Gas of Virginia, and Washington Gas. In each consulting engagement, Jim strives to understand his client's objectives and tailor his team's analyses to leverage best practices, while providing strategic insights with the client's specific needs in mind.

EXPERIENCE

Vice President | Principal Consultant, Resource Innovations / Nexant (2013 - Present)

As an account executive and team leader in the Advisory Services Group, Jim ensures compliance with regulatory and energy program rules and coordinates staff workload and budgets. He works directly with clients, service providers, and customers to provide quality assurance on projects. Jim also manages regional and national client planning and benchmarking studies, as well as third-party impact and process evaluations.

Sr. Project Manager | Project Manager, Resource Innovations / Nexant (2007 - 2012)

As a Senior Project Manager and Southeast regional lead, Jim oversaw design and implementation of utility-sponsored DSM programs, including management of program design, administration, engineering, trade ally, and marketing program teams in NC and SC.

Sr. Project Engineer | Project Engineer, Resource Innovations / Nexant (2002 - 2006)

As a Project Engineer, Jim performed energy audits and analyses on facilities to identify, provide implementation support for, and verify the effectiveness of energy efficiency improvements. He was a Certified Home Energy Report (HERS) rater and supported the implementation of publicly funded energy efficiency and load management programs, including due diligence reviews of energy efficiency projects installed in California, New York, and Utah.

EDUCATION, CERTIFICATIONS, AND LICENSING

M.S. in Engineering Management - Duke University

B.S. in Civil and Environmental Engineering - Duke University

AFFILIATIONS

Southeast Energy Efficiency Alliance (SEEA) - Former Member of the Board of Directors (2014 - 2019)

AREAS OF EXPERTISE



Integrated Resource Planning (IRP) Support • Energy Analysis and Market Characterization • DSM & DER Market Potential Studies • Portfolio Planning, Program Design, and Evaluation • Regulatory Support and Expert Witness • Program Management

REPRESENTATIVE PROJECTS

Florida Power & Light Company - Florida Statewide DSM Technical Potential Study (2017 - 2019, and 2022 - 2024)

Jim led the Resource Innovations team that was retained by Florida Power & Light in the state of Florida to complete technical potential studies of Demand Side Management (DSM) measures and renewable energy systems on behalf of six utilities. The six electric utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA) include four Florida investor-owned utilities (IOUs): Florida Power & Light Company (FPL), Duke Energy Florida, LLC (DEF), Tampa Electric Company (TECO), and Florida Public Utilities Company (FPUC) that are regulated by the Florida Public Service Commission (FPSC) and two municipal utilities: JEA and Orlando Utilities Commission (OUC) that are not regulated by the FPSC. The FPSC establishes goals for the FEECA utilities to reduce the growth of Florida's peak electric demand and energy consumption and reviews the progress towards those goals frequently (every five years at a minimum). The scope of the studies included Energy Efficiency (EE), Demand Response (DR), and Distributed Energy Resources (DER) opportunities across the residential, commercial, and industrial sectors, including interaction between these categories of DSM to account for overlapping impacts. In addition to the technical potential analysis, Jim and his team assessed the economic and achievable opportunities for a subset of the six utilities. The results of this study were used as the basis of the utilities' DSM goal-setting process for 2025-2034 in the 2024 Florida Goals Proceeding. Following the completion of the studies, Jim provided regulatory support for these proceedings, including the preparation of direct written testimony, deposition, and support for the discovery process by preparing required responses to data requests and regulatory interrogatories.

Jim also led Resource Innovations' team that conducted the technical potential study and provided regulatory support for the 2019 FEECA goalsetting proceedings.

Duke Energy - Market Potential Studies (2015 - Present)

Jim has directed multiple DSM market potential studies for Duke Energy's North Carolina, South Carolina, Indiana, and Ohio service territories. The studies for each service territory integrated both energy efficiency and demand response opportunities across Duke Energy's residential, commercial, and industrial customer classes; and determined the technical, economic, and program potential. Resource Innovations conducts the studies in close coordination with Duke Energy's IRP team, as well as program design and delivery teams, to provide an accurate assessment of market potential that can be directly applied to Duke Energy's current and future DSM planning efforts.

Duke Energy - Program Evaluations (2014 - Present)

Jim currently serves as the Project Manager for the evaluation, measurement, and verification (EM&V) of six DSM program offerings, which include Duke Energy's Residential HVAC program, MyHER program, EE Education program, Save Energy & Water Kits program, Non-Residential Custom program, and Power Manager program. The evaluation activities include separate impact and process evaluations across Duke Energy's five service territories to assess program performance, adherence to best practices, and opportunities for program improvements. Jim provides daily project management oversight of project staff, coordination of resources, and quality control oversight of project deliverables.

Santee Cooper - Market Assessment, DSM Program Design, and Implementation (2009 - Present)



Jim provides strategic program design support activities for Santee Cooper's suite of energy efficiency programs across the residential and commercial market segments, as well as strategic program advisory services for Santee Cooper's long-term energy reduction goals. Jim also led the market assessment and market potential study that Resource Innovations conducted for Santee Cooper's service territory in 2019 as well as updated studies in 2023 and 2025. The 2019 study included primary data collection to benchmark equipment efficiency and saturation in the service territory and incorporate this data into the development of future market potential. Previously, Jim managed the initial development, rollout, and management of Santee Cooper's commercial energy efficiency programs.

Columbia Gas of Virginia (CVA) - DSM Program Design, Cost-Benefit Analysis, and Implementation (2010 - Present)

Jim is the technical lead for the program design and regulatory support services team assisting CVA's WarmWise program offerings. This support includes portfolio planning and regulatory support for CVA's residential and commercial energy efficiency programs, as well as providing rebate processing and other support services to assist CVA in the implementation of their programs. Jim led portfolio planning efforts, including market characterization analysis, technical analysis of proposed programs and portfolio, development of annual program budgets and savings targets, and regulatory support of CVA's program filings with the Virginia State Corporation Commission, including providing written testimony supporting the analysis.

Dominion Energy - DSM Program Design and Implementation (2020 - Present)

Jim oversees DSM portfolio planning and program design projects for Dominion Energy's natural gas utilities in North Carolina, South Carolina, and Ohio. In each of these service territories, Jim and his team worked collaboratively with Dominion Energy to identify applicable DSM measures, quantify measure impacts, create logical program offerings, and analyze the cost-effectiveness of the offerings. Jim also supported the DSM regulatory process in each jurisdiction through the development of expert witness testimony and assistance with responses to regulatory data requests.

Virginia Natural Gas - DSM Program Design, Cost-Benefit Analysis, and Regulatory Support (2014 - Present)

On behalf of Virginia Natural Gas, Jim leads technical and regulatory support for the residential DSM portfolio. Support activities include program cost-effectiveness analysis and preparation of regulatory filings including annual status updates to the Virginia State Corporation Commission, and technical analysis and testimony for regulatory approval of program updates and modifications.

Georgia Power Company - DSM Program Analysis and IRP Support (2005 - 2019)

Jim provided technical and regulatory support for Georgia Power Company's DSM program analysis in the residential and commercial markets for their 2007, 2010, 2013, 2016, and 2019 IRP filings. The program analysis support included comprehensive compilation and assessment of applicable DSM measures and technologies across the residential, commercial, and industrial sectors, as well as the determination of the overall market potential through four separate technical potential studies (completed in 2007, 2012, 2015, and 2018). Jim also led the portfolio planning efforts that included developing preliminary program designs, savings targets, and budgets, along with supporting cost-effectiveness analysis to determine the feasibility of individual measures and program offerings for implementation.

Elizabethtown Gas - DSM Program Design and Regulatory Support (2016 - 2018)

In support of Elizabethtown Gas, Jim led technical and regulatory support to develop updated DSM program offerings for residential and commercial customers. He worked collaboratively with



Elizabethtown Gas to develop cost-beneficial programs for eligible customers. Activities included program cost-effectiveness analysis and testimony preparation for regulatory program filing with the New Jersey Board of Public Utilities.

Dominion Virginia Power - Program Development and Regulatory Support (2014 - 2016)

Jim served as the program design lead and expert witness in support of Dominion Virginia Power's regulatory filing for three proposed DSM program offerings. He provided input on the delivery structure, eligibility criteria, and cost-effectiveness analysis in the development of program offerings. Additionally, Jim provided written and oral testimony on behalf of Dominion Virginia Power in support of the technical analysis on the feasibility and cost-effectiveness of the programs to the Virginia State Corporation Commission.

Los Angeles Department of Water and Power (LADWP) - Energy Efficiency Potential Study (2013 - 2015)

Jim managed the development of an energy efficiency potential study for the LADWP. Under his direction, his team quantified the energy efficiency potential for LADWP's service territory, including collection of primary data through facility auditing to determine the energy efficiency potential of facilities owned by the City of Los Angeles. The study followed industry best practices to determine energy efficiency potential and undertook unique approaches to aggregate and bundle measures into program delivery channels to identify all possible achievable savings. The study informed LADWP's short-term program planning, as well as updates to their 10-year program planning targets.

CPS Energy - Market Potential Study, DSM Program Design, and M&V (2008 - 2014)

Jim provided technical expertise and support for DSM services to CPS Energy, which included: developing an energy efficiency market potential study, designing, and implementing DSM programs, and performing program measurement and verification (M&V). The comprehensive market potential study analyzed the economic and achievable energy and demand impacts of cost-effective DSM measures across CPS Energy's residential, commercial, and industrial customer segments. The program design utilized the identified market potential to enhance CPS Energy's existing DSM programs and provided recommendations on new programs that target CPS Energy's long-term energy efficiency goals. Jim and his team also provided annual M&V of CPS Energy's DSM programs.

Danville Utilities - Residential Program Design and Implementation (2011 - 2013)

Jim led the initial development of Danville Utilities' Home\$ave program in Virginia. This residential program initiative included a suite of energy efficiency measures targeting Danville's residential customer base. Jim managed the rollout of the program offering that included rebate processing, trade ally outreach, marketing support, and verification of measure installation and achieved energy savings.

CONFERENCE PRESENTATIONS

Herndon, J. (2023). "Foundations of Energy Efficiency: Program Planning & Delivery", Southeast Energy Summit, October 2023, Atlanta, GA.

Herndon, J.; Jacot, D. (2015). "LADWP EE Potential Study: Innovative Approach to Achievable Potential," International Energy Program Evaluation Conference (IEPEC), August 2015, Long Beach, CA.



Technical Potential Study of Demand Side Management

JEA

Date: 03.07.2024

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Executive Summary

In October 2022, the six electric utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA Utilities) retained Resource Innovations, Inc. for the purpose of identifying and characterizing the market for demand-side management (DSM) opportunities, including energy efficiency (EE) improvement and building retrofits, peak load reductions from demand response (DR), and demand-side renewable energy (DSRE) systems.

The main objective of the study was to assess the technical potential of demand-side resources for reducing customer electric energy consumption and seasonal peak capacity demands.

This report provides the detailed methodology and results for the technical potential analysis of JEA's service territory.

1.1 Methodology

Resource Innovations estimates DSM savings potential by applying an analytical framework that aligns baseline market conditions for energy consumption and demand with DSM opportunities. After describing the baseline condition, Resource Innovations applies estimated measure savings to disaggregated consumption and demand data. The approach varies slightly according to the type of DSM resources and available data; the specific approaches used for each type of DSM are described below.

1.1.1 EE Potential

This study utilized Resource Innovations' proprietary EE modeling tool, TEA-POT (Technical / Economic / Achievable POTential). This modeling tool was built on a platform that provides the ability to create and analyze multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual program savings. The methodology for the EE potential assessment was based on a hybrid "top-down/bottom-up" approach, which started with the current utility load forecast, then disaggregated it into its constituent customer-class and end-use components. Our assessment examined the effect of the range of EE measures and practices on each end-use, taking into account current market saturations, and technical feasibility. These unique impacts were aggregated to produce estimates of potential at the end-use, customer class, and system levels for JEA.

1.1.2 DR Potential

The assessment of DR potential in JEA's service territory was an analysis of mass market direct load control programs for residential and small commercial and industrial (C&I) customers, and an analysis of DR programs for large C&I customers. The direct load control program assessment focused on the potential for demand reduction through heating, ventilation, and air conditioning (HVAC), water heater, managed electric vehicle charging, and pool pump load control. These end-uses were of particular interest because of their large contribution to peak period system load. For this analysis, a range of direct load control measures were examined for each customer segment to highlight the range of potential. The assessment further accounted for existing DR programs for JEA when calculating the total DR potential.

1.1.3 DSRE Potential

The DSRE technologies included in this study are rooftop solar photovoltaic (PV) systems, battery storage systems charged from customers' PV systems, and combined heat and power (CHP) systems. The study leveraged the customer segmentation and load disaggregation data assembled for the EE and DR analyses, and applied our DSRE model, SPIDER™ (Spatial Penetration and Integration of Distributed Energy Resources), for economic and adoption analysis of solar and battery storage. This model dynamically responds to rapidly changing technologies and accounts for all key time-varying elements such as technology costs, incentives, tax credits, and electric rates. To estimate technical potential for CHP, the study utilized a series of unique distributed generation potential models for each primary market sector (commercial and industrial), calculating the average building consumption, assigning minimum facility size thresholds, and estimating building energy savings share percentage for each CHP technology based on its generation capacity.

1.2 Savings Potential

Technical potential for EE, DR, and DSRE are as follows:

1.2.1 EE Potential

EE technical potential describes the savings potential when all technically feasible EE measures are fully implemented, ignoring all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt EE.

The estimated EE technical potential results are summarized in Table 1.

Table 1. EE Technical Potential

	Savings Potential		
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Energy (GWh)
Residential	517	297	1,887
Non-Residential¹	280	251	1,690
Total	797	548	3,577

1.2.2 DR Potential

DR technical potential describes the magnitude of loads that can be managed during conditions when grid operators need peak capacity. For residential and small C&I customers where DR generally takes the form of direct utility control, technical potential for DR is limited by the loads that can be controlled remotely at scale such as heating, cooling, water heaters, managed electric vehicle charging, and pool pumps. For large C&I customers, this included their entire electric demand during a utility's system peak, as many of these types of customers will forego virtually all electric demand temporarily if the financial incentive is large enough.

The estimated DR technical potential results are summarized in Table 2.

Table 2. DR Technical Potential

	Savings Potential	
	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Residential	443	1,451
Non-Residential	673	578
Total	1,116	2,029

¹ Non-Residential results include all commercial and industrial customer segments.

1.2.3 DSRE Potential

DSRE technical potential estimates quantify all technically feasible distributed generation opportunities from PV systems, battery storage systems charged from PV, and CHP technologies based on the customer characteristics of JEA's customer base.

The estimated DSRE technical potential results are summarized in Table 3.

Table 3. DSRE Technical Potential²

	Savings Potential		
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Energy (GWh)
PV Systems			
Residential	493	19	4,146
Non-Residential	214	3	1,617
Total	707	22	5,763
Battery Storage charged from PV Systems			
Residential	304	557	0
Non-Residential	0	158	0
Total	304	715	0
CHP Systems			
Total	397	359	1,811

² PV systems and CHP systems were independently analyzed for technical potential without consideration of the competition between technologies or customer preference for DSRE system.

2 Introduction

In October, 2022, the six electric utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA Utilities) retained Resource Innovations, Inc. for the purpose of identifying and characterizing the market for demand-side management (DSM) opportunities, including energy efficiency (EE) improvement and building retrofits, peak load reductions from demand response (DR), and demand-side renewable energy (DSRE) systems. The main objective of the study was:

- Assessing the technical potential of demand-side resources for reducing customer electric energy consumption and seasonal peak capacity demands.

This report provides the detailed methodology and results for the technical potential analysis of JEA's service territory.

The following deliverables were developed by Resource Innovations as part of the project and are addressed in this report:

- DSM measure list and detailed assumption workbooks
- Disaggregated baseline demand and energy use by year, sector, and end-use
- Baseline technology saturations, energy consumption, and demand
- Technical potential demand and energy savings
- Supporting calculation spreadsheets

2.1 Technical Potential Study Approach

Resource Innovations estimates technical potential according to the industry standard categorization, as follows:

Technical Potential is the theoretical maximum amount of energy and capacity that could be displaced by DSM, regardless of cost and other barriers that may prevent the installation or adoption of a DSM measure.

For this study, technical potential included full application of commercially available DSM technologies to all residential, commercial, and industrial customers in the utility's service territory.

Quantifying DSM technical potential is the result of an analytical process that refines DSM opportunities that align with JEA's customers' electric consumption patterns. Resource Innovations' general methodology for estimating technical potential is a hybrid "top-

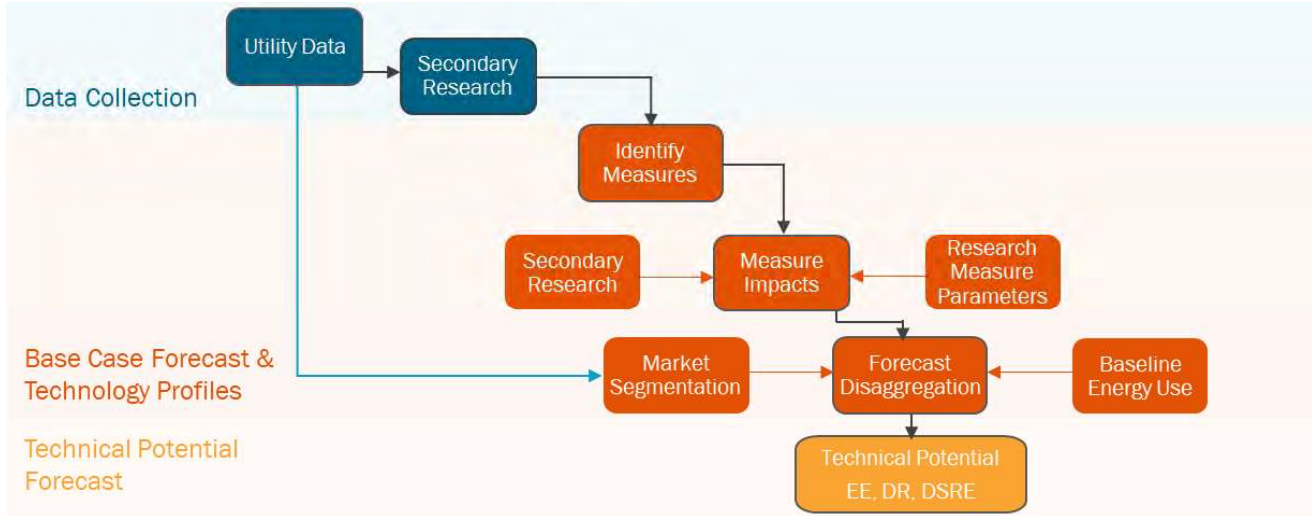
Introduction

down/bottom-up” approach, which is described in detail in Sections 3 through 5 of this report and includes the following steps:

- Develop a baseline forecast: the study began with a disaggregation of the utility’s official electric energy forecast to create a baseline electric energy forecast. This forecast does not include any utility-specific assumptions around DSM performance. Resource Innovations applied customer segmentation and consumption data from each utility and data from secondary sources to describe baseline customer-class and end-use components. Additional details on the forecast disaggregation are included in Section 3.
- Identify DSM opportunities: A comprehensive set of DSM opportunities applicable to JEA’s climate and customers were analyzed to best depict DSM technical potential. Effects for a range of DSM technologies for each end-use could then be examined while accounting for current market saturations, technical feasibility, and impacts.
- Collect cost and impact data for measures: For those measures applicable to JEA’s customers, Resource Innovations conducted primary and secondary research and estimated costs, energy savings, measure life, and demand savings. We differentiated between the type of cost (capital, installation labor, maintenance, etc.) to separately evaluate different implementation modes: retrofit (capital plus installation labor plus incremental maintenance); new construction (incremental capital and incremental maintenance); and burnout costs (incremental capital and incremental maintenance costs for replacement of appliances and equipment that has reached the end of its useful life). Additional details on measure development are included in Section 4.

Figure 1 provides an illustration of the technical potential modeling process conducted for JEA, with the assessment starting with the current utility load forecast, disaggregated into its constituent customer-class and end-use components, and calibrated to ensure consistency with the overall forecast. Resource Innovations considered the range of DSM measures and practices application to each end-use, accounting for current market saturations, and technical feasibility. These unique impacts were aggregated to produce estimates of potential at the technology, end-use, customer class, and system levels.

Figure 1. Approach to Technical Potential Modeling



Resource Innovations estimated DSM technical potential based on a combination of market research, utility load forecasts and customer data, and measure impact analysis, all in coordination with JEA. Resource Innovations examined the technical potential for EE, DR, and DSRE opportunities; this report is organized to offer detail on each DSM category, with additional details on technical potential methodology presented in Section 5.

2.2 EE Potential Overview

To estimate EE potential, this study utilized Resource Innovations' modeling tool, TEA-POT (Technical / Economic / Achievable POTential). This modeling tool was built on a platform that provides the ability to create and analyze multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual utility program savings, as described in Section 5.1.1 below. While the analysis estimates the impacts of individual EE measures, the model accounts for interactions and overlap of individual measure impacts within an end-use or equipment type. The model provides transparency into the assumptions and calculations for estimating EE potential.

2.3 DR Potential Overview

To estimate DR market potential, Resource Innovations considered customer demand during utility peaking conditions and projected customer response to DR measures. Customer demand was determined by looking at segment-level interval data for each customer segment. For each segment, Resource Innovations determined the portion of a customer's load that could be curtailed during the system peak.

2.4 DSRE Potential Overview

The DSRE technologies included in this study are rooftop solar photovoltaic (PV) systems, battery storage systems charged from PV, and combined heat and power (CHP) systems. The study leveraged the customer segmentation and load disaggregation data assembled for the EE and DR analyses, and applied our DSRE model, SPIDER™ (Spatial Penetration and Integration of Distributed Energy Resources), for economic and adoption analysis of solar and battery storage. This model dynamically responds to rapidly changing technologies and accounts for all key time-varying elements such as technology costs, incentives, tax credits, and electric rates. To estimate technical potential for CHP, the study utilized a series of unique distributed generation potential models for each primary market sector (commercial and industrial), calculating the average building consumption, assigning minimum facility size thresholds, and estimating building energy savings share percentage for each CHP technology based on its generation capacity.

3 Baseline Forecast Development

3.1 Market Characterization

The JEA base year energy use and sales forecast provided the reference point to determine potential savings. The end-use market characterization of the base year energy use and reference case forecast included customer segmentation and load forecast disaggregation. The characterization is described in this section, while the subsequent section addresses the measures and market potential energy and demand savings scenarios.

3.1.1 Customer Segmentation

In order to estimate EE, DR, and DSRE potential, the sales forecast and peak load forecasts were segmented by customer characteristics. As electricity consumption patterns vary by customer type, Resource Innovations segmented customers into homogenous groups to identify which customer groups are eligible to adopt specific DSM technologies, have similar building characteristics and load profiles, or are able to provide DSM grid services.

Resource Innovations segmented customers according to the following:

- 1) By Sector - how much of JEA's energy sales, summer and winter peak demand forecast is attributable to the residential, commercial, and industrial sectors?
- 2) By Customer - how much electricity does each customer typically consume annually and during system peaking conditions?
- 3) By End-Use - within a home or business, what equipment is using electricity during the system peak? How much energy does this end-use consume over the course of a year?

Table 4 summarizes the segmentation within each sector. In addition to the segmentation described here for the EE and DSRE analyses, the residential customer segments were further segmented by heating type (electric heat, gas heat, or unknown) and by annual consumption bins within each sub-segment for the DR analysis.

Baseline Forecast Development

Table 4. Customer Segmentation

Residential	Commercial		Industrial	
Single Family	Assembly	Miscellaneous	Agriculture and Assembly	Primary Resources Industries
Multi-Family	College and University	Offices	Chemicals and Plastics	Stone/Glass/Clay/Concrete
Manufactured Homes	Grocery	Restaurant	Construction	Textiles and Leather
	Healthcare	Retail	Electrical and Electronic Equipment	Transportation Equipment
	Hospitals	Schools K-12	Lumber/Furniture/Pulp/Paper	Water and Wastewater
	Institutional	Warehouse	Metal Products and Machinery	Other
	Lodging/Hospitality		Miscellaneous Manufacturing	

From an equipment and energy use perspective, each segment has variation within each building type or sub-sector. For example, the energy consuming equipment in a convenience store will vary significantly from the equipment found in a supermarket. To account for this variation, the selected end-uses describe energy consumption patterns that are consistent with those typically studied in national or regional surveys, such as the U.S. Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS), Commercial Building Energy Consumption Survey (CBECS) and Manufacturing Energy Consumption Survey (MECS), among others. The end-uses selected for this study are listed in Table 5.

Table 5. End-Uses

Residential End-Uses	Commercial End-Uses	Industrial End-Uses
Space heating ³	Space heating ³	Process heating
Space cooling ³	Space cooling ³	Process cooling
Domestic hot water	Domestic hot water	Compressed air
Ventilation and circulation	Ventilation and circulation	Motors/pumps

³ Includes the contribution of building envelope measures and efficiencies.

Baseline Forecast Development

Residential End-Uses	Commercial End-Uses	Industrial End-Uses
Lighting	Interior lighting	Fan, blower motors
Cooking	Exterior lighting	Process-specific
Appliances	Cooking	Industrial lighting
Electronics	Refrigeration	Exterior lighting
Miscellaneous	Office equipment	HVAC ³
	Miscellaneous	Other

For DR, the end-uses targeted were those with controllable load for residential customers (i.e., HVAC, water heaters, pool pumps, and electric vehicles) and small C&I customers (HVAC and electric vehicles). For large C&I customers, all load during peak hours was included assuming these customers would potentially be willing to reduce electricity consumption for a limited time if offered a large enough incentive during temporary system peak demand conditions.

3.1.2 Forecast Disaggregation

A common understanding of the assumptions and granularity in the baseline load forecast was developed with input from JEA. Key discussion topics reviewed included:

- How current DSM offerings are reflected in the energy and demand forecast.
- Assumed weather conditions and hour(s) of the day when the system is projected to peak.
- Are there portions of the load forecast attributable to customers or equipment not eligible for DSM programs?
- How are projections of population increase, changes in appliance efficiency, and evolving distribution of end-use load shares accounted for in the peak demand forecast?

3.1.2.1 Electricity Consumption (kWh) Forecast

Resource Innovations segmented JEA's electricity consumption forecast into electricity consumption load shares by customer class and end-use. The baseline customer segmentation represents the electricity market by describing how electricity was consumed within the service territory. Resource Innovations developed the forecast for the year 2025, and based it on data provided by JEA, primarily their 2023 Ten-Year Site Plan, which was the most recent plan available at the time the studies were initiated. The data addressed current baseline consumption, system load, and sales forecasts.

Baseline Forecast Development

3.1.2.2 Peak Demand (kW) Forecast

A fundamental component of DR potential was establishing a baseline forecast of what loads or operational requirements would be absent due to existing dispatchable DR or time varying rates. This baseline was necessary to assess how DR can assist in meeting specific planning and operational requirements. We utilized JEA's summer and winter peak demand forecast, which was developed for system planning purposes.

3.1.2.3 Estimating Consumption by End-Use Technology

As part of the forecast disaggregation, Resource Innovations developed a list of electricity end-uses by sector (Table 5). To develop this list, Resource Innovations began with JEA's estimates of average end-use consumption by customer and sector. Resource Innovations combined these data with other information, such as utility residential appliance saturation surveys, as available, to develop estimates of customers' baseline consumption. Resource Innovations calibrated the utility-provided data with data available from public sources, such as the EIA's recurring data-collection efforts that describe energy end-use consumption for the residential, commercial, and manufacturing sectors.

To develop estimates of end-use electricity consumption by customer segment and end-use, Resource Innovations applied estimates of end-use and equipment-type saturation to the average energy consumption for each sector. The following data sources and adjustments were used in developing the base year 2025 sales by end-use:

Residential Sector:

- The disaggregation was based on JEA's rate class load shares and intensities.
- Baseline intensity was calibrated to account for differences in end-use saturation, fuel source, and equipment saturation as follows:
 - JEA rate class load share is based on average per customer.
 - Resource Innovations made conversions to usage estimates generated by applying JEA's 2020 Appliance Saturation Study (APSS) report, EIA RECS data, residential end-use study data from other FEECA utilities, and EIA's Annual Energy Outlook (AEO) 2023.

Commercial Sector:

- The disaggregation was based on JEA's rate class load shares, intensities, and EIA CBECS data.
- Segment data from EIA and JEA.

Baseline Forecast Development

- Baseline intensity was calibrated to account for differences in end-use saturation, fuel source, and equipment saturation as follows:
 - Rate class load share based on EIA CBECS and end-use forecasts from JEA.

Industrial Sector:

- The disaggregation was based on rate class load shares, intensities, and EIA MECS data.
- Segment data from EIA and JEA.
- Baseline intensity was calibrated to account for differences in end-use saturation, fuel source, and equipment saturation as follows:
 - Rate class load share based on EIA MECS and end-use forecasts from JEA.

3.2 Analysis of Customer Segmentation

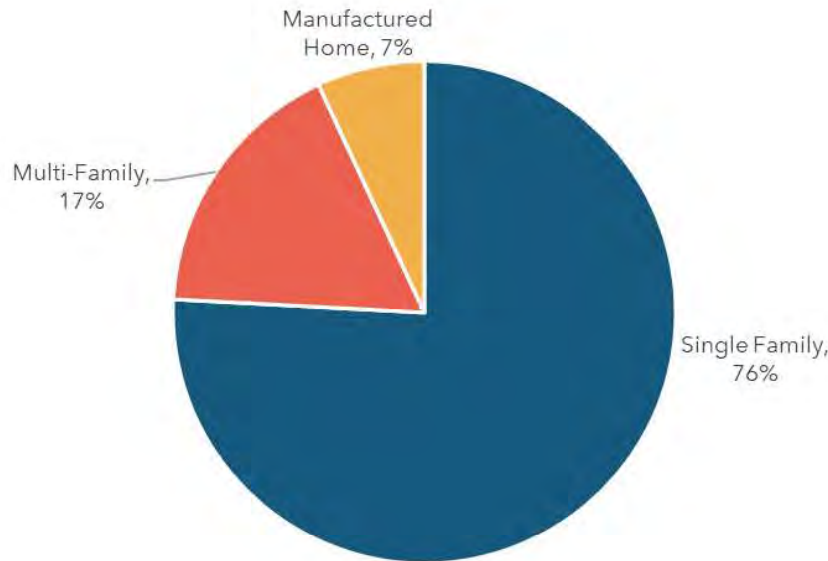
Customer segmentation is important to ensuring that a MPS examines DSM measure savings potential in a manner that reflects the diversity of energy savings opportunities existing across the utility's customer base. JEA provided Resource Innovations with data concerning the premise type and loads characteristics for all customers for the MPS analysis. Resource Innovations examined the provided data from multiple perspectives to identify customer segments. Resource Innovations' approach to segmentation varied slightly for non-residential and residential accounts, but the overall logic was consistent with the concept of expressing the accounts in terms that were relevant to DSM opportunities.

3.2.1 Residential Customers (EE, DR, and DSRE Analysis)

Segmentation of residential customer accounts enabled Resource Innovations to align DSM opportunities with appropriate DSM measures. Resource Innovations used utility customer data, supplemented with EIA data, to segment the residential sector by customer dwelling type (single family, multi-family, or manufactured home). The resulting distribution of customers according to dwelling unit type is presented in Figure 2.

Baseline Forecast Development

Figure 2. Residential Customer Segmentation



3.2.2 Non-Residential (Commercial and Industrial) Customers (EE and DSRE Analysis)

For the EE and DSRE analysis, Resource Innovations segmented C&I accounts using the utility's North American Industry Classification System (NAICS) or Standard Industrial Classification (SIC) codes, supplemented by data produced by the EIA's CBECS and MECS. Resource Innovations classified the customers in this group as either commercial or industrial, on the basis of DSM measure information available and applicable to each. For example, agriculture and forestry DSM measures are commonly considered industrial savings opportunities. Resource Innovations based this classification on the types of DSM measures applicable by segment, rather than on the annual energy consumption or maximum instantaneous demand from the segment as a whole. The estimated energy sales distributions Resource Innovations applied are shown below in Figure 3 and Figure 4.

Baseline Forecast Development

Figure 3. Commercial Customer Segmentation

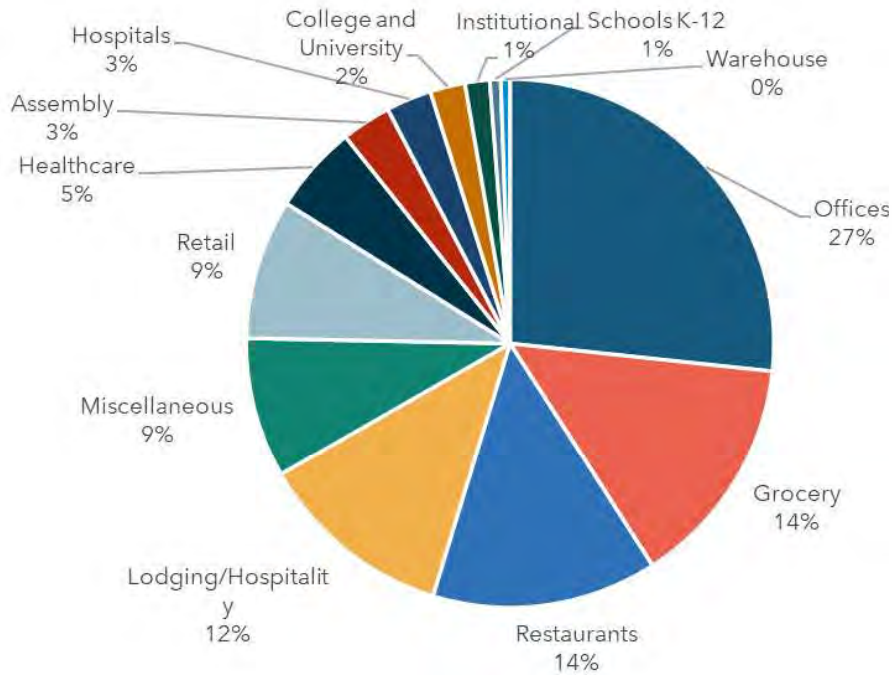
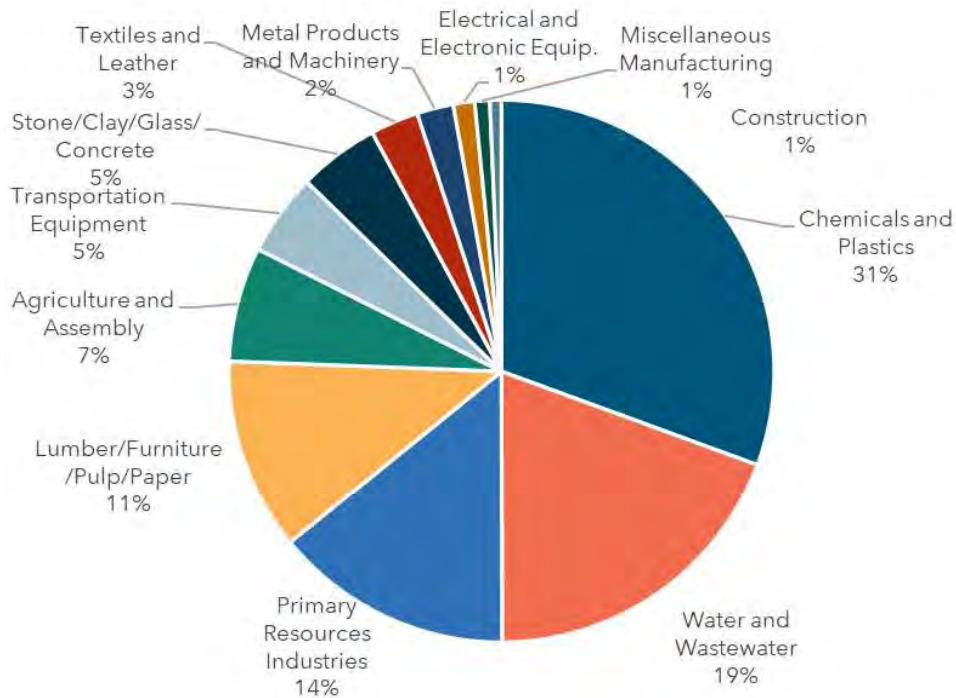


Figure 4. Industrial Customer Segmentation



Baseline Forecast Development

3.2.3 Commercial and Industrial Accounts (DR Analysis)

For the DR analysis, Resource Innovations divided the non-residential customers into the two customer classes of small C&I and large C&I using rate class and annual consumption. For the purposes of this analysis, small C&I customers are those on the General Service (GS) tariff. Large C&I customers are all customers on the General Service Demand (GSD) tariff or on the General Service Large Demand (GSLD) tariff. Resource Innovations further segmented these two groups based on customer size. For small C&I, segmentation was determined using annual customer consumption and for large C&I the customer's maximum demand was used. Both customer maximum demand and customer annual consumption were calculated using billing data provided by JEA.

Table 6 shows the account breakout between small C&I and large C&I.

Table 6. Summary of Customer Classes for DR Analysis

Customer Class	Annual kWh	Estimated Number of Accounts
Small C&I	0-15,000 kWh	32,188
	15,001-25,000 kWh	6,347
	25,001-50,000 kWh	1,131
	50,001 kWh +	13,802
	Total	53,468
Large C&I	0-50 kW	331
	51-300 kW	3,842
	301-500 kW	8
	501 kW +	153
	Total	4,334

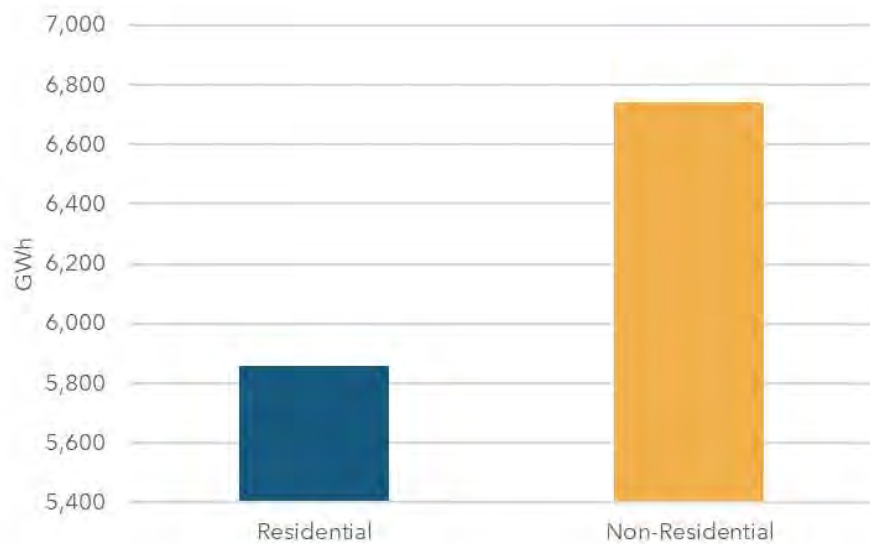
Baseline Forecast Development

3.3 Analysis of System Load

3.3.1 System Energy Sales

Technical potential is based on JEA's load forecast for the year 2025 from their 2023 Ten Year Site Plan, which is illustrated in Figure 5.

Figure 5. 2025 Electricity Sales Forecast by Sector



3.3.2 System Demand

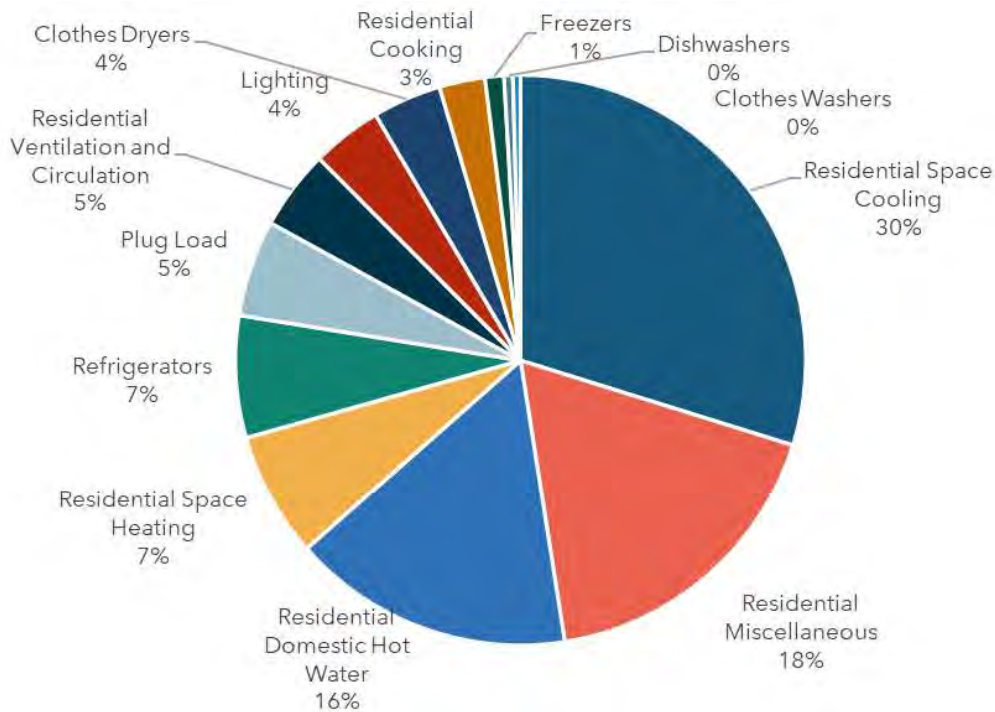
To determine the technical potential for DR, Resource Innovations first established peaking conditions for each utility by looking at when each utility historically experienced its maximum demand. The primary data source used to determine when maximum DR impact was the historical system load for JEA. The data provided contained the system loads for all 8,760 hours of the most recent five years leading up to the study (2016-2021). The utility summer and winter peaks were then identified within the utility-defined peaking conditions. For JEA the summer peaking conditions were defined as August from 4:00-5:00 PM and the winter peaking conditions were defined as January from 7:00-8:00 AM. The seasonal peaks were then selected as the maximum demand during utility peaking conditions.

Baseline Forecast Development

3.3.3 Load Disaggregation

The disaggregated annual electric loads⁴ for the base year 2025 by sector and end-use are summarized in Figure 6, Figure 7, and Figure 8.

Figure 6. Residential Baseline (2025) Energy Sales by End-Use



⁴ Full disaggregation of system demand by end-use was not conducted, as DR potential for residential and small C&I customers focused on specific end-uses of particular interest because of their large contribution to peak period system load, and was not end-use specific for large C&I customers. A description of the end-use analysis for residential and small C&I customers is included in Section 5.1.2

Baseline Forecast Development

Figure 7. Commercial Baseline (2025) Energy Sales by End-Use

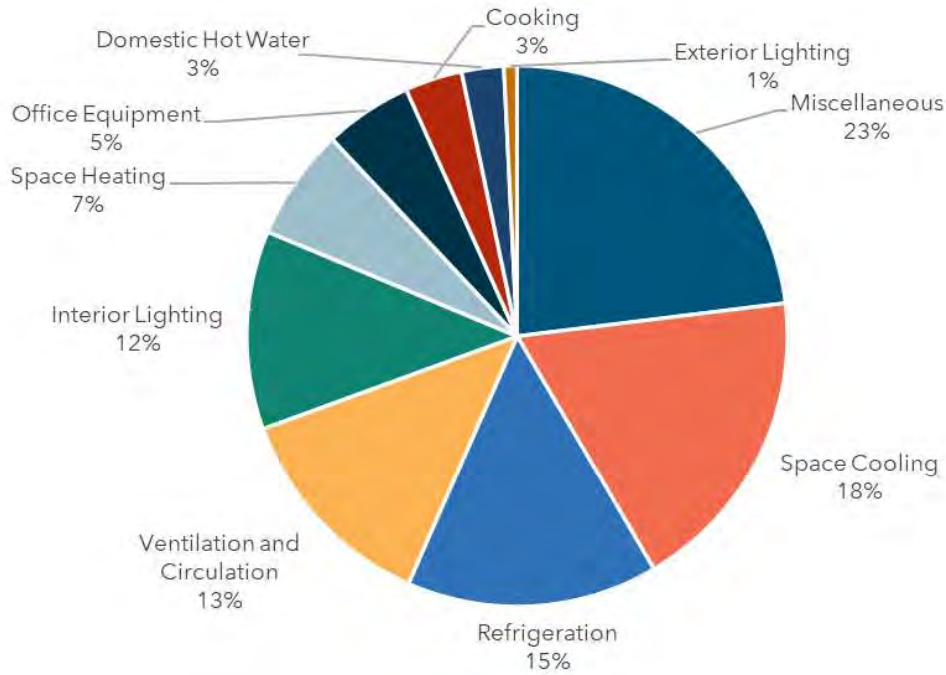
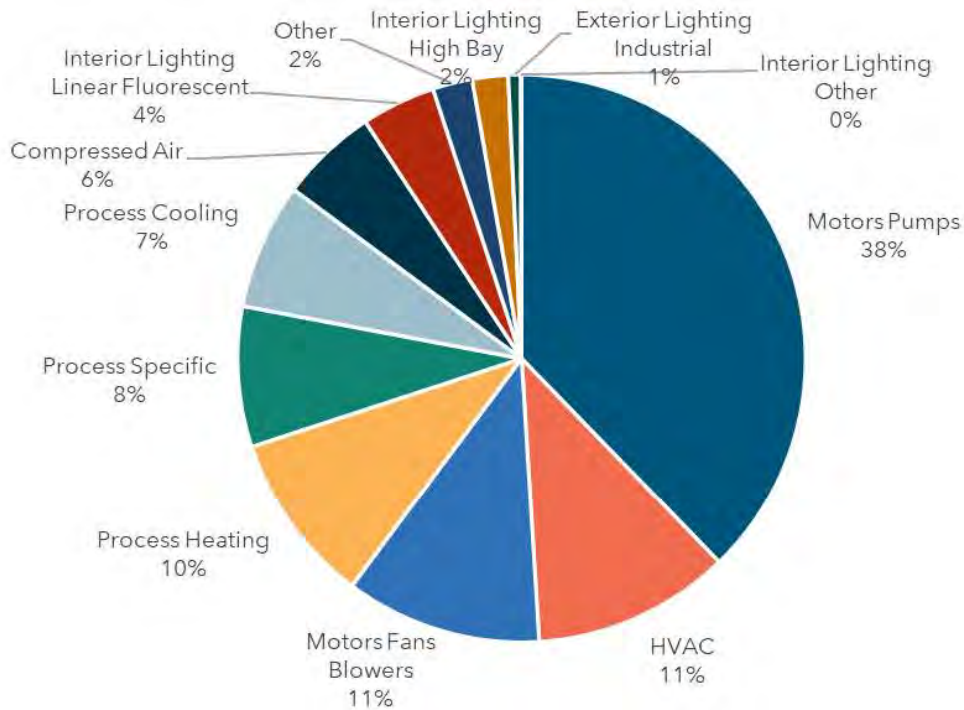


Figure 8. Industrial Baseline (2025) Energy Sales by End-Use



4 DSM Measure Development

DSM potential is described by comparing baseline market consumption with opportunities for savings. Describing these individual savings opportunities results in a list of DSM measures to analyze. This section presents the methodology to develop the EE, DR, and DSRE measure lists.

4.1 Methodology

Resource Innovations identified a comprehensive catalog of DSM measures for the study. The measure list is the same for all FEECA Utilities. The iterative vetting process with the utilities to develop the measure list began by initially examining the list of measures included in the 2019 Goals docket. This list was then adjusted based on proposed measure additions and revisions provided by the FEECA Utilities. Resource Innovations further refined the measure list based on reviews of Resource Innovations' DSM measure library, compiled from similar market potential studies conducted in recent years throughout the United States, as well as measures included in other utility programs where Resource Innovations is involved with program design, implementation, or evaluation. The FEECA Utilities also reached out to interested parties and received input with recommendations on measure additions to the 2019 measure list. Their measure suggestions were reviewed and incorporated into the study as appropriate. External measure suggestions and actions are summarized in Appendix D. The extensive, iterative review process involving multiple parties has ensured that the study included a robust and comprehensive set of DSM measures.

See Appendix A for the list of EE measures, Appendix B for the list of DR measures, and Appendix C for the list of DSRE measures analyzed in the study.

4.2 EE Measures

EE measures represent technologies applicable to the residential, commercial, and industrial customers in the FEECA Utilities' service territories. The development of EE measures included consideration of:

- EE technologies that are applicable to Florida and commercially available: Measures that are not applicable due to climate or customer characteristics were excluded, as were "emerging" technologies that are not currently commercially available to FEECA utility customers.
- Current and planned Florida Building Codes and Federal equipment standards (Codes & Standards) for baseline equipment: Measures included from prior studies

DSM Measure Development

were adjusted to reflect current Codes & Standards as well as updated efficiency tiers, as appropriate.

- Eligibility for utility DSM offerings in Florida: For example, behavioral measures were excluded from consideration, as they historically have not been allowed to count towards utility DSM goals. Behavioral measures are intended to motivate customers to operate in a more energy-efficient manner (e.g., setting an air-conditioner thermostat to a higher temperature) without accompanying: a) physical changes to more efficient end-use equipment or to their building envelope, b) utility-provided products and tools to facilitate the efficiency improvements, or c) permanent operational changes that improve efficiency which are not easily revertible to prior conditions. These types of behavioral measures were excluded because of the variability in forecasting the magnitude and persistence of energy and demand savings from the utility's perspective. Additionally, decoupling behavioral measure savings from the installation of certain EE technologies like smart thermostats can be challenging and could result in overlapping potential with other EE measures included in the study.

Upon development of the final EE measure list, utility-specific measure details were developed. RI maintains a proprietary online database of energy efficiency measures for MPS studies, which was used as a starting point for measure development for this study. Measures are added or updated at the request of project stakeholders or because of changes to the EE marketplace (for example, new codes and standards, or current practice in the market). Measure data are refined as new data or algorithms are developed for estimating measure impacts, and updated for each study to incorporate inputs parameters specific to the service territory being analyzed. The database contains the following information for each of the measures:

- Measure description: measure classification by type, end-use, and subsector, and description of the base-case and the efficient-case scenarios.
- kWh savings: Energy savings associated with each measure were developed through engineering algorithms or building simulation modeling, taking climate data and customer segments into consideration as appropriate. Reference sources used for developing residential, commercial, and industrial measure savings included a variety of Florida-specific, as well as regional and national sources, such as utility-specific measurement & verification (M&V) data, technical reference manuals (TRM) from other jurisdictions, ENERGY STAR calculators, and manufacturer or retailer specifications for particular products.
- Energy savings were applied in RI's TEA-POT model as a percentage of total baseline consumption. Peak demand savings were determined using utility-specific load shapes or coincidence factors.

DSM Measure Development

- Measure Expected Useful Lifetime: Sources included the Database for Energy Efficient Resources (DEER), the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) Handbook, TRMs, and other regional and national measure databases and EE program evaluations.
- Measure Costs: Per-unit costs (full or incremental, depending on the application) associated with measure installations. Sources included: TRMs, ENERGY STAR calculator, online market research, FEECA utility program data, and other secondary sources.

The measure details from the online measure library are exported for use in RI's TEA-POT model, accompanied by utility-specific estimates of measure applicability. Measure applicability is a general term encompassing an array of factors, including technical feasibility of installation, and the measure's current saturation as well as factors to allocate savings associated with competing measures. Information used was primarily derived from data in current regional and national databases, as well as JEA's program tracking data. These factors are described in Table 7.

Table 7. Measure Applicability Factors

Measure Impact	Explanation	Sources
Technical Feasibility	The percentage of buildings that can have the measure physically installed. Various factors may affect this, including, but not limited to, whether the building already has the baseline measure (e.g., dishwasher), and limitations on installation (e.g., size of unit and space available to install the unit).	Various secondary sources and engineering experience.
Measure Incomplete Factor	The percentage of buildings without the specific measure currently installed.	Utility RASS; EIA RECS, CBECS; MECS; ENERGY STAR sales figures; and engineering experience.
Measure Share	Used to distribute the percentage of market shares for competing measures (e.g., only blown-in ceiling insulation or spray foam insulation, not both would be installed in an attic).	Utility customer data, Various secondary sources and engineering experience.

As shown in Table 8, the measure list includes 395 unique energy-efficiency measures. Expanding the measures to account for all appropriate installation scenarios resulted in

DSM Measure Development

9,535 measure permutations, which are the application of individual measures to various customer segments, construction types, and end-uses (i.e., a single air-source heat pump “measure” can be installed in single family, multi-family, and manufactured homes, as well as new and existing vintages of each home type, and impacts both space cooling and space heating end-uses, resulting in twelve separate measure “permutations” analyzed).

Table 8. EE Measure Counts by Sector

Sector	Unique Measures	Permutations
Residential	119	1,173
Commercial	164	5,798
Industrial	112	2,564

4.3 DR Measures

The DR measures included in the measure list utilize the following DR strategies:

- **Direct Load Control.** Utility control of selected equipment at the customer’s home or business, such as HVAC or water heaters.
- **Critical Peak Pricing (CPP) with Technology.** Electricity rate structures that vary based on time of day. Includes CPP when the rate is substantially higher for a limited number of hours or days per year (customers receive advance notification of CPP event) coupled with technology that enables customer to lower their usage in a specific end-use in response to the event (e.g., HVAC via smart thermostat).
- **Contractual DR.** Customers receive incentive payments or a rate discount for committing to reduce load by a pre-determined amount or to a pre-determined firm service level upon utility request.
- **Automated DR.** Utility dispatched control of specific end-uses at a customer facility.

DR initiatives that do not rely on the installation of a specific device or technology to implement (such as a voluntary curtailment program or time of use rates) were not included.

A workbook was developed for each measure which included the same measure inputs as previously described for the EE measures. In addition, the DR workbook included expected load reduction from the measure, based on utility technical potential, existing utility DR programs, and other nationwide DR programs if needed.

For technical potential, Resource Innovations did not break out results by specific measure or control technology because all of the developed measures target the end-uses estimated

DSM Measure Development

for technical potential (i.e., potential is reported for space cooling end-use and not allocated to switches, smart thermostats, etc.).

4.4 DSRE Measures

The DSRE measure list includes rooftop PV systems, battery storage systems charged from PV systems, and CHP systems.

PV Systems

PV systems utilize solar panels (a packaged collection of PV cells) to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter, a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted systems that face south-west, south, and/or, south-east. The potential associated with roof-mounted systems installed on residential and commercial buildings was analyzed.

Battery Storage Systems Charged from PV Systems

Distributed battery storage systems included in this study consist of behind-the-meter battery systems installed in conjunction with an appropriately-sized PV system at residential and commercial customer facilities. These battery systems typically consist of a DC-charged battery, a DC/AC inverter, and electrical system interconnections to a PV system. On their own battery storage systems do not generate or conserve energy, but can collect and store excess PV generation to provide power during particular time periods, which for DSM purposes would be to offset customer demand during the utility's system peak.

CHP Systems

In most CHP applications, a heat engine creates shaft power that drives an electrical generator (fuel cells can produce electrical power directly from electrochemical reactions). The waste heat from the engine is then recovered to provide other on-site needs. Common prime mover technologies used in CHP applications and explored in this study include:

- Steam turbines
- Gas turbines
- Micro turbines
- Fuel Cells
- Internal combustion engines

DSM Measure Development

A workbook was developed for each measure which included the inputs previously described for EE measures and prime mover operating parameters.

5 Technical Potential

In the previous sections, the approach for DSM measure development was summarized, and the 2025 base year load shares and reference-case load forecast were described. The outputs from these tasks provided the input for estimating the technical potential scenario, which is discussed in this section.

The technical potential scenario estimates the potential energy and demand savings when all technically feasible and commercially available DSM measures are implemented without regard for cost-effectiveness and customer willingness to adopt the most impactful EE, DR, or DSRE technologies. Since the technical potential does not consider the costs or time required to achieve these savings, the estimates provide a theoretical upper limit on electricity savings potential. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. For this study, technical potential included full application of the commercially available DSM measures to all residential, commercial, and industrial customers in the utility's service territory.

5.1 Methodology

5.1.1 EE Technical Potential

EE technical potential refers to delivering less electricity to the same end-uses. In other words, technical potential might be summarized as "doing the same thing with less energy, regardless of the cost."

DSM measures were applied to the disaggregated utility electricity sales forecasts to estimate technical potential. This involved applying estimated energy savings from equipment and non-equipment measures to all electricity end-uses and customers. Technical potential consists of the total energy and demand that can be saved in the market which Resource Innovations reported as single numerical values for each utility's service territory.

The core equation used in the residential sector EE technical potential analysis for each individual efficiency measure is shown in Equation 1 below, while the core equation used in the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 2.

Technical Potential

Equation 1: Core Equation for Residential Sector EE Technical Potential



Where:

- **Baseline Equipment Energy Use Intensity** = the electricity used per customer per year by each baseline technology in each market segment. In other words, the baseline equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.
- **Saturation Share** = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential cooling, the saturation share would be the fraction of all residential electric customers that have central air conditioners in their household.
- **Percent Incomplete** = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of central air conditioners that is not already energy efficient.
- **Feasibility Factor** = the fraction of units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (i.e., it may not be possible to install LEDs in all light sockets in a home because the available styles may not fit in every socket).
- **Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Equation 2: Core Equation for Non-Residential Sector EE Technical Potential



Where:

- **Total Stock Square Footage by Segment** = the forecasted square footage level for a given building type (e.g., square feet of office buildings).
- **Baseline Equipment Energy Use Intensity** = the electricity used per square foot per year by each baseline equipment type in each market segment.

Technical Potential

- **Saturation Shares** = the fraction of total end-use energy consumption associated with the efficient technology in a given market segment. For example, for packaged terminal air-conditioner (PTAC), the saturation share would be the fraction of all space cooling kWh in a given market segment that is associated with PTAC equipment.
- **Percent Incomplete** = the fraction of equipment that is not considered to already be energy efficient.
- **Feasibility Factor** = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (i.e., it may not be possible to install Variable Frequency Drives (VFD) on all motors in a given market segment).
- **Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

It is important to note that the technical potential estimate represents electricity savings potential at a specific point in time. In other words, the technical potential estimate is based on data describing status quo customer electricity use and technologies known to exist today. As technology and electricity consumption patterns evolve over time, the baseline electricity consumption will also change accordingly. For this reason, technical potential is a discrete estimate of a dynamic market. Resource Innovations reported the technical potential for 2025, based on currently known DSM measures and observed electricity consumption patterns.

Measure Interaction and Competition (Overlap)

While the technical potential equations listed above focus on the technical potential of a single measure or technology, Resource Innovations' modeling approach does recognize the overlap of individual measure impacts within an end-use or equipment type, and accounts for the following interactive effects:

- **Measure interaction:** Installing high-efficiency equipment could reduce energy savings in absolute terms (kWh) associated with non-equipment measures that impact the same end-use. For example, installing a high-efficiency heat pump will reduce heating and cooling consumption which will reduce the baseline against which attic insulation would be applied, thus reducing savings associated with installing insulation. To account for this interaction, Resource Innovations' TEA-POT model ranks measures that interact with one another and reduces the baseline consumption for the subsequent measure based on the savings achieved by the preceding measure. For technical potential, interactive measures are ranked based on total end-use energy savings percentage.
- **Measure competition (overlap):** The "measure share"—as defined above—accounted for competing measures, ensuring savings were not double-counted. This interaction

occurred when two or more measures “competed” for the same end-use. For example, a T-12 lamp could be replaced with a T-8 or linear LED lamp.

Addressing Naturally-Occurring EE

Naturally occurring energy efficiency includes actions taken by customers to improve the efficiency of their homes and businesses in the absence of utility program intervention. For the analysis of technical potential, Resource Innovations verified with JEA’s forecasting group that the baseline sales forecasts incorporated two known sources of naturally-occurring efficiency:

- Codes and Standards: The sales forecasts already incorporated the impacts of known Code & standards changes.
- Baseline Measure Adoption: The sales forecast excluded the projected impacts of future DSM efforts but included already implemented DSM penetration.

By properly accounting for these factors, the technical potential analysis estimated the additional EE opportunities beyond what is already included in the utility sales forecast.

5.1.2 DR Technical Potential

The concept of technical potential applies differently to DR than for EE. Technical potential for DR is effectively the magnitude of loads that can be curtailed during conditions when utilities need peak capacity reductions. In evaluating this potential at peak capacity, the following were considered: which customers are consuming electricity at those times? What end-uses are in play? Can those end-use loads be managed? Large C&I accounts generally do not provide the utility with direct control over particular end-uses. Instead, many of these customers will forego electric demand temporarily if the financial incentive is large enough. For residential and small C&I customers where DR generally takes the form of direct utility control, technical potential for DR is limited by the loads that can be controlled remotely at scale.

This framework makes end-use disaggregation an important element for understanding DR potential, particularly in the residential and small C&I sectors. When done properly, end-use disaggregation not only provides insights into which loads are on and off when specific grid services are needed, it also provides insight concerning how key loads and end-uses, such as air conditioning use, vary across customers. Resource Innovations’ approach used for load disaggregation is more advanced than what is used for most potential studies. Instead of disaggregating annual consumption or peak demand, Resource Innovations produced end-use load disaggregation for all 8,760 hours. This was needed because the loads available at times when different grid applications are needed can vary substantially. Instead

Technical Potential

of producing disaggregated loads for the average customer, the study was produced for several customer segments. For JEA, Resource Innovations examined three residential segments based on customer housing type, four different small C&I segments based on customer size, and four different large C&I segments based on customer size, for a total of 11 different customer segments.

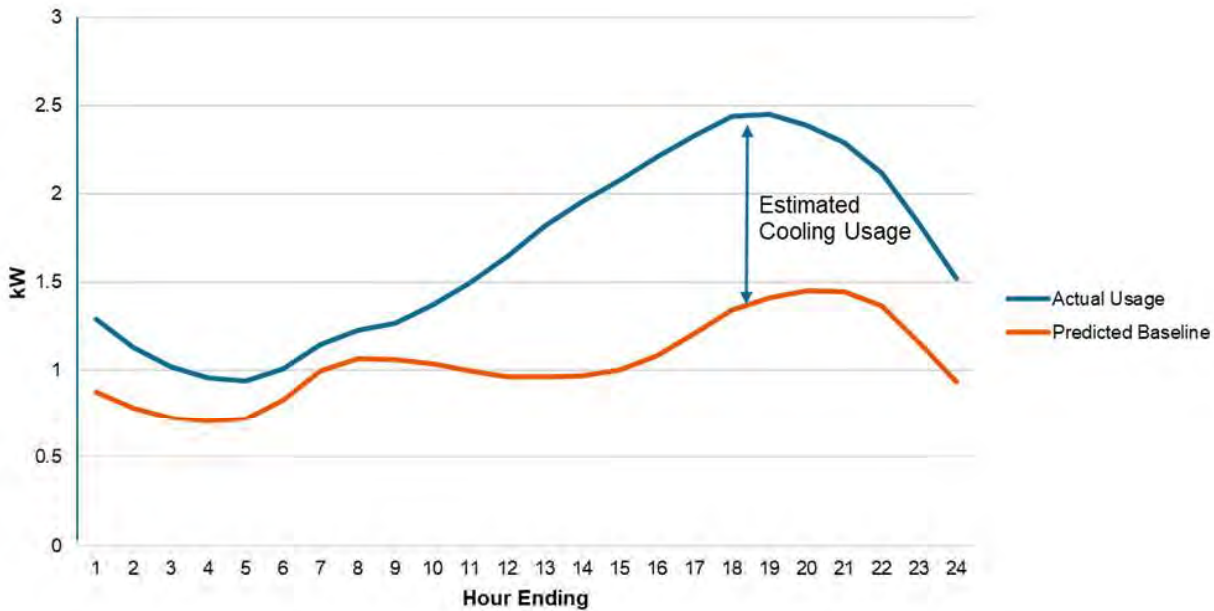
Technical potential, in the context of DR, is defined as the total amount of load available for reduction that is coincident with the period of interest; in this case, the system peak hour for the summer and winter seasons. Thus, two sets of capacity values are estimated: a summer capacity and a winter capacity.

As previously mentioned, for technical potential purposes, all coincident large C&I load is considered dispatchable, while residential and small C&I DR capacity is based on specific end-uses. Summer DR capacity for residential customers was comprised of air-conditioning (AC), pool pumps, water heaters, and managed electric vehicle charging. For small C&I customers, summer capacity was based on AC load. For winter DR capacity, residential was based on electric heating, pool pumps, and water heaters. For small C&I customers, winter capacity was based on electric heating.

AC and heating load profiles were generated for residential and small C&I customers using a segment-level interval data provided by JEA. Resource Innovations then used the interval data to create an average load profile for each customer segment.

The average load profile for each customer segment was combined with historical weather data, and used to estimate hourly load as a function of weather conditions. AC and heating loads were estimated by first calculating the baseline load on days when cooling degree days (CDD) and heating degree days (HDD) were equal to zero, and then subtracting this baseline load. This methodology is illustrated by Figure 9 (a similar methodology was used to predict heating loads).

Figure 9: Methodology for Estimating Cooling Loads



This method was able to produce estimates for average AC/heating load profiles for the different customer segments within the residential and small C&I sectors.

Profiles for residential water heater and pool pump loads were estimated by utilizing end-use load data from NREL's residential end-use load profile database.

For all eligible loads, the technical potential was defined as the amount that was coincident with system peak hours for each season, which are August from 4:00-5:00 PM for summer, and January from 7:00-8:00 AM for winter. As mentioned in Section 4, for technical potential there was also no measure breakout needed, because all measures will target the end-uses' estimated total loads.

5.1.3 DSRE Technical Potential

5.1.3.1 PV Systems

To determine technical potential for PV systems, RI estimated the percentage of rooftop square footage in Florida that is suitable for hosting PV technology. Our estimate of technical potential for PV systems in this report is based in part on the available roof area and consisted of the following steps:

Technical Potential

- Step 1: Outcomes from the forecast disaggregation analysis were used to characterize the existing and new residential, commercial and industrial building stocks.
 - To calculate the total roof area for residential buildings, the average roof area per household is multiplied by the number of households.
 - For commercial and industrial buildings, RI calculated the total roof area by first dividing the load forecast by the energy usage intensity, which provides an estimate of the total building square footage. This result is then divided by the average number of floors to derive the total roof area.
- Step 2: The total available roof area feasible for installing PV systems was calculated. Relevant parameters included unusable area due to other rooftop equipment and setback requirements, in addition to possible shading from trees and limitations of roof orientation (factored into a “technical suitability” multiplier).
- Step 3: Estimated the expected power density (kW per square foot of roof area).
- Step 4: Estimated the hourly PV generation profile using NREL’s PV Watts Calculator
- Step 5: Calculated total energy and coincident peak demand potential by applying RI’s Spatial Penetration and Integration of Distributed Energy Resources (SPIDER) Model.

The methodology presented in this report uses the following formula to estimate overall technical potential of PVs:

Equation 3: Core Equation for Solar DSRE Technical Energy Potential



Where:

- **Suitable Rooftop PV Area for Residential [Square Feet]:** Number of Residential Buildings x Average Roof Area Per Building x Technical Suitability Factor
- **Suitable Rooftop PV Area for Commercial [Square Feet] :** Energy Consumption [kWh] / Energy Intensity [kWh / Square Feet] / Average No. of Stories Per Building x Technical Suitability Factor
- **PV Power Density [kW-DC/Square Feet]:** Maximum power generated in Watts per square foot of solar panel.
- **Generation Factor:** Annual Energy Generation Factor for PV, from PV Watts (dependent on local solar irradiance)

5.1.3.2 Battery Storage Systems Charged from PV Systems

Battery storage systems on their own do not generate power or create efficiency improvements, but store power for use at different times. Therefore, in analyzing the technical potential for battery storage systems, the source of the stored power and overlap with technical potential identified in other categories was considered.

Battery storage systems that are powered directly from the grid do not produce annual energy savings but may be used to shift or curtail load during particular time periods. As the DR technical potential analyzes curtailment opportunities for the summer and winter peak period, and battery storage systems can be used as a DR technology, the study concluded that no additional technical potential should be claimed for grid-powered battery systems beyond that already attributed to DR.

Battery storage systems that are connected to on-site PV systems also do not produce additional energy savings beyond the energy produced from the PV system⁵. However, PV-connected battery systems do create the opportunity to store energy during period when the PV system is generating more than the home or business is consuming and use that stored power during utility system peak periods.

To determine the additional technical potential peak demand savings for “solar plus storage” systems, our methodology consisted of the following steps:

- Assume that every PV system included in PV Technical Potential is installed with a paired storage system.
- Size the storage system assuming peak storage power is equal to peak PV generation and energy storage duration is three hours.
- Apply RI’s hourly dispatch optimization module in SPIDER to create an hourly storage dispatch profile that flattens the individual customer’s load profile to the greatest extent possible accounting for a) customer hourly load profile, b) hourly PV generation profile, and c) battery peak demand, energy capacity, and roundtrip charge/discharge efficiency.
- Calculate the effective hourly impact for the utility using the above storage dispatch profile, aligned with the utility’s peak hour (calculated separately for summer and winter)
- Report the output storage kW impact on utility coincident peak demand in summer and winter.

⁵ PV-connected battery systems experience some efficiency loss due to storage, charging, and discharging. However, for this study, these losses were not quantified.

5.1.3.3 CHP Systems

The CHP analysis created a series of unique distributed generation potential models for each primary market sector (commercial and industrial).

Only non-residential customer segments whose electric and thermal load profiles allow for the application of CHP were considered. The technical potential analysis followed a three-step process. First, minimum facilities size thresholds were determined for each non-residential customer segment. Next, the full population of non-residential customers were segmented and screened based on the size threshold established for that segment. Finally, the facilities that were of sufficient size were matched with the appropriately sized CHP technology.

To determine the minimum threshold for CHP suitability, a thermal factor was applied to potential candidate customer loads to reflect thermal load considerations in CHP sizing. In most cases, on-site thermal energy demand is smaller than electrical demand. Thus, CHP size is usually dictated by the thermal load in order to achieve improved efficiencies.

The study collected electric and thermal intensity data from other recent CHP studies. For industrial customers, Resource Innovations assumed that the thermal load would primarily be used for process operations and was not modified from the secondary data sources for Florida climate conditions. For commercial customers, the thermal load is more commonly made up of water heating, space heating, and space cooling (through the use of an absorption chiller). Therefore, to account for the hot and humid climate in Florida, which traditionally limits weather-dependent internal heating loads, commercial customers' thermal loads were adjusted to incorporate a higher proportion of space cooling to space heating as available opportunities for waste heat recovery.

Resource Innovations worked with the utility-provided customer data, focusing on annual consumption due to the absence of NAICS or SIC codes for this utility data. Non-residential customers were subsequently classified based on annual consumption and size. Since NAICS or SIC codes were unavailable, no formal segmentation occurred. Instead, the analysis focused exclusively on annual utility usage. Facilities with annual loads below the kWh thresholds were deemed unlikely to possess the consistent electric and thermal loads necessary to support CHP and were consequently excluded from consideration. Conversely, those meeting the size criteria were aligned with the corresponding CHP technology.

In general, internal combustion engines are the prime mover for systems under 500kW with gas turbines becoming progressively more popular as system size increases above that. Based on the available load by customer, adjusted by the estimated thermal factor for each

segment, CHP technologies were assigned to utility customers in a top-down fashion (i.e., starting with the largest CHP generators).

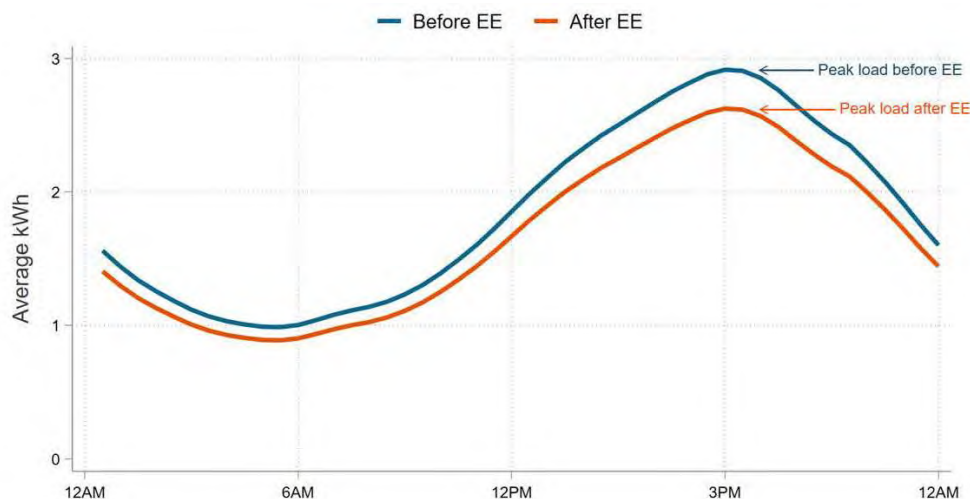
Measure Interaction

PV systems and battery storage charged from PV systems were analyzed collectively due to their common power generation source; and therefore, the identified technical potential for these systems is additive. However, CHP systems were independently analyzed for technical potential without consideration of the competition between DSRE technologies or customer preference for a particular DSRE system. Therefore, results for CHP technical potential should not be combined with PV systems or battery storage systems for overall DSRE potential but used as independent estimates.

5.1.4 Interaction of Technical Potential Impacts

As described above, the technical potential was estimated using separate models for EE, DR, and DSRE systems. However, there is interaction between these technologies; for example, a more efficient HVAC system would result in a reduced peak demand available for DR curtailment, as illustrated in Figure 10.

Figure 10: Illustration of EE Impacts on HVAC System Load Shape



Therefore, after development of the independent models, the interaction between EE, DR, and DSRE was incorporated as follows:

- The EE technical potential was assumed to be implemented first, followed by DR technical potential and DSRE technical potential.

Technical Potential

- To account for the impact of EE technical potential on DR, the baseline load forecast for the applicable end-uses was adjusted by the EE technical potential, resulting in a reduction in baseline load available for curtailment.
- For DSRE systems, the EE and DR technical potential was incorporated in a similar fashion, adjusting the baseline load used to estimate DSRE potential.
 - For the PV analysis, this did not impact the results as the EE and DR technical potential did not affect the amount of PV that could be installed on available rooftops.
 - For the battery storage charged from PV systems, the reduced baseline load from EE resulted in additional PV-generated energy being available for the battery systems and for use during peak periods. The impact of DR events during the assumed curtailment hours was incorporated into the modeling of available battery storage and discharge loads.
- For CHP systems, the reduced baseline load from EE resulted in a reduction in the number of facilities that met the annual energy threshold needed for CHP installations. Installed DR capacity was assumed to not impact CHP potential as the CHP system feasibility was determined based on energy and thermal consumption at the facility. It should be noted that CHP systems not connected to the grid could impact the amount of load available for curtailment with utility-sponsored DR. Therefore, CHP technical potential should not be combined with DR potential but used as independent estimates.

5.2 EE Technical Potential

5.2.1 Summary

Table 9 summarizes the EE technical potential by sector:

Table 9. EE Technical Potential

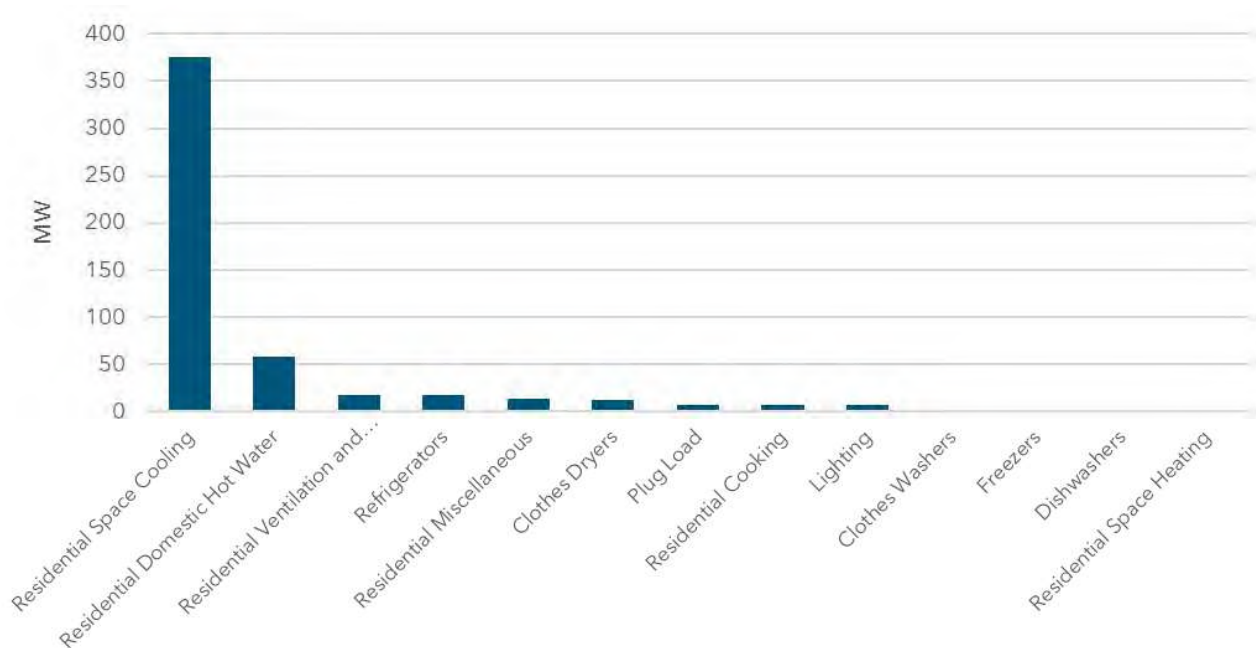
	Savings Potential		
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Energy (GWh)
Residential	517	297	1,887
Non-Residential⁶	280	251	1,690
Total	797	548	3,577

⁶ Non-Residential results include all commercial and industrial customer segments.

5.2.2 Residential

Figure 11, Figure 12, and Figure 13 summarize the residential sector EE technical potential by end-use.

Figure 11: Residential EE Technical Potential by End-Use (Summer Peak Savings)



Technical Potential

Figure 12: Residential EE Technical Potential by End-Use (Winter Peak Savings)

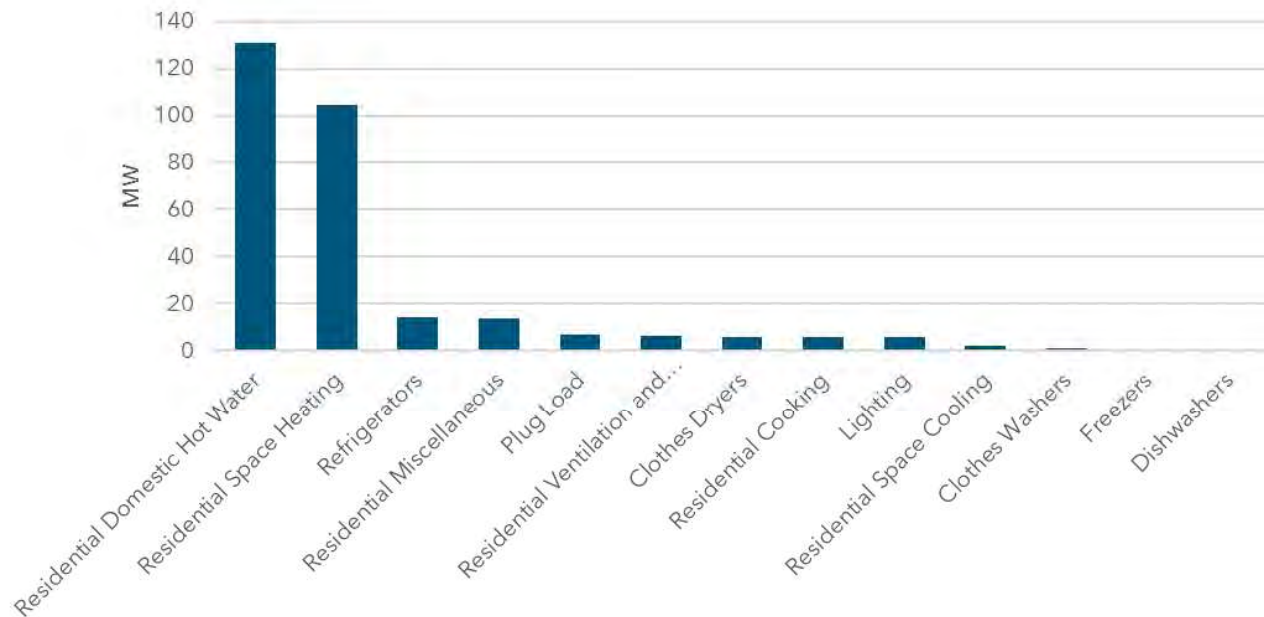
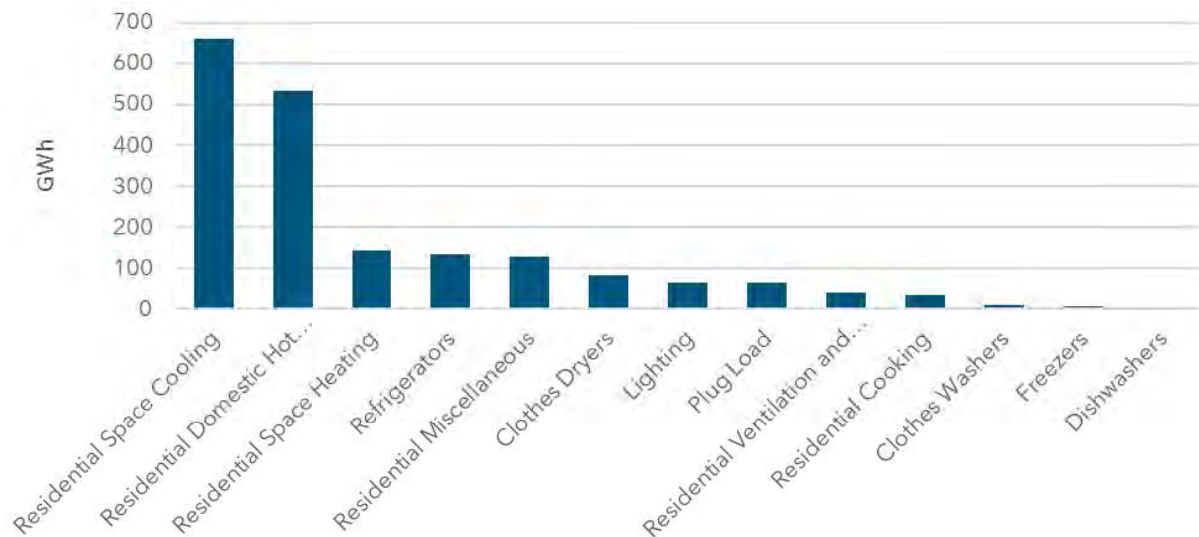


Figure 13: Residential EE Technical Potential by End-Use (Energy Savings)

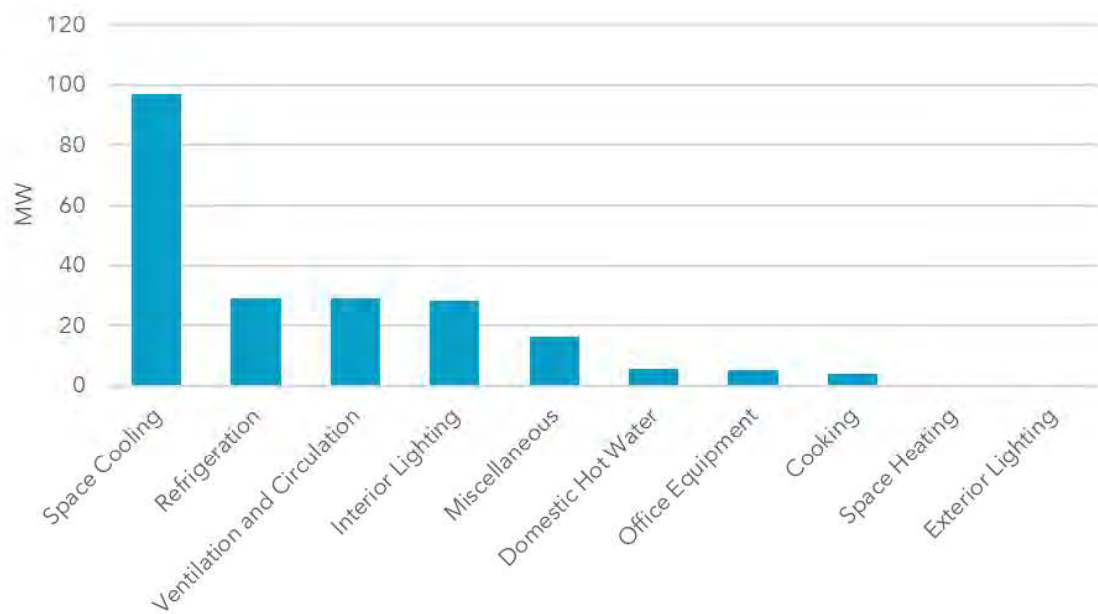


5.2.3 Non-Residential

5.2.3.1 Commercial Segments

Figure 14, Figure 15, and Figure 16 summarize the commercial sector EE technical potential by end-use.

Figure 14: Commercial EE Technical Potential by End-Use (Summer Peak Savings)



Technical Potential

Figure 15: Commercial EE Technical Potential by End-Use (Winter Peak Savings)

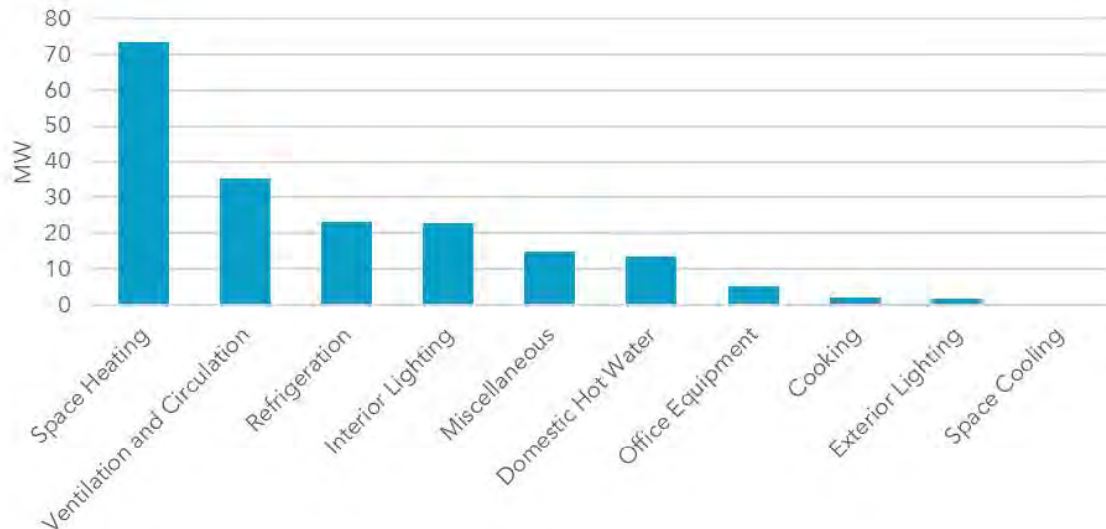
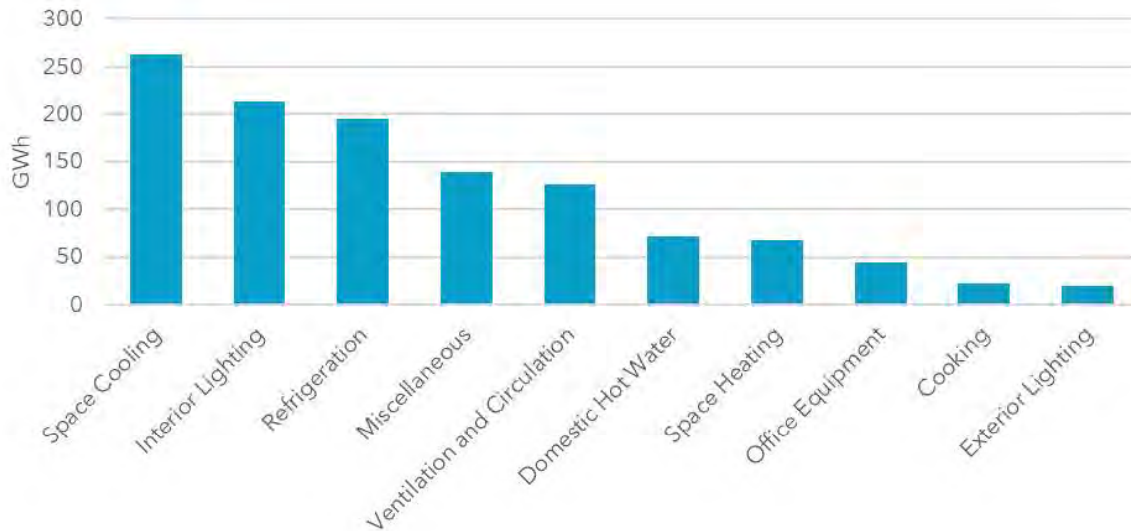


Figure 16: Commercial EE Technical Potential by End-Use (Energy Savings)



5.2.3.2 Industrial Segments

Figure 17, Figure 18, and Figure 19 summarize the industrial sector EE technical potential by end-use.

Technical Potential

Figure 17: Industrial EE Technical Potential by End-Use (Summer Peak Savings)

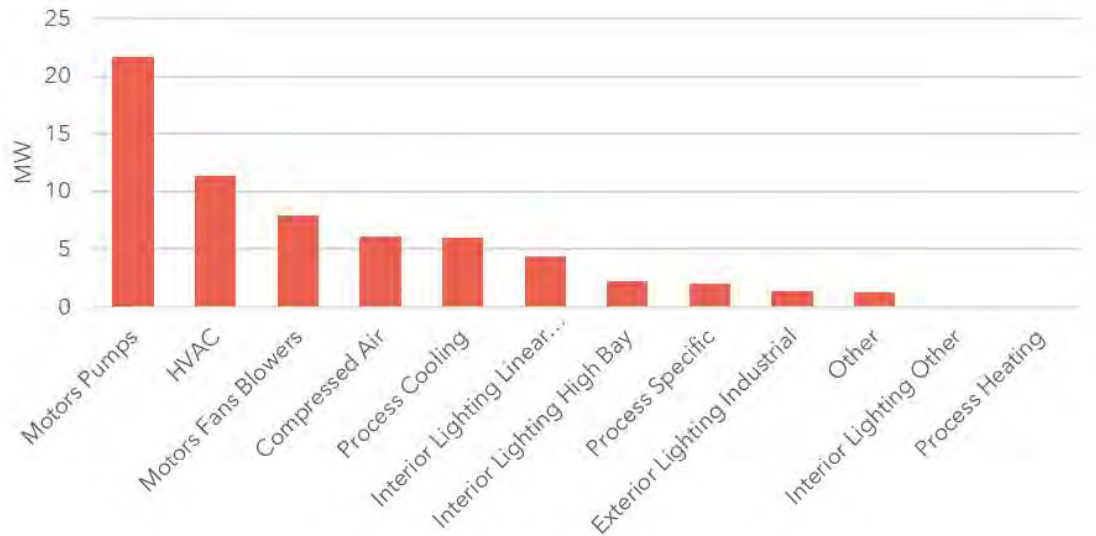


Figure 18: Industrial EE Technical Potential by End-Use (Winter Peak Savings)

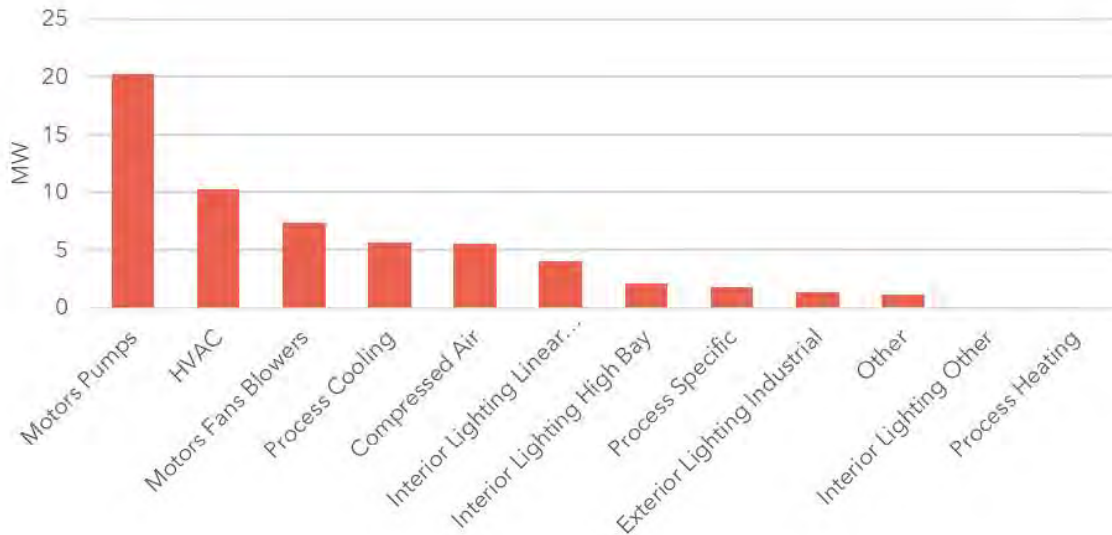
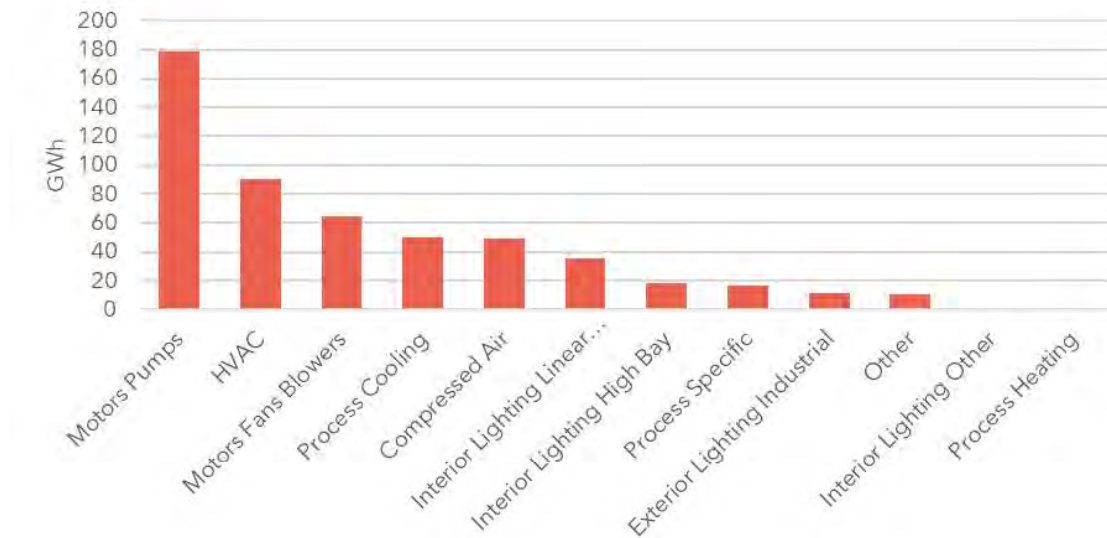


Figure 19: Industrial EE Technical Potential by End-Use (Energy Savings)



5.3 DR Technical Potential

Technical potential for DR is defined for each class of customers as follows:

- Residential & Small C&I customers – Technical potential is equal to the aggregate load for all end-uses that can participate in JEA’s current programs plus DR measures not currently offered in which the utility uses specialized devices to control loads (i.e., direct load control programs). This includes cooling and heating loads for residential and small C&I customers and water heater and pool pump loads for residential customers. Not all demand reductions are delivered via direct load control of end-uses. The magnitude of demand reductions from non-direct load control such as time varying pricing, peak time rebates and targeted notifications is linked to cooling and heating loads.
- Large C&I customers – Technical potential is equal to the total amount of load for each customer segment (i.e., that customers reduce their total load to zero when called upon).

Table 10 summarizes the seasonal DR technical potential by sector:

Technical Potential

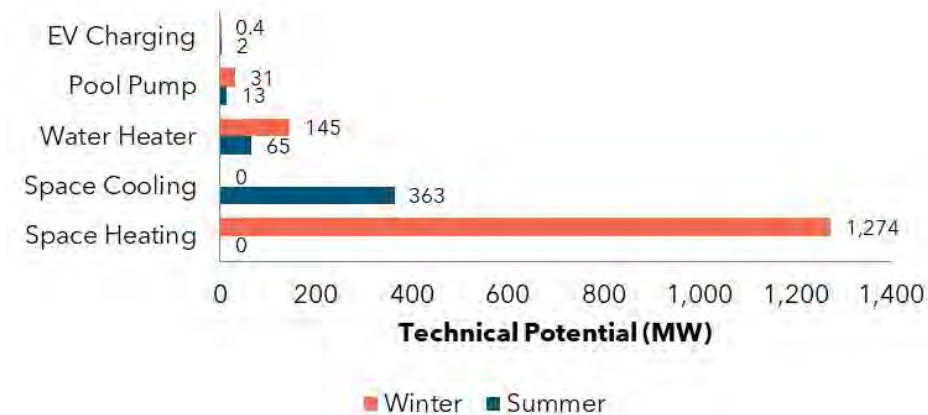
Table 10. DR Technical Potential

	Savings Potential	
	Summer Peak Demand (MW)	Winter Peak Demand (MW)
Residential	443	1,451
Non-Residential	673	578
Total	1,116	2,029

5.3.1 Residential

Residential technical potential is summarized in Figure 20.

Figure 20: Residential DR Technical Potential by End-Use



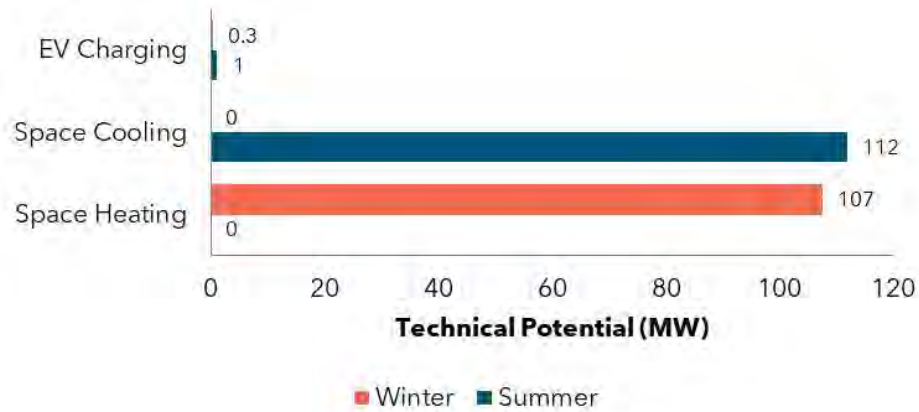
5.3.2 Non-Residential

5.3.2.1 Small C&I Customers

For small C&I technical potential, Resource Innovations looked at cooling and heating loads only. Small C&I technical potential is provided in Figure 21.

Technical Potential

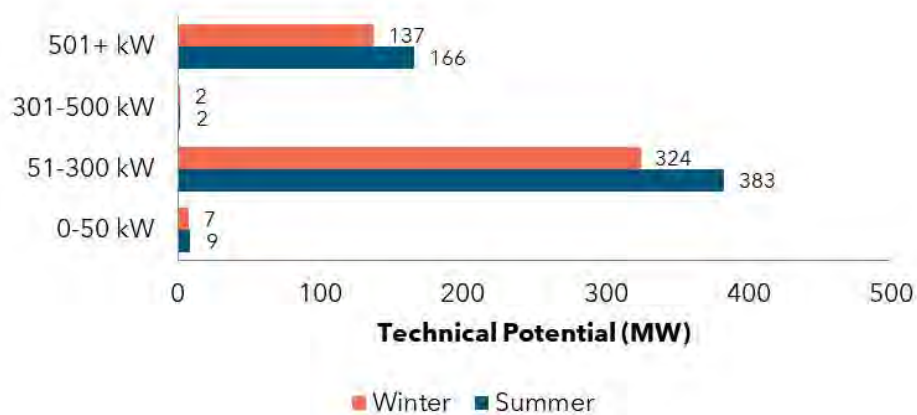
Figure 21: Small C&I DR Technical Potential by End-Use



5.3.2.2 Large C&I Customers

Figure 22 provides the technical potential for large C&I customers, broken down by customer size.

Figure 22: Large C&I DR Technical Potential by Segment



5.4 DSRE Technical Potential

Table 11 provides the results of the DSRE technical potential for each customer segment:

Technical Potential

Table 11. DSRE Technical Potential⁷

	Savings Potential		
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Energy (GWh)
PV Systems			
Residential	493	19	4,146
Non-Residential	214	3	1,617
Total	707	22	5,763
Battery Storage charged from PV Systems			
Residential	304	557	0
Non-Residential	0	158	0
Total	304	715	0
CHP Systems			
Total	397	359	1,811

⁷ PV systems and CHP systems were independently analyzed for technical potential without consideration of the competition between technologies or customer preference for DSRE system.

Appendix A EE Measure List

For information on how Resource Innovations developed this list, please see Section 4.

Table 12: Residential EE Measures

Measure	End-Use	Description	Baseline
120v Heat Pump Water Heater 50 Gallons	Residential Domestic Hot Water	120v Heat Pump Water Heater 50 Gallons	Code-Compliant 50 Gallon Electric Resistance Water Heater
Air Sealing-Infiltration Control	Residential Space Cooling, Residential Space Heating	Standard Heating and Cooling System with Improved Infiltration Control	Standard Heating and Cooling System with Standard Infiltration Control
Air-to-Water Heat Pump	Residential Space Cooling, Residential Space Heating	Energy Star Air-to-Water Heat Pump, 25 SEER, 13 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF (updated)
ASHP - 15 SEER/14.3 SEER2 from base electric resistance	Residential Space Cooling, Residential Space Heating	ASHP 15 SEER from base electric resistance	Base AC, 15 SEER, Electric resistance heating
ASHP - 24 SEER/22.9 SEER2 (from elec resistance)	Residential Space Cooling, Residential Space Heating	ASHP: 24/22.9 SEER/SEER2, 10.5 HSPF	Base AC, 15 SEER, Electric resistance heating
ASHP - 24 SEER/22.9 SEER2, 10.5 HSPF	Residential Space Cooling, Residential Space Heating	ASHP: 24/22.9 SEER/SEER2, 10.5 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF (updated)
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	Residential Space Cooling, Residential Space Heating	CEE Advanced Tier ASHP: 17.8/17 SEER/SEER2; 10.0 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF (updated)
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	Residential Space Cooling, Residential Space Heating	CEE Advanced Tier ASHP: 17.8/17 SEER/SEER2; 10.0 HSPF	Base AC, 15 SEER, Electric resistance heating
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF	Residential Space Cooling, Residential Space Heating	CEE Tier 2 ASHP: 16.8/16 SEER/SEER2; 9.0 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF (updated)
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	Residential Space Cooling, Residential Space Heating	CEE Tier 2 ASHP: 16.8/16 SEER/SEER2; 9.0 HSPF	Base AC, 15 SEER, Electric resistance heating

EE Measure List

Measure	End-Use	Description	Baseline
ASHP - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2 (from elect resistance)	Residential Space Cooling, Residential Space Heating	ENERGY STAR/CEE Tier 1 ASHP: 16/15.2 SEER/SEER2, 9.0 HSPF	Base AC, 15 SEER, Electric resistance heating
ASHP - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2, 9.0 HSPF	Residential Space Cooling, Residential Space Heating	ENERGY STAR/CEE Tier 1 ASHP: 16/15.2 SEER/SEER2, 9.0 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF (updated)
Basement or Crawlspace Wall Insulation R-15	Residential Space Cooling, Residential Space Heating	Increased Basement or Crawlspace Wall Insulation (R-15)	Code-Compliant Exterior Below-Grade Wall Insulation (R-10)
Bathroom Faucet Aerators	Residential Domestic Hot Water	Low-Flow Faucet Aerator with Flow Rate of 1.5 gpm	Faucet Aerator with Federal Standard Flow Rate of 2.2 gpm
CEE Advanced Tier Clothes Dryer	Clothes Dryers	CEE Advanced Tier Clothes Dryer	One Clothes Dryer meeting Federal Standard
CEE Advanced Tier Clothes Washer	Clothes Washers	Tier 3 CEE Clothes washer	One Clothes Washer meeting Federal Standard
CEE Tier 3 Refrigerator	Refrigerators	Residential Tier 3 Refrigerator	One Refrigerator meeting Federal Standard
Ceiling Insulation (R11 to R38)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1982-1985) homes	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R11 to R49)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1982-1985) homes - Beyond Code	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R19 to R38)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1982-2020) homes	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R19 to R49)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1982-2020) homes - Beyond Code	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R2 to R38)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, older (pre-1982) homes	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R2 to R49)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, older (pre-1982) homes - Beyond Code	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R30 to R38)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1986-2020) homes	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R30 to R49)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1986-2020) homes - Beyond Code	Existing ceiling insulation based on building code at time of construction
Ceiling Insulation (R38 to R49)	Residential Space Cooling, Residential Space Heating	Blown-in insulation in ceiling cavity/attic, existing (1986-2020) homes - Beyond Code	Existing ceiling insulation based on building code at time of construction

EE Measure List

Measure	End-Use	Description	Baseline
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	Residential Space Cooling	Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	Code-Compliant Central AC, 15 SEER (updated)
Central AC - 24 SEER/22.9 SEER2	Residential Space Cooling	Central AC - 24 SEER/22.9 SEER2	Code-Compliant Central AC, 15 SEER (updated)
Central AC - CEE Advanced Tier: 17.8 SEER/17 SEER2	Residential Space Cooling	Central AC - CEE Advanced Tier: 17.8 SEER/17 SEER2	Code-Compliant Central AC, 15 SEER (updated)
Central AC - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2	Residential Space Cooling	Central AC - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2	Code-Compliant Central AC, 15 SEER (updated)
Central AC Tune Up	Residential Space Cooling	System tune-up, including coil cleaning, refrigerant charging, and other diagnostics	Existing Typical Central AC without Regular Maintenance/tune-up
Dehumidifier Recycling	Plug Load	No dehumidifier	One Dehumidifier meeting Federal Standard
Drain Water Heat Recovery	Residential Domestic Hot Water	50 Gallon Electric Resistance Heater and Drain Water Heat Exchanger	50 Gallon Electric Resistance Heater, No Drain Water Heat Recovery
Duct Insulation	Residential Space Cooling, Residential Space Heating	Standard Electric Heating and Central AC with Insulated Ductwork	Standard Electric Heating and Central AC with Uninsulated Ductwork
Duct Repair	Residential Space Cooling, Residential Space Heating	Duct Repair to eliminate/minimize leaks, includes testing and sealing	Standard Electric Heating and Central AC with typical duct leakage
ECM Circulator Pump	Residential Miscellaneous	Install ECM Circulator Pump	Install Standard Circulator Pump
Energy Star Air Purifier	Plug Load	One Air Purifier meeting ENERGY STAR 2.0 Standards	One Standard Conventional Air Purifier
Energy Star Audio-Video Equipment	Plug Load	One DVD/Blu-Ray Player meeting current ENERGY STAR Standards	One Market Average DVD/Blu-Ray Player
Energy Star Bathroom Ventilating Fan	Residential Ventilation and Circulation	Bathroom Exhaust Fan meeting current ENERGY STAR Standards	Bathroom Exhaust Fan meeting Federal Standard
Energy Star Ceiling Fan	Residential Miscellaneous	60" Ceiling Fan Meeting ENERGY STAR 3.1 Standards	Standard 60" Ceiling Fan
Energy Star Clothes Dryer	Clothes Dryers	One Electric Resistance Clothes Dryer meeting ENERGY STAR 1.1 Standards	One Clothes Dryer meeting Federal Standard
Energy Star Clothes Washer	Clothes Washers	One Clothes Washer meeting ENERGY STAR 8.1 Standards	One Clothes Washer meeting Federal Standard

EE Measure List

Measure	End-Use	Description	Baseline
Energy Star Dehumidifier	Plug Load	One Dehumidifier meeting ENERGY STAR 5.0 Standards	One Dehumidifier meeting Federal Standard
Energy Star Dishwasher	Dishwashers	One Dishwasher meeting ENERGY STAR 7.0 Requirements (effective on July 19, 2023), electric water heating	One Dishwasher meeting Federal Standard
Energy Star Dishwasher (Gas Water Heating)	Dishwashers	One Dishwasher meeting ENERGY STAR 7.0 Requirements, gas water heating	One Dishwasher meeting Federal Standard; gas water heating
Energy Star Door	Residential Space Cooling, Residential Space Heating	100ft ² of Opaque Door meeting Energy Star Version 6.0 Requirements (U-Value: 0.17)	100ft ² of Opaque Door meeting current FL Code Requirements
ENERGY STAR EV supply equipment (level 2 charger)	Residential Miscellaneous	Level 2 Electric Vehicle Supply Equipment (EVSE)	Level 1 Electric Vehicle Supply Equipment (EVSE)
Energy Star Freezer	Freezers	One Freezer meeting current ENERGY STAR 5.1 Standards	One Freezer meeting Federal Standard
Energy Star Ground Source Heat Pump	Residential Space Cooling, Residential Space Heating	Energy Star GSHP, 17.1 SEER, 12 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF
Energy Star Imaging Equipment	Plug Load	One imaging device meeting current ENERGY STAR Standards	One non-ENERGY STAR imaging device
Energy Star Monitor	Plug Load	One Monitor meeting ENERGY STAR 8.0 Standards	One Standard Monitor
Energy Star Personal Computer	Plug Load	One Personal Computer meeting ENERGY STAR 8.0 Standards	One Personal Computer meeting ENERGY STAR® 3.0 Standards
Energy Star Refrigerator	Refrigerators	One Refrigerator/Freezer meeting ENERGY STAR 5.1 Standards	One Refrigerator/Freezer meeting Federal Standard
Energy Star Room AC	Residential Space Cooling	Room AC meeting current ENERGY STAR standards	Code-Compliant Room AC
Energy Star Set-Top Receiver	Plug Load	One Set-top Box meeting ENERGY STAR 4.1 Standards	One Market Average Set-top Box
Energy Star TV	Plug Load	One Television meeting ENERGY STAR 9.0 Standards	One non-ENERGY STAR Television
Energy Star Windows	Residential Space Cooling, Residential Space Heating	100ft ² of Window meeting Energy Star Version 6.0 Requirements (U-Value: 0.27, SHGC: 0.21)	100ft ² of Window current FL energy code requirements
Exterior Wall Insulation	Residential Space Cooling, Residential Space Heating	Increased Exterior Above-Grade Wall Insulation (R-13)	Market Average Existing Exterior Above-Grade Wall Insulation

EE Measure List

Measure	End-Use	Description	Baseline
Filter Whistle	Residential Ventilation and Circulation	Install the Furnace Filter Alarm	No Furnace Filter Alarm on a Central Forced-Air Furnace
Floor Insulation	Residential Space Heating	Increased Floor Insulation (R-30)	Code-Compliant Floor Insulation
Freezer Recycling	Freezers	No Freezer	Current Market Freezer
Green Roof	Residential Space Cooling	Vegetated Roof Surface on top of Standard Roof	Standard Black Roof
Heat Pump Clothes Dryer	Clothes Dryers	One Heat Pump Clothes Dryer	One Clothes Dryer meeting Federal Standard
Heat Pump Pool Heater	Residential Miscellaneous	Heat Pump Swimming Pool Heater	Electric Resistance Swimming Pool Heater
Heat Pump Tune Up	Residential Space Cooling, Residential Space Heating	System tune-up, including coil cleaning, refrigerant charging, and other diagnostics	Standard Heating and Cooling System without Regular Maintenance/tune-up
Heat Pump Water Heater 50 Gallons-CEE Advanced Tier	Residential Domestic Hot Water	CEE Advanced Tier Heat Pump Water Heater 50 Gallons	Code-Compliant 50 Gallon Electric Resistance Water Heater
Heat Pump Water Heater 50 Gallons-ENERGY STAR	Residential Domestic Hot Water	Heat Pump Water Heater 50 Gallons	Code-Compliant 50 Gallon Electric Resistance Water Heater
Heat Pump Water Heater 80 Gallons-ENERGY STAR	Residential Domestic Hot Water	Energy Star Heat Pump Water Heater 80 Gallons	Code-Compliant 80 Gallon Electric Resistance Water Heater
Heat Trap	Residential Domestic Hot Water	Heat Trap	Existing Water Heater without heat trap
High Efficiency Convection Oven	Residential Cooking	One Full-Size Convection Oven meeting ENERGY STAR 3.0 Standards	One Standard Economy-Grade Full-Size Oven
High Efficiency Induction Cooktop	Residential Cooking	One residential induction cooktop	One standard residential electric cooktop
Home Energy Management System	Lighting, Plug Load, Residential Space Cooling, Residential Space Heating	Typical HVAC by Building Type Controlled by Energy Management System	Typical HVAC by Building Type, Manually Controlled
Hot Water Pipe Insulation	Residential Domestic Hot Water	1' of Insulated Pipe in Unconditioned Spaces, Insulation of R-5	1' of Pipe in Unconditioned Spaces with Code Minimum of 1"of Insulation
HVAC ECM Motor	Residential Ventilation and Circulation	A brushless permanent magnet (ECM) blower motor for electric furnace	Permanent Split Capacitor Motor for Electric Furnace
HVAC Economizer	Residential Space Cooling	Install residential economizer	No economizer
HVAC Zoning System	Residential Space Cooling, Residential Space Heating	Install dampers in the ducts, dividing home into multiple	Single zone HVAC system

EE Measure List

Measure	End-Use	Description	Baseline
		zones, each controlled by its own thermostat	
Indoor Daylight Sensor	Lighting	Install Indoor Daylight Sensors, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Induction Range	Residential Cooking	Residential induction range	Electric range
Instantaneous Hot Water System	Residential Domestic Hot Water	Instantaneous Hot Water System	Standard Efficiency Storage Tank Water Heater
Kitchen Faucet Aerators	Residential Domestic Hot Water	Low-Flow Faucet Aerator with Flow Rate of 1.5 gpm	Faucet Aerator with Federal Standard Flow Rate of 2.2 gpm
LED - 9W_CFL Baseline	Lighting	LED (assume 9W) replacing CFL baseline lamp	14W CFL (60W equivalent)
LED - 9W_Halogen Baseline	Lighting	LED (assume 9W) replacing EISA-2020 compliant baseline lamp	EISA-2020 compliant baseline lamp (60W equivalent)
LED Specialty Lamps-5W Chandelier	Lighting	5 W Chandelier LED	Standard incandescent chandelier lamp
Linear LED	Lighting	Linear LED Lamps in Linear Fluorescent Fixture	Standard (32w) T8 lamps in Linear Fluorescent Fixture
Low Flow Showerhead	Residential Domestic Hot Water	Low-Flow Handheld Showerhead, Flow Rate: 1.60 gpm	Standard Handheld Showerhead, Flow Rate: 2.50 gpm
New Construction - Whole Home Improvements - Tier 1	Whole Home	Performance-based improvements in new homes - 20% savings	Residential New Construction (Baseline Efficiency)
New Construction - Whole Home Improvements - Tier 2	Whole Home	Performance-based improvements in new homes - 35% savings	Residential New Construction (Baseline Efficiency)
Occupancy Sensors Switch Mounted	Lighting	Switch Mounted Occupancy Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Outdoor Lighting Timer	Lighting	Timer on Outdoor Lighting, Controlling 120 Watts	120 Watts of Lighting, Manually Controlled
Outdoor Motion Sensor	Lighting	Motion Sensor on Outdoor Lighting, Controlling 120 Watts	120 Watts of Lighting, Manually Controlled
Ozone Laundry	Clothes Washers	Add a New, Single-Unit Ozone Laundry System to the Clothes Washer	One Clothes Washer meeting Federal Standard
Programmable Thermostat	Residential Space Cooling, Residential Space Heating	Standard Heating and Cooling System with Programmable Thermostat	Standard Heating and Cooling System with Manual Thermostat
Properly Sized CAC	Residential Space Cooling	Properly Sized Central Air Conditioning	Standard Central Air Conditioning, Oversized

EE Measure List

Measure	End-Use	Description	Baseline
Radiant Barrier	Residential Space Cooling	Radiant Barrier	No radiant barrier
Reflective Roof	Residential Space Cooling	Reflective Roof Treatment	Standard dark shingle
Refrigerator Coil Cleaning	Refrigerators	Refrigerator Coil Cleaning	
Refrigerator Recycling	Refrigerators	No Refrigerator	Current Market Average Refrigerator
Residential Whole House Fan	Residential Space Cooling	Standard Central Air Conditioning with Whole House Fan	Standard Central Air Conditioning, No Whole House Fan
Sealed crawlspace	Residential Space Cooling, Residential Space Heating	Encapsulated and semi-conditioned crawlspace	Naturally vented, unconditioned crawlspace
Smart Breaker	Whole Home	Smart Breaker	standard electric breakers
Smart Panel	Whole Home	Multi-channel device that attaches to customer's circuit breaker to enable monitoring and control of major end-use appliances by customer	standard electric panel
Smart Power Strip	Plug Load	Smart plug strips for entertainment centers and home office	Standard entertainment center or home office usage, no smart strip controls
Smart Thermostat	Residential Space Cooling, Residential Space Heating	Standard Heating and Cooling System with Smart Thermostat	Standard Heating and Cooling System with Manual Thermostat
Solar Attic Fan	Residential Space Cooling	Standard Central Air Conditioning with Solar Attic Fan	Standard Central Air Conditioning, No Solar Attic Fan
Solar Pool Heater	Residential Miscellaneous	Solar Swimming Pool Heater	Electric Resistance Swimming Pool Heater
Solar Powered Pool Pumps	Residential Miscellaneous	Solar Powered Pool Pump	Variable Speed Pool Pump Motor
Solar Thermal Water Heating System	Residential Domestic Hot Water	Solar Thermal System with Electric Backup	Code-Compliant 50 Gallon Electric Resistance Water Heater
Spray Foam Insulation(Base R11)	Residential Space Cooling, Residential Space Heating	Open cell spray foam along roofline in existing (1982-1985) homes	Existing ceiling insulation based on building code at time of construction
Spray Foam Insulation(Base R19)	Residential Space Cooling, Residential Space Heating	Open cell spray foam along roofline in existing (1982-1985) homes	Existing ceiling insulation based on building code at time of construction
Spray Foam Insulation(Base R2)	Residential Space Cooling, Residential Space Heating	Open cell spray foam along roofline in older (pre-1982) homes	Existing ceiling insulation based on building code at time of construction

EE Measure List

Measure	End-Use	Description	Baseline
Spray Foam Insulation(Base R30)	Residential Space Cooling, Residential Space Heating	Open cell spray foam along roofline in existing (1986-2020) homes	Existing ceiling insulation based on building code at time of construction
Thermostatic Shower Restriction Valve	Residential Domestic Hot Water	50 Gallon Electric Resistance Heater and Thermostatic Shower Valves	50 Gallon Electric Resistance Heater and Standard Shower Valves
Variable Refrigerant Flow (VRF) HVAC Systems	Residential Space Cooling, Residential Space Heating	Variable Refrigerant Flow (VRF) HVAC Systems	Code-Compliant ASHP, 15 SEER, 8.8 HSPF
Water Heater Blanket	Residential Domestic Hot Water	50 Gallon Electric Resistance Water Heater with Insulated Tank Wrap	Code-Compliant 50 Gallon Electric Resistance Water Heater, No Tank Wrap
Water Heater Thermostat Setback	Residential Domestic Hot Water	50 Gallon Electric Resistance Water Heater with Temperature Setpoint of 119°F	Code-Compliant 50 Gallon Electric Resistance Water Heater (Temp. Setpoint = 130°F)
Water Heater Timeclock	Residential Domestic Hot Water	Water Heater Timeclock	Existing Water Heater without time clock
Weather stripping	Residential Space Cooling, Residential Space Heating	Specific quantity of weather stripping to seal	
Window Caulking	Residential Space Cooling, Residential Space Heating	Window caulking	
Window Sun Protection	Residential Space Cooling	Window Film Applied to Standard Window	Standard Window with below Code Required Minimum SHGC

Table 13: Commercial EE Measures

Measure	End-Use	Description	Baseline
1.5HP Open Drip-Proof (ODP) Motor	Ventilation and Circulation	High Efficiency 1.5 HP Open-Drip Proof Motor	1.5HP Open-Drip Proof Motor with Current Minimum EPACT Efficiency
10HP Open Drip-Proof (ODP) Motor	Ventilation and Circulation	High Efficiency 10 HP Open-Drip Proof Motor	10HP Open-Drip Proof Motor with Current Minimum EPACT Efficiency
20HP Open Drip-Proof (ODP) Motor	Ventilation and Circulation	High Efficiency 20 HP Open-Drip Proof Motor	20HP Open-Drip Proof Motor with Current Minimum EPACT Efficiency
Advanced Rooftop Controller	Ventilation and Circulation	Advanced Rooftop Controller	Without Advanced Rooftop Controller
Air Compressor Optimization	Miscellaneous	Performing Routine Maintenance on 20HP Inlet	20 HP Inlet Modulation Fixed-Speed Compressor

EE Measure List

Measure	End-Use	Description	Baseline
		Modulation Fixed-Speed Compressor	
Air Curtains	Space Cooling, Space Heating	Air Curtain across door opening	Door opening with no air curtain
Airside Economizer	Space Cooling	Airside Economizer	No economizer
Anti-Sweat Controls	Refrigeration	One Medium Temperature Reach-In Case with Anti-Sweat Heater Controls	One Medium Temperature Reach-In Case without Anti-Sweat Heater Controls
Auto Off Time Switch	Interior Lighting	Auto-Off Time Switch on Interior Lighting, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Automatic Door Closer for Walk-in Coolers and Freezers	Refrigeration	One Medium Temperature Walk-In Refrigerator Door with Auto-Closer	One Medium Temperature Walk-In Refrigerator Door without Auto-Closer
Beverage Vending Machine Controls	Refrigeration	One non-ENERGY STAR beverage vending machine equipped with infrared occupancy sensing controls	One non-ENERGY STAR beverage vending machine, no controls
Bi-Level Lighting Control (Exterior)	Exterior Lighting	Bi-Level Controls on Exterior Lighting, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Bi-Level Lighting Control (Interior)	Interior Lighting	Bi-Level Controls on Interior Lighting, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Ceiling Insulation (R19 to R38)	Space Cooling, Space Heating	Blown-in insulation in ceiling cavity/attic	Market Average Existing Ceiling Insulation in older steep slope, residential style commercial building
Ceiling Insulation (R19 to R49)	Space Cooling, Space Heating	Blown-in insulation in ceiling cavity/attic - Beyond Code	Market Average Existing Ceiling Insulation in older steep slope, residential style commercial building
Ceiling Insulation (R2 to R38)	Space Cooling, Space Heating	Blown-in insulation in ceiling cavity/attic	Market Average Existing Ceiling Insulation in older steep slope, residential style commercial building
Ceiling Insulation (R2 to R49)	Space Cooling, Space Heating	Blown-in insulation in ceiling cavity/attic - Beyond Code	Market Average Existing Ceiling Insulation in older steep slope, residential style commercial building
Chilled Water Reset	Space Cooling	One Chiller with Reset of Chilled Water Temperature Setpoint	One Chiller with Fixed Chilled Water Temperature
Chiller maintenance	Space Cooling	O&M improvements to restore chiller performance	

EE Measure List

Measure	End-Use	Description	Baseline
CO Sensors for Parking Garage Exhaust	Miscellaneous	Enclosed Parking Garage Exhaust with CO Control	Constant Volume Enclosed Parking Garage Exhaust
Commercial Duct Sealing	Space Cooling, Space Heating	Standard Electric Heating and Central AC with Improved Duct Sealing	Standard Electric Heating and Central AC, Standard Duct Sealing
Commercial Strategic Energy Management	Whole Building	Commercial Strategic Energy Management	No active energy management
Custom measure - Non-lighting	Space Cooling, Space Heating	Custom Improvement to Facility's Operations	Baseline Technology/Process
Data Center Hot Cold Aisle	Office Equipment	Equipment configuration that saves HVAC	No hot, cold aisle containment
Dedicated Outside Air System (DOAS)	Space Cooling, Space Heating	Install Dedicated Outside Air System (DOAS)	Typical HVAC by Building Type
Demand Controlled Circulating Systems	Domestic Hot Water	Recirculation Pump with Demand Control Mechanism	Uncontrolled Recirculation Pump
Demand Controlled Ventilation	Ventilation and Circulation	Return Air System with CO2 Sensors	Standard Return Air System, No Sensors
Demand Defrost	Refrigeration	Walk-In Freezer System with Demand-Controlled Electric Defrost Cycle	Walk-In Freezer System with Timer-Controlled Electric Defrost Cycle
Destratification Fans	Space Heating	Destratification Fans improve temperature distribution by circulating warmer air from the ceiling back down to the floor level	No destratification fan
Door Gasket (Cooler)	Refrigeration	New Door Gasket on One-Door Medium Temperature Reach-In Case	Worn or Damaged Door Gasket on One-Door Medium Temperature Reach-In Case
Door Gasket (Freezer)	Refrigeration	New Door Gasket on One-Door Medium Temperature Reach-In Case	Worn or Damaged Door Gasket on One-Door Medium Temperature Reach-In Case
Drain water heat recovery	Domestic Hot Water	Hot Water Loop with 50 Gallon Electric Resistance Heater and Drain Water Heat Exchanger	Standard Hot Water Loop with 50 Gallon Electric Resistance Heater, No Drain Water Heat Recovery
Dual Enthalpy Economizer	Ventilation and Circulation	Standard HVAC Unit with an economizer and dual enthalpy differential control	HVAC unit with no economizer or with a non-functional disabled economizer
Duct Insulation	Space Cooling, Space Heating	Standard Electric Heating and Central AC with Insulated Ductwork (R-8)	Standard Electric Heating and Central AC with Uninsulated Ductwork (R-4)
Ductless Mini-Split AC	Space Cooling	Ductless Mini-Split AC, 4 Ton, 16 SEER	Code-Compliant AC Unit, 4 Ton, 15 SEER

EE Measure List

Measure	End-Use	Description	Baseline
Ductless Mini-Split HP	Space Cooling, Space Heating	Ductless Mini-Split HP, 17 SEER, 9.5 HSPF	Code-Compliant ASHP, 15 SEER, 8.8 HSPF
DX Coil Cleaning	Space Cooling	DX Coil Cleaning	DX Coil Not Cleaned
ECM Motors on Furnaces	Space Heating	Variable Speed Electronically Commutated Motor for an Electric Furnace	Permanent Split Capacitor Motor for Electric Furnace
Efficient Battery Charger	Miscellaneous	Efficient Battery Charger	FR or SCR charging stations with power conversion efficiency < 89% or > 10 W
Efficient Exhaust Hood	Cooking	Kitchen ventilation with automatically adjusting fan controls	Kitchen ventilation with constant speed ventilation motor
Efficient Motor Belts	Miscellaneous	Synchronous belt, 98% efficiency	Standard V-belt drive
Efficient New Construction Lighting	Interior Lighting	Efficient New Construction Lighting, 15% Better than Code	New Construction with Lighting Power Density meeting Code Minimum
Energy Recovery Ventilation System (ERV)	Space Cooling	Unitary Cooling Equipment that Incorporates Energy Recovery	Current Market Packaged or Split DX Unit
Energy Star Combination Oven	Cooking	Energy Star Combination Oven meeting ENERGY STAR Version 3.0 Standards	One Standard Economy-Grade 10-Pan Combination Oven
Energy Star Commercial Clothes Washer	Miscellaneous	One Commercial Clothes Washer meeting current ENERGY STAR Version 8.1 Standards	One Commercial Clothes Washer meeting Federal Standard
Energy Star Commercial Dishwasher	Domestic Hot Water	One Commercial Dishwasher meeting ENERGY STAR Version 3.0 Standards	One Dishwasher meeting Federal Standard
Energy Star Commercial Glass Door Freezer	Refrigeration	One Glass Door Freezer meeting ENERGY STAR Version 5.0 Standards	One Glass Door Freezer meeting Federal Standards
Energy Star Commercial Glass Door Refrigerator	Refrigeration	One Glass Door Refrigerator meeting ENERGY STAR Version 5.0 Standards	One Glass Door Refrigerator meeting Federal Standards
Energy Star Commercial Solid Door Freezer	Refrigeration	One Solid Door Freezer meeting ENERGY STAR Version 5.0 Standards	One Solid Door Freezer meeting Federal Standards
Energy Star Commercial Solid Door Refrigerator	Refrigeration	One Solid Door Refrigerator meeting ENERGY STAR Version 5.0 Standards	One Solid Door Refrigerator meeting Federal Standards
Energy Star convection oven	Cooking	Energy Star convection oven meeting ENERGY STAR Version 3.0 Standards	One Standard Economy-Grade Full-Size Convection Oven

EE Measure List

Measure	End-Use	Description	Baseline
Energy Star EV Chargers	Miscellaneous	Level 2 Electric Vehicle Supply Equipment (EVSE)	Level 1 Electric Vehicle Supply Equipment (EVSE)
Energy Star Fryer	Cooking	One Standard Vat Electric Fryer meeting ENERGY STAR Version 3.0 Standards	One Standard Economy-Grade Standard Vat Electric Fryer
Energy Star Griddle	Cooking	One Griddle meeting current ENERGY STAR Version 1.2 Standards	One Conventional Griddle
Energy Star Hot Food Holding Cabinet	Cooking	One Hot Food Holding Cabinet meeting current ENERGY STAR Version 2.0 Standards	One Standard Hot Food Holding Cabinet
Energy Star Ice Maker	Refrigeration	One Continuous Self-Contained Ice Maker meeting ENERGY STAR Version 3.0 Standards	One Continuous Self-Contained Ice Maker meeting Federal Standard
ENERGY STAR Imaging Equipment	Office Equipment	One imaging device meeting current ENERGY STAR Standards	One non-ENERGY STAR imaging device
Energy Star LED Directional Lamp	Interior Lighting	Energy Star 7.6W Directional LED lamp	50W Incandescent lamp
Energy Star Monitors	Office Equipment	One Monitor meeting ENERGY STAR 8.0 Standards	One Standard Monitor
Energy Star PCs	Office Equipment	One Personal Computer (desktop or laptop) meeting current ENERGY STAR® Standards	One non-ENERGY STAR® Personal Computer
Energy Star room AC	Space Cooling	Room AC meeting current ENERGY STAR standards	Code-Compliant Room AC, 1 Ton, 10.9 CEER
Energy Star Servers	Office Equipment	One Server meeting ENERGY STAR 2.0 Standards	One Standard Server
Energy Star Steamer	Cooking	One 4-Pan Electric Steamer meeting ENERGY STAR® 2.0 Standards	One Standard Economy-Grade 4-Pan Steamer
Energy Star Uninterruptable Power Supply	Office Equipment	Standard Desktop Plugged into Energy Star Uninterruptable Power Supply at 25% Load	Standard Desktop Plugged into Average Rotary Uninterruptable Power Supply at 25% Load
Energy Star Vending Machine	Refrigeration	One Refrigerated Vending Machine meeting ENERGY STAR Version 4.0 Standards	One Refrigerated Vending Machine meeting ENERGY STAR® 1.0 Standards
ENERGY STAR Water Cooler	Miscellaneous	One Storage Type Hot/Cold Water Cooler Unit meeting ENERGY STAR Version 3.0 Standards	One Standard Storage Type Hot/Cold Water Cooler Unit
Energy Star windows	Space Cooling, Space Heating	100ft2 of Window meeting Energy Star Version 6.0	100ft2 of Window meeting Energy Star Version 5.0

EE Measure List

Measure	End-Use	Description	Baseline
		Requirements (U-Value: 0.27, SHGC: 0.21)	Requirements (U-Value: 0.3, SHGC: 0.3)
Engine Block Timer	Miscellaneous	Plug-in timer that activates engine block timer to reduce unnecessary run time	Engine block heater (typically used for backup generators) running continuously
Escalator Motor Efficiency Controller	Miscellaneous	Install Escalator Motor Efficiency Controller	Escalator without Motor Efficiency Controller
Facility Commissioning	Space Cooling, Space Heating, Ventilation and Circulation	Perform facility commissioning to optimize building operations in new facilities	Standard new construction facility with no commissioning
Facility Energy Management System	Space Cooling, Space Heating, Ventilation and Circulation	Typical HVAC by Building Type Controlled by Energy Management System	Standard/manual facility equipment controls
Faucet Aerator	Domestic Hot Water	Low-flow lavatory faucet aerator, flow rate: 1.0 gpm	Federal lavatory flow rate standard, 1994, flow rate: 2.2 gpm
Floating Head Pressure Controls	Refrigeration	Medium-Temperature Refrigeration System with 5HP Compressor and Adjustable Condenser Head Pressure Control Valve	Medium-Temperature Refrigeration System with 5 HP Compressor without Adjustable Condenser Head Pressure Control Valve
Floor Insulation	Space Cooling, Space Heating	Increased Floor Insulation (R-19)	Market Average Existing Floor Insulation
Geothermal Heat Pump	Space Cooling, Space Heating	Geothermal Heat Pump	Code-Compliant Air Source Heat Pump
Green roof	Space Cooling, Space Heating	Vegetated Roof Surface on top of Standard Roof	Standard Black Roof
HE Air Cooled Chiller - All Compressor Types - 100 Tons	Space Cooling	HE Air Cooled Chiller - Air Compressor Types - 100 Tons	Code-Compliant Air Cooled Positive Displacement Chiller, 100 Tons
HE DX 11.25-20.0 Tons Elec Heat	Space Cooling, Space Heating	High Efficiency Packaged or Split DX Unit, 15 Tons, 11.5 SEER	Code-Compliant Packaged or Split DX Unit, 15 Tons, 11 SEER
HE DX 11.25-20.0 Tons Other Heat	Space Cooling	High Efficiency Packaged or Split DX Unit, 15 Tons, 11.5 SEER	Code-Compliant Packaged or Split DX Unit, 15 Tons, 11 SEER
HE DX 5.4-11.25 Tons Elect Heat	Space Cooling, Space Heating	High Efficiency Packaged or Split DX Unit, 7.5 Tons, 12 SEER	Code-Compliant Packaged or Split DX Unit, 7.5 Tons, 11 SEER
HE DX 5.4-11.25 Tons Other Heat	Space Cooling	High Efficiency Packaged or Split DX Unit, 7.5 Tons, 12 SEER	Code-Compliant Packaged or Split DX Unit, 7.5 Tons, 11 SEER

EE Measure List

Measure	End-Use	Description	Baseline
HE DX Less than 5.4 Tons Elect Heat	Space Cooling, Space Heating	High Efficiency Packaged or Split DX Unit, 5 Tons, 14.5 SEER	Code-Compliant Packaged or Split DX Unit, 5 Tons, 13 SEER
HE DX Less than 5.4 Tons Other Heat	Space Cooling	High Efficiency Packaged or Split DX Unit, 5 Tons, 14.5 SEER	Code-Compliant Packaged or Split DX Unit, 5 Tons, 13 SEER
HE Water Cooled Chiller - Centrifugal Compressor - 200 Tons	Space Cooling	Water Cooled Centrifugal Chiller with Integral VFD, 200 Tons	Code-Compliant Water Cooled Centrifugal Chiller, 200 Tons
HE Water Cooled Chiller - Centrifugal Compressor - 500 Tons	Space Cooling	Water Cooled Centrifugal Chiller with Integral VFD, 500 Tons	Code-Compliant Water Cooled Centrifugal Chiller, 500 Tons
HE Water Cooled Chiller - Rotary or Screw Compressor - 175 Tons	Space Cooling	Water Cooled Positive Displacement Chiller with Integral VFD, 175 Tons	Code-Compliant Water Cooled Positive Displacement Chiller, 175 Tons
HE Water Cooled Chiller - Rotary or Screw Compressor - 50 Tons	Space Cooling	Water Cooled Positive Displacement Chiller with Integral VFD, 50 Tons	Code-Compliant Water Cooled Positive Displacement Chiller, 50 Tons
Heat Pump Pool Heater Commercial	Miscellaneous	High Efficiency Pool Heater Eff. $\geq 84\%$	Standard Efficiency Pool Heater 78% Eff.
Heat Pump Water Heater	Domestic Hot Water	Efficient 50 Gallon Electric Heat Pump Water Heater	Code-Compliant 50 Gallon Electric Heat Pump Water Heater
High Efficiency Air Compressor	Miscellaneous	20 HP VFD Air Compressor	20 HP Inlet Modulation Fixed-Speed Compressor
High Efficiency Data Center Cooling	Space Cooling	High Efficiency CRAC (computer room air conditioner)	Standard Efficiency CRAC
High Efficiency PTAC	Space Cooling	High Efficiency PTAC	Code-Compliant PTAC
High Efficiency PTHP	Space Cooling, Space Heating	High Efficiency PTHP	Code-Compliant PTHP
High Efficiency Refrigeration Compressor_Discus	Refrigeration	High Efficiency Refrigeration Compressors	Standard Compressor
High Efficiency Refrigeration Compressor_Scroll	Refrigeration	High Efficiency Refrigeration Compressors	Standard Compressor
High Speed Fans	Ventilation and Circulation	High Speed Fan, 24" - 35" Blade Diameter	Standard Speed Fan, 24" - 35" Blade Diameter
Hot water pipe insulation	Domestic Hot Water	1' of Insulated Pipe in Unconditioned Spaces, Insulation of R-4	1' of Pipe in Unconditioned Spaces with Code Minimum of 1" of Insulation

EE Measure List

Measure	End-Use	Description	Baseline
Hotel Card Energy Control Systems	Space Cooling, Space Heating	Guest Room HVAC Unit Controlled by Hotel-Key-Card Activated Energy Control System	Guest Room HVAC Unit, Manually Controlled by Guest
Indoor daylight sensor	Interior Lighting	Install Indoor Daylight Sensors, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Induction Cooktops	Cooking	Efficient Induction Cooktop	One Standard Electric Cooktop
Infiltration Reduction - Air Sealing	Space Cooling, Space Heating	Reduced leakage through caulking, weather-stripping	Standard Heating and Cooling System with Moderate Infiltration
Instantaneous Hot Water System Commercial	Domestic Hot Water	Instantaneous Hot Water System	Code-Compliant Electric Storage Water Heater
LED - 14W_CFL Baseline	Interior Lighting	LED (assume 14W) replacing CFL	100W equivalent CFL
LED - 9W Flood_CFL Baseline	Exterior Lighting	LED (assume 9W) replacing CFL	14W CFL
LED Canopy Lighting (Exterior)	Exterior Lighting	One 67.2W LED Canopy Light	Average Lumen Equivalent Exterior Incandescent Area Lighting
LED Display Lighting (Exterior)	Exterior Lighting	One Letter of LED Signage, < 2ft in Height	One Letter of Neon or Argon-mercury Signage, < 2ft in Height
LED Display Lighting (Interior)	Interior Lighting	One Letter of LED Signage, < 2ft in Height	One Letter of Neon or Argon-mercury Signage, < 2ft in Height
LED Exit Sign	Interior Lighting	One 5W Single-Sided LED Exit Sign	One 9W Single-Sided CFL Exit Sign
LED Exterior Wall Packs	Exterior Lighting	One 35W LED Wall Pack	Average Lumen Equivalent Exterior Incandescent Area Lighting
LED High Bay_HID Baseline	Interior Lighting	One 140W High Bay LED Fixture	Lumen-Equivalent HID High Bay Fixture
LED High Bay_LF Baseline	Interior Lighting	One 140W High Bay LED Fixture	Lumen-Equivalent Linear Fluorescent High Bay Fixture
LED Linear - Fixture Replacement	Interior Lighting	2x4 LED Troffer	Lumen-Equivalent 32-Watt T8 Lamp
LED Linear - Lamp Replacement	Interior Lighting	Linear LED (16W)	Lumen-Equivalent 32-Watt T8 Lamp
LED Parking Lighting	Exterior Lighting	One 160W LED Area Light	Average Lumen Equivalent Exterior HID Area Lighting
LEED New Construction Whole Building	Space Cooling, Space Heating	LEED New Construction Whole Building	Comparable facility, code-compliance construction
Light Tube	Interior Lighting	One 14" Light Tube, Delivering light to 250 S.F. of Commercial Space	250 S.F. of Commercial Space Lit by Typical Lighting Strategies

EE Measure List

Measure	End-Use	Description	Baseline
Low Flow Shower Head	Domestic Hot Water	Low-Flow Handheld Showerhead, Flow Rate: 1.50 gpm	Standard Handheld Showerhead, Flow Rate: 2.50 gpm
Low-Flow Pre-Rinse Sprayers	Domestic Hot Water	Low-Flow Pre-Rinse Sprayer with Flow Rate of 1.6 gpm	Pre-Rinse Sprayer with Federal Standard Flow Rate of 2.25 gpm
Network PC Power Management	Office Equipment	One computer and monitor attached to centralized energy management system that controls when desktop computers and monitors plugged into a n	One computer and monitor, manually controlled
Networked Lighting Controls	Interior Lighting	Install Networked Lighting Controls System on Interior Lighting, 500 Watts Controlled	500 Watts of Lighting, Controlled either Manually or by Sensor as Specified by Code
Night Covers for Display Cases	Refrigeration	One Open Vertical Case with Night Covers	One Existing Open Vertical Case, No Night Covers
Occupancy Sensors, Ceiling Mounted	Interior Lighting	Ceiling Mounted Occupancy Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Occupancy Sensors, Switch Mounted	Interior Lighting	Switch Mounted Occupancy Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Outdoor Lighting Controls	Exterior Lighting	Install Exterior Photocell Dimming Controls, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Outdoor motion sensor	Exterior Lighting	Install Exterior Motion Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Ozone Laundry Commercial	Miscellaneous	Add a new ozone laundry system onto a commercial clothes washer	One commercial clothes washer without ozone laundry system
Programmable thermostat	Space Cooling, Space Heating	Pre-set programmable thermostat that replaces manual thermostat	Standard Heating and Cooling System with Manual Thermostat
PSC to ECM Evaporator Fan Motor (Reach-In)	Refrigeration	Medium Temperature Reach-In Case with equivalent size Electronically Commutated Evaporator Fan Motor	Medium Temperature Reach-In Case with Permanent Split Capacitor Evaporator Fan Motor
PSC to ECM Evaporator Fan Motor (Walk-In, Refrigerator)	Refrigeration	Medium Temperature Walk-In Case with Electronically Commutated Evaporator Fan Motor	Medium Temperature Walk-In Case with Permanent Split Capacitor Evaporator Fan Motor
Q-Sync Evaporator Fan Motor	Refrigeration	Medium Temperature Reach-In Case with	Medium Temperature Reach-In Case with 20W Permanent Split Capacitor Fan Motor

EE Measure List

Measure	End-Use	Description	Baseline
		equivalent size Q-Sync Evaporator Fan Motor	
Reflective Roof Treatment	Space Cooling	Reflective Roof Treatment	Standard Black Roof
Refrigerated Display Case LED Lighting	Refrigeration	60" Refrigerated Case LED Strip	Lumen-Equivalent 32-Watt T8 Fixture
Refrigerated Display Case Lighting Controls	Refrigeration	Occupancy Sensors for Refrigerated Case Lighting to reduce run time	Market-Share Weighted Existing Linear Fluorescent Fixture
Refrigeration Commissioning	Refrigeration	Commissioned Refrigeration System	Non-Commissioned Refrigeration System
Refrigeration Economizer	Refrigeration	Walk-in refrigerator with economizer	Walk-in refrigerator without economizer
Regenerative Drive Elevator Motor	Miscellaneous	Regenerative drive produced energy when motor in overhaul condition	Standard motor
Retro-Commissioning (Existing Construction)	Space Cooling, Space Heating, Ventilation and Circulation	Perform facility retro-commissioning, including assessment, process improvements, and optimization of energy-consuming equipment and systems	
Roof Insulation	Space Cooling, Space Heating	Roof Insulation (built-up roof applicable to flat/low slope roofs)	Code-Compliant Flat Roof
Server Virtualization	Office Equipment	2 Virtual Host Server	20 Single Application Servers
Smart Strip Plug Outlet	Office Equipment	One Smart Strip Plug Outlet	One Standard plug strip/outlet
Smart thermostat	Space Cooling, Space Heating	Thermostats that include "smart" features such as occupancy sensors, geo-fencing, multi-zone sensors	Standard Heating and Cooling System with Manual Thermostat
Solar Pool Heater Commercial	Miscellaneous	Solar Swimming Pool Heater	Electric Resistance Swimming Pool Heater
Solar Powered Pool Pump	Miscellaneous	Solar Powered Pool Pump Motor	Variable Speed Pool Pump Motor
Solar Thermal Water Heating System Commercial	Domestic Hot Water	Solar Thermal System with Electric Backup	Code-Compliant 50 Gallon Electric Resistance Water Heater
Strip Curtains - Freezers	Refrigeration	Walk-in freezer with strip curtains at least 0.06 inches thick covering the entire area of the doorway	Walk-in freezer without strip curtains
Strip Curtains - Refrigerators	Refrigeration	Walk-in cooler with strip curtains at least 0.06 inches	Walk-in cooler without strip curtains

EE Measure List

Measure	End-Use	Description	Baseline
		thick covering the entire area of the doorway	
Suction Pipe Insulation - Freezers	Refrigeration	Suction Pipe Insulation - Freezers	Uninsulated freezer suction lines
Suction Pipe Insulation - Refrigerators	Refrigeration	Suction Pipe Insulation - Refrigerators	Uninsulated refrigeration suction lines
Thermal Energy Storage	Space Cooling	Deploy thermal energy storage technology (ice harvester, etc.) to shift load	Code compliant chiller
Thermostatic Shower Restriction Valve Commercial	Domestic Hot Water	Hot Water Loop with 50 Gallon Electric Resistance Heater and Pressure Balance Shower Valves	Standard Hot Water Loop with 50 Gallon Electric Resistance Heater and Standard Shower Valves
Time Clock Control	Interior Lighting	Time Clock Controlled Lighting, 500 Watts Controlled	500 Watts of Lighting, Controlled either Manually or by Sensor as Specified by Code
Variable Refrigerant Flow (VRF) HVAC Systems	Space Cooling, Space Heating	Variable Refrigerant Flow (VRF) HVAC Systems	Code-Compliant PTHP
VAV System	Ventilation and Circulation	Variable Air Volume Distribution System	Constant Air Volume Distribution System
VFD on Cooling Tower Fans	Space Cooling	Cooling Tower Fans with VFD Control	Cooling Tower Fans without VFD Control
VFD on HVAC Pump	Space Cooling, Space Heating	VFD on HVAC Pump	7.5 HP HVAC Pump Motor, no VFD Control
VSD Controlled Compressor	Refrigeration	Refrigeration System with VSD Control	Refrigeration System with Standard Slide-Valve Control System
Wall Insulation	Space Cooling, Space Heating	Increased Exterior Above-Grade Wall Insulation	Market Average Existing Exterior Above-Grade Wall Insulation
Warehouse Loading Dock Seals	Space Cooling, Space Heating	Seals to reduce infiltration losses at loading dock	Loading dock with no seals
Water Cooled Refrigeration Heat Recovery	Domestic Hot Water	The heat reclaim system transfers waste heat from refrigeration system to space heating or hot water	No heat recovery
Water Heater Setback	Domestic Hot Water	A 50 gallon electric hot water tank with a thermostat setting reduced to no lower than 120 degrees.	A 50 gallon electric hot water tank with a thermostat setting that is higher than 120 degrees, typically hot water tanks with settings of 130 degrees or higher.
Water source heat pump	Space Cooling, Space Heating	Water Source Heat Pump, 2.5 Tons, 17.4 EER, 4.4 COP	Code-Compliant ASHP
Waterside Economizer	Space Cooling	Waterside Economizer	No economizer

EE Measure List

Measure	End-Use	Description	Baseline
Window shade film	Space Cooling	Window Film with SHGC of 0.35 Applied to Standard Window	Standard Window with below Code Required Minimum SHGC
Zero Energy Doors	Refrigeration	Install zero energy doors for a reach-in refrigerated cooler or freezer	Standard vertical reach-in refrigerated cooler or freezer with anti-sweat heaters on the glass surface of the doors

Table 14: Industrial EE Measures

Measure	End-Use	Description	Baseline
1.5HP Open Drip-Proof (ODP) Motor	Motors Pumps	High Efficiency 1.5 HP Open-Drip Proof Motor	1.5HP Open-Drip Proof Motor with Current Minimum EPACT Efficiency
10HP Open Drip-Proof (ODP) Motor	Motors Pumps	High Efficiency 10 HP Open-Drip Proof Motor	10HP Open-Drip Proof Motor with Current Minimum EPACT Efficiency
20HP Open Drip-Proof (ODP) Motor	Motors Pumps	High Efficiency 20 HP Open-Drip Proof Motor	20HP Open-Drip Proof Motor with Current Minimum EPACT Efficiency
3-phase High Frequency Battery Charger - 1 shift	Other	3-phase High Frequency Battery Charger	Standard Charger
Advanced Rooftop Controller	HVAC	Advanced Rooftop Controller	Without Advanced Rooftop Controller
Air Compressor Optimization	Compressed Air	Performing Routine Maintenance on 20HP Inlet Modulation Fixed-Speed Compressor	20 HP Inlet Modulation Fixed-Speed Compressor
Air curtains	HVAC	Air Curtain across door opening	Door opening with no air curtain
Airside economizer	HVAC	Airside Economizer	No economizer
Auto Closer on Refrigerator Door	Process Cooling	One Medium Temperature Walk-In Refrigerator Door with Auto-Closer	One Medium Temperature Walk-In Refrigerator Door without Auto-Closer
Auto Off Time Switch	Interior Lighting High Bay	Auto-Off Time Switch on Interior Lighting, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Bi-Level Lighting Control (Exterior)	Exterior Lighting Industrial	Install Exterior Bi-Level Lighting Control, 500 Watts Controlled	500 Watts of Lighting, No Dim Setting
Bi-Level Lighting Control (Interior)	Interior Lighting High Bay	Bi-Level Controls on Interior Lighting, 500 Watts Controlled	500 Watts of Lighting, No Dim Setting

EE Measure List

Measure	End-Use	Description	Baseline
Chilled Water Reset	HVAC	One Chiller with Reset of Chilled Water Temperature Setpoint	One Chiller with Fixed Chilled Water Temperature
Cogged Belt on 15hp ODP Motor	Motors Pumps	15HP ODP Motor with Cogged Belts Installed on Supply and/or Return Air Fans	15HP ODP Motor with Smooth V-Belts Installed on Supply and/or Return Air Fans
Cogged Belt on 40hp ODP Motor	Motors Pumps	40HP ODP Motor with Cogged Belts Installed on Supply and/or Return Air Fans	40HP ODP Motor with Smooth V-Belts Installed on Supply and/or Return Air Fans
Compressed Air Desiccant Dryer	Process Specific	heated regenerative desiccant dryer without dew point demand controls	heatless regenerative desiccant dryer without dew point demand controls
Compressed Air No-Loss Condensate Drains	Process Specific	Install no-loss condensate drains	Install standard condensate drains
Compressed Air Storage Tank	Compressed Air	20 HP Inlet Modulation Fixed-Speed Compressor with Receiver Tank	20 HP Inlet Modulation Fixed-Speed Compressor, No Receiver Tank
Custom Measure - Non-Lighting	HVAC	Custom Improvement to Facility's Operations	Baseline Technology/Process
Dairy Refrigeration Heat Recovery	Other	refrigeration equipment with refrigeration heat recovery tank installed	existing dairy farm with refrigeration equipment and a water heater unit without an RHR unit
Dedicated Outside Air System (DOAS)	HVAC	Install Dedicated Outside Air System (DOAS)	Typical HVAC by Building Type
Demand Controlled Ventilation	HVAC	Return Air System with CO2 Sensors	Standard Return Air System, No Sensors
Demand Defrost	Process Cooling	Walk-In Freezer System with Demand-Controlled Electric Defrost Cycle	Walk-In Freezer System with Timer-Controlled Electric Defrost Cycle
Dew Point Sensor Control for Dessicant CA Dryer	Compressed Air	1000 CFM Heated Desicant Air Dryer with Dew Point Controls	1000 CFM Modulating Heated Desicant Air Dryer
Drip Irrigation Nozzles	Other	Flow Control Nozzles	Standard Irrigation Nozzles
Dual Enthalpy Economizer	Process Cooling	Standard HVAC Unit with an economizer and dual enthalpy differential control	HVAC unit with no economizer or with a non-functional disabled economizer
DX Coil Cleaning	HVAC	DX Coil Cleaning	DX Coil Not Cleaned
Efficient Compressed Air Nozzles	Compressed Air	1/4" Engineered Air Nozzle	1/4" Open-End Air Nozzle

EE Measure List

Measure	End-Use	Description	Baseline
Efficient New Construction Lighting	Interior Lighting High Bay	Efficient New Construction Lighting, 15% Better than Code	New Construction with Lighting Power Density meeting Code Minimum
Electric Actuators	Other	Electric Actuator	Pneumatic Actuator
Energy Efficient Laboratory Fume Hood	HVAC	Variable Air Volume High Performance Fume Hood	Constant Volume Conventional Bypass Fume Hood
Energy Efficient Transformers	Other	Energy Efficient Dry Type Transformer (CSL-3)	Standard Transformer (TP-1)
Energy Recovery Ventilation System	HVAC	Unitary Cooling Equipment that Incorporates Energy Recovery	Code-Compliant Packaged or Split DX Unit, 7.5 Tons, 11.2 EER
Energy Star LED Directional Lamp	Interior Lighting Other	Energy Star 7.6W Directional LED lamp	50W Incandescent lamp
Energy Star room ac	HVAC	Room AC meeting current ENERGY STAR standards	Code-Compliant Room AC
Energy Star windows	HVAC	100ft2 of Window meeting Energy Star Version 6.0 Requirements (U-Value: 0.27, SHGC: 0.21)	100ft2 of Window meeting Energy Star Version 5.0 Requirements (U-Value: 0.3, SHGC: 0.3)
Engine Block Timer	Other	An engine block heater operated by an outdoor plug-in timer	An engine block heater that is manually plugged in
Facility Commissioning	HVAC	Perform facility commissioning	Comparable facility, no commissioning
Facility Energy Management System	HVAC	Typical HVAC by Building Type Controlled by Energy Management System	Typical HVAC by Building Type, Manually Controlled
Fan Thermostat Controller	HVAC	Typical HVAC by Building Type with Fan Thermostat Controller Installed	Typical HVAC by Building Type with Programmable Thermostat
Floating Head Pressure Controller	Process Cooling	Medium-Temperature Refrigeration System with 5HP Compressor and Adjustable Condenser Head Pressure Control Valve	Medium-Temperature Refrigeration System with 5 HP Compressor without Adjustable Condenser Head Pressure Control Valve
Grain Bin Aeration Control System	Process Specific	Grain Storage Fan System with Automatic Controls	Grain Storage Fan System with Manual Controls
HE Air Cooled Chiller - All Compressor Types - 100 Tons	HVAC	HE Air Cooled Chiller - All Compressor Types - 100 Tons	Code-Compliant Air Cooled Positive Displacement Chiller, 100 Tons
HE Air Cooled Chiller - All Compressor Types - 300 Tons	HVAC	Air Cooled Positive Displacement Chiller with Integral VFD, 300 Tons, 13.7 EER	Code-Compliant Air Cooled Positive Displacement Chiller, 300 Tons, 12.5 EER

EE Measure List

Measure	End-Use	Description	Baseline
HE DX 11.25-20.0 Tons Elec Heat	HVAC	High Efficiency Packaged or Split DX Unit, 15 Tons, 11.5 SEER	Code-Compliant Packaged or Split DX Unit, 15 Tons, 11 SEER
HE DX 11.25-20.0 Tons Other Heat	HVAC	High Efficiency Packaged or Split DX Unit, 15 Tons, 11.5 SEER	Code-Compliant Packaged or Split DX Unit, 15 Tons, 11 SEER
HE DX 5.4-11.25 Tons Elect Heat	HVAC	High Efficiency Packaged or Split DX Unit, 7.5 Tons, 12 SEER	Code-Compliant Packaged or Split DX Unit, 7.5 Tons, 11 SEER
HE DX 5.4-11.25 Tons Other Heat	HVAC	High Efficiency Packaged or Split DX Unit, 7.5 Tons, 12 SEER	Code-Compliant Packaged or Split DX Unit, 7.5 Tons, 11 SEER
HE DX Less than 5.4 Tons Elect Heat	HVAC	High Efficiency Packaged or Split DX Unit, 5 Tons, 14.5 SEER	Code-Compliant Packaged or Split DX Unit, 5 Tons, 13 SEER
HE DX Less than 5.4 Tons Other Heat	HVAC	High Efficiency Packaged or Split DX Unit, 5 Tons, 14.5 SEER	Code-Compliant Packaged or Split DX Unit, 5 Tons, 13 SEER
HE Water Cooled Chiller - Centrifugal Compressor - 200 Tons	HVAC	Water Cooled Centrifugal Chiller with Integral VFD, 200 Tons	Code-Compliant Water Cooled Centrifugal Chiller, 200 Tons
HE Water Cooled Chiller - Centrifugal Compressor - 500 Tons	HVAC	Water Cooled Centrifugal Chiller with Integral VFD, 500 Tons	Code-Compliant Water Cooled Centrifugal Chiller, 500 Tons
HE Water Cooled Chiller - Rotary or Screw Compressor - 175 Tons	HVAC	Water Cooled Positive Displacement Chiller with Integral VFD, 175 Tons	Code-Compliant Water Cooled Positive Displacement Chiller, 175 Tons
HE Water Cooled Chiller - Rotary or Screw Compressor - 50 Tons	HVAC	Water Cooled Positive Displacement Chiller with Integral VFD, 50 Tons	Code-Compliant Water Cooled Positive Displacement Chiller, 50 Tons
High Bay Occupancy Sensors, Ceiling Mounted	Interior Lighting High Bay	Ceiling Mounted Occupancy Sensor, 800 Watts Controlled	800 Watts of Lighting, Manually Controlled
High Efficiency Air Compressor	Compressed Air	20 HP VFD Air Compressor	20 HP Inlet Modulation Fixed-Speed Compressor
High Efficiency Refrigeration Compressor - Discus	Process Cooling	High Efficiency Refrigeration Compressors	Standard Compressor

EE Measure List

Measure	End-Use	Description	Baseline
High Efficiency Refrigeration Compressor - Scroll	Process Cooling	High Efficiency Refrigeration Compressors	Standard Compressor
High Efficiency Welder	Process Specific	High Efficiency Welder	Standard Welding Practices
High Speed Fans	HVAC	High Speed Fan, 24" - 35" Blade Diameter	Standard Speed Fan, 24" - 35" Blade Diameter
High Volume Low Speed Fan (HVLS)	Motors Fans Blowers	20' High Volume Low Speed Fan	Conventional Circulating Fan
Indoor Agriculture - LED Grow Lights	Interior Lighting High Bay	LED grow light	1000W High Pressure Sodium
Indoor daylight sensor	Interior Lighting High Bay	Install Indoor Daylight Sensors, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Industrial Duct Sealing	HVAC	Standard Electric Heating and Central AC with Improved Duct Sealing	Standard Electric Heating and Central AC, Standard Duct Sealing
Injection Mold and Extruder Barrel Wraps	Other	2' Diameter, 20' Long Machine Barrel with 1" Insulation	2' Diameter, 20' Long Machine Barrel with no Insulation
Insulated Pellet Dryer Tanks and Ducts	Process Heating	Insulation for Pellet Tank and Duct	Uninsulated Pellet Tank and Duct
LED - 14W_CFL Baseline	Interior Lighting Other	LED (assume 14W) replacing CFL	100W equivalent CFL
LED Canopy Lighting (Exterior)	Exterior Lighting Industrial	One 67.2W LED Canopy Light	Average Lumen Equivalent Exterior Incandescent Area Lighting
LED Display Lighting (Exterior)	Exterior Lighting Industrial	One Letter of LED Signage, < 2ft in Height	One Letter of Neon or Argon-mercury Signage, < 2ft in Height
LED Display Lighting (Interior)	Interior Lighting Other	One Letter of LED Signage, < 2ft in Height	One Letter of Neon or Argon-mercury Signage, < 2ft in Height
LED exit sign	Interior Lighting Other	One 5W Single-Sided LED Exit Sign	One 9W Single-Sided CFL Exit Sign
LED Exterior Wall Packs	Exterior Lighting Industrial	One 35W LED Wall Pack	Average Lumen Equivalent Exterior Incandescent Area Lighting
LED High Bay_HID Baseline	Interior Lighting High Bay	One 140W High Bay LED Fixture	Lumen-Equivalent HID High Bay Fixture
LED High Bay_LF Baseline	Interior Lighting High Bay	One 140W High Bay LED Fixture	Lumen-Equivalent Linear Fluorescent High Bay Fixture
LED Linear - Fixture Replacement	Interior Lighting Linear Fluorescent	2x4 LED Troffer Fixture	Lumen-Equivalent 32-Watt T8 Fixture

EE Measure List

Measure	End-Use	Description	Baseline
LED Linear - Lamp Replacement	Interior Lighting Linear Fluorescent	Linear LED	Lumen-Equivalent 32-Watt T8 Lamp
LED Parking Lighting	Exterior Lighting Industrial	One 160W LED Area Light	Average Lumen Equivalent Exterior HID Area Lighting
LEED New Construction Whole Building	HVAC	LEED Qualifying New Construction	Comparable facility, code-compliance construction
Light Tube	Interior Lighting Other	One 14" Light Tube, Delivering light to 250 S.F. of Industrial Space	250 S.F. of Industrial Space Lit by Typical Lighting Strategies
Low Energy Livestock Waterer	Motors Pumps	Install Thermostatically Controlled Livestock Watering System	Standard Livestock Watering System
Low Pressure Sprinkler Nozzles	Motors Pumps	Low Pressure Irrigation Nozzles operate at 35 psi or lower	Standard high pressure irrigation nozzles that operate at 50 psi or greater
Low Pressure-drop Filters	Compressed Air	20 HP Inlet Modulation Fixed-Speed Compressor with Low Pressure Drop Filter	20 HP Inlet Modulation Fixed-Speed Compressor, No Particulate Removal
Milk Pre-Cooler	Other	Installed pre-cooler heat exchanger	no pre-cooler heat exchanger installed
Networked Lighting Controls	Interior Lighting Linear Fluorescent	Install Networked Lighting Controls System on Interior Lighting, 500 Watts Controlled	500 Watts of Lighting, Controlled either Manually or by Sensor as Specified by Code
Occupancy Sensors, Ceiling Mounted	Interior Lighting High Bay	Ceiling Mounted Occupancy Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Occupancy sensors, switch mounted	Interior Lighting Linear Fluorescent	Switch Mounted Occupancy Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Outdoor Lighting Controls	Exterior Lighting Industrial	Install Exterior Photocell Dimming Controls, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Outdoor motion sensor	Exterior Lighting Industrial	Install Exterior Motion Sensor, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
Packaged Terminal AC	HVAC	High Efficiency Packaged Terminal AC	Code-Compliant PTAC, 10.9 EER
Process Cooling Ventilation Reduction	Process Cooling	Standard Process Cooling with Reduced Ventilation	Standard Process Cooling
Programmable thermostat	HVAC	Standard Heating and Cooling System with Programmable Thermostat	Standard Heating and Cooling System with Manual Thermostat
Reflective Roof Treatment	HVAC	Reflective Roof Treatment	Standard Black Roof

EE Measure List

Measure	End-Use	Description	Baseline
Refrigeration Commissioning	Process Cooling	Commissioned Refrigeration System	Non-Commissioned Refrigeration System
Retro-Commissioning (Existing Construction)	HVAC	Perform Facility Retro-commissioning	
Roof insulation	HVAC	Roof Insulation (built-up roof applicable to flat/low slope roofs)	Code-Compliant Flat Roof
Smart thermostat	HVAC	Standard Heating and Cooling System with Smart Thermostat	Standard Heating and Cooling System with Manual Thermostat
Strategic Energy Management	HVAC	SEM goal setting and tracking	No active energy management
Synchronous Belt on 15hp ODP Motor	Motors Pumps	15 HP Open-Drip Proof Motor with Synchronous Belts Installed on Supply and/or Return Air Fans	15 HP Open-Drip Proof Motor with Smooth V-Belts Installed on Supply and/or Return Air Fans
Synchronous Belt on 5hp ODP Motor	Motors Pumps	5 HP Open-Drip Proof Motor with Synchronous Belts Installed on Supply and/or Return Air Fans	5 HP Open-Drip Proof Motor with Smooth V-Belts Installed on Supply and/or Return Air Fans
Synchronous Belt on 75hp ODP Motor	Motors Pumps	75 HP Open-Drip Proof Motor with Synchronous Belts Installed on Supply and/or Return Air Fans	75 HP Open-Drip Proof Motor with Smooth V-Belts Installed on Supply and/or Return Air Fans
Thermal energy storage	HVAC	Deploy thermal energy storage technology (ice harvester, etc.) to shift load	Code compliant chiller
Time Clock Control	Interior Lighting High Bay	Time Clock Controlled Lighting, 500 Watts Controlled	500 Watts of Lighting, Manually Controlled
VAV System	HVAC	Variable Air Volume Distribution System	Constant Air Volume Distribution System
VFD on Air Compressor	Compressed Air	20 HP VFD Air Compressor	20 HP Inlet Modulation Fixed-Speed Compressor
VFD on Cooling Tower Fans	Process Cooling	Cooling Tower Fans with VFD Control	Cooling Tower Fans without VFD Control
VFD on HVAC Fan	Motors Fans Blowers	5 HP HVAC Fan Motor, with VFD Control	5 HP HVAC Fan Motor, no VFD Control
VFD on HVAC Pump	Motors Pumps	VFD on HVAC Pump	7.5 HP HVAC Pump Motor, no VFD Control
VFD on process pump	Motors Pumps	20 HP Process Pump Equipped with VFD Control	20 HP Process Pump, Constant Speed
VSD Controlled Compressor	Process Cooling	Refrigeration System with VSD Control	Refrigeration System with Standard Slide-Valve Control System

EE Measure List

Measure	End-Use	Description	Baseline
Water source heat pump	HVAC	Water Source Heat Pump, 2.5 Tons, 17.4 EER, 4.4 COP	Code-Compliant ASHP
Waterside economizer	HVAC	Waterside Economizer	No economizer
Window shade film	HVAC	Window Film with SHGC of 0.35 Applied to Standard Window	Standard Window with below Code Required Minimum SHGC

The following EE measures from the 2019 Technical Potential Study were eliminated from the current study⁸:

Table 15: 2019 EE Measures Eliminated from Current Study

Sector	Measure	End-Use	Reason for Removal
Residential	CFL - 15W Flood	Lighting	Better technology (LED) available
Residential	CFL - 15W Flood (Exterior)	Lighting	Better technology (LED) available
Residential	CFL - 13W	Lighting	Better technology (LED) available
Residential	CFL - 23W	Lighting	Better technology (LED) available
Residential	Low Wattage T8 Fixture	Lighting	Better technology (LED) available
Residential	15 SEER Central AC	Space Cooling	Updated Federal Standard
Residential	15 SEER Air Source Heat Pump	Space Cooling, Space Heating	Updated Federal Standard
Residential	14 SEER ASHP from base electric resistance heating	Space Cooling, Space Heating	Updated Federal Standard
Residential	Two Speed Pool Pump	Miscellaneous	Updated Florida Energy Code
Residential	Variable Speed Pool Pump	Miscellaneous	Updated Florida Energy Code
Residential	Storm Door	Space Cooling, Space Heating	Minimal/uncertain energy savings
Commercial	CFL - 15W Flood	Exterior Lighting	Better technology (LED) available
Commercial	High Efficiency HID Lighting	Exterior Lighting	Better technology (LED) available

⁸ Additional measures from the 2019 study were updated to reflect current vintage/technology for the current study.

EE Measure List

Sector	Measure	End-Use	Reason for Removal
Commercial	LED Street Lights	Exterior Lighting	Market standard
Commercial	LED Traffic and Crosswalk Lighting	Exterior Lighting	Market standard
Commercial	CFL-23W	Interior Lighting	Better technology (LED) available
Commercial	High Bay Fluorescent (T5)	Interior Lighting	Better technology (LED) available
Commercial	Premium T8 - Fixture Replacement	Interior Lighting	Better technology (LED) available
Commercial	Premium T8 - Lamp Replacement	Interior Lighting	Better technology (LED) available
Commercial	Two Speed Pool Pump	Miscellaneous	Updated Florida Energy Code
Commercial	Variable Speed Pool Pump	Miscellaneous	Updated Florida Energy Code
Commercial	Tank Wrap on Water Heater	Domestic Hot Water	Limited applicability
Commercial	Ceiling Insulation (R12 to R38)	Space Cooling, Space Heating	Consolidated measure baseline assumptions
Commercial	Ceiling Insulation (R30 to R38)	Miscellaneous	Consolidated measure baseline assumptions

Appendix B DR Measure List

Table 16: Residential DR Measures

Measure	Type	Season	Description
Central air conditioner - Load Shed	Direct load control	Summer	Direct load control program where utility provides day ahead notification that it will send remote signal to shed AC unit load during peak usage period.
Central Heating - Load Shed	Direct load control	Winter	Direct load control program where utility provides day ahead notification that it will send remote signal to shed AC unit load during peak usage period.
Central air conditioner - 50% cycling	Direct load control	Summer	Direct load control program where utility provides day ahead notification that it will send remote signal to cycle AC unit during peak usage period
Central Heating - 50% cycling	Direct load control	Winter	Direct load control program where utility provides day ahead notification that it will send remote signal to cycle AC unit during peak usage period
Smart thermostats - Utility Installation	Direct load control	Summer and Winter	Similar to AC load control program, but allows customers to participate using a compatible smart thermostat rather than an AC switch
Smart thermostats - BYOT	Direct load control	Summer and Winter	Similar to AC load control program, but allows customers to participate using a compatible smart thermostat rather than an AC switch
CPP + Tech	Pricing	Summer and Winter	Electricity rate that varies based on time of day. Can be same rate schedule for every day during a given season (time of use, or TOU) and with critical peak pricing (CPP) days when peak period rates are substantially higher for a limited number of days per year (customers receive advance notification of CPP event). Customers also receive technology that they can pre-program to curtail load when an event is called.
Water heater control	Direct load control	Summer and Winter	Load control installed on a water heater (integrated or external switch)
Pool pump switches	Direct load control	Summer and Winter	Load control program with switch installed on pool pump
Room AC	Direct load control	Summer	Load control program that is focused on room AC units rather than central AC
Managed EV Charging - switch	Direct load control	Summer and Winter	Load control switch that is installed on an EV charger
Managed EV Charging - telematics	Direct load control	Summer and Winter	Direct load control program leveraging EV smart charging software
Battery Storage with PV	Pricing/Direct load control	Summer and Winter	PV charges battery and battery discharges to grid

DR Measure List

Table 17: Small C&I DR Measures

Measure	Type	Season	Description
Central air conditioner - Load Shed	Direct load control	Summer	Direct load control program where utility provides day ahead notification that it will send remote signal to shed AC unit load during peak usage period.
Central Heating - Load Shed*	Direct load control	Winter	Direct load control program where utility provides day ahead notification that it will send remote signal to shed AC unit load during peak usage period.
Central air conditioner - 50% cycling	Direct load control	Summer	Direct load control program where utility provides day ahead notification that it will send remote signal to cycle AC unit during peak usage period
Central Heating - 50% cycling*	Direct load control	Winter	Direct load control program where utility provides day ahead notification that it will send remote signal to cycle AC unit during peak usage period
Smart thermostats - Utility Installation*	Direct load control	Summer and Winter	Similar to AC load control program, but allows customers to participate using a compatible smart thermostat rather than an AC switch
Smart thermostats - BYOT*	Direct load control	Summer and Winter	Similar to AC load control program, but allows customers to participate using a compatible smart thermostat rather than an AC switch
CPP + Tech	Pricing	Summer and Winter	Electricity rate that varies based on time of day. Can be same rate schedule for every day during a given season (time of use, or TOU) and with critical peak pricing (CPP) days when peak period rates are substantially higher for a limited number of days per year (customers receive advance notification of CPP event). Customers also receive technology that they can pre-program to curtail load when an event is called.
Managed EV Charging - switch	Direct load control	Summer and Winter	Load control switch that is installed on an EV charger
Managed EV Charging - telematics	Direct load control	Summer and Winter	Direct load control program leveraging EV smart charging software
Battery Storage with PV	Pricing/Direct load control	Summer and Winter	PV charges battery and battery discharges to grid

Table 18: Large C&I DR Measures

Measure	Type	Season	Description
CPP + Tech	Pricing	Summer and Winter	Electricity rate that varies based on time of day. Can be same rate schedule for every day during a given season (time of use, or TOU) and with critical peak pricing (CPP) days when peak period rates are substantially higher for a limited number of days per year (customers receive advance notification of

DR Measure List

Measure	Type	Season	Description
			CPP event). Customers also receive technology that they can pre-program to curtail load when an event is called.
Auto DR	Utility-controlled loads	Summer and Winter	Custom load control of specific end-uses/processes that is triggered by utility signal to building management system; customer can sometimes opt-out of specific events
Firm Service Level	Contractual	Summer and Winter	Customer commits to a maximum usage level during peak periods and, when notified by the utility, agrees to cut usage to that level.
Guaranteed Load Drop	Contractual	Summer and Winter	Customer agrees to reduce usage by an agreed upon amount when notified

No DR measures from the 2019 Technical Potential Study were eliminated from the current study.

Appendix C DSRE Measure List

Table 19: Residential DSRE Measures

Measure	Description
PV System	Roof-mounted system, including multiple panels, AC/DC inverter, racking system, and electrical system interconnections
Battery Storage from PV System	Lithium-ion battery system designed to integrate with an on-site PV system to store and discharge excess energy from PV generation

Table 20: Non-Residential DSRE Measures

Measure	Description
PV System	Roof-mounted system, including multiple panels, AC/DC inverter, racking system, and electrical system interconnections
Battery Storage from PV System	Lithium-ion battery system designed to integrate with an on-site PV system to store and discharge excess energy from PV generation
CHP - Fuel Cell	An electrochemical cell-based generator that reacts hydrogen fuel with oxygen
CHP - Micro Turbine	Small combustion turbine that burns gaseous or liquid fuel to drive a generator
CHP - Gas Turbine	A combustion turbine that burns gaseous or liquid fuel to drive a generator
CHP - Reciprocating Engine	An engine that uses one or more pistons to convert pressure into rotational motion
CHP - Steam Turbine	A turbine that extracts thermal energy from pressured steam to drive a generator

No DSRE measures from the 2019 Technical Potential Study were eliminated from the current study.

Appendix D External Measure Suggestions

Table 21: External Measure Suggestions and Actions

Measure Suggestion	Stakeholder Comments	Action taken for FEECA Study
Efficient Electrification Measures	All measures that can produce substantial site energy savings by converting from natural gas or other fossil fuels should be included in the Florida electric utilities' next efficiency potential study. Key examples include efficient heat pumps to displace gas furnaces and efficient heat pump water heaters to displace gas water heaters. It is important to note that these electrification measures provide not only heating energy savings and water heating energy savings, but can also potentially provide cooling efficiency benefits as well. In the case of heat pumps, that can occur because efficient heat pumps can operate in cooling mode more efficiently than standard central air conditioners. In the case of heat pump water heaters, cooling and dehumidification benefits can occur when/if the water heater is in conditioned space because they transfer heat (particularly latent heat) from the air around them to the water they are heating. A growing number of jurisdictions - including Illinois, Minnesota and some northeastern states - have begun to include efficient electrification measures in their efficiency programs portfolios.	Fuel-switching and electrification are outside the scope of this study
Networked Lighting Controls	LED lighting technology has become increasingly accepted and installed in commercial buildings. The next big efficiency opportunity in commercial lighting efficiency is in sophisticated controls integrated into the light fixtures themselves - both luminaire level lighting controls and networked lighting controls. For example, a 2017 report for both the Northwest Energy Efficiency Alliance and the Design Lights Consortium, a non-profit that works with utilities and manufacturers of lighting products (and which many utilities across the country reference for determination of eligibility of lighting products for efficiency program rebates), found that networked lighting controls can provide on the order of 50% additional savings after LED conversion. Other studies have also found the national savings potential from such products to be enormous. Moreover, these products can be designed to provide not only lighting energy savings but also a number of other non-energy benefits (e.g., asset tracking, such as the ability of hospitals to know the location of all wheel chairs). Numerous utilities across the country now actively promote this technology through their efficiency programs. For example, Commonwealth Edison, the utility serving Chicago and other parts of northern Illinois, is currently getting a significant portion of its commercial lighting savings from promotion of networked lighting controls	Added to measure list for 2024 study

Measure Suggestion	Stakeholder Comments	Action taken for FEECA Study
Ductless mini-split heat pumps to displace inefficient electric baseboard heating	While most Florida residential buildings with electric heat provide that heat with heat pumps, at least some (perhaps most likely being older multi-family rental buildings) still use inefficient electric resistance heat. Ductless mini- split heat pump retrofits can very efficiently displace such inefficient electric heat and should be added to the residential measure list.	Added to measure list for 2024 study
Air Source Heat Pump baseline assumptions	There are seven air source heat pump (ASHP) measures included in the residential measure list. Two of them - one at SEER 14 and a second at SEER 21 - are listed as relative to an electric resistance baseline. Five of them - SEER 15, SEER 16, SEER 17, SEER 18 and SEER 21 - appear to be relative to a baseline of a standard new ASHP. Are we interpreting this correctly? If so, we have a couple of comments/questions/suggestions: • The efficiency standards assessed need to be modified to be consistent with new federal standards, including new testing procedures. • For cases where the baseline is "electric resistance", why only assessing two efficiency tiers (i.e., fewer than for standard ASHP baselines)? The same number of efficiency tiers should be assessed for both baselines.	Incorporated suggestions into 2024 study, including updated baseline standard and assessing same efficiency tiers for both baselines
Heat Pump Water Heater Efficiency	The Res EE tab of the utilities draft measure list suggests that the efficiency of a heat pump water heater is an EF of 2.50. That is unrealistically low. In fact, of the 222 products listed on the Energy Star website, none had UEFs less than 2.80 and only 29 (13%) had UEFs that were less than 3.4; the average was 3.57. Indeed, the first product listed on a search of heat pump water heaters on Home Depot's website is a 50 gallon, Rheem (Pro Terra) product with a UEF of 3.75 and a cost of \$1699.	Incorporated suggestion into 2024 study
New Construction Measure Packages	The measures lists did not appear to include packages of measures for building new residential and/or new commercial buildings to levels of efficiency beyond those required by code. Utilities in many jurisdictions run new construction efficiency programs supporting such measure packages. In the residential sector, many base their programs on the long-standing Federal Energy Star standard. However, increasingly utility programs are promoting additional efficiency tiers - often as part of all-electric new construction program offerings - that go well beyond the Energy Star standard. For example, Consumers Energy (Michigan) offers \$1000 rebates to builders who construct Energy Star single family homes	Incorporated suggestion into 2024 study with 2 tiers of residential new construction whole-home improvement measures.

Measure Suggestion	Stakeholder Comments	Action taken for FEECA Study
	with a Home Energy Rating (HERS) score of 57 or less, but offer higher rebates for more efficient buildings - up to \$4000 for all electric homes with a HERS score of 40 or less. The Florida utilities potential study should assess savings potential for both the Energy Star level and a tier or two of additional efficiency beyond that level. Similar assessments of new commercial building savings potential should also be assessed.	
Custom Industrial Measures	The utilities' list of industrial efficiency measures addresses common industrial efficiency opportunities. However, it does not address efficiency opportunities that may be unique to individual industries or even to individual industrial facilities. That can include such things as changes in types of materials used in manufacturing, reductions in waste streams, improved use of water delivered by agricultural irrigation systems, and/or other things that are not directly related to energy using equipment or controls of such equipment. It is obviously not possible to list all such measures. However, a potential study will understate savings potential if it does not include a way of capturing such potential in its estimates. One potential way to get a sense of such potential is to review results of comprehensive industrial efficiency programs run by other utilities to identify the portion of actual program savings from such unique custom measures - and then assume that portion of custom savings could be added to the savings estimated in the study for named measures.	Added to measure list for 2024 study
Electric Vehicle measures	Some EV chargers are more efficient than others. The Federal Energy Star program has a standard for them. Savings potential may not be huge, but should be considered in the study. With a growing number of EV sales, the study should also consider the potential savings from promoting the most efficient EVs within different size/style categories	Added to measure list for 2024 study
Removing screw-based LEDs	The screw-based LEDs on both the Residential and Commercial measure lists should now be considered baseline due to federal efficiency standards adopted earlier this year. Utility load forecasts for IRPs should reflect resulting improvements in end use efficiency.	Screw-based LEDs were included in the study but with limited applicability to reflect current market
Removing Commercial fluorescent lighting	LED technology - for both fixtures and lamps - has advanced significantly in recent years, to the point where it should be the only technology considered for commercial lighting. Measures such as high performance T-8 fluorescent fixtures and high bay T-5 fluorescent fixtures should be replaced with LED alternatives in the study.	Updated measure list for 2024 study to only include LED-based lamps for linear fluorescent replacements

Measure Suggestion	Stakeholder Comments	Action taken for FEECA Study
Removing fossil-gas fueled CHP	Fossil-fuel fired CHP systems should not be considered “renewable” and have questionable benefits if electric generation is expected to get increasingly more renewable and clean. Biogas-fueled CHP – such as systems installed in wastewater treatment facilities that use methane byproducts of processing waste – should be included in the study.	2024 study will continue to assess all CHP options
Adding livestock methane power generation to renewables list	For example, see the “cow power” program currently being run by Green Mountain Power, Vermont’s largest electric utility	2024 study will continue to assess DSRE options consistent with prior study, including customer-sited solar, solar plus storage, and CHP
Adding EV managed charging to DR list	With national market shares for EVs growing, it is important that utilities consider programs for managing when charging occurs. Numerous utilities are currently running managed charging programs. This does not currently appear to be on the measure list and should be added to the Florida utilities’ potential study.	Added to measure list for 2024 study
Residential “smart thermostat” measure can provide both efficiency savings and demand response potential	This is recognized in the inclusion of smart thermostats in both the Res EE and DR tabs of the measure list spreadsheet. We simply want to flag that it is important when assessing cost-effectiveness of this measure that these two potential benefits are considered together. In other words, the cost should be considered compared to the combined efficiency and DR potential rather than separately considered relative to just EE savings and then separately again compared to just DR potential	2024 study will include interactive impacts of EE and DR opportunities
Emerging Technologies	The efficiency potential study measure list appears to be somewhat outdated. It does not include a number of new and emerging technologies. The potential list of such technologies is long. We suggest reviewing the attached list of emerging technologies developed almost two years ago by Consumers Energy (Michigan) and including them in the study.	Consumers Energy study was reviewed and commercially available measures were added to measure list for 2024 study, including heat pump water heaters - CEE advanced tier, heat pump clothes dryers, ozone laundry systems, and 21+ SEER HVAC units



DSM Market Potential Update

JEA

Date: 05.22.2026

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1 Introduction

At JEA's request, Resource Innovations ("RI") developed an update to the Demand Side Management ("DSM") Market Potential Study ("MPS") conducted for JEA as part of the 2024 Florida Energy Efficiency and Conservation Act ("FEECA") goalsetting proceedings¹. The goal of the update was to quantify the magnitude of DSM opportunities in JEA's service territory from 2026-2035, focusing on overall energy efficiency ("EE") and demand response ("DR") impacts based on JEA's current load and economic forecasts.

The analysis for both EE and DR market potential updates consisted of two primary tasks:

1. Disaggregate and apply updated load forecast data to update DSM impacts
2. Update economics and re-run modeling for EE and DR achievable potential

This report provides the detailed methodology and results for this updated DSM analysis of JEA's service territory.

¹ FPSC Docket No. 20240016-EG

2 Methodology

Resource Innovations estimated JEA's DSM savings potential in the 2024 FEECA proceedings using the load and economic forecasts available at the time, which were based on JEA's 2023 Ten Year Site Plan. The 2024 MPS used for the FEECA proceedings followed standard industry practices, applying an analytical framework that aligned with baseline market conditions for energy consumption and demand, and then applied measure savings for individual DSM opportunities to disaggregated consumption and demand data.

To update the DSM savings potential, RI utilized the framework of the 2024 JEA MPS, including customer segmentation, forecast disaggregation, and DSM measure impacts, and applied updates that align with JEA's current load and economic forecasts. This updated analysis provides an up-to-date snapshot of DSM opportunities relative to JEA's current planning conditions.

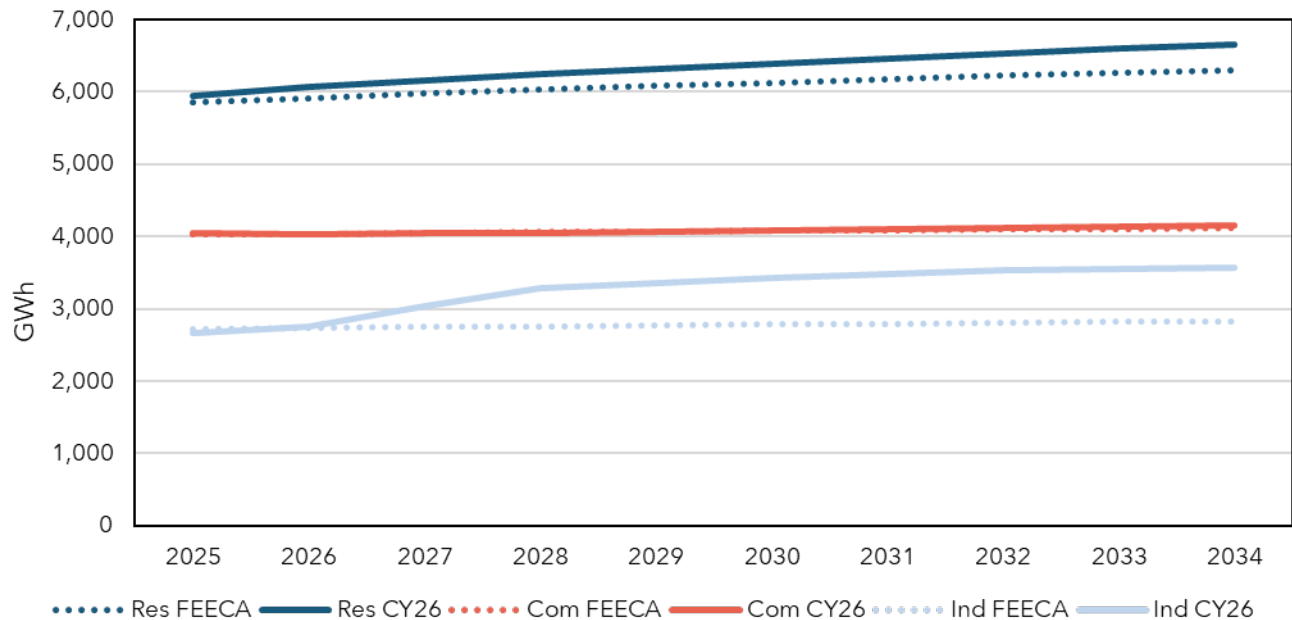
RI's analysis for updating the EE and DR MPS included the following tasks.

2.1 EE MPS Updates

2.1.1 Update Load Forecast

RI initiated the analysis by collecting updated JEA load forecast data from JEA's 2026 Ten Year Site Plan, as well as supplemental details on customer segments that make up new load growth. This load forecast was compared with the 2023 Ten Year Site Plan data used for the 2024 JEA MPS. Figure 2-1 provides a comparison of the load forecasts by sector.

Figure 2-1: Load Forecast Comparison



Based on review of the load forecasts as well as supplemental insights provided by JEA on the 2026 Ten Year Site Plan forecast, the increase in residential sector growth appears to be primarily organic growth, with little to no change in future consumption shares across residential customer segments (single family, multi-family, and manufactured housing) or residential end-uses assumed for the DSM analysis. The load forecast for the commercial sector remains largely unchanged from the 2023 Ten Year Site Plan. The industrial sector forecast includes increased growth between 2026 and 2028, which includes contributions from new construction. Based on this increased forecast, RI reassessed the customer segmentation for the newly added industrial accounts and mapped each account to the appropriate 2024 JEA MPS customer segment, while maintaining the same end-use allocation assumption within a customer segment.

2.1.2 Update Economic Screening and Achievable Potential Results

JEA provided RI with current economic forecast data for the updated MPS analysis. This data included current avoided marginal energy costs and avoided capacity costs. Figure 2-2 provides a comparison of forecasted avoided energy costs and Figure 2-3 compares avoided capacity cost forecasts.

Figure 2-2: Comparison of Avoided Marginal Energy Costs

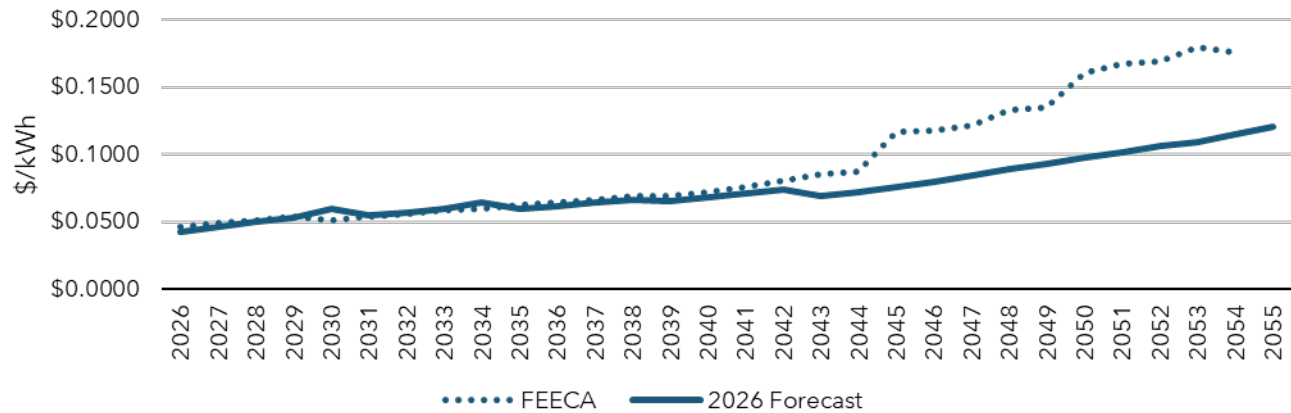
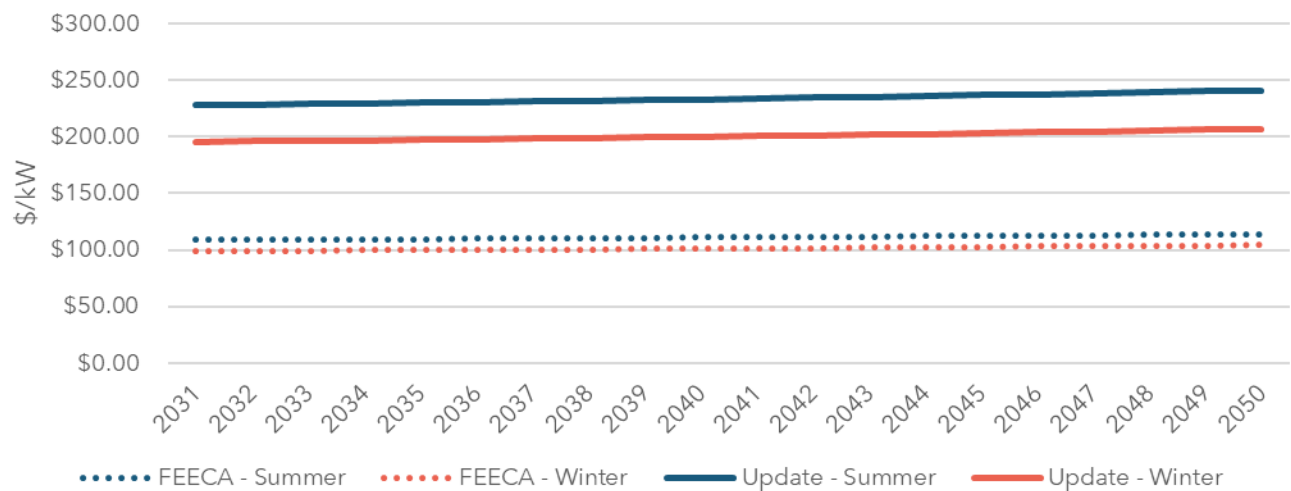


Figure 2-3: Comparison of Avoided Capacity Costs



RI reviewed and incorporated the updated economic data provided by JEA into our TEAPot model to be utilized for updated economic and achievable potential estimates. RI's TEAPot model is a proprietary DSM modeling tool used for market potential studies. This modeling tool was built on a platform that provides the ability to create and analyze multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual program savings. A more detailed description of the TEAPot model and RI's MPS methodology is included in RI's FEECA Technical Potential Study Report².

² <https://www.floridapsc.com/pscfiles/library/filings/2024/01556-2024/01556-2024.pdf>

RI updated the cost-effectiveness screening for all EE measures included in the 2024 MPS to reflect the updates discussed above and identify passing measures in two cost effectiveness scenarios consistent with the 2024 JEA MPS:

- RIM Scenario - this scenario was used as the primary scenario in the analysis and included all measures achieving a cost-effectiveness ratio of 1.0 or higher from the Rate Impact Measure test ("RIM") and Participant Cost Test ("PCT") perspectives that had a simple payback of two years or greater.
- TRC Scenario - this scenario was used as a sensitivity in the analysis and included all measures achieving a cost-effectiveness ratio of 1.0 or higher from the Total Resource Cost test ("TRC") and PCT perspectives that had a simple payback of two years or greater.

Measure impacts (savings, incremental cost, and useful life associated with each EE measure) were not updated as the values used in the 2024 JEA MPS were assumed to still be applicable for this update. However, RI removed federal energy efficient home improvement tax credits for eligible residential measures under the Inflation Reduction Act (IRA), as residential energy efficiency and clean energy tax credits expired at the end of 2025.

Although avoided capacity costs increased as compared to those used in the 2024 JEA MPS, the cost-effectiveness of energy efficiency measures remains primarily driven by avoided marginal energy costs. The RIM ratio is particularly sensitive to lost utility revenues, which are largely a function of retail rates and therefore more closely aligned with avoided energy costs. As a result, increases in avoided capacity benefit would not fully offset the associated revenue impacts under the RIM test. Measures with higher peak demand savings are expected to experience improvements in the TRC ratio, as increased avoided capacity values can partially or fully offset lower avoided energy values. In contrast, measures with limited peak demand impacts may experience reduced cost-effectiveness. Table 2-1 presents a comparison of the number of unique measures that passed the screening for each cost-effectiveness scenario in the 2024 JEA MPS and in this updated analysis. Table 2-2 provides additional detail on the passing measures for each scenario, with the count of overlapping, new, and removed measures identified in this updated analysis compared to those included in the 2024 study.

Table 2-1. Number of Unique Passing Measures by Cost-Effectiveness Scenario

Sector	RIM Scenario (Primary)		TRC Scenario (Sensitivity)	
	2024 MPS	2026 Update	2024 MPS	2026 Update
Residential	5	4	30	20
Commercial	0	0	61	68
Industrial	0	0	35	34

Table 2-2. Summary of Measure Changes

RIM Scenario (Primary)			
Category	Residential	Commercial	Industrial
Count of Overlapping Measures	4	N/A	N/A
Count of Added New Measures	0	N/A	N/A
Count of Removed Measures	1	N/A	N/A
TRC Scenario (Sensitivity)			
Category	Residential	Commercial	Industrial
Count of Overlapping Measures	18	59	30
Count of Added New Measures	2	9	4
Count of Removed Measures	12	2	5

The existing FEECA measure list remains comprehensive, as no new high-impact measures have been identified since the 2024 analysis. However, the updated screening results indicate that certain residential high-impact measures, such as heat pump water heaters, are no longer cost-effective under the revised economic assumptions in the TRC scenario.

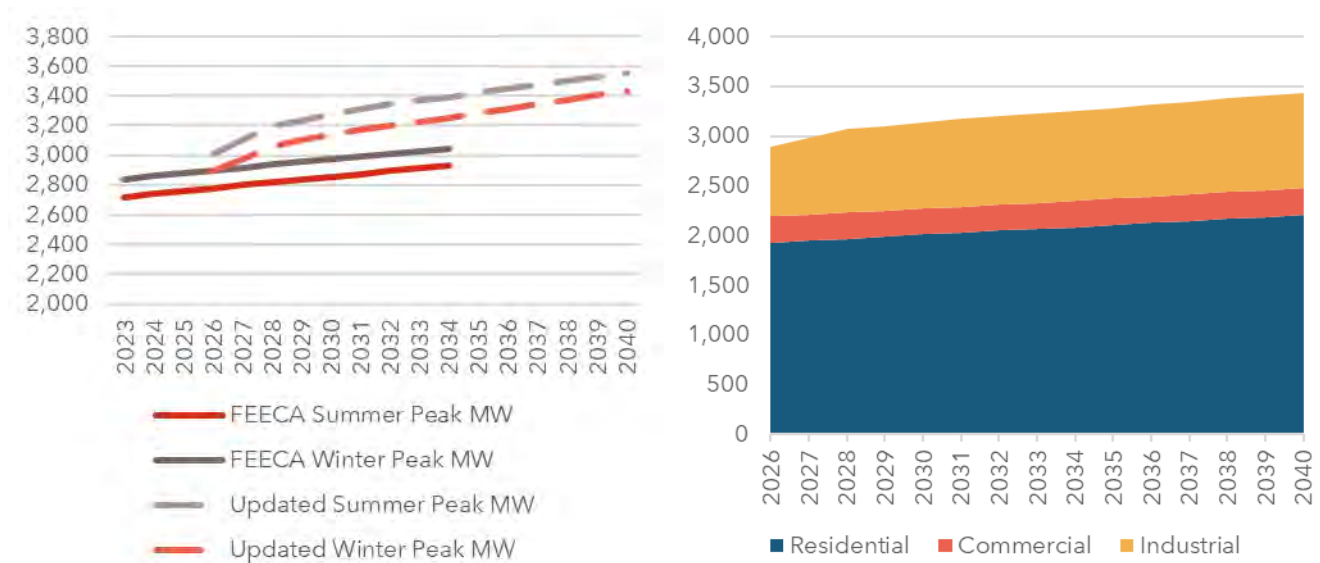
RI updated the economic and achievable potential analysis in our TEAPot model using the load forecast and measure data from the 2024 JEA MPS, along with the updated measure-level cost-effectiveness results. The updated analysis also included the application of market adoption curves to all cost-effective measures based on the updated economic data.

2.2 DR MPS Updates

2.2.1 Update Peak Load Forecast

To reflect JEA’s most recent expectations of peak system growth, the DR potential estimates found by the 2024 JEA MPS were updated using the current peak load forecast. Because our potential estimates are reported at the sector level, the updated system-level load forecast was first disaggregated into Residential, Small Commercial, and Large Commercial & Industrial (C&I) class sectors. The disaggregation incorporated steps to account for the disproportionate growth in peak load within the Large C&I sector, in particular, to reflect the anticipated expanded presence of large-load facilities in the region. Figure 2-4 provides a summary of the updated peak load forecast in comparison to the forecast used in the FEECA study as well as the disaggregated sector-level forecast.

Figure 2-4: Updated Peak Load Forecast and Disaggregation



After disaggregating the system forecast, a scaling factor was developed for each sector and year to quantify the relative change in peak period demand between the updated and original forecasts. The scaling factors were calculated as the ratio of the updated and original sector-level loads for each year.

The sector- and year-specific scaling factors were applied to the original DR potential (MW) to generate updated projections of achievable DR capacity. This approach was implemented to preserve the underlying structure and measure-level assumptions built into the original study while reflecting proportional growth in sector-level DR opportunity.

The underlying premise is that DR potential scales proportionally with peak load demand at the sector level.

2.2.2 Updated Avoided Capacity Costs

In addition to incorporating JEA's updated peak load forecast, the estimated per unit avoided capacity costs (\$/kW) were updated to reflect JEA's current estimate as illustrated in Figure 2-3.

Avoided capacity costs represent the primary utility benefit associated with DR programs, as they capture the value of avoided generation, transmission, and distribution expenses. Updated seasonal avoided cost values provided by JEA, shown in Figure 2-3 above, were incorporated directly into the cost-effectiveness framework used in the 2024 MPS. All other cost-effectiveness inputs, including measure impacts and costs, were unchanged from those

used in the 2024 study. The RIM scenario was used as the primary scenario for DR, consistent with the approach for EE.

The current avoided capacity cost estimates represent a substantial increase over those used in the FEECA study. As a result, the recalculated benefits increase proportionally with the DR impacts for each measure, without changing any of the associated cost assumptions. This results in improved economic performance across the DR potential landscape. In practical terms, the higher avoided capacity values make certain DR opportunities economically feasible that were not cost-effective under the original cost assumptions. Figure 2-5 and Figure 2-6 show the increase in cost-effectiveness screening results for the Residential and Small Commercial measures that exceeded the 1.0 RIM benefit-cost threshold after applying the updated avoided capacity cost values.

Figure 2-5: Updated Residential Cost-Effectiveness Screening Results

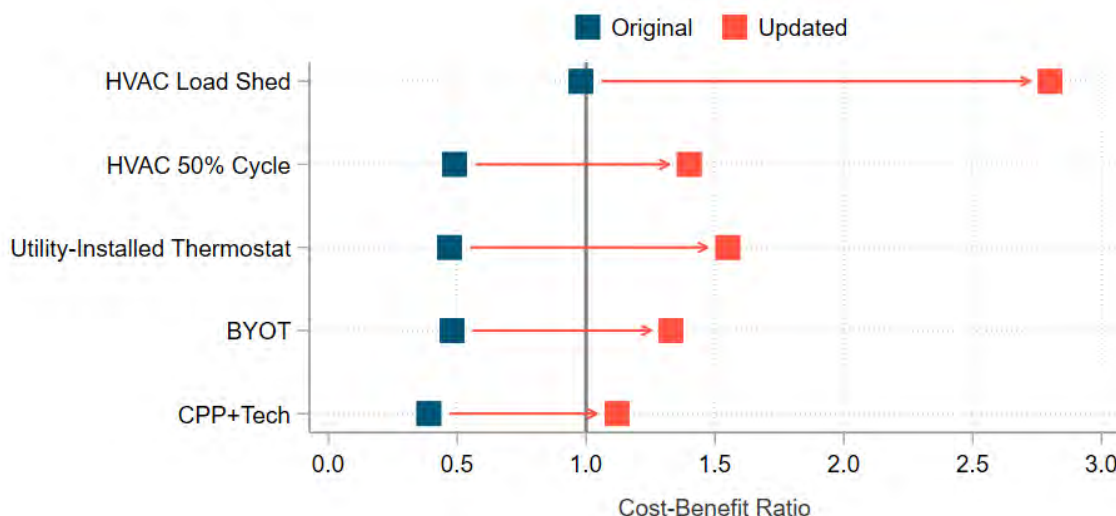
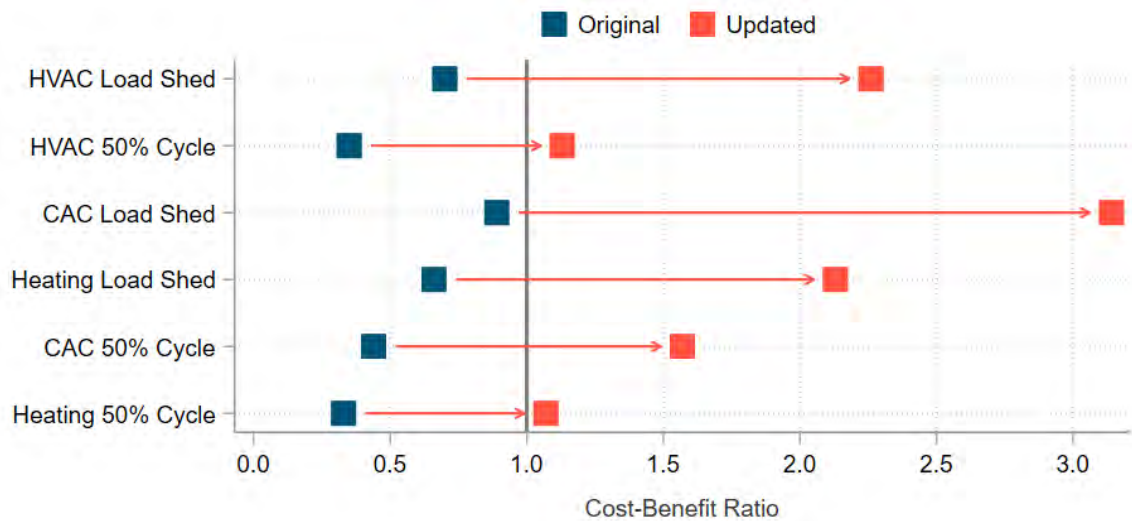


Figure 2-6: Updated Small Commercial Cost-Effectiveness Screening Results



It is important to point out that while each of the individual DR measures listed in Figure 2-5 and Figure 2-6 are economically feasible as standalone opportunities, many of them target the same equipment and/or end-use and therefore need to be treated as competing rather than additive when calculating the aggregated DR potential under realistic scenarios. For example, all Small Commercial measures shown in Figure 2-6 target a facility's HVAC load that can be curtailed for DR only once per peak day. As a result, the achievable potential reflects a selected subset of measures based on overall potential, while removing or adjusting for measures that compete for the same end-use load or eligible customer population.

3 Results

3.1 EE MPS Results

Based on the updated MPS analysis that incorporated JEA's 2026 load forecasts and updated avoided costs, Table 3-1 summarizes the EE cumulative achievable potential by 2035 (designated as "AP" in Table 3-1) by sector and scenario.

Table 3-1. Updated EE Cumulative Achievable Potential by 2035

RIM Scenario (Primary)	Residential	Commercial	Industrial	System
2026 Base Load (GWh)	6,069	4,028	2,754	12,851
AP Energy Savings (GWh)	0.13	N/A	N/A	0.13
% of 2026 Base Load	0.00%	N/A	N/A	0.00%
2026 Summer Peak (MW)	1,578	373	825	2,776
AP Summer Peak Savings (MW)	0.09	N/A	N/A	0.09
% of Summer Peak	0.00%	N/A	N/A	0.00%
2026 Winter Peak (MW)	1,935	260	709	2,904
AP Winter Peak Savings (MW)	0.02	N/A	N/A	0.02
% of Winter Peak	0.00%	N/A	N/A	0.00%
TRC Scenario (Sensitivity)	Residential	Commercial	Industrial	System
2026 Base Load (GWh)	6,069	4,028	2,754	12,851
AP Energy Savings (GWh)	62	123	150	335
% of 2026 Base Load	1.02%	3.06%	5.45%	2.61%
2026 Summer Peak (MW)	1,578	373	825	2,776
AP Summer Peak Savings (MW)	16	23	18	57
% of Summer Peak	1.01%	6.17%	2.18%	2.05%
2026 Winter Peak (MW)	1,935	260	709	2,904
AP Winter Peak Savings (MW)	15	18	17	50
% of Winter Peak	0.78%	6.92%	2.40%	1.72%

The updated results indicate no material change in achievable potential savings under the RIM scenario as compared to the 2024 JEA MPS. Under the TRC sensitivity scenario, however, changes in achievable potential vary by sector, as summarized below.

- **Residential:** TRC achievable potential declines relative to the FEECA results, primarily due to the lower avoided marginal energy costs, which reduce the primary benefit for some high-impact measures such as heat pump water heaters.

- **Commercial:** TRC achievable potential increases modestly, driven by organic load growth and the addition of measures that pass cost-effectiveness screening under the updated assumptions.
- **Industrial:** TRC achievable potential increases noticeably, reflecting strong near-term base load growth in the industrial sector.

Table 3-2 and Table 3-3 summarize the annual cumulative demand savings for the winter and summer seasons, respectively, by year and screening scenario.

Table 3-2. Updated EE Cumulative Winter Demand Savings (MW)

Scenario	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
RIM	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
TRC	3.39	7.28	11.70	16.37	21.47	26.97	32.75	38.59	44.40	50.12

Table 3-3. Updated EE Cumulative Summer Demand Savings (MW)

Scenario	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
RIM	0.01	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.08	0.09
TRC	3.47	7.60	12.43	17.67	23.52	29.94	36.79	43.80	50.67	57.49

3.2 DR MPS Results

The updated load forecasts and avoided capacity costs affect different dimensions of DR potential. Load forecast updates increase the overall magnitude of achievable DR capacity while the avoided capacity cost updates increase the economic value of that capacity. Updating the load forecast in isolation - without revising the original avoided cost assumptions - results in a modest increase in the aggregate peak load available for DR but does not materially change the cost-effectiveness of individual measures. Applying the updated avoided capacity costs increases the per unit value of those load reductions, making selected DR opportunities that were previously uneconomic, now economically feasible.

Three residential DR measures contribute to achievable potential after updates to the load forecast and avoided capacity cost assumptions are implemented, and accounting for measure competition: HVAC Load Shed (switches); Bring-Your-Own Smart Thermostats (BYOT); and Critical Peak Pricing. Table 3-4 summarizes the annual cumulative demand savings for the residential sector for the winter and summer seasons, respectively, by year and measure.

Table 3-4: Updated Residential DR Cumulative Potential (MW)

Measure	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
HVAC Load Shed	Summer	3.3	4.7	6.0	7.1	8.1	8.9	9.7	10.3	10.9	11.4
	Winter	7.3	10.4	13.2	15.6	17.8	19.6	21.3	22.7	24.0	25.1
BYOT	Summer	0.5	0.8	1.0	1.3	1.6	1.8	2.0	2.2	2.4	2.5
	Winter	1.1	1.7	2.3	2.9	3.4	3.9	4.4	4.8	5.2	5.5
Critical Peak Pricing	Summer	3.4	5.1	6.9	8.6	10.2	11.8	13.2	14.5	15.6	16.5
	Winter	1.9	2.9	3.9	4.9	5.8	6.7	7.5	8.2	8.8	9.4
Total Residential	Summer	7.2	10.6	13.9	17.0	19.8	22.5	24.9	27.0	28.8	30.5
	Winter	10.4	15.0	19.4	23.4	27.0	30.3	33.2	35.8	38.0	40.0

Table 3-5 summarizes annual impacts for the small commercial sector, based on central air-conditioning (CAC) and heating load shed (switches) measures.

Table 3-5: Updated Small Commercial DR Cumulative Potential (MW)

Measure	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
CAC Load Shed	Summer	1.8	2.6	3.3	4.0	4.6	5.1	5.6	6.1	6.5	6.8
Heating Load Shed	Winter	1.0	1.4	1.8	2.2	2.5	2.8	3.1	3.3	3.6	3.8

The four Large C&I measures that were included in the MPS are all cost-effective; however, because they apply to the same target population and peak loads, the DR potential for each individual measure is mutually exclusive of the other measures. As a result, achievable potential for the Large C&I sector is represented by the measure with the largest DR opportunity, automated demand response, as shown in Table 3-6.

Table 3-6: Updated Large C&I DR Cumulative Potential (MW)

Measure	Season	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Auto DR	Summer	6.1	9.3	12.6	15.8	18.8	21.6	24.3	26.6	28.7	30.6
	Winter	4.8	7.3	9.9	12.4	14.9	17.1	19.2	21.1	22.8	24.3

Table 3-7 and Table 3-8 present the total summer and winter DR cumulative potential for the years 2026-2035, after implementing updates to the load forecast and avoided capacity cost projections.

Table 3-7: Updated DR Cumulative Summer Demand Savings (MW)

Sector	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	7.2	10.6	13.9	17.0	19.8	22.5	24.9	27.0	28.8	30.5
Small Com	1.8	2.6	3.3	4.0	4.6	5.1	5.6	6.1	6.5	6.8
Large C&I	6.1	9.3	12.6	15.8	18.8	21.6	24.3	26.6	28.7	30.6
TOTAL	15.1	22.5	29.8	36.7	43.2	49.3	54.8	59.7	64.1	67.9

Table 3-8: Updated DR Cumulative Winter Demand Savings (MW)

Sector	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	10.4	15.0	19.4	23.4	27.0	30.3	33.2	35.8	38.0	40.0
Small Com	1.0	1.4	1.8	2.2	2.5	2.8	3.1	3.3	3.6	3.8
Large C&I	4.8	7.3	9.9	12.4	14.9	17.1	19.2	21.1	22.8	24.3
TOTAL	16.1	23.8	31.1	38.0	44.4	50.2	55.5	60.2	64.4	68.0

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

BRIAN PIPPIN

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP 3)

DIRECT TESTIMONY OF BRIAN PIPPIN

DOCKET NO. _____-EC

June 4, 2026

Q. Please state your name and address.

A. My name is Brian Pippin. My business address is 225 N. Pearl St., Jacksonville, Florida 32202.

Q. By whom are you employed and in what capacity?

A. I am employed by JEA as Director of Customer Solutions.

Q. What are your responsibilities in your current position.

A. My current responsibilities include overseeing JEA’s demand-side management (DSM) portfolio. In this capacity, I oversee JEA’s efforts to achieve the numerical goals set by the Florida Public Service Commission (Commission) pursuant to the Florida Energy Efficiency and Conservation Act (FEECA). I assist in the evaluation of new electric DSM measures for inclusion in JEA’s DSM portfolio based upon the value the measures bring to our customers and JEA.

1 **Q. Please summarize your educational background and professional**
2 **experience.**

3 A. I hold a Bachelor of Science in Industrial Engineering from the Georgia Institute
4 of Technology and a Master of Business Administration from the University of
5 Memphis. I've worked at JEA for 21 years, initially providing energy and water
6 conservation education to customers and later developing and implementing
7 energy and water efficiency programs, to now managing the overall electric
8 DSM portfolio.

9

10 **Q. Have you testified before the Florida Public Service Commission**
11 **previously?**

12 A. Yes. I prepared pre-filed written testimony in the last FEECA docket, Docket
13 No. 20240016-EG.

14

15 **Q. What is the purpose of your testimony in this proceeding?**

16 A. The purpose of my testimony is to describe JEA's DSM, energy efficiency and
17 conservation efforts and achievements. I will also address the absence of
18 available cost-effective additional conservation measures to mitigate the need
19 for St. Johns River Power Park Unit 3 (SJRPP Unit 3).

20

21 **Q. Are you sponsoring any exhibits in the case?**

22 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
23 under my supervision and are attached to this pre-filed testimony:

- 24 • Exhibit No. __ (BP-1) – Resume of Brian Pippin
- 25 • Exhibit No. __ (BP-2) – JEA's DSM Goals 2025-2034

1 I am also sponsoring Sections 1.6, 7.0, 7.1, 7.1.1, and 7.1.2 (including all tables
2 and figures referenced in these sections) of JEA's Need Study, which is
3 identified as Exhibit No. ____ (JB-2).

4
5 **Q. What measure of DSM cost-effectiveness is appropriate for municipal utilities**
6 **like JEA?**

7 A. The Rate Impact Measure test (RIM) test measures the impact on customer rates
8 caused by a program. The Commission determined over a decade ago (Order No.
9 PSC-14-0696 at 10) that because RIM ensures no customer rate impacts, it is
10 particularly appropriate for municipal utilities.

11
12 **Q. Does JEA have Commission-approved numeric conservation goals?**

13 A. Yes. JEA's residential and commercial/industrial numeric conservation goals for
14 the 2025 through 2034 period were established by the Commission pursuant to
15 Order No. PSC-2024-0432-FOF-EG on September 20, 2025. The Commission
16 approved JEA's DSM plan setting forth the programs that JEA anticipated offering
17 to achieve the numeric conservation goals on April 17, 2025, pursuant to Order
18 No. PSC-2025-0135-CO-EG.

19
20 **Q. What are JEA's approved conservation goals?**

21 A. JEA's approved numeric conservation goals for 2025-2034 are reflected in Exhibit
22 No. __ (BP-2). This exhibit includes the stipulated increases in program
23 participation and associated kW and MWh reductions pursuant to Attachment A,
24 Paragraph 4 of the above-referenced Order. I note that the Neighborhood Energy
25 Efficiency Program (NEE) goal increase in Paragraph 4(a) of Attachment A was

not incorporated in the DSM goals table in Paragraph 6, Issue 12 of Attachment A. JEA recognizes that its approved goals include the stipulated NEE increase in Paragraph 4(a) as reflected on Exhibit No. __ (BP-2).

Q. What programs does JEA offer to meet those goals?

A. JEA offers four programs to customers: (1) Residential Home Efficiency Upgrades Rebate Program; (2) Residential Energy Efficient Products Rebates Program; (3) Residential Neighborhood Energy Efficiency Program; and (4) Commercial/Industrial Prescriptive Lighting Rebates Program. JEA also continues to offer residential and commercial/industrial energy surveys, although annual energy reductions associated with these surveys are not counted toward achieving DSM goals. Other DSM programs that are not counted toward JEA's DSM goals include (1) Energy Efficient Products Program; (2) MyWay Prepaid Program; (3) Commercial Prescriptive Program; (4) Small Business Program; and (5) Custom Commercial Program. Finally, in 2025, JEA piloted and now offers the JEA Virtual Commissioning Program as a complimentary service for select commercial customers with peak energy usage, such as churches, municipal buildings, and schools. At no cost, a trained energy advisor remotely analyzes a building's historical energy data and recommends adjustments to lighting and HVAC (heating, ventilation, and air conditioning) schedules. These changes are designed to better align with periods of low or no occupancy, helping reduce operating and maintenance costs. The energy advisor then evaluates and verifies the resulting energy savings for the customer and monitors for permanency of the change going forward.

1 **Q. Is JEA currently meeting its numeric conservation goals?**

2 A. Yes. In 2025, JEA exceeded its Commission-approved goals for residential and

3 commercial/industrial for the winter and summer peaks and overall MWh energy

4 savings.

5

6 **Q. What were JEA’s total energy savings from FEECA DSM programs in 2025?**

7 A. JEA achieved a winter peak reduction of 1,545 kW, a summer peak reduction of

8 1,758 kW, and energy reduction of 9,738 MWh.

9

10 **Q. What were JEA’s total energy savings for the additional non-FEECA**

11 **programs offered in 2025?**

12 A. JEA achieved an additional winter peak reduction of 103 kW, a summer peak

13 reduction of 201 kW, and energy reduction of 1,043 MWh.

14

15 **Q. Does JEA also offer an interruptible rate option?**

16 A. Yes.

17

18 **Q. What is the purpose of this program?**

19 A. This program is designed to lower load during peak periods. We actively

20 encourage customers with flexible loads to participate in these programs. Out of

21 221 service agreements, 42 are interruptible.

22

23 **Q. What is the demand reduction associated with the interruptible load**

24 **program?**

1 A. The interruptible load program reduces the need for capacity planning reserves to
2 meet peak demands by 120 MW for the summer (increasing to 124 MW beginning
3 in 2028) and 107 MW for the winter (increasing to 111 MW beginning in 2028).

4
5 **Q. How did JEA determine what goals and programs to propose to the**
6 **Commission?**

7 A. The goals and programs proposed by JEA and approved by the Commission in
8 2024 are based on the technical, economic and achievable potential studies
9 conducted by Resource Innovations (RI) in support of the 2024 FEECA goal-
10 setting process.

11
12 **Q. Has JEA evaluated whether the analysis of cost-effective DSM from 2024**
13 **continues to accurately reflect available, cost-effective conservation**
14 **measures?**

15 A. Yes. To ensure that the analysis regarding the availability of cost-effective
16 conservation measures was current, specifically those that may be available to
17 mitigate the need for SJRPP Unit 3, JEA worked with RI to update the analysis
18 conducted in 2024. The pre-filed direct testimony of Mr. Jim Herndon of RI
19 discusses the methodology and results of that analysis.

20
21 **Q. Do you agree with the results of that analysis?**

22 A. Yes. I also agree with Mr. Herndon's pre-filed written testimony regarding the
23 increases in demand response (DR) potential reflecting theoretical achievable
24 potential rather than what is practicably achievable. The RI updated analysis is
25 intentionally optimistic as it prioritizes measures with the highest demand impacts

1 without consideration of the utility’s overall DSM strategy or practical challenges
2 implementing the identified measures.

3
4 In this case, a significant share of the projected DR savings comes from a
5 traditional “switch-based,” or direct load control (DLC), approach. This method
6 requires utilities to install physical relays—such as on air conditioning
7 compressors—to shut off load during peak events. DLC programs are capital-
8 intensive and slow to deploy due to the need for on-site installations. Between 2018
9 and 2020, the utility industry began shifting away from launching new DLC
10 programs. Instead, the industry has moved toward leveraging advanced metering
11 infrastructure and cloud-based control through “bring your own equipment”
12 (BYOE) programs. These programs use customer-owned devices—such as smart
13 thermostats—that are often pre-configured by manufacturers for DR participation.
14 The rapid adoption of smart thermostats (e.g., Nest, ecobee), lower installation
15 costs compared to DLC, and improved customer experience have made BYOE the
16 industry standard. As a result, most utilities no longer launch new standalone DLC
17 programs; existing programs are typically maintained for legacy capacity and only
18 expanded in limited, niche situations. For these reasons, if JEA were to pursue a
19 residential DR program in the future, we are unlikely to pursue a legacy DLC
20 program in favor of a more robust BYOE program.

21

22 **Q. In your opinion, has JEA implemented available conservation measures?**

23 A. Yes. The Commission set DSM goals and approved JEA’s DSM program for
24 2025-2034 in 2024 based on an evaluation of available, cost-effective

1 conservation measures. JEA has implemented the approved programs, along
2 with additional conservation measures, and exceeded its goals in 2025.

3

4 **Q. In your opinion, are there sufficient DSM or conservation measures**
5 **reasonably available to JEA to mitigate the need for SJRPP Unit 3?**

6 A. No. Despite the peak demand reductions associated with JEA's existing DSM
7 and conservation programs, which are reflected in JEA's load forecast, the need
8 for additional capacity exists and there is not a reasonable scenario in which
9 sufficient cost-effective DSM, energy efficiency, DR, or conservation could be
10 added to avoid the need for additional capacity.

11

12 JEA projects a need for 72 MW in the 2031 timeframe, increasing to 222 MW
13 in 2033, and 802 MW in 2035. To mitigate the need for SJRPP Unit 3, JEA
14 would need to more than 30 times the amount of DSM reflected in JEA's current
15 goals for 2031, and 46 times the amount of DSM JEA achieved in 2025 (winter).
16 To put this in perspective, JEA's projected need for 72 MW in 2031 far exceeds
17 the 2031 FEECA goals of the State's largest electric utility.

18

19 The updated analysis discussed by Mr. Herndon confirms JEA's conclusion that
20 no reasonably available, cost-effective, conservation or DSM measures exist to
21 mitigate the need for SJRPP Unit 3. Even if JEA were able to implement all of
22 the cost-effective, maximum achievable EE and DR identified in RI's updated
23 analysis, putting aside practical limitations to doing so, those measures would
24 still not be sufficient to mitigate the need for SJRPP Unit 3.

25

1 **Q.** **Does this complete your testimony?**

2 **A.** **Yes.**

Brian C. Pippin

PROFESSIONAL SUMMARY

Customer experience-oriented business leader and program manager with 21 years of utility knowledge in new product/program design, development and implementation that build customer loyalty. A natural collaborator, orator, and influencer who's successfully executed multiple cross-functional customer facing initiatives through effective team leadership, shared visioning and the continuous improvement of people, processes, and systems.

PROFESSIONAL EXPERIENCE

JEA - Jacksonville, FL

2016 – Present

Director, Customer Solutions/ Strategic Segment Manager

- Tasked with the implementing the strategy, design, delivery, and market development of JEA's demand side management (DSM), beneficial electrification, renewable energy and beyond-the-meter customer solutions portfolio.
- Effectively manage JEA's energy and water DSM portfolio (25+ measures) for both residential and commercial customers with a budget more than \$15MM annually.
- Successfully implemented a year-long residential demand pilot with 3,000 customers by leading 30+ cross-functional employees, representing 12 different departments, from the customer call center to metering.
- Directly managed 4 Program Managers and 14 external contract employees.

2014 – 2016

Customer Solutions Manager

- Tasked with the growth and market development of JEA's billing and payment (bill, autopay, prepaid, budget billing) solutions.
- Tripled enrollment numbers for all billing and payment programs through creative marketing, evolving the offering and call center sales strategy.

2006 – 2014

Conservation and Efficiency Specialist

- Authored 20+ residential and commercial customer targeted fact sheets centered on the technical and financial efficacy of energy and water saving practices and products.
- Delivered 100s of consultative presentations (one-on-one/one-on-many) to customers on JEA programs and service offerings most notably through a two-year stint as host of the "Q&A with JEA" FM radio show and co-host of the "JEA Efficiency Coach" TV show.

2005 – 2006

New Technology Analyst

- Focused on the business case development for all new technology projects from pre-planning to implementation. Most notably helping to establish JEA's Technology Project

Brian C. Pippin

Committee (TPC) which provides the Senior Leadership Team a vehicle to review and evaluate the business case of technology projects.

2004 – 2005

Operations Analyst

- Support the preplanning, planning, analysis, design, construction, testing and implementation of data processing and information systems.
- Reengineer process maps to improve efficiency and effectiveness of SDLC execution. Consult with cross-functional business units to identify and quantify the savings drivers in their current processes to analyze the financial metrics of the project.

EDUCATION

1999 – 2001 University of Memphis
Master of Business Administration

Memphis, TN

1992 – 1997 Georgia Institute of Technology
Bachelor of Industrial Engineering

Atlanta, GA

CAREER RELATED CERTIFICATIONS

- Building Analyst (BA) – Inactive
Building Performance Institute, Inc.
- Class 1 Home Efficiency Rating System (HERS) Energy Auditor – Inactive
Residential Energy Service Network
- Certified Energy Manager (CEM) – Inactive
Association of Energy Engineers
- Certified Green Professional (CGP) – Inactive
National Association of Home Builders
- Six-Sigma Black Belt Trained
In-House Curriculum & Certification

Approved JEA Numeric Conservation Goals

Year	Residential Reduction Goals			Commercial/Industrial Reduction Goals		
	Summer (MW)	Winter (MW)	Annual Energy (GWh)	Summer (MW)	Winter (MW)	Annual Energy (GWh)
2025	0.76	1.02	3.789	0.44	0.37	3.346
2026	0.92	1.13	4.279	0.47	0.39	3.562
2027	1.11	1.25	4.860	0.50	0.41	3.771
2028	1.34	1.39	5.514	0.53	0.42	3.975
2029	1.58	1.52	6.196	0.56	0.44	4.169
2030	1.81	1.65	6.830	0.58	0.45	4.334
2031	1.98	1.74	7.307	0.60	0.46	4.444
2032	2.03	1.78	7.518	0.60	0.46	4.470
2033	1.96	1.77	7.409	0.59	0.46	4.403
2034	1.77	1.70	7.026	0.57	0.45	4.257

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

BRADLEY KUSHNER

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

DOCKET NO. _____-EC

June 4, 2026

Q. Please state your name and address.

A. My name is Bradley E. Kushner. My business address is 4767 New Broad Street, Orlando, Florida 32814.

Q. By whom are you employed and in what capacity?

A. I am employed by nFront Consulting LLC (nFront) as a Manager, and I am the Managing Director of nFront’s Energy practice.

Q. What are your responsibilities in your current position.

A. I oversee management of the financial and business aspects of nFront and work with others in the firm to provide consulting services to clients. My responsibilities include project management and project support for various projects for electric utility clients. These projects include integrated resource plans, power supply studies, power supply requests for proposals, demand-side management (DSM)/conservation reports, and other regulatory filings.

1 **Q. Please describe nFront Consulting LLC.**

2 A. nFront Consulting is organized into two service practices – Energy and
3 Transmission & Delivery. nFront Consulting’s Energy practice provides
4 advisory services to support our electric industry clients. We assist in the areas
5 of planning, implementing and managing resources, portfolios, and individual
6 unit operations. We interact on behalf of our clients with regulatory, political,
7 and environmental agencies; the financial community; and other professional
8 service providers on national, state, and local levels.

9
10 nFront Consulting’s Transmission & Delivery Services Practice provides
11 independent transmission consulting, analyses and advisory services to support
12 project financing, acquisitions, development, transmission risk, curtailment and
13 congestion assessments, transmission planning, resource integration, and open
14 access, expert witness and regulatory services.

15

16 **Q. Please summarize your educational background and professional**
17 **experience.**

18 A. I have a Bachelor of Science degree in mechanical engineering and a Master of
19 Business Administration. I have more than 25 years of experience in the
20 engineering and consulting industry, including experience in the development
21 of integrated resource plans, and other capacity planning studies for clients
22 throughout the United States. Utilities in Florida for which I have worked
23 include JEA, Florida Municipal Power Agency, Kissimmee Utility Authority,
24 Orlando Utilities Commission, Lakeland Electric, Gainesville Regional
25 Utilities, Reedy Creek Improvement District (now the Central Florida Tourism

1 Oversight District), Tampa Electric Company, and the City of Tallahassee. I
2 have performed production cost modeling, economic analysis, and related
3 support for six electric power plant need determination petitions on behalf of
4 Florida utilities and approved by the Florida Public Service Commission
5 (Commission). I have also testified before the Commission in several Need for
6 Power and Florida Energy Efficiency and Conservation Act (FEECA) goal-
7 setting proceedings.

8

9 **Q. Is Exhibit No. __ (BK-1) a true and correct copy of your resume?**

10 A. Yes.

11

12 **Q. What is the purpose of your testimony in this proceeding?**

13 A. The purpose of my testimony is to address three areas related to the need for
14 St. Johns River Power Park Unit 3 (SJRPP Unit 3). First, I will address the
15 capacity expansion and production cost modeling that was performed to
16 compare alternatives to determine that SJRPP Unit 3 is the most cost-effective
17 alternative and to estimate the expected operation of JEA's Northside
18 Generating Station Unit 3 (NGS Unit 3). My testimony will include the cost
19 and performance estimates for the solar photovoltaic (PV), battery energy
20 storage system (BESS), and nuclear small modular reactor (SMR) alternatives
21 utilized in the capacity expansion and production cost modeling. I will also
22 discuss whether conservation measures exist to mitigate JEA's need for SJRPP
23 Unit 3. Finally, I will discuss the adverse consequences of denial of SJRPP
24 Unit 3 to JEA and its customers.

25

1 **Q. Are you sponsoring any exhibits in the case?**

2 A. Yes. I am sponsoring the following exhibits, which were prepared by me or
3 under my supervision and are attached to this pre-filed testimony:

- 4 • Exhibit No. __ (BK-1) – Resume of Bradley E. Kushner
- 5 • Exhibit No. __ (BK-2) – Modeling Results Table

6 I am also sponsoring Sections 6.4, 6.4.1, 6.4.2, 6.4.2.1, 6.4.3, 6.4.6, 6.4.7,
7 6.4.7.1, 6.4.7.2, and 6.5 of JEA’s Need Study (including all tables and figures
8 referenced in those sections), identified as Exhibit No. ____ (JB-2), which
9 were prepared by me or under my supervision. Finally, I am co-sponsoring
10 Exhibit No. MO-2, Capital and Performance Assumptions for Generating
11 Alternatives, and Section 6.4.4 of the Need Study as to the solar PV, BESS,
12 and SMR alternatives. Mr. Matt Oakes is addressing the natural gas
13 alternatives in his pre-filed direct testimony.

14

15 **Q. What is your understanding of JEA’s projected need for additional**
16 **capacity?**

17 A. As discussed in Ms. Melinda Fischer’s testimony, JEA’s current forecast
18 shows a need for additional capacity to maintain reserve margin requirements,
19 increasing from 72 MW in 2031 to 222 MW in 2033 and 802 MW in 2035.

20

21 **Q. What has been your role in evaluating the options to meet JEA’s capacity**
22 **need?**

23 A. I have been a part of the Black & Veatch team supporting JEA’s resource
24 planning efforts, including overseeing (i) development of an integrated
25 resource plan (IRP) and technology assessment; (ii) the production cost

1 modeling to support the economic evaluation of market alternatives received in
2 response to JEA's October 2024 request for proposals (Market Test RFP); and
3 (iii) the updated production cost modeling to confirm SJRPP Unit 3 is the
4 least-cost alternative. As part of the Black & Veatch team responsible for the
5 production cost modeling, I reviewed and verified the cost and performance
6 estimates for the solar PV, BESS, and SMR alternatives utilized in the
7 modeling.

8
9 **CAPTIAL COST AND PERFORMANCE ESTIMATES**

10 **Q. Please describe the methodology utilized to develop the cost and operation**
11 **and maintenance (O&M) estimates for the solar PV, BESS, and SMR**
12 **generating alternatives.**

13 A. Black & Veatch prepared the cost and O&M assumptions for the solar
14 resources based on a conceptual design of the resource. These estimates were
15 then adjusted based on in-house project data and more detailed estimates that
16 Black & Veatch has recently developed for other projects with similar
17 technology. The cost assumptions for the BESS resources were developed
18 based on in-house project data and the latest cost estimates published by
19 credible sources such as U.S. Energy Information Administration (EIA) and
20 National Renewable Energy Laboratory (NREL). Finally, the cost assumptions
21 for the SMR resources were developed based on the latest cost estimates
22 published by EIA and NREL, as well as general research on announced project
23 costs.

1 **Q. Please describe the methodology utilized to develop the performance**
2 **estimates for the solar PV, BESS, and SMR generating alternatives.**

3 A. To prepare the solar annual energy and degradation performance estimates,
4 Black & Veatch simulated operation at varying operating conditions using the
5 PVSyst suite of solar PV simulation software that is licensed by Black &
6 Veatch. For BESS performance estimates, Black & Veatch developed
7 availability, degradation and useful life assumptions based on observed
8 industry benchmarks Finally, the SMR performance estimates are based on
9 public sources and research papers.

10

11 **Q. How did the cost estimates change over the course of SJRPP Unit 3**
12 **evaluation?**

13 A. Over the course of JEA's evaluation of technologies, market alternatives, and
14 cost-effectiveness of SJRPP Unit 3, Black & Veatch updated the solar PV,
15 BESS, and SMR cost estimates to ensure the costs utilized were representative
16 of the current market.

17

18 **ECONOMIC MODELING**

19 **Q. Please describe the methodology utilized to conduct the economic analysis**
20 **of technologies to support the selection of SJRPP Unit 3.**

21 A. JEA considered various generating resource options, including multiple
22 configurations of solar PV and BESS options, numerous different natural gas
23 options (including a range of sizes, types, simple and combined cycle
24 configurations, and conversion of exiting simple cycle units to combined cycle

1 configuration), biomass technologies, and SMR. JEA utilized PLEXOS® to
2 evaluate the economics of the various technologies.

3

4 **Q. What is PLEXOS®?**

5 A. PLEXOS® is an industry standard, capacity expansion and production cost
6 model used by multiple utilities and other utility industry professionals.

7

8 **Q. What was the result of this analysis?**

9 A. Based on the PLEXOS® modeling and consideration of system benefits and
10 risks, JEA determined that an advanced class 1 x 1 combined cycle unit would
11 provide the most benefits to the JEA system as the most economical
12 technology addition to satisfy reserve margin requirements while providing
13 reliable and dispatchable power, allowing for efficient use of natural gas, and
14 reducing system emissions. The advanced class 1 x 1 combined cycle is the
15 same technology and configuration as the proposed SJRPP Unit 3.

16

17 **Q. Were you also responsible for the economic analysis of Market Test RFP**
18 **alternatives received in response to JEA's October 2024 request for**
19 **proposals?**

20 A. Yes.

21

22 **Q. Please discuss the methodology utilized in this analysis.**

23 A. The methodology utilized in the economic analysis of market alternatives
24 received in response to the Market Test RFP was consistent with that utilized

1 in the economic analysis of technologies to support the selection of SJRPP
2 Unit 3.

3
4 **Q. Did the Market Test RFP analysis utilize the same underlying**
5 **assumptions as those utilized for the evaluation of technologies?**

6 A. Yes. The economic evaluation of alternatives received in response to the
7 Market Test RFP (conducted in 2025) utilized the same assumptions as the
8 evaluation supporting technology selection (also conducted in 2025).

9
10 As addressed in the pre-filed testimony of Ms. Fischer, JEA's Board selected
11 moving forward with construction and operation of SJRPP Unit 3 based on the
12 results of the IRP process that began over three years ago and has been
13 continually refined with updated information and assumptions related to, for
14 example, load forecast, fuel forecast, and technology costs through the
15 economic analysis of technologies to support the selection of SJRPP Unit 3.
16 To illustrate, the capital cost of the 1 x 1 advanced class combined cycle unit
17 utilized in the technology selection assessment in 2025 as well as the economic
18 analysis of Market Test RFP alternatives (approximately \$2,312 per kW in
19 2031 base year dollars; winter net output) increased as compared to that used
20 in the 2023 IRP (\$919 per kW in 2023 base year dollars; winter net output).
21 Similarly, the 2025 technology assessment evaluation utilized updated load
22 and fuel price forecasts consistent with JEA's 2025 Ten Year Site Plan
23 (TYSP).

24

1 **Q. What were the results of the economic analysis of the Self-Build Resource**
2 **and market alternatives?**

3 A. Economic analysis was performed to evaluate the economics of the least-cost
4 resource plan that included the Self-Build Resource as compared to resource
5 plans that included each of the proposed power purchase agreements (PPA)
6 received in response to the Market Test RFP for the base case and a range of
7 sensitivities, all as outlined in the Market Test RFP. The results of the analysis
8 showed that Self-Build Resource is the highest ranked option as compared to
9 any of the PPA proposals received in response to the Market Test RFP.

10

11 **Q. Did JEA conduct additional economic analysis prior to filing this request**
12 **for a determination of need for SJRPP Unit 3?**

13 A. Yes. To confirm SJRPP Unit 3 as the least cost alternative utilizing the most
14 up-to-date and refined information and assumptions, we conducted additional
15 economic modeling to support this filing. While we updated information and
16 assumptions, the methodology utilized to perform the updated economic
17 analysis was consistent with the methodology discussed previously in my
18 testimony with respect to the capacity expansion and production cost modeling
19 performed for the technology selection and the Market Test RFP evaluations.

20

21 **Q. What information and assumptions were updated?**

22 A. As compared to the economic analysis performed to evaluate the Self-Build
23 Resource and the PPAs received in response to the Market Test RFP, the
24 economic analysis for the updated economic analysis included updates to the
25 load forecast, fuel price projections, existing and planned future resources, the

1 Self-Build Resource cost, the cost and performance estimates for alternative
2 technologies, assumptions related to JEA's aspirational clean energy goals,
3 assumptions related to the U.S. Environmental Protection Agency (EPA)
4 Greenhouse Gas standards for electric generating units (GHG Rule), and
5 assumptions related to the operation of JEA's existing NGS Unit 3.

6
7 **Q. How did the load and fuel forecast information change?**

8 A. JEA updated its forecast projections in support of its 2026 Ten Year Site Plan
9 TYSP filing with the Commission. As discussed in Ms. Fischer's pre-filed
10 testimony, the 2026 TYSP load forecast shows continued increased growth.
11 The 2026 TYSP also includes updated fuel price projections. This load
12 forecast and fuel price projection information was utilized in the updated
13 economic analysis.

14
15 **Q. What changes regarding existing and planned future resources were
16 incorporated into the updated economic analysis?**

17 A. The updated economic analysis reflected changes to JEA's existing PPA with
18 Florida Power & Light (FPL), sales of capacity and energy from the Vogtle
19 nuclear units, and purchases of power from The Energy Authority.
20 Additionally, the updated economic modeling reflects placing the existing
21 NGS Unit 3 generating unit into limited use on liquid fuel (operating at or
22 below 8 percent annual capacity factor and used as a back-up for peak demand
23 periods, emergencies, and unexpected outages of other units) coincident with
24 SJRPP Unit 3 commercial operation, with full retirement of NGS Unit 3 in
25 2035.

1

2 **Q. How did you update the modeling assumptions as to cost and performance**
3 **estimates?**

4 A. For purposes of the updated economic modeling, we utilized the updated cost
5 and performance estimates reflected in Exhibit No. __ (MO-2).

6

7 **Q. How do the estimates that Black & Veatch utilized for generating**
8 **alternatives in the updated economic modeling compare to current market**
9 **conditions?**

10 A. The updated economic modeling conducted to confirm SJRPP Unit 3 as the
11 most cost-effective alternative utilized the best information available as to
12 market conditions. In general, the cost for generation technologies may vary
13 over time based on a number of factors. For example, increased demand leads
14 to an increase in technology costs. To the extent the cost for generation
15 technologies has increased since Black & Veatch conducted the updated
16 modeling, this increase would be seen for all technologies. It should be noted
17 that SJRPP Unit 3 has been partially protected from these increases because, as
18 discussed in the pre-filed direct testimony of Ms. Fischer, JEA has signed a
19 reservation agreement with GE Vernova that locks in the cost for the power
20 island equipment.

21

22 **Q. Did the modeling include assumptions regarding clean energy goals?**

23 A. No. The model was not constrained by any artificial mandate related to JEA's
24 aspirational clean energy goals for the reasons addressed in Ms. Jody Brooks'
25 pre-filed written testimony.

1

2 **Q. What assumptions did you utilize regarding the GHG Rule?**

3 A. For the technology assessment and economic evaluation of proposals received
4 in response to the Market Test RFP, we assumed the GHG Rule was in effect.
5 Evaluation of proposals received in response to the Market Test RFP also
6 considered sensitivities in which the GHG Rule was not in effect and was in
7 effect over a shorter horizon. Given EPA's proposed repeal of the GHG Rule
8 and finalized repeal of the 2009 Endangerment Finding, we assumed the GHG
9 Rule was not in effect for purposes of the updated economic modeling.

10

11 **Q. Did you incorporate any costs associated with carbon dioxide (CO₂)**
12 **emissions?**

13 A. No. There are no existing or planned future regulations that would impose a
14 cost for CO₂ emissions.

15

16 It should be noted that the proposed SJRPP Unit 3 is approximately 37 percent
17 more efficient than JEA's existing NGS Unit 3 generating unit. The addition of
18 SJRPP Unit 3 in 2031 would result in net reductions of CO₂ emissions of
19 approximately 5.7 million tons as compared to the next least-cost resource plan
20 that does not include SJRPP Unit 3 in 2031, with those reductions occurring
21 over the 2031 through 2035 period, as that next least-cost resource plan
22 includes a unit similar to SJRPP Unit 3 in 2035.

23

24 **Q. Did the updated modeling include renewable energy options, including**
25 **solar and clean energy portfolios?**

1 A. Yes. The evaluation of resource options to confirm SJRPP Unit 3 as the most
2 cost-effective alternative considered solar PV and two different sizes/durations
3 of BESS technologies (50 MW/4 hour storage and 100 MW/10 hour storage).
4 As part of the PLEXOS® modeling, these options were evaluated as potential
5 resources that would be added if doing so was part of the overall most cost-
6 effective resource plan to meet forecast capacity and energy requirements.

7
8 **Q. What were the results of the analysis under the base case?**

9 A. For the base case, the PLEXOS® modeling indicated that the proposed SJRPP
10 Unit 3 with an in-service date of 2031 is included in the least-cost resource
11 plan.

12
13 **Q. Did you also evaluate what the economic cost would be to JEA's**
14 **customers of the next lowest cost resource plan?**

15 A. Yes. To determine the cost to JEA of denial of SJRPP Unit 3 in the 2031
16 timeframe, we conducted PLEXOS® modeling under a simulation that did not
17 allow the selection of a 1 x 1 advanced class combined cycle unit in 2031. The
18 resulting resource plan is referred to herein as the "Next Lowest Cost
19 Alternative."

20
21 **Q. What were the results of that analysis?**

22 A. The Next Lowest Cost Alternative would be approximately \$91 million more
23 expensive in terms of cumulative present worth cost (CPWC) to JEA's
24 customers than the resource plan that includes the addition of SJRPP Unit
25 3 in the 2031 timeframe. Importantly, the Next Lowest Cost Alternative would

1 still include the addition of an advanced class 1 x 1 combined cycle unit
2 (similar to the proposed SJRPP Unit 3) in the near-term, as the Next Lowest
3 Cost Alternative includes the addition of an advanced class simple cycle
4 combustion turbine in 2031 followed by an advanced class 1 x 1 combined
5 cycle unit in 2035.

6
7 **Q. Did you include sensitivity analyses in the updated economic modeling?**

8 A. Yes. In recognition that forecasting key modeling inputs and assumptions over
9 a 35-year timeframe involves uncertainty, in addition to the Base Case and
10 Next Lowest Cost Alternative, a number of sensitivities were evaluated,
11 including high load growth, low load growth, high natural gas prices, low
12 natural gas prices, and high capital cost. In addition, the economic cost of
13 delaying SJRPP Unit 3 by one year was also evaluated.

14
15 **Q. Why were those sensitivities chosen?**

16 A. The sensitivities related to loads, fuel prices, and capital costs were selected as
17 those sensitivities reflect changes to input assumptions that are typically most
18 influential on the comparative economic evaluations utilized in evaluating
19 options for meeting system capacity and energy requirements. Importantly, the
20 sensitivities may also be viewed as proxies for changes in other assumptions
21 not directly addressed in the sensitivities. As an example, the high fuel price
22 sensitivity may be viewed as a proxy for other factors that would increase
23 operating costs as compared to the base case (such as potential future
24 regulation of CO₂).

1 The sensitivity performed to reflect the economic cost of a one-year delay in
2 the operation of SJRPP Unit 3 was chosen to illustrate that delay in approving
3 the addition of SJRPP Unit 3 would adversely impact JEA's customers.

4
5 **Q. What were the results of those sensitivity analyses?**

6 A. As reflected in Exhibit No. __ (BK-2), in all cases and sensitivities (except for
7 the Next Lowest Cost Alternative resource plan, which by construct cannot
8 include the addition of SJRPP Unit 3 as the initial resource addition), SJRPP
9 Unit 3 was selected as the preferred initial resource addition and part of the
10 least cost resource plan.

11
12 **Q. Please describe the results of the analysis of delaying SJRPP Unit 3 by one**
13 **year.**

14 A. Delaying the proposed SJRPP Unit 3 from 2031 to 2032 would increase the
15 overall CPWC of the resource plan by \$22 million.

16
17 **Q. In your opinion, is SJRPP Unit 3 the most cost-effective alternative**
18 **available to meet JEA's need?**

19 A. Yes.

20
21 **NORTHSIDE GENERATING STATION UNIT 3**

22 **Q. Did you evaluate the expected operation of JEA's existing NGS Unit 3**
23 **following operation of SJRPP Unit 3?**

24 A. Yes. Based on JEA's current plans, we limited NGS Unit 3 to fuel oil and to a
25 capacity factor of 8% beginning in 2031 with full retirement in 2035 in the

1 PLEXOS® modeling. We utilized the results of that analysis to estimate how
2 often NGS Unit 3 would be expected to operate following commercial
3 operation of SJRPP Unit 3.
4

5 **Q. What were the results of this analysis?**

6 A. Based on the model outputs, NGS Unit 3 was projected to operate at a capacity
7 factor below 1% from 2031 through its retirement in 2035.
8

9 **Q. How does the addition of SJRPP Unit 3 factor into reduced operation of**
10 **NGS Unit 3?**

11 A. JEA's ability to place NGS Unit 3 into limited use is dependent upon SJRPP
12 Unit 3 being brought on-line. Without the addition of SJRPP Unit 3, JEA
13 would be unable to realize the benefits to its system of reduced dependence on
14 NGS Unit 3, and would continue to rely on an aging, less efficient generating
15 unit, leading to costly and substantial required upgrades, higher system costs,
16 increased use of natural gas, and higher CO₂ emissions as compared to
17 operation of SJRPP Unit 3.
18

19 **AVAILABILITY OF CONSERVATION MEASURES**

20 **Q. Are you familiar with JEA's existing DSM goals, programs, and**
21 **conservation efforts and the Market Potential Study (MPS) conducted by**
22 **Resource Innovations for JEA to evaluate the availability of conservation**
23 **measures?**

24 A. Yes. I testified in the 2024 FEECA goal-setting proceeding regarding JEA's
25 load forecast and methodology used to develop avoided capacity costs that

1 were provided to Resource Innovations (RI) for use in their analyses of DSM
2 measures for JEA. I was likewise involved in the recent updated evaluation of
3 available conservation measures, including as to the forecast and avoided
4 capacity cost information provided to RI.

5

6 **Q. Please describe how the updated avoided capital costs per KW-year were**
7 **calculated.**

8 A. The updated avoided capital costs were calculated by taking the updated
9 capital cost for SJRPP Unit 3 and multiplying by the annual fixed charge rate
10 (7.01 percent) to determine a levelized installed capital cost, which was then
11 divided by the seasonal (i.e., winter and summer) capacity ratings to develop
12 levelized updated avoided annual installed capital costs per kW-year for the
13 summer and winter periods.

14

15 **Q. Please describe how the updated avoided fixed operating and maintenance**
16 **costs per KW-year were calculated.**

17 A. The updated avoided fixed O&M costs were calculated by taking the updated
18 fixed O&M costs for SJRPP Unit 3 and dividing by the seasonal (i.e., winter
19 and summer) capacity ratings to develop annual avoided fixed O&M costs per
20 kW-year for the summer and winter periods. The annual fixed O&M costs
21 were escalated at 3.5 percent per year.

22

23 **Q. Please describe how the updated avoided firm natural gas transportation**
24 **costs per KW-year were calculated.**

- 1 A. The updated avoided firm natural gas transportation costs were calculated by
2 taking the annual incremental firm natural gas transportation costs associated
3 with SJRPP Unit 3 and dividing by the seasonal (i.e., winter and summer)
4 capacity ratings to develop annual avoided firm natural gas transportation costs
5 per kW-year for the summer and winter periods.
6
- 7 **Q. Please describe how the total updated avoided costs per KW-year were**
8 **calculated.**
- 9 A. The total updated avoided costs per kW-year were calculated by adding the
10 annual updated avoided capital costs, fixed O&M costs, and firm natural gas
11 transportation costs for the summer and winter periods.
12
- 13 **Q. Are you familiar with the results of the updated MPS analysis?**
- 14 A. Yes.
15
- 16 **Q. In your opinion, are there conservation measures available to mitigate the**
17 **need for SJRPP Unit 3?**
- 18 A. No. The updated MPS analysis shows that there are no cost-effective energy
19 efficiency measures and shows that while there may be cost-effective demand
20 response measures that JEA could theoretically implement, doing so would not
21 mitigate the need for SJRPP Unit 3.
22
- 23 **Q. In your opinion, is JEA utilizing conservation measures to the extent**
24 **reasonably available?**

1 A. Yes. JEA's existing numeric conservation goals were approved by the
2 Commission as part of the 2024 FEECA process, and the programs to achieve
3 those goals were included in JEA's DSM Plan that was approved by the
4 Commission in 2025. During calendar year 2025, the programs offered by
5 JEA included in JEA's 2025 DSM Plan exceeded both its residential and
6 commercial/industrial numeric conservation goals. Further, JEA offers
7 additional programs beyond those included in its 2025 DSM Plan, resulting in
8 additional demand and energy reductions.

9

10 It should be noted that JEA's projected capacity requirements reflect demand
11 reductions associated with achieving approximately two times JEA's
12 Commission-approved numeric conservation goals. Stated otherwise, JEA's
13 projected need for capacity accounts for demand reductions associated with its
14 Commission-approved goals as well as incremental demand reductions above
15 and beyond its goals.

16

17 **ADVERSE CONSEQUENCES OF DENIAL**

18 **Q. Would denial of SJRPP Unit 3 have adverse economic consequences for**
19 **JEA and its customers?**

20 A. Yes. Denial of SJRPP Unit 3 would result in an added CPWC cost of \$91
21 million to JEA customers. Delay of even one year would have an economic
22 impact of an additional \$22 million in CPWC costs to JEA customers.

23

24 **Q. Would denial of SJRPP Unit 3 have other adverse consequences for JEA?**

1 A. Yes. Denial of the proposed SJRPP Unit 3 would mean that JEA's customers
2 would be denied the most cost-effective option to meet JEA's needs while
3 providing flexibility relative to dispatch and operations to enhance grid
4 reliability and mitigate risk and reduce consumption of natural gas. Denial of
5 SJRPP Unit 3 would result in increased utilization of natural gas and increased
6 emissions of CO₂. Further, if SJRPP Unit 3 is not approved, JEA would be
7 unable to place NGS Unit 3 into limited use and would instead have to
8 continue to rely on a less efficient resource that is approaching the end of its
9 ability to continue to operate reliably.

10

11 **Q. Does this complete your testimony?**

12 A. Yes.

13

OVERVIEW

Mr. Kushner has more than 25 years in the energy industry with a specialty in electric utility system resource planning. His expertise includes the following areas:

- Determination of Need Studies
- Conservation / Demand-Side Management / Energy Efficiency
- Expert Testimony
- Electric Utility Resource Planning / Production Cost Modeling
- Regulatory Compliance and Support
- Integrated Resource Plans / Power Supply Studies
- Conventional Energy Technologies
- Renewable Energy Technologies
- Economic Analysis
- Independent Engineering
- Project Management
- Power Supply Requests for Proposals (RFPs)

Mr. Kushner has provided testimony in many power plant need determination proceedings, conservation and energy efficiency dockets, and integrated resource plans. Mr. Kushner has managed numerous need for power applications, integrated resource plans, power supply studies, demand-side management/energy efficiency/conservation evaluations and power supply request for proposals (RFPs), among other studies. Mr. Kushner has a demonstrated ability to manage internal and external project teams with diverse experience levels and areas of expertise, both in co-located and virtual environments. Mr. Kushner's experience in project management and expertise in the areas outlined above allow him to collaborate with clients to deliver outstanding services to his clients. His ability to effectively communicate in writing and verbally helps to keep stakeholders informed throughout project lifecycles and has contributed to his successful experiences as an expert witness and in formal presentations to clients' Board of Directors.

PROJECT EXPERIENCE

Determination of Need Studies

Mr. Kushner as managed or otherwise been involved with the development and filing of several Determination of Need studies in the State of Florida, including Stanton Energy Center Unit A, Stanton Energy Center Unit B, Treasure Coast Energy Center, Cane Island Power Park Unit 4, and Greenland Energy Center.

Demand-Side Management / Energy Efficiency/ Conservation (DSM/EE/Conservation)

Mr. Kushner's experience with the evaluation of DSM/EE/Conservation is highlighted by his involvement in the development of conservation goals and demand-side management plans for Florida utilities as part of the 2009, 2014, and 2019 Florida Energy Efficiency and Conservation Act (FEECA)

filings. Mr. Kushner led development of the filings and testified as to the appropriateness of the numeric goals and process utilized to evaluate the cost-effectiveness of DSM/EE/Conservation programs.

Expert Witness Support

Mr. Kushner has testified as a witness in numerous proceedings related to Determination of Need petitions and Florida Energy Efficiency and Conservation Act (FEECA) filings in the State of Florida and has been involved as a witness in integrated resource planning (IRP) proceedings elsewhere in the United States. Related experience includes coordinating/leading responses to hundreds of interrogatories and production of document requests.

Electric Utility System Resource Planning / Production Cost Modeling

With his extensive experience in Electric Utility System Resource Planning and production cost modeling, Mr. Kushner recognizes that while industry best practices provide effective guidelines, the unique nature of each client's situation require strategic thinking and the ability to develop plans that are specific to the client's needs. Mr. Kushner's expertise in generation (including conventional and renewable technologies), demand-side management, and fundamentals of production cost modeling allow Mr. Kushner to deliver comprehensive resource plans that clients can utilize for future decision making.

Integrated Resource Plans /Power Supply Studies

Mr. Kushner has been involved as the project manager, study manager, and lead analyst on several integrated resource plans (IRP) or power supply studies during his professional career. Mr. Kushner has been involved in such studies for clients in Florida as well as clients in Alaska, Colorado, Massachusetts, Michigan, New York, Oklahoma, Texas, and Wisconsin, as well as other states and territories.

Power Supply Requests for Proposals (RFPs)

Power purchases are often an important component of electric utility system planning, and conducting a competitive power supply RFP process may be critical to the ensuring the most cost-effective, reliable, and environmentally responsible alternatives are being considered. Mr. Kushner has experience in the complete RFP lifecycle, including collaborating with clients to develop the RFP, supporting clients during issuance and subsequent management of the RFP process, screening and evaluating RFP responses, presenting the results of the RFP to clients and stakeholders, and supporting negotiations related to power purchase agreements. Mr. Kushner has managed or otherwise been involved in numerous RFP processes focused on both conventional and renewable generating technologies.

Independent Engineering / Project Financing Support

Mr. Kushner has managed projects in the area of independent engineering, related to merger and acquisition support as well as development of new power projects. Most recently, Mr. Kushner managed the independent engineering assessment of a new biomass facility in North America for which the developer was trying to obtain project financing. The independent engineering assessment included development of a due diligence report on behalf of the developer, supporting negotiations with potential investors, supporting development of the credit agreement with the eventual loan syndicate, and monthly construction monitoring activities.

PROFESSIONAL HISTORY

Mr. Kushner began his career with Black & Veatch Corporation in 2000 and has been involved in electric utility system resource planning and independent engineering engagements since that time in various roles at Black & Veatch. Most recently, Mr. Kushner was Department Head for Black & Veatch's Management Consulting group and was a Director for Black & Veatch Management Consulting LLC's electric system resource planning service offering before joining nFront Consulting LLC in 2016. Mr. Kushner is currently a Manager of nFront Consulting and the Managing Director of nFront Consulting's Energy practice.

EDUCATIONAL

Mr. Kushner's educational background includes a B.S. in Mechanical Engineering from the University of Missouri - Columbia and a Master of Business Administration from Emporia State University.

CPWC Results for Base Case and Sensitivities

Case Description	CPWC (\$ Millions)	Resource Addition Selected for 2031
Base Case (Least-cost)	\$28,459	7HA.03 1x1 CC (SJRPP Unit 3)
Next Lowest Cost Alternative (Base Case, but not allowed to build 1x1 CC in 2031)	\$28,550	1x0 GE 7HA.03 Simple Cycle (7HA.03 1x1 CC added in 2035)
Delay of the Unit 1 Year	\$28,481	7HA.03 1x1 CC (in 2032) (SJRPP Unit 3)
High Load Growth	\$29,328	7HA.03 1x1 CC (SJRPP Unit 3)
Low Load Growth	\$26,758	7HA.03 1x1 CC (SJRPP Unit 3)
High Natural Gas Prices	\$29,805	7HA.03 1x1 CC (SJRPP Unit 3)
Low Natural Gas Prices	\$25,759	7HA.03 1x1 CC (SJRPP Unit 3)
High Capital Cost	\$28,864	7HA.03 1x1 CC (SJRPP Unit 3)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2026 _____-EC

**IN RE: PETITION OF JEA FOR DETERMINATION OF NEED
FOR ST. JOHNS RIVER POWER PARK UNIT 3**

DIRECT TESTIMONY & EXHIBITS OF:

WAYNE OLIVER

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BEFORE THE PUBLIC SERVICE COMMISSION

JEA

PETITION TO DETERMINE NEED FOR

ST. JOHNS RIVER POWER PARK UNIT 3 (SJRPP UNIT 3)

DIRECT TESTIMONY OF WAYNE J. OLIVER

DOCKET NO. _____

June 4, 2026

I. INTRODUCT AND QUALIFICATION

Q. Please state your name and address.

A. My name is Wayne J. Oliver. My business address is 26 Shipway Place,
Charlestown, Massachusetts, 02129.

Q. By whom are you employed and in what capacity?

A. I am the CEO of Merrimack Energy Group, Inc.

Q. What is Merrimack Energy Group, Inc.?

A. Merrimack Energy Group, Inc. (Merrimack Energy) primarily provides
services as an Independent Evaluator (IE) or Independent Monitor (IM) to
oversee competitive procurement processes undertaken by electric utilities,
other power buyers, and regulatory commissions. In addition to providing IE or
IM services, Merrimack Energy has served as an advisor to electric utilities in
the development and implementation of competitive procurement processes,
including proposal economic evaluation, non-price project viability
assessments, fuel supply procurement, contract design, and financial

1 assessments. Merrimack Energy has also provided strategic consulting and
2 analytical support services to all segments of the energy market, including
3 conducting benchmark studies, electric and gas market studies, and asset
4 acquisition assessments. Merrimack Energy has extensive experience in all
5 phases of power procurement and resource planning in power markets
6 throughout the United States and Canada.

7
8 **Q. Please describe your responsibilities in your current position.**

9 A. My primary area of specialization is the provision of IE and IM services for
10 power supply solicitations. I have served as project manager in over 160
11 competitive bidding or competitive procurement assignments that have
12 included a range of technologies, project or contract structures, and product
13 types dating back to the late 1980s.

14
15 **Q. Please state your professional experience and educational background.**

16 A. I have over 40 years of experience in the energy industry. During that time, I
17 have held senior level positions as an economist and consultant with
18 government agencies and private sector firms. I was formerly a Founder and
19 Senior Officer of Reed Consulting Group, Inc. I also served as a Director of
20 Navigant Consulting, Inc. after the acquisition of Reed Consulting Group by
21 Metzler and Associates and the subsequent formation of Navigant Consulting.
22 I have also been an assistant professor in the Economics Department at
23 Northeastern University and an adjunct professor in the Finance Department at
24 Babson College, where I taught courses in risk management (at a Master of

1 Business Administration level) and futures and options. I have a Masters
2 degree in economics from Northeastern University.

3

4 **Q. Have you previously testified before state regulatory commissions?**

5 A. Yes. I have testified before a number of state Commissions in the U.S.,
6 Provincial Commissions in Canada, and Federal agencies in the U.S. and
7 Canada. I have testified before the regulatory commissions in Louisiana,
8 Arkansas, Texas, New Mexico, Hawaii, Utah, Oklahoma, New York,
9 Massachusetts, Vermont, and Connecticut. I have also testified on behalf of
10 Hydro Quebec and BC Hydro in Canada and before the Federal Energy
11 Regulatory Commission and National Energy Board of Canada. Most of my
12 recent testimony has been as IE or IM in proceedings involving Certificates of
13 Public Convenience and Necessity for utility projects or for approval of power
14 contracts with third parties resulting from a competitive procurement process
15 on which I have served as IE or IM.

16

17 **Q. Is Exhibit No. ____ (WJO-1) a true and correct copy of your resume?**

18 A. It is.

19

20 **Q. Please more specifically describe your experience relative to power supply**
21 **requests for proposal (RFPs)?**

22 A. I have served as the IE or IM for over 160 conventional and renewable power
23 procurement solicitations across 23 states and 3 Canadian provinces. This
24 includes all source solicitations, and other solicitations that have included long-
25 term conventional gas-fired combined cycle and combustion turbine peaking

1 projects, renewable resources, energy storage projects, distributed energy
2 resources, demand response, demand-side management and energy efficiency
3 options, combined heat and power projects, micro-grid options, and offshore
4 wind projects. Among other things, I have provided IE oversight and
5 assessments associated with bid evaluation and selection processes.

6
7 **Q. What is the purpose of your testimony in this proceeding?**

8 A. Merrimack Energy was retained by JEA to serve as IE for JEA's Solicitation
9 for Long-Term Firm Dispatchable Capacity and Energy Resources market test
10 RFP (Market Test RFP) issued in October 2024 to solicit proposals for firm,
11 dispatchable capacity and associated energy to help meet JEA's 2030 (and
12 beyond) capacity needs. Merrimack Energy monitored JEA's solicitation of
13 market alternatives (i.e., resources that would be owned and operated by others
14 with capacity and energy sold to JEA via power purchase agreement [PPAs]).
15 In my role as the IE, I was involved in reviewing and participating in the
16 design and development of JEA's solicitation process, the issuance of the
17 solicitation, and response evaluation and selection, including consideration of
18 JEA's one-on-one combined cycle self-build resource (Self-Build Resource).
19 Ultimately, I concluded that JEA's Market Test RFP process was undertaken
20 in a fair and equitable manner and agreed with JEA's conclusion that the Self-
21 Build Resource was a reasonable decision based on both economic and
22 qualitative factors. The purpose of my testimony is to describe my role as IE
23 and present my findings.

24
25 **Q. Are you sponsoring any exhibits in the case?**

1 A. Yes. I am sponsoring the following exhibits, which were prepared by me
2 under my supervision and are attached to this pre-filed testimony:

- 3 • Exhibit No. __ (WO-1) - Professional Resume of Wayne Oliver
- 4 • Exhibit No. __ (WO-2) - Merrimack Energy Group, Inc.'s Independent
5 Evaluation Report

6
7 **Q. Please describe the role you performed as an independent evaluator in**
8 **JEA's Market Test RFP.**

9 As the IE in JEA's Market Test RFP, my role was to help ensure that the RFP
10 design, process, and evaluation was impartial and objective such that all
11 responses to the solicitation were treated consistently, with no undue
12 preference given to any responses or respondents or JEA's Self-Build
13 Resource. In my role, I was involved in design and development of the RFP
14 documents, issuance of the RFP, and review of the evaluation and selection
15 process and results of the evaluation. More specifically, I proposed additional
16 measures to further ensure that the process would be fair, consistent, and
17 equitable, including recommendations for marketing the RFP to additional
18 industry publications to increase market competition. In addition, I
19 recommended that the Self-Build Resource proposal be provided to Merrimack
20 Energy prior to opening of third-party bids to ensure transparency and fairness.
21 JEA implemented these recommendations. I also reviewed inputs to be used in
22 the economic evaluations and ensured they were locked down prior to
23 submission of resources to ensure a consistent evaluation of the market
24 responses and subsequent comparison against the Self-Build Resource. JEA
25 conferred with me on a number of issues relating to proposal RFP compliance

1 decisions, interpretation of proposal information, clarification requests, and
2 economic evaluation assumptions. Regarding RFP compliance, I conferred
3 with JEA regarding flexible application of the minimum requirements to the
4 third-party proposals despite concerns regarding conformance. As a result,
5 only one of the proposals was disqualified as inconsistent with the RFP's
6 minimum requirements. I concurred with this disqualification decision. I
7 reviewed all of the clarification communications between JEA and the
8 respondent. Ultimately, I oversaw JEA's quantitative and qualitative
9 evaluation process, confirming consistency in application of the scoring
10 criteria, reviewing JEA's scoring and analysis, and independently concluding
11 and agreeing with selection of the Self-Build Resource based on economic and
12 qualitative factors.

13
14 **Q. Was the response to JEA's proposal consistent with your experience and**
15 **expectations?**

16 A. Yes. JEA received four proposals from one bidder (Florida Power & Light
17 Company [FPL]) in response to the Market Test RFP seeking new generation
18 resources. Three of the proposals included Power Purchase Agreements
19 (PPAs) ranging from 20 to 30-year terms to be served by FPL's existing
20 generation resources (PPA Proposals 1-3). The fourth included a PPA coupled
21 with a commitment to enter development of an unspecified future jointly
22 owned electrical generating plant (Proposal 4). The limited response was
23 consistent with my expectations given that in recent years leading up to JEA's
24 RFP, I saw very few new gas-fired generation combined cycle, combustion
25 turbine, or reciprocal engine proposal options bid into RFPs, as independent

1 project developers transitioned from submission of thermal resource options to
2 renewable and/or storage resources.

3

4 **Q. Were you involved in the evaluation process?**

5 A. Yes. The evaluation process was consistent with that described in the Market
6 Test RFP instructions, including assessment of compliance with minimum
7 requirements; follow-up clarifying questions; quantitative evaluation;
8 qualitative evaluation; combined scoring of quantitative and qualitative factors
9 and resource selection. I was involved at each stage participating in
10 discussions with the JEA project team, reviewing evaluation results, and
11 submitting follow-up questions related to the evaluation results and processes.

12

13 **Q. Please describe the evaluation of compliance with minimum requirements.**

14 A. The first stage of the evaluation process consisted of a review of the third-party
15 responses and options to assess if the responses complied with the minimum
16 requirements listed in the Market Test RFP instructions. I was involved in
17 JEA's evaluation of the four proposals for compliance with minimum
18 requirements. None of the PPA proposals strictly complied with the RFP
19 minimum requirements relative to, for example, liquid fuel back-up, dispatch,
20 and a detailed transmission plan. Despite these concerns, JEA and I focused
21 on the intent of the minimum requirements as opposed to strict compliance
22 since the minimum requirements were more applicable to new generating units
23 than system sales. We, therefore, agreed regarding moving forward with
24 evaluation of PPA Proposals 1 through 3. Proposal 4, however, was classified
25 as non-conforming for several reasons. Most glaringly, Proposal 4 did not

1 include pricing information or operational information for the new generating
2 unit to allow for an evaluation of this option. I agreed with JEA's screening
3 for compliance with minimum requirements.

4

5 **Q. Did JEA send any follow-up clarifying questions regarding the proposals?**

6 A. Yes. To assist in assessing whether the proposals met the minimum
7 requirements and to ensure accuracy for modeling and evaluation purposes,
8 JEA sent two rounds of questions to FPL seeking clarification of information
9 submitted, primarily regarding transmission and delivery considerations, fuel
10 supply and transportation, and project operational characteristics.

11

12 **Q. Were you involved in the quantitative and qualitative evaluation of**
13 **proposals?**

14 A. Yes. Once the assessment of minimum requirements was complete, the
15 evaluation process began to focus on the economic (quantitative) and
16 qualitative analysis of the three PPA options.

17

18 **Q. Do you believe JEA's evaluation process was conducted fairly?**

19 A. Yes. The Market Test RFP proposals and JEA's Self-Build Resource were
20 evaluated consistently and on an equal footing using an equitable and
21 transparent evaluation process that exceeded industry standards.

22

23 **Q. Are your role in the Market Test RFP process and conclusions related to**
24 **that process included in the report attached as Exhibit No. __ (WO-2)?**

25 A. Yes.

1

2 **Q. Does that report remain true and correct today?**

3 A. Yes.

4

5 **Q. Does this complete your testimony?**

6 A. Yes.

Wayne J. Oliver

Merrimack Energy
26 Shipway Place
Charlestown, Mass. 02129
(781) 856-0007
waynejoliver@aol.com

A Management Consultant/Economist with a diverse background in the energy field. Areas of expertise include power procurement and contracting, strategic planning, asset valuation, power project evaluation, energy supply/demand forecasting and planning, competitive fuels analysis, risk management, rate analysis and expert testimony, regional energy market analysis, and project economic and financial analysis. Focus on electric, gas and renewable resource industries. Provided expert testimony at the Federal Energy Regulatory Commission, National Energy Board of Canada, and in over 10 states and Canadian Provinces in nearly 50 proceedings.

PROFESSIONAL EMPLOYMENT

2000-present	Merrimack Energy Group, President
1988-2000	Reed Consulting Group/Navigant Consulting, Inc. Managing Director/Senior Vice President/Founder of Reed
1999	Babson College , Adjunct Professor, Finance Department
1984-1988	R.J. Rudden Associates, Inc. Senior Consultant
1983-1984	Massachusetts Executive Office of Energy Resources Consultant
1981-1983	Algonquin Gas Transmission Company Corporate Planner
1980-1981	Massachusetts Executive Office of Energy Resources -- Analysis and Regulations Program Assistant Director
1978-1980	New England Regional Commission -- Energy Policy Analysis Program Energy Program Coordinator/Senior Economist

PROFESSIONAL EXPERIENCE

Power Procurement/Competitive Bidding

Served as Independent Evaluator or Independent Consultant for over 125 competitive procurement assignments on behalf of utilities, regulatory agencies and public organizations for a range of resource options and contract structures. As Independent Evaluator responsible to ensure the competitive procurement process is undertaken in a fair and unbiased manner. Also, assisted a number of utilities in the development and implementation of competitive bidding processes and associated RFPs for long-term supply-side resources, renewable resources, option contracts, distributed resources and demand-side resources. Evaluated hundreds of power supply proposals for a wide range of power generation technology options and contract structures.

Resume of Wayne J. Oliver, Page 2

Directed a major study for a large electric utility involving the development of a viability methodology for assessing non-utility generation projects based on the use of Critical Path methodology.

Independent Evaluator or Independent Monitor for a number of power solicitation or competitive bidding processes including: Entergy Services, Inc., Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric Company, NV Energy, PacifiCorp, Arizona Public Service Company, Avista Utilities, Delmarva Power, El Paso Electric, Entergy Arkansas, Entergy Texas, Entergy Louisiana, Baltimore Gas and Electric, Duke Power, Hydro-Quebec (Baseload and Dispatchable Supply, Wind, Biomass, Cogeneration, and several Short-Term Call for Tenders), Portland General Electric, BC Hydro, Central and SouthWest Services (five separate RFPs), Commonwealth Edison, Public Service Company of Oklahoma and Southwestern Electric Power Company RFPs for power supplies.

Assisted Hawaiian Electric with the company's policy associated with the design of competitive bidding rules in Hawaii. Testified for four days on industry practices associated with competitive procurement processes.

Assisted several utilities with the development of an evaluation methodology and contract terms for RFP's for Power Options. Managed the development of an options pricing model to evaluate bids received.

Renewable Resources

Developed renewable resource RFPs and assisted in bid evaluation for Hydro-Quebec Distribution (4000 MW Wind and 100 MW Biomass), Avista Utilities, Massachusetts Technology Collaborative, Portland General Electric (wind, geothermal, and biomass proposals), Central Power & Light Company (wind only RFP), Public Service Company of Oklahoma, Southwestern Electric Power Company, West Texas Utilities, and Hawaiian Electric Company. Served as Independent Evaluator for several renewable resource solicitations including Pacific Gas & Electric, Southern California Edison, NV Energy, Entergy Arkansas, Entergy Texas, Arizona Public Service, and PacifiCorp.

Chaired two major conferences on green pricing initiatives and renewable resource development

Asset Valuation

Conducted due diligence analysis for several banks regarding the potential financing for merchant power projects, gas storage projects, and gas pipeline assets.

Conducted asset valuation analysis for utilities and power generators interested in acquiring power generation assets. Analysis included valuation of gas-fired combined cycle and CTs, coal projects, hydroelectric facilities, power contracts, pipeline capacity commitments, and electric transmission assets.

Competitive Energy Pricing

Negotiated several special contracts with unique pricing arrangements between utilities and customers.

Developed a market price evaluation methodology and pricing process for a large electric utility for wholesale and retail marketing initiatives.

Risk Management

Conducted seminars for utilities on the use of risk management techniques and financial derivatives to hedge risks, including the use of options, futures and swaps. Applied financial option techniques in the development of physical option arrangements.

Developed a risk management strategy for a major electric utility to hedge its fuel and power trading price risk.

Resume of Wayne J. Oliver, Page 3

Fuel Supply Acquisition Strategy and Procurement

Completed gas procurement strategies and portfolio designs for several electric utilities. Responsibilities included evaluating pipeline and storage options, developing a procurement strategy, and recommending a course of action. The projects involved integrating the production cost and operations of the generation units with gas supply and transportation contracting considerations to develop a least cost strategy.

Energy Market and Economic Policy Studies

Conducted a number of studies for utility and non-utility clients on the market for power in various regions of the US and in Canada.

Conducted several market studies and power price forecasts in support of due diligence efforts for acquisition of power generation assets.

Utility Restructuring

Advised senior management of electric utilities on evaluating and developing strategies for enhancing the value of the utility's assets. Also assisted several utilities in the development of GENCO strategies.

Strategic Planning and Analysis

Completed a strategic planning study for a major electric utility assessing the opportunities for the company in the changing natural gas market, including fuel purchasing strategies, and gas fired cogeneration and combined cycle opportunities.

Forecasting and Modeling

Developed integrated planning and forecasting system for a small electric utility. The system was comprised of production cost, generation planning, cost of service, demand forecasting and rate design modules.

Managed a number of projects and utilized several production cost and generation expansion models for evaluation of power supply proposals and resource options.

Financial Analysis

Assisted several utilities in the financial analysis of distributed resources for the purposes of establishing a DG business unit.

Assisted in the preparation of financial and economic feasibility studies of power generation projects for a consortium of banks.

Prepared several financial prefeasibility studies of proposed power generation projects for utilities, independent power producers and industrials.

EDUCATION

Northeastern University, Completed Doctoral Course work, Economics, 1977

Northeastern University, M.A., 1976

Assumption College, B.A., 1973

OTHER

Past Chairman, Massachusetts Natural Gas Task Force.

Adjunct Professor, Department of Finance, Babson College; Courses taught include Risk Management (MBA Program), Options and Futures

Instructor/Lecturer, Department of Economics, Northeastern University; Courses taught include Energy Economics, Statistics, International Economics, and Principles of Economics.

Independent Evaluator Report

JEA 2024 Market Based Resources Request for Proposals

May 5, 2026



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1 EXECUTIVE SUMMARY

JEA plans to file a petition with the Florida Public Service Commission ("FPSC" or "Commission") for a determination of need for a nominal approximately 675 MW 1x1 combined cycle unit to be installed at the existing St. Johns River Power Park ("SJRPP") site in Jacksonville, Florida.

JEA issued a Solicitation for Long-Term Firm Dispatchable Capacity and Energy Resources ("Market Test RFP" or "Solicitation") on October 2, 2024, with responses due on April 21, 2025. The Market Test RFP was issued to solicit proposals for firm, dispatchable capacity and associated energy to help meet projected customer peak demands (plus reserve margin requirements) and energy requirements beginning in 2030. JEA indicated in the Market Test RFP Instructions document ("RFP Instructions")¹ that it intended to provide a 1x1 combined cycle self-build resource ("Self-Build Resource") in response to the Solicitation and evaluate all resource alternatives submitted that complied with the requirements of the Solicitation relative to the Self-Build Resource. JEA also stated that it anticipated that the generation technology having the highest likelihood of success as an alternative to the Self-Build Resource would be an advanced-class combined cycle technology resource, with operating parameters that include the ability to operate in baseload and load-following roles across the full unit load range. The Solicitation therefore included a market test of a Self-Build Resource by JEA, the characteristics of which were included in the Solicitation documents available to the market.

Merrimack Energy Group, Inc. ("Merrimack Energy") was selected to serve as the Independent Evaluator ("IE") by JEA for the Market Test RFP. Merrimack Energy's involvement began in the early stages of development of the Market Test RFP documents and continued through final evaluation and selection of the preferred resource. Merrimack Energy's overriding responsibility was to ensure that the Solicitation process was undertaken in a fair and unbiased manner with no undue preference provided to a self-build option.

The third-party responses were submitted to JEA electronically via the Zycus Supplier Network platform on April 21, 2025, with the Self-Build Resource submitted to the IE several hours before the third-party proposals were publicly opened by JEA.

JEA received four proposals from one respondent in response to the Solicitation, three of which were deemed compliant with the minimum requirements of the Solicitation. A team of JEA staff with specialized expertise in a variety of areas ("JEA Evaluators") reviewed and evaluated the three compliant third-party responses and the Self-Build Resource relative to the evaluation criteria and methodology provided in the Market Test RFP documents available to all respondents. The Self-Build Resource was scored by the JEA Evaluators as the highest-ranking resource option from both a quantitative and qualitative perspective. Merrimack Energy reviewed the quantitative scores, conducted a review of the qualitative scoring, and likewise agreed that the Self-Build Resource ranked highest in quantitative and qualitative categories.

¹ In addition to the main RFP Instructions document, JEA prepared and included thirteen related appendices for respondents to review in preparing their responses. There were also six addenda to the main RFP Instructions and other documents provided to potential respondents to assist them in developing their responses. The entirety of the main RFP Instructions document, the thirteen appendices, and six addenda represent the entire RFP instructions package.

Overall, the Solicitation process and evaluation was transparent, consistent, comprehensive, and fair.

JEA's Board approved moving forward with the Self-Build Resource in August 2025.

2 INTRODUCTION

JEA selected Merrimack Energy to serve as the IE for JEA's Market Test RFP. Merrimack Energy's role was to independently evaluate responses to the Market Test RFP and ensure that the Solicitation process was undertaken in a fair and unbiased manner with no undue preference provided to any proposal, including the Self-Build Resource.

To evaluate the cost-effectiveness of the Self-Build Resource, JEA issued the Market Test RFP. JEA stated in the RFP Instructions that it intended to propose the Self-Build Resource in response to the Solicitation; anticipated that the generation technology having the highest likelihood of success as an alternative to the Self-Build Resource would be an advanced class combined cycle resource with operating parameters that include the ability to operate in baseload and load following roles across the full unit load range; and intended to evaluate all compliant resource alternatives submitted relative to the Self-Build Resource. JEA further indicated that, regardless of technology, JEA must have sole rights to unit commitment and de-commitment, which includes dynamic scheduling. While JEA's resource planning process identified an advanced-class combined-cycle unit as the preferred technology, other dispatchable technologies were not prohibited from being proposed in response to the Solicitation. JEA made clear in the RFP Instructions that unless a different preferred resource alternative was identified through the Solicitation, JEA anticipated pursuing the development of the Self-Build Resource.

Merrimack Energy's role as IE began during the development of the RFP documents and continued through the evaluation and selection of the preferred resource option. This independent evaluation report documents Merrimack Energy's role and activities.

3 ROLE & ACTIVITIES OF THE INDEPENDENT EVALUATOR

Merrimack Energy's overall role was to help ensure that the Solicitation design, process, and evaluation was impartial and objective such that all responses to the Solicitation were treated consistently, with no undue preference given to any responses or respondents.

The overall Scope of Services of the IE is listed in Appendix H of the RFP Instructions. The responsibilities and activities of the IE included oversight, review, and monitoring throughout the various phases of the Solicitation including:

1. Design and development of the Solicitation.
2. Issuance of the Solicitation.
3. Response evaluation and selection.
4. Contract negotiations with the selected responses, if applicable.

4 JEA'S COMPETITIVE PROCUREMENT SOLICITATION PROCESS

This section of the IE report describes the key activities and processes undertaken in the Solicitation process from development of the RFP documents and related methodologies and processes to final evaluation and JEA Board approval.

4.1 BACKGROUND

The RFP Instructions provide a detailed description of JEA's competitive procurement process and requirements for respondents. This section of the report provides a high-level summary of the Market Test RFP process.

4.2 SUMMARY OF THE COMPONENTS OF JEA'S MARKET TEST RFP

The Market Test RFP process was designed as a highly transparent process to provide a significant amount of information to guide potential respondents. The RFP Instructions clearly identified the required resource characteristics; the eligibility requirements for respondents; the timing and amount of capacity (MW) required; the schedule for the Solicitation process; the evaluation and selection criteria, methodology, and process; and a description of the role of electric transmission and fuel supply availability and cost.

4.3 SAFEGUARDS

JEA implemented a highly transparent process that identified in the RFP Instructions the minimum requirements for responses to be eligible to compete and described the specific quantitative and qualitative criteria and weightings to be used to evaluate the proposed resources. JEA also used the Zycus Supplier Network platform which allowed JEA to communicate with all respondents at the same time. In addition, JEA staff who provided services to the Self-Build Resource team and JEA Evaluators were required to execute non-disclosure agreements.

JEA was equally transparent relative to the Self-Build Resource. The RFP Instructions included Appendix A (Self-Build Option Information), which included operational information associated with the Self-Build Resource, O&M costs, average heat rates, estimated total installed costs, and equivalent availability factor. Appendix A also included the location of the Self-Build Resource, guaranteed commercial operation date ("COD") and dual fuel requirements. Appendix A noted that the Self-Build Resource would utilize existing infrastructure and resources, including fuel infrastructure and interconnection facilities at the SJRPP site.

Merrimack Energy also proposed additional "safeguards" to further ensure the process would be fair, consistent, and equitable such that no resource, including the Self-Build Resource, received an unfair advantage. More specifically, Merrimack Energy suggested that the Self-Build Resource be required to submit the same information and documentation required of third-party respondents. Merrimack Energy also suggested that the Self-Build Resource proposal

be provided to Merrimack Energy before the third-party proposals were opened to ensure the Self-Build Resource team would not have access to third-party proposal information before submitting details regarding the Self-Built Resource. JEA implemented these recommended safeguards.

Importantly, the third-party responses and the Self-Build Resource were scored using the same process, information, and criteria as described in Section 4.6 below.

4.4 OUTREACH ACTIVITIES

Merrimack Energy requested information about how JEA intended to publicize the Market Test RFP to help ensure as much competition as possible in the Solicitation process. Merrimack Energy suggested that JEA publicize the Market Test RFP by providing notices to industry organizations as well as the trade press who may consider publishing a notification of the Market Test RFP. JEA provided notifications to several publications including the Jacksonville Daily Record and electric industry trade publications. The Jacksonville Daily Record and two trade publications included the notification in their publications.

4.5 THE MARKET TEST RFP PROCESS

JEA issued the Market Test RFP on October 2, 2024, with six addenda issued thereafter.

All interested respondents were required to attend the pre-response meeting held on December 2, 2024, to be eligible to submit a response. The purpose of the pre-response meeting was to provide an overview of the Market Test RFP process, schedule, and requirements and to also solicit and respond to initial questions from respondents. Four potential respondents attended the mandatory pre-response meeting.

As explained in the RFP Instructions, all questions were required to be submitted in writing electronically on the Zycus Supplier Network platform at least 5 business days prior to the bid opening date. JEA reserved the right to provide responses to questions to all bidders that did not refer to specific individual project information. JEA responded to twelve questions from Respondents during the Q&A period.

4.6 JEA PROPOSAL EVALUATION

JEA detailed the proposal evaluation methodology and scoring process in several RFP Instruction documents, including Appendix J (Evaluation Methodology and Scorecard), Appendix C (Minimum Requirements), and Appendix B (Transmission Interconnection and Deliverability Considerations), all of which could be accessed by potential respondents and applied equally to the Self-Build Resource.

JEA implemented a multi-stage evaluation process comprised of (1) minimum requirements; (2) economic (quantitative) evaluation; and (3) qualitative evaluation. The economic and qualitative assessments were combined into an overall score weighted 70% based on economic

scoring and 30% based on qualitative scores. Importantly, this process and evaluation criteria and scoring matrix were very transparent for respondents.

The multi-stage evaluation process was designed to initially select the best proposal(s) or resources to compare to the Self-Build Resource, and subsequently to evaluate the Self-Build Resource relative to the selected third-party proposal(s) to determine the preferred resource(s) for which to move forward toward selection and contract negotiations, if required. JEA indicated to Merrimack Energy early in the process that final consideration of the preferred resource(s) would be made by JEA's Board.

4.6.1 Minimum Requirements

JEA noted in the RFP Instructions that respondents must meet the minimum requirements to be eligible to have their response evaluated by JEA. Respondents were also required to submit the Minimum Requirements Form provided in Appendix C of the RFP Instructions. Respondents were required to confirm that they met each minimum requirement and provide documentation supporting the respondent's claim. As illustrated below, minimum requirements ranged from providing general responses to meeting specific operational and developmental requirements. Evaluation of whether a proposal met the minimum requirements listed was the first step in the evaluation process. The minimum requirements listed in the RFP Instructions include:

- Respondents have fully completed all required forms and provided all required information, consistent with Section 5, Section 6, and Section 17 of the RFP Instructions.
- Responses must have a guaranteed delivery start date or COD of no later than 12/31/2030 as shown in Table 2 of Section 3 – Schedule.
- Responses are for at least 525 MW (average ambient conditions).
- Respondent provides a project development schedule that identifies, at a minimum, the schedule milestones, any environmental permitting, transmission interconnection and delivery, and other applicable regulatory processes to facilitate the quoted delivery start date or COD of the proposed resource.
- Respondent certifies that along with the response for the generation resource(s), the respondent has submitted detailed plans and schedules for transmission interconnection, including submission into the interconnection queue, and the implementation of any required transmission upgrades, and the associated transmission service(s) for the power to be delivered to JEA service territory in compliance with all the state and federal regulations. This must be done for any resource regardless of its location (on-system or off-system).
- Respondent satisfy and account for within its response JEA's credit standards outlined in Appendix G – (Credit Requirements).
- For resources that JEA will not be operating (e.g., power purchase agreement ["PPAs"] and off-system build-transfer agreements ["BTAs"]), Respondent acknowledges that the response is for firm-delivered energy, and respondent is responsible for providing gas transportation adequate to ensure firm delivery of energy. Respondent to provide the volume of firm gas transport secured from which pipeline provider, the term of the contract, and any other pertinent supply details.
- Responses must include five (5) days of onsite liquid back-up fuel storage and 5 days on-site demineralized water storage and/or installed production capability.
- Responses include resources with commercially-proven technology. Technologies in the demonstration process are not acceptable.

- Response must include dynamic scheduling (e.g., automatic generation control ["AGC"]) by JEA for the proposed resource.
- Resource must include JEA's ability to commit and decommit the proposed facility at JEA's sole discretion, or the bottom of the dispatch range must be 0 MWs.
- Any resulting agreement between the respondent and JEA will require long-term coordination and approval of scheduled maintenance by JEA.
- For any BTA or Asset Purchase Agreement ["APA"] proposal outside of JEA's service territory, an O&M Agreement must be included within the response;
- JEA requires a term of 20 years or more, and any PPA Response with terms less than 30 years or the expected life of the resource (whichever is less) must include options for contract extensions beyond the proposed PPA term to the lesser of 30 years or the expected end-of-life date.
- Respondent acknowledges that any studies associated with the system impact must be performed by a transmission consulting engineering firm with experience in the respective (FRCC/ITS) regions.
- As outlined in Appendix B – Transmission Interconnection and Delivery Considerations, the respondent acknowledges that all applicable estimated capital costs for any system improvements or new constructions, and the costs of any transmission services through the project life cycle, that will not be estimated by JEA, have been provided along with the response. The bidder acknowledges that the respondent price is all inclusive of such costs.
- Respondent is not on the State of Florida Convicted Vendor List, State of Florida's Suspended Vendor List, the City of Jacksonville's Disqualified Vendor List, have their bidding privileges actively suspended by JEA, been debarred by JEA or have had a contract with JEA terminated for default within the last two (2) years.
- Respondent acknowledges that immediately following JEA Board approval to negotiate, respondent will support JEA with all necessary information for filing of petition for Determination of Need and Site certification Application, as applicable to the response.
- Respondent must attend the mandatory pre-response meeting.

4.6.2 Economic/Quantitative Evaluation

The economic evaluation assessed the cumulative present worth cost ("CPWC") to the JEA system over a 30-year time horizon. The proposed resources, including the Self-Build Resource, were evaluated using the PLEXOS capacity expansion and production cost model, from which the CPWC of resource plans including each of the proposed resources were determined. The PLEXOS model is widely used by utilities undertaking portfolio optimization assessments for determination of the portfolio of resources that meet system requirements at the lowest reasonable cost. The economic evaluation accounted for 70 points out of 100 total points for the assessment.

JEA utilized the PLEXOS model to develop optimal capacity expansion plans that include each of the selected resources based on each of the scenarios and sensitivities listed below:

- The reference case ("Base Case"), which assumed the US Environmental Agency's ("EPAs") Greenhouse Gas Rule ("GHG Rule")² was in place and effective over a 30-year time horizon (total of 30 points for this case);
- Base case assuming EPA's GHG Rule is in place and effective over a 15-year time horizon (total of 10 points for this case);
- Base Case without EPA's GHG Rule in place and effective over a 30-year time horizon (total of 15 points for this case);
- Average of sensitivity cases (i.e., high load forecast sensitivity, low load forecast sensitivity and high gas price sensitivity) (total of 15 points).³

Responses were ranked based on minimizing the CPWC of serving JEA load over the 30-year or 15-year planning horizon. Responses with a lower CPWC received a higher score than responses with a higher CPWC. For example, the proposed response included in the resource plan with the lowest cost CPWC would receive the maximum points for that case while other proposed responses would receive a score based on the maximum points minus the plan's percentage above the CPWC of the least cost plan, as described in Appendix J of the RFP Instructions. PLEXOS model inputs were reviewed by Merrimack Energy and locked down prior to submission of proposed resources to ensure a consistent evaluation of the market responses and subsequent comparison against the Self-Build Resource.

4.6.3 Qualitative Evaluation

For the qualitative evaluation, JEA provided Appendix J – (Evaluation Methodology and Scorecard) which clearly identified the scoring methodology and provided the qualitative scoring matrix which included the evaluation criteria, scoring definitions with point total ranges, and weights for each criterion.

JEA considered the respondents' relevant commercial experience and credit worthiness, transmission status, costs and impacts, fuel supply, operational flexibility, project status and design, and environmental considerations associated with respondents' proposals. The evaluation methodologies for these considerations were thoroughly and transparently described in the RFP Instructions.

4.7 RECEIPT OF RESPONSES

Third-party responses and the Self-Build Resource were provided on April 21, 2025, as required by the RFP Instructions. Merrimack Energy was provided a copy of the Self-Build Resource prior to JEA publicly opening the third-party responses.

² The GHG Rule would limit the capacity factor of a new gas-fired power plant to 40% unless carbon capture and storage is implemented to meet a 90% capture consistent with the best system for emission reduction.

³ All of these sensitivity cases assumed the GHG Rule was in effect over a 30-year time horizon. As of the date of this report, the U.S. Environmental Protection Agency ("EPA") has proposed to repeal the GHG emissions standards for fossil-fueled electric generating units and has rescinded the 2009 Endangerment Finding.

FPL submitted four proposals. Three of these proposals included PPAs ranging from 20 to 30-year terms to be served by FPL's existing generation resources. The fourth included a PPA coupled with a commitment to enter development of a future jointly owned and unspecified electrical generating plant with JEA. Table 1 below provides a summary of the responses submitted.

Table 1: Summary of Responses/Proposals Submitted

Proposal	Term	Proposal Description
Proposal 1 - 30-year System Sale - Intermediate	December 31, 2030 – December 30, 2060	525 MW up to 700 MW of energy and capacity from FPL system having pricing characteristics of a natural gas-fired combined cycle gas turbine unit.
Proposal 2 - 30-year System Sale Blend of Intermediate/Peaking	December 31, 2030 – December 30, 2060	525 MW up to 700 MW of energy and capacity from FPL system having pricing characteristics representative of a blend of 70% of a natural gas-fired combined cycle gas turbine unit and the remaining 30% of natural gas-fired simple cycle gas-fired simple cycle gas turbine unit.
Proposal 3 – 20-year System Intermediate	December 31, 2030 – December 30, 2050	525 MW up to 700 MW of energy and capacity from FPL system having pricing characteristics representative of a natural gas-fired combined cycle gas turbine unit.
Proposal 4 – 10-year System Sale Intermediate plus New Build	December 31, 2030 – December 30, 2040	525 MW up to 700 MW of energy and capacity from FPL system having pricing characteristics representative of a natural gas-fired combined cycle gas turbine unit. This offer is tied to an agreement between JEA and FPL to jointly build and own a generating unit in the future of a size and location to be determined.

4.8 THIRD-PARTY PROPOSAL EVALUATION PROCESS

JEA initiated its evaluation of the responses consistent with the resource review and evaluation process identified in the RFP Instructions, including the following activities:

- Assessment of minimum requirements;
- Follow-up clarifying questions;
- Quantitative evaluation;
- Qualitative evaluation; and
- Resource selection

4.9 CONFORMANCE WITH MINIMUM RFP REQUIREMENTS

The first stage in the evaluation process consisted of a review of the third-party responses and options to assess if the responses complied with the minimum requirements listed in the RFP Instructions.

JEA and the IE agreed that PPA proposals 1 through 3 should be classified as conforming, despite concerns relative to compliance with certain requirements such as the requirements for liquid fuel back-up, dispatch requirements, and lack of a detailed transmission plan. Merrimack Energy and JEA team focused on the intent of the minimum requirements as opposed to the specific requirements listed in the RFP Instructions and moved forward with the evaluation of PPA proposals 1 through 3. Proposal 4, however, which included a commitment to enter into a development agreement for a jointly owned power plant, was classified as non-conforming for several reasons. Most glaringly, Proposal 4 did not include pricing information or operational information for the new generating unit to allow for an evaluation of this option.

4.10 FOLLOW-UP CLARIFYING QUESTIONS

To assist in assessing whether the proposals met the minimum requirements and to ensure accuracy for modeling and evaluation purposes, JEA sent two rounds of questions to FPL seeking clarification of information submitted, primarily regarding transmission and delivery considerations, fuel supply and fuel transportation, and project operational characteristics.

JEA exchanged a number of Q&As with FPL to ensure it fully understood the components and nuances of the responses and could effectively model the responses in a consistent manner.

4.11 QUANTITATIVE EVALUATION OF THIRD-PARTY PROPOSALS AND SELF-BUILD RESOURCE

The next step in the process was to evaluate the three compliant PPA proposals relative to the Self-Build Resource. JEA initially intended to only evaluate the top-ranking third-party proposal against the Self-Build Resource. However, given the similarities of the PPAs, JEA moved forward with evaluating all three of the PPA options relative to the Self-Build Resource. JEA utilized the PLEXOS model to develop an optimal capacity expansion plan that included each proposed resource for each of the scenarios and sensitivities noted in Section 4.6.2 herein. As the results reported in Table 2 illustrate, the Self-Build Resource is part of the least cost resource plan in the Base Case with the GHG Rule as well as the Base Case with No GHG Rule. PPA 2 is part of the least cost resource plan in the average of the sensitivity cases, while PPA 3 is part of the least cost resource plan in the Base GHG Case over a 15-year timeframe.⁴

⁴ JEA included estimated costs of approximately \$100 million in the evaluation of each of the PPAs to reflect JEA's assessment of the transmission system upgrades required on JEA's transmission system to preserve JEA's import/export capability. The Self-Build Resource would require minimal transmission integration with an estimated cost of \$7.7 million. This cost was also included in the cost of the Self-Build Resource in the evaluation. Merrimack Energy has no reason to dispute the estimated transmission line

Table 2 Total System Economic Evaluation Results (in \$1,000) for Each Case (CPWC - \$1,000)

Cases	Self-Build	PPA 1	PPA 2	PPA 3
Base Case – GHG – 30 years	\$29,957,888	\$30,089,810	\$30,130,087	\$30,400,698
Base Case – GHG – 15 years	\$17,614,693	\$17,513,343	\$17,490,429	\$17,454,803
No GHG – 30 years	\$28,499,845	\$29,362,428	\$29,347,207	\$29,493,687
Average of Sensitivity Cases	\$32,006,963	\$31,766,258	\$31,703,323	\$32,030,254

Because the quantitative scoring was based on the economic evaluation results provided in Table 2, with each PPA and the Self-Build Resource scored on the basis of a maximum of 70 points, the PPAs and Self-Build Resource received the same quantitative scores from each Evaluator as shown in Table 3.

Table 3: Quantitative Scores for Each Resource

Quantitative Scoring	Maximum Points	FPL Response 1	FPL Response 2	FPL Response 3	Self-Build Option
Evaluator 1	70	65.9991	66.2479	64.0035	68.1262
Lowest Overall CPWC, Base Case (With GHG Rule) 30 years	30	29.5596	29.4252	28.5219	30.0000
Lowest CPWC, Base Case (with GHG Rule) 15 years	10	9.6646	9.7959	10.0000	9.0840
Lowest Overall CPWC Base Case (Without GHG Rule) 30 years	15	11.9734	12.0268	11.5128	15.0000
Sensitivity Cases CPWC	15	14.8015	15.0000	13.9688	14.0423
Evaluator 2	70	65.9991	66.2479	64.0035	68.1262

costs; however, to determine whether the inclusion of these JEA system upgrade costs would impact the scoring and ranking of the PPAs relative to the Self-Build Resource, Merrimack Energy performed an independent assessment of the CPWC of the stream of costs associated with the transmission line upgrades applied to the PPA options to assess if the economic results would change. Merrimack Energy found that even if the upgrade costs were not applied at all to the PPAs, the Self-Build Resource would still be included in the least cost resource plans in the Base Case (with or without the GHG Rule).

Lowest Overall CPWC, Base Case (With GHG Rule) 30 years	30	29.5596	29.4252	28.5219	30.0000
Lowest CPWC, Base Case (with GHG Rule) 15 years	10	9.6646	9.7959	10.0000	9.0840
Lowest Overall CPWC Base Case (Without GHG Rule) 30 years	15	11.9734	12.0268	11.5128	15.0000
Sensitivity Cases CPWC	15	14.8015	15.0000	13.9688	14.0423
Evaluator 3	70	65.9991	66.2479	64.0035	68.1262
Lowest Overall CPWC, Base Case (With GHG Rule) 30 years	30	29.5596	29.4252	28.5219	30.0000
Lowest CPWC, Base Case (with GHG Rule) 15 years	10	9.6646	9.7959	10.0000	9.0840
Lowest Overall CPWC Base Case (Without GHG Rule) 30 years	15	11.9734	12.0268	11.5128	15.0000
Sensitivity Cases CPWC	15	14.8015	15.0000	13.9688	14.0423

Merrimack Energy reviewed the results of JEA's quantitative analysis and concluded the overall scoring and evaluation was reasonable.

4.12 QUALITATIVE EVALUATION OF THIRD-PARTY PROPOSALS AND SELF-BUILD RESOURCE

Three internal evaluators from JEA were responsible for scoring each resource from a qualitative perspective based on the risk assessment scorecard included in Appendix J of the RFP⁵. As shown in Table 4, since the PPAs were very similar from a qualitative perspective, each evaluator scored each PPA consistently (e.g., each evaluator gave all three PPAs the same score). However, the scores for each PPA varied by evaluator based on the evaluator's interpretation and application of the evaluation criteria (e.g., evaluator 1 gave all three PPAs the same score and evaluator 2 also gave all PPAs the same score, but evaluator 1's and evaluator 2's scores for each PPA differ).

Table 4: Qualitative Scores for Each Resource

Qualitative Scoring	Maximum Points	FPL Response 1	FPL Response 2	FPL Response 3	Self-Build Option
Evaluator 1	30	16.4100	16.4100	16.4100	26.3700
System Reliability (Flexibility)	6.0	1.6400	1.6400	1.6400	5.1200

⁵ Appendix J includes the JEA Solicitation Scorecard which includes the total scoring methodology, economic assessment scoring, and the risk assessment scorecard. The risk assessment scorecard includes the qualitative evaluation criteria, weightings for each criterion, and score definitions for each sub-category within the specific criteria. Responses provided by each respondent for each resource relative to the questions in Appendix F (Respondent Questionnaire) provides information about each resource that evaluators and SMEs could use to conduct their qualitative evaluations. 4

Experience and Commercial	4.5	2.3100	2.3100	2.3100	3.7200
Transmission Status	6.0	1.2800	1.2800	1.2800	5.7800
Project Status and Technical Design	3.0	1.4000	1.4000	1.4000	2.7700
Environmental	4.5	3.7800	3.7800	3.7800	4.0800
Fuel Supply	6.0	6.0000	6.0000	6.0000	4.9000
Evaluator 2	30	22.1800	22.1800	22.1800	28.8400
System Reliability (Flexibility)	6.0	2.1600	2.1600	2.1600	5.2600
Experience and Commercial	4.5	3.6600	3.6600	3.6600	4.5000
Transmission Status	6.0	2.8600	2.8600	2.8600	5.8800
Project Status and Technical Design	3.0	3.0000	3.0000	3.0000	3.0000
Environmental	4.5	4.5000	4.5000	4.5000	4.5000
Fuel Supply	6.0	6.0000	6.0000	6.0000	5.7000
Evaluator 3	30	21.5700	21.5700	21.5700	27.5700
System Reliability (Flexibility)	6.0	2.6000	2.6000	2.6000	4.9200
Experience and Commercial	4.5	3.4800	3.4800	3.4800	4.0500
Transmission Status	6.0	3.0040	3.0040	3.0040	6.0000
Project Status and Technical Design	3.0	2.2500	2.2500	2.2500	2.9000
Environmental	4.5	4.5000	4.5000	4.5000	3.9000
Fuel Supply	6.0	5.7000	5.7000	5.7000	5.8000

As the results presented in Table 3 and Table 4 illustrate, the Self-Build Resource was scored as the highest-ranking resource option from both an economic and qualitative or risk assessment perspective by all three evaluators. While the evaluators scored the resource options differently based on their interpretation of the risk assessment scorecard in Appendix J, all the evaluators scored the Self-Build Resource higher than all three PPA proposals. The Self-Build Resource scored higher than all three PPA proposals. In particular, the Self-Build Resource scored higher than the PPAs in the system reliability (flexibility), transmission status, and project status and technical design categories. The PPAs did not offer the system reliability/operational flexibility benefits of the Self-Build Resource. In addition, the evaluators viewed the transmission requirements and system impacts to add risks to the JEA system with the PPAs included. The total scores for each evaluator are shown in Table 5.

Table 5: Total Scores for Each Evaluator

Total Scores	Maximum Points	PPA 1	PPA 2	PPA 3	Self-Build Resource
Evaluator 1	100	82.4091	82.6579	80.4135	94.4962

Evaluator 2	100	88.1791	88.4279	86.1835	96.9662
Evaluator 3	100	87.5691	87.8179	85.5735	95.6962

Merrimack Energy reviewed the economic results and the qualitative scores provided by the evaluators. Based on the Merrimack Energy's review, the overall results appeared reasonable and consistent among the evaluators. The Self-Build Resource scored the highest in both the economic and qualitative categories. As a result, Merrimack Energy concluded that the scoring and ranking of the resources was reasonable and consistent.

5 CONCLUSIONS

Merrimack Energy's important conclusions and findings regarding the Market Test RFP are:

1. The Market Test RFP process was undertaken in a fair and equitable manner by JEA with sufficient input and monitoring by Merrimack Energy. The Solicitation was a very transparent and consistent process designed to treat all respondents and proposed resource options the same. The process was well-structured and well-managed within a consistent framework whereby all potential respondents had adequate information upon which to base a well-designed proposal. The transparency of the process generally exceeded industry standards for competitive procurement processes, based on the level of detail provided regarding the evaluation criteria, scoring matrix, allocation of points and weights.
2. The RFP instructions clearly identified JEA's requirements regarding generation alternatives, key operating characteristics, the minimum or eligibility requirements, the amount of capacity (MW) and energy requested, the timing of requirements, schedule, review and evaluation criteria and methodology.
3. The role of the IE in JEA's Solicitation process was consistent with Appendix H to the RFP Instructions. Merrimack Energy had a very active role, from development of the RFP documents through final evaluation.
4. All potential respondents were treated the same and provided access to the same information at the same time through the Zycus Supplier Network platform.
5. Information for the Self-Build Resource was provided to Merrimack Energy prior to the receipt and public opening of any third-party resources.
6. The evaluation process followed by JEA was consistent with the approaches followed by other utilities for system optimization processes. Furthermore, the PLEXOS model is standard in the industry for developing least cost portfolios of resources designed to meet system reliability requirements for capacity and energy at the lowest reasonable cost as part of power procurement solicitation processes.

7. JEA followed its evaluation and scoring process for both the evaluation of third-party resources as part of the Market Test RFP as well as comparison of eligible third-party resources relative to the Self-Build Resource.
8. Merrimack Energy concluded that JEA evaluators' scoring of the Self-Build Resource as the highest ranked from an economic perspective, qualitative perspective, and combined economic and qualitative perspective was reasonable.
9. All compliant responses were consistently evaluated, using the same input assumptions, and ranked based on a quantitative and qualitative screening assessment as identified in the RFP Instructions. All evaluation results were thoroughly scrutinized by JEA and Merrimack Energy.
10. Selection of the Self-Build Resource was a reasonable decision based on both economic and qualitative evaluation results.

In conclusion, it is Merrimack Energy's view that the Market Test RFP process and assessment undertaken by JEA were consistent with industry standards, transparent, comprehensive, and fair. JEA established procedures and rules which guided the Solicitation process, including the evaluation and selection process, and applied such procedures consistently throughout the Solicitation process.