IMPROVING LIVES. BUILDING COMMUNITY. to be the best utility in the country

JEA BOARD OF DIRECTORS MEETING

JEA New Headquarters | 1st Floor | Room 120-B&C | 225 North Pearl Street, Jacksonville, FL 32202
March 28, 2023, | 9:00 am – 12:00 pm

WELCOME

Meeting Called to Order Time of Reflection Introductions Adoption of Agenda (Action)	Bobby Stein, Chair
Safety Briefing	Brandon Edwards, Director, Security & Emergency Preparedness
Values Moment	Brian Pippin, Director, Customer Experience, Insights & Strategy

COMMENTS / PRESENTATIONS

Council Liaison's Comments	Council Member Michael Boylan
Comments from the Public	Public
Managing Director / CEO Report	Jay Stowe, Managing Director / CEO
JEA Performance Update	Stefanie Monroe, Director, Analytics

BOARD AND COMMITTEE REPORTS AND ITEMS FOR CONSIDERATION

Finance & Operations Committee Report	General Joseph DiSalvo, Committee Chair
JEA Board of Directors – Slate of Officers (Action)	Jody Brooks, Chief Administrative Officer
Consent Agenda (Action) Board Meeting Minutes – February 28, 2023 April as Florida's Water Conservation Month Interlocal Agreement with Jacksonville Port Authority – Raising the Transmission Lines Over Fulton Cut Crossing Southeast Energy Exchange Market (SEEM) and Open Access Transmission Tariff Appointment and Delegation of Authority to Execute Florida Department of Transportation Documents Biannual Review of Procurement Code	Bobby Stein, Chair

PLAN FOR THE FUTURE

Vogtle Update	Jody Brooks, Chief Administrative Officer
Electric Integrated Resource Plan Discussion	Raynetta Curry Marshall, Chief Operating Officer Pedro Melendez, Vice President, Engineering & Construction

OTHER BUSINESS AND CLOSING CONSIDERATION

Old and Other New Business/Open Discussion
Chair's Report
Announcements – Next Board Meeting April 25, 2023
Adjournment

INFORMATIONAL MATERIAL

Appendix A: Financial Statements

Appendix B: 2023 Electric Generation Integrated Resource Plan

Appendix C: Finance & Operations Committee Materials – March 10

Appendix D: Public Comments

BOARD CALENDAR

2023 Board Meetings
9:00 am – April 25, June 27, August 29, September 26

2023 Committee Meetings
External Affairs Committee – April 18, September 8
Finance & Operations Committee – April 14, June 23, September 15
Governance, Audit, and Compliance Committee – August 4
Customer & Workforce Committee – March 31, August 25
Executive Committee – As Needed

JEA Board of Directors Meeting
March 28, 2023


Safety Briefing
Brandon Edwards, Director, Security & Emergency Preparedness

JEA
Building Community

Safety Briefing - New Headquarters

In the event of an emergency, JEA Security will call 911 and coordinate any required evacuation

Emergency Evacuation Route: Exit building via Pearl Street main entrance/exit or Monroe Street exit to the left of the American flag

Assembly Point: Front of Duval County Clerk of Courts (Corner of W Adams St. & Clay St.)

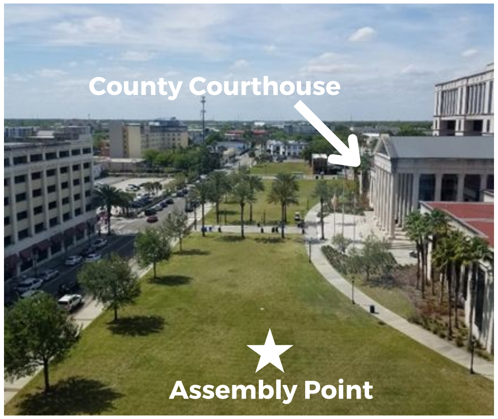
Evacuation or Medical Assist: Notify JEA Security Officer

Hazard & Situational Awareness

Cell Phone & Computer Etiquette

Pearl Street Exit

Monroe Street Exit
Left of the American Flag



Values Moment

Integrity

Brian Pippin, Director, Customer Experience, Insights & Strategy

Our Values

Safety
We put the physical and emotional wellbeing of people first, both at and away from work.

Respect
We treat others with courtesy and respect, seeking diverse perspectives and helping to bring out the best in everyone.

<u>**Integrity**</u>
We place the highest standard on ethics and personal responsibility, worthy of the trust our customers and colleagues place in us.


Why the Project Never Ends
Proximity
Objectivity
New "Driver"
Timing
Tomorrow, Not Today
Socialize It
Image
Self-Worth
Only a Reflection
Inertia
Impact not Completion
Reason Existence
FOMO
Not Every Opportunity
Mission & Values
We place the highest standard on ethics and personal responsibility, worthy of the trust our customers and colleagues place in us


MANAGING DIRECTOR/CEO REPORT
Jay Stowe, Managing Director/CEO

Celebrating Women in Trade

Florida Municipal Electric Association

Florida Lineman Competition

Competition Participants

Apprentices

Ryan Kornegay, Auston La Favor, Noah Sapp, Hunter Thomas, Payton Thompson

Journeyman Team 1

Doug Baye, Caleb Macabitas, Codty Stokes, Adam Holland

Journeyman Team 2

Dan Baye, Matt Poncher, Clay Cook, Jeremy Starr

Judges

John Santiago

Rocky Waldroup

Coach

Robert Hess

PERFORMANCE UPDATE

Data through February 28, 2023

Stefanie Monroe, Director, Analytics

JEA

FY23 PERFORMANCE SCORECARD

Data through February 28, 2023

FYTD Result
FY23 Goal
At Risk
Pay-for-performance

Safety & Environmental

Safety - Lost Time Incident Rate (LTIR)

0.34
0.00 0.11 0.60

FY23 Forecast: 0.27

Sanitary Sewer Overflows Impacting Waters of the US per 100 Miles of Pipe

0.58
0.00 0.24 0.66

FY23 Forecast: 0.66

Employee Engagement & Diversity

Employee Engagement (Survey)

0 82 100

Diversity - Female Representation

23.6%
0.8 YoY

FY23 Forecast: 23.1%

Diversity - People of Color Representation

27.4%
0.7 YoY

FY23 Forecast: 26.8%

Customer Satisfaction

Residential

4	3	2	1

4th Quartile

FY23 Forecast: 2nd Quartile

Commercial

4	3	2	1

2nd Quartile

FY23 Forecast: 2nd Quartile

Financial

Blue target line represents Planned YTD. Range maximum represents yearly budget goal.

Operations & Maintenance Spend

$208.1M
$198.2M
$0.0M $506.3M

FY23 Forecast: $487.2M

Capital Spend

$261.7M
$222.1M
$0.0M $640.0M

FY23 Forecast: $811.4M

Revenue - Total System

$791.1M
$766.1M
$0.00bn $1.96bn

FY23 Forecast: 1.873.7bn

Fuel & Purchased Power Expense

$290.0M
$265.0M
$0.0M $671.6M

FY23 Forecast: $575.7M

Reliability

System Average Interruption Duration Index (SAIDI)

65.0
0.0 51.79 103.6

FY23 Forecast: 50.82 minutes

Estimated Time to Restoration (ETR) Accuracy %

0.86
0.87
0.00 1.00

FY23 Forecast: 0.88

Water Unplanned Outages (Number of Customers)

1,542 7,700
0 8,000

FY23 Forecast: 4,020

Grid Water Pressure (average minutes <30 psi)

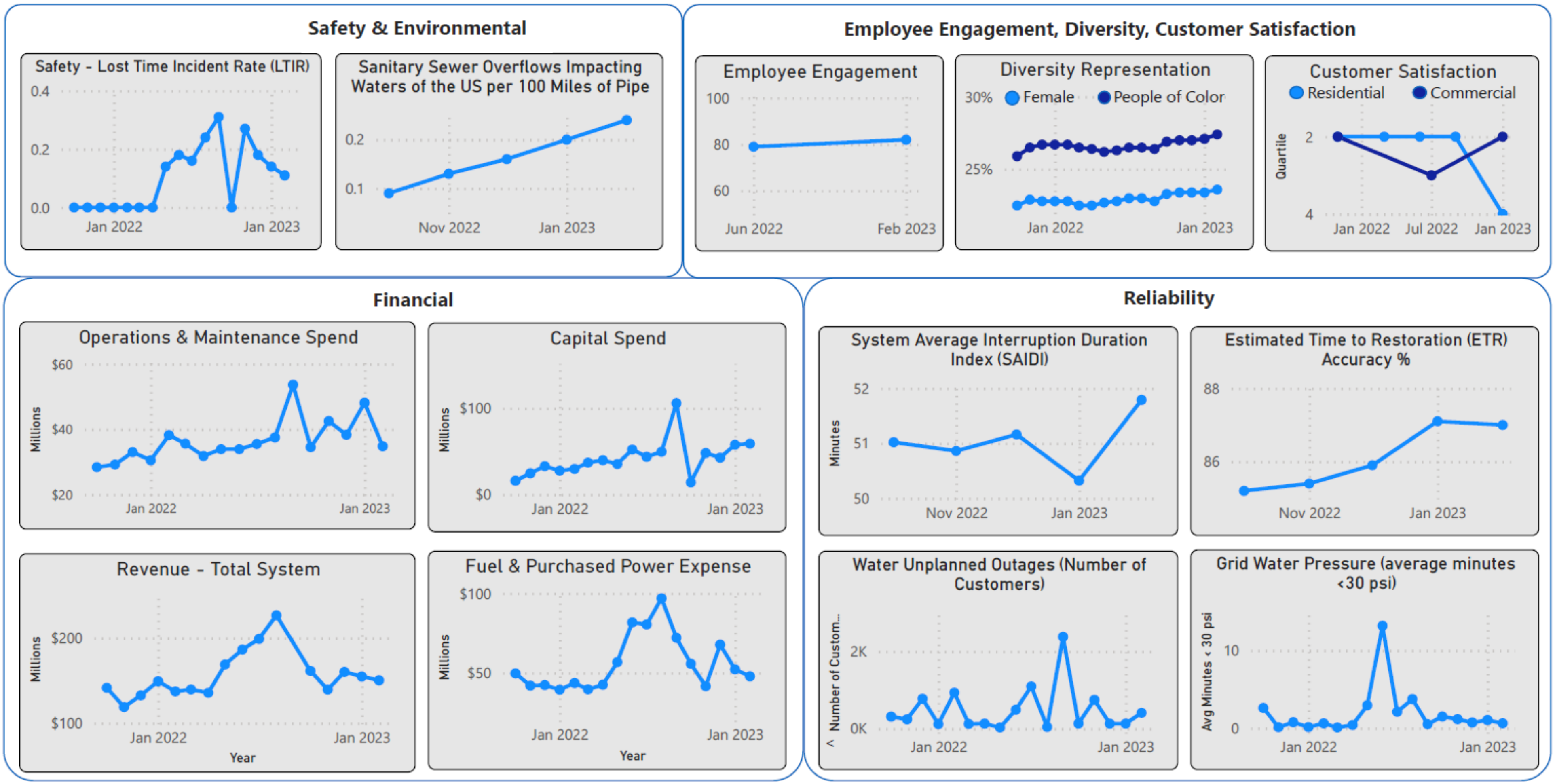
2.80
1.01
0.00 4.00

FY23 Forecast: 2.5

JEA

FY23 PERFORMANCE SCORECARD

Data through February 28, 2023




Finance & Operations Committee Report
General Joseph DiSalvo, Committee Chair
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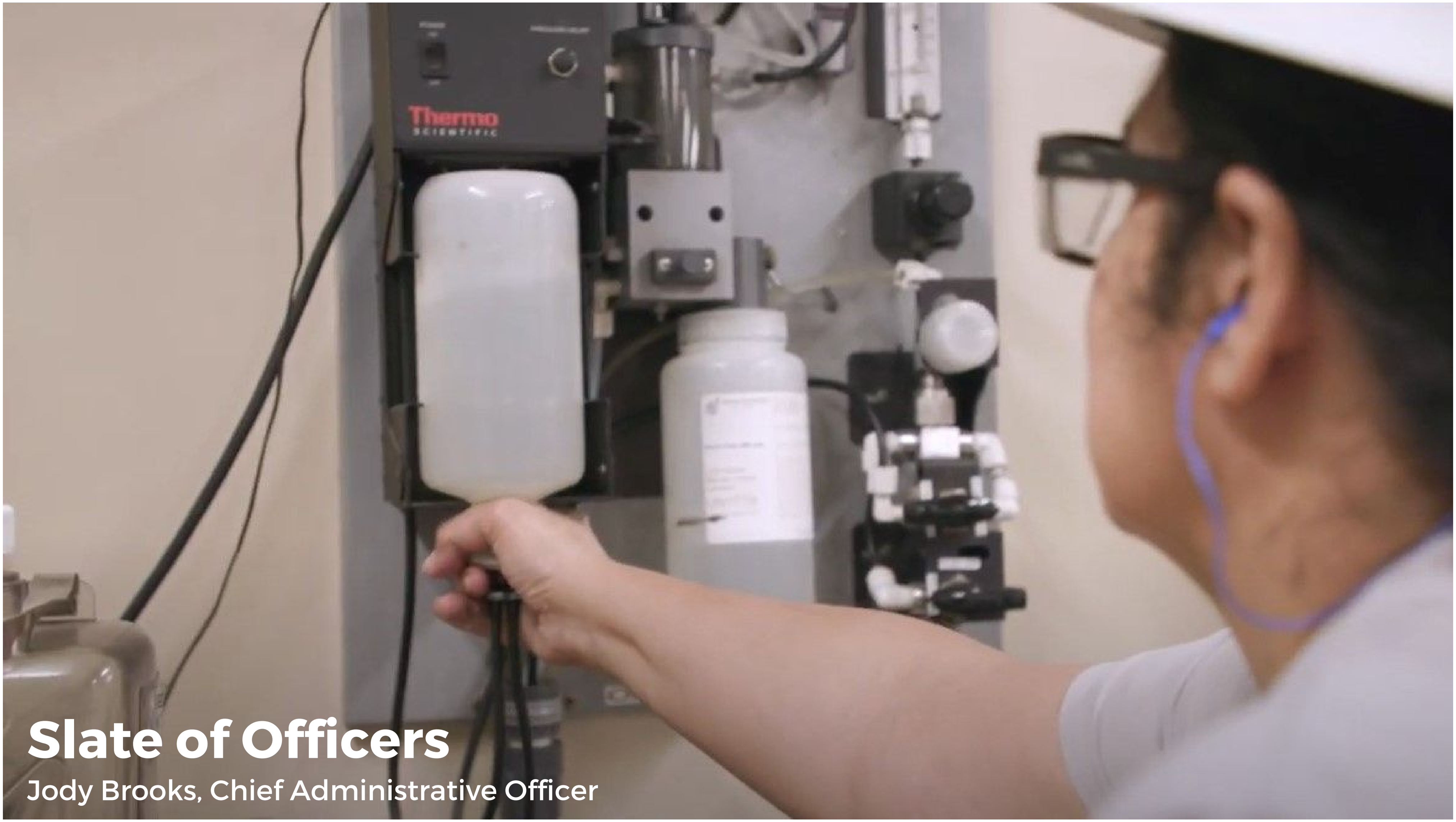


Slate of Officers

Jody Brooks, Chief Administrative Officer

Slate of Officers

Bobby Stein
Board Chair

Marty Lanahan
Vice Chair

General Joseph DiSalvo
Secretary

Slate of Officers as recommended by the Governance, Audit, and Compliance Committee at the January 13, 2023 meeting


Plant Vogtle Update
Units 3 and 4
Jody Brooks, Chief Administrative Officer
Plan for the Future

Vogtle Unit 3

Reaches Initial Criticality and Synced to the Grid

March 6, 2023

Georgia Power announced that Vogtle Unit 3 had safely reached initial criticality

March 9, 2023

Unit 3 achieved Mode 1 status - reactor power exceeded 5% level

TBD

Unit 3 initial synchronization to the grid - reactor power exceeded 20% level

May/June 2023

Unit 3 anticipated commercial operation date

Electric Integrated Resource Plan

Raynetta Curry Marshall
Chief Operating Officer

Pedro Melendez
Vice President, Planning, Engineering & Construction

IRP
INTEGRATED RESOURCE PLANNING

IRP Process and Report

IRP

Began IRP in September 2021

Stakeholder Meetings

Meetings held January 2022 - February 2023

May 25, 2023 final stakeholder meeting

Board Briefings

Board of Directors Meetings - January 11, 2022 and February 22, 2022

External Affairs Committee Meetings - July 25, 2022 and December 16, 2022

Finance & Operations Committee Meetings - September 9, 2022, December 16, 2022, March 10, 2023

IRP Modeling

Sensitivity Matrix included supplemental scenario with modeling results covering reliability, sustainability, and affordability

- Results indicate the need for 1275 MW of Solar & Battery, and 571 MW of higher efficiency gas resource

Next IRP 3 - 4 years

Potential Goals

JEA Potential Goals by 2030

35% CLEAN ENERGY

RETIRE LESS EFFICIENT GENERATION

80% CO_2 REDUCTION (FROM 2005)

100% CLEAN ENERGY TO SERVE JEA FACILITIES

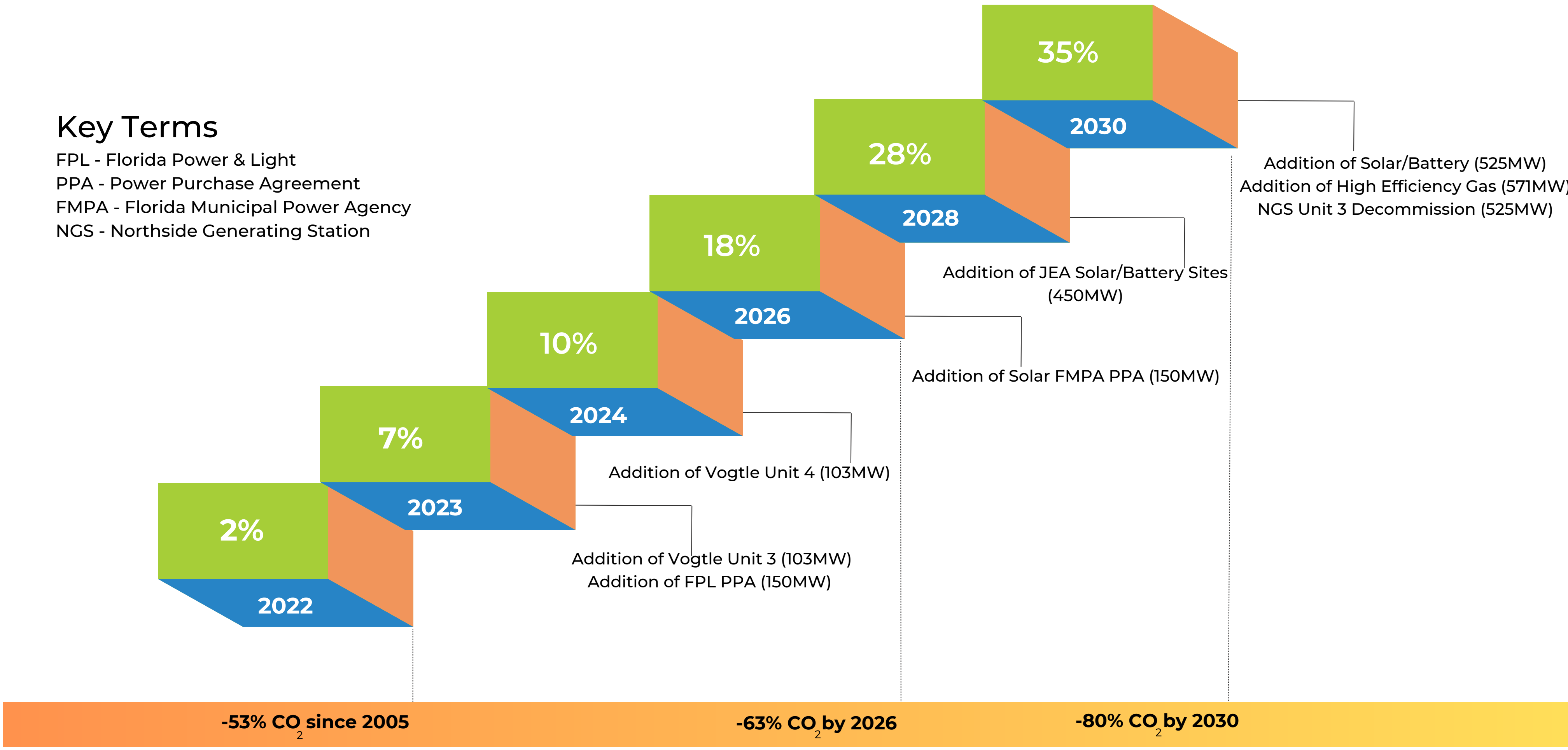
OFFSET ELECTRIFICATION DEMAND WITH ENERGY EFFICIENCY PROGRAMS

Path to Clean Energy and Carbon Reduction Goals

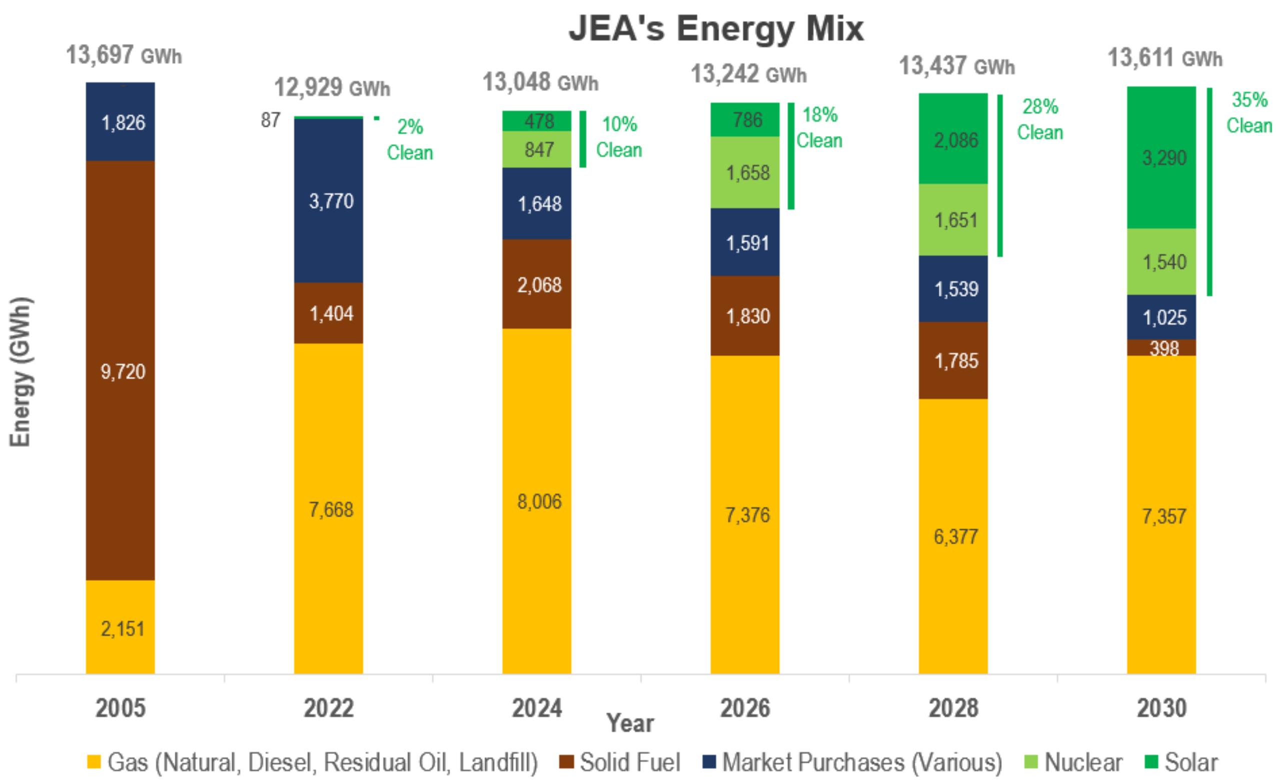
IRP

Key Terms

FPL - Florida Power & Light
PPA - Power Purchase Agreement
FMPA - Florida Municipal Power Agency
NGS - Northside Generating Station



JEA Energy Mix by Fuel Type



1,314 MW Solar represents 381 MW Net capacity

Higher efficiency generation ensures reliability and sustainability

Significantly less dependency on solid fuels and market purchases

Sustaining energy efficiency program

IRP Cost of Existing vs. New Additional Resources Plan

The IRP identified least-cost resource plans to meet forecasted energy requirements between 2022 through 2051

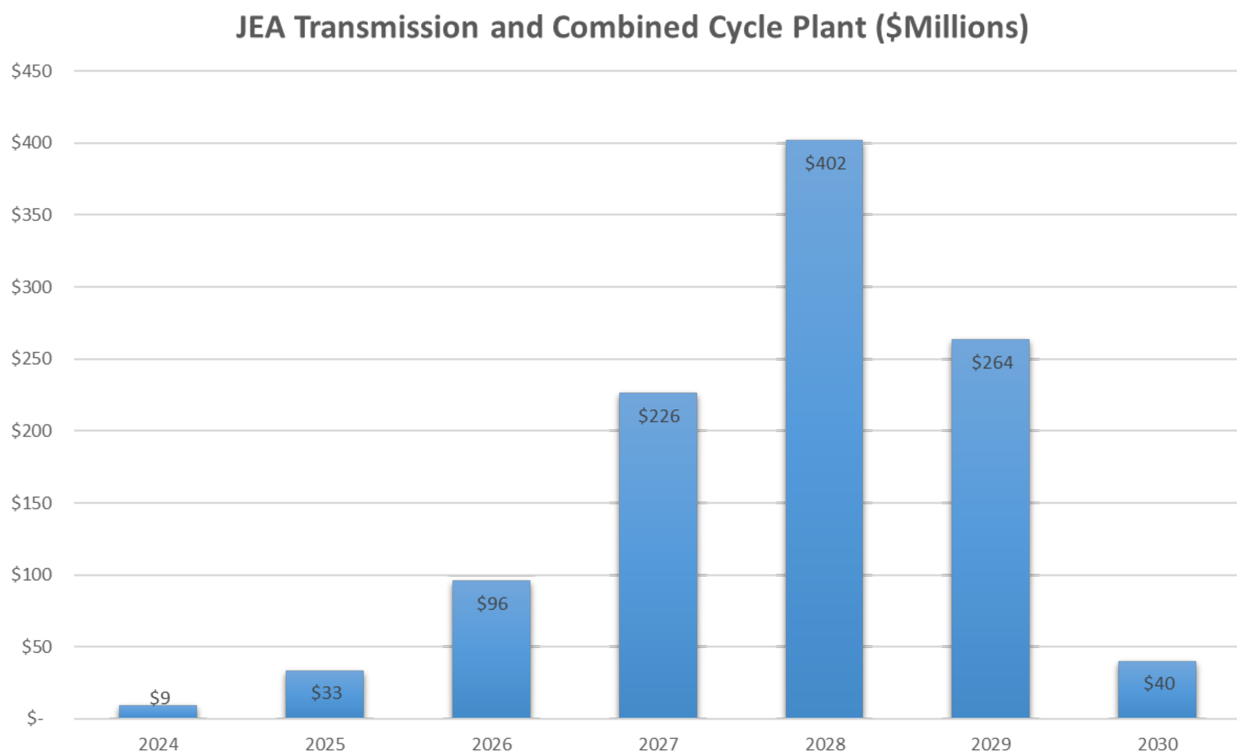
Estimated cost (Net Present Value) considering IRP inputs:

- $16.5B to produce energy with existing generation resources
- $16.1B to produce energy with new additional resources
  - 1275 MW Solar/Battery
  - 571 MW High Efficiency Gas
  - NGS Unit 3 Decommission

The new resources plan balances reliability, affordability, and sustainability to serve JEA customers

IRP

JEA Capital Projects Cost 2024 - 2030



Capital investment to integrate JEA solar sites, a new Combined Cycle plant, NGS Unit 3 decommission

Electric system integration studies are necessary to determine transmission cost for unidentified solar/battery sites

IRP

Offset Electrification Demand

IRP modeling accounted for an increased energy demand of 434 GWh in 2030 from electric vehicles

Expanding energy efficiency and customer solutions to offset electrification demand

2030

434 GWh

Electrification

Personal Electric Vehicle

2030

434 GWh

Demand-side Management

Energy Efficiency

Distributed Energy Resources

Customer-Owned Solar

JEA Potential Goals by 2030

35% CLEAN ENERGY

RETIRE LESS EFFICIENT GENERATION

80% CO_2 REDUCTION (FROM 2005)

100% CLEAN ENERGY TO SERVE JEA FACILITIES

OFFSET ELECTRIFICATION DEMAND WITH ENERGY EFFICIENCY PROGRAMS


JEA
CHAIR'S REPORT
Bobby Stein, Board Chair

Building Community

Next JEA Board of Directors Meeting

April 25, 2023

9:00 am

JEA BOARD OF DIRECTORS MEETING MINUTES
February 28, 2023

The JEA Board met in regular session at 9:00 am on Tuesday, February 28, 2023, on the 19th Floor, 21 W. Church Street, Jacksonville, Florida. The public was invited to attend this meeting in-person at the physical location and virtually via WebEx.

WELCOME

Meeting Called to Order – Board Chair Bobby Stein called the meeting to order at 9:00 am. Board members in attendance were Marty Lanahan, John Baker, General Joseph DiSalvo, Rick Morales, and Tom VanOsdol. Board member Dr. Zachary Faison attended the meeting virtually.

Others in attendance in-person were Jay Stowe, Managing Director/CEO, Jody Brooks, Chief Administrative Officer; Laura Dutton, Chief Strategy Officer; Raynetta Curry Marshall, Chief Operating Officer; David Emanuel, Chief Human Resources Officer; Sheila Pressley, Chief Customer Officer; Ted Phillips, Chief Financial Officer; Laura Schepis, Chief External Affairs Officer; Regina Ross, Chief Legal Officer, Office of General Counsel; Jordan Pope, Vice President, Corporate Strategy; Madricka Jones, Executive Assistant to the CEO, and Melissa Charleroy, Manager, Board Services.

Time of Reflection – A moment of reflection was observed by all.

Adoption of the Agenda – On ***motion*** by Board Vice Chair Lanahan and seconded by Mr. Baker, the agenda was approved.

Values Moment – Due to unforeseen technical issues, Brian Pippin, Director, Customer Experience Insights and Solutions was unable to provide the Values Moment. Mr. Stowe covered the subject of integrity in the Managing Director/CEO update.

COMMENTS / PRESENTATIONS

Council Liaison's Comments – Chair Stein thanked Council Member Michael Boylan for his work on the homeless situation in the Jacksonville area. Council Member Boylan extended appreciation to JEA management and the Board of Directors for the good work being done by the organization and announced the nomination of Board members Marty Lanahan and Tom VanOsdol to a second term.

Comments from the Public

In-Person Public Comments:

Ms. Lisa Williams, spoke to the Board on renewable energy.

Mr. Logan Cross, representing the Sierra Club of Northeast Florida and member of the Electric Integrated Resource Plan (IRP) Stakeholder Advisory Committee, spoke to the Board on renewable energy.

Ms. Lori Ann, JEA customer, spoke to the Board on renewable energy.

Dr. Joshua Melko, Associate Professor of Chemistry at the University of North Florida, spoke to the Board on the Inflation Reduction Act and the provisions it gives to make renewable energy tax credits available to public power entities like JEA.

Mr. John Burr spoke to the Board regarding climate change and lowering fossil fuel emissions.

Email Public Comments: Located in the Informational Materials section

WebEx Public Comments: Due to unforeseen technical issues with WebEx, online public comments were unavailable.

Managing Director / CEO Report – Jay Stowe, Managing Director/CEO, recognized team members that volunteered on the beautification project at Windy Hill Elementary School. Mr. Stowe called upon Ms. Marshall to provide and update on the fire at the Northside Generating Station. Mr. Stowe highlighted the JEA hosted Black History Month event, received recognition for the second year in a row on the Forbes list of Best Midsized Employers, and the Employee Engagement Survey that is currently underway. Mr. Stowe recognized Ms. Pressley and team members that hosted 25 utilities for The Low Income Energy Issues Forum focusing on affordability solutions. Mr. Stowe reviewed legislative matters and the Integrated Resource Plan Stakeholder Engagement meeting held on February 2, 2023.

JEA Performance Update – Jesus Garcia, Director, Customer Relationship Management Systems, provided an update of the JEA Performance Scorecard data through January 31, 2023. Focusing on the strategic focus areas, Mr. Garcia highlighted results for sanitary sewer overflows, estimated time to restoration, and safety. This presentation was received for information.

RATE HEARING

Meeting Called to Order – Board Chair Stein called the rate hearing to order at 9:43am and asked for Public Comments regarding today's Rate Hearing.

In-Person Public Comments:

Mr. Ben Frazier discussed the rate increase proposal and the effects it could potentially have on lower income households.

Email Public Comments: None

Virtual Comments:

Mr. Bruce Stevens addressed the Board on how the rate increase would impact he and his wife.

Mr. Mike Ludwick, member of the Northside Coalition of Jacksonville, urged the Board to keep the basic charge and reinstate the conservation charge to prevent less of an impact on lower usage customers.

Ms. Sarah Harper addressed the Board regarding the rate increase and the comparison of usage in smaller homes to larger ones.

Rates Overview – Due to technical difficulties, Victor Blackshear, Director, Financial Planning & Rates was unable to present. Board Chair Stein called upon Ted Phillips, Chief Financial Officer. Mr. Phillips provided a review of the FY23 electric rate adjustment illustrations; electric residential bill presentment; rates & fees recommendations to include updating electric rates to achieve target revenues, revise electric tariffs to align with rate objectives, and revise water & sewer tariff to align with the pricing policy. Board members held discussions.

On ***motion*** by General DiSalvo and seconded by Rick Morales, Resolution 2023-13 including Electric and Water and Sewer Tariff Document changes were approved.

Chair Stein adjourned the Rate Hearing and returned to the regular Board meeting at 10:28 am.

FOR BOARD CONSIDERATION

CONSENT AGENDA

The Consent Agenda consists of agenda items that require Board approval but are routine in nature or have been discussed in previous public meetings of the Board.

On ***motion*** by Marty Lanahan and seconded by John Baker, all Consent Agenda items were approved.

Board Meeting Minutes – January 24, 2023

Chair Stein stepped out at 10:31 am and returned at 10:32 am.

Government Relations Update – Laura Schepis, Chief External Affairs Officer, provided the Board with an overview of the legislation and policy discussions under Speaker Paul Renner to include municipal utilities service to extra territorial customers and municipal utilities and revenue transfers to general funds. This presentation was received for information.

Plant Vogtle Update – Jody Brooks, Chief Administrative Officer, provided an update on the revised operational schedule stating Unit 3 projected date of service will be May/June 2023 and Unit 4 in the last 4^{th} quarter 2023/1^{st} quarter 2024. This presentation was received for information.

OTHER BUSINESS AND CLOSING CONSIDERATION

Old and Other New Business / Open Discussion – None

Chair's Report – Chair Stein commended team members and the Finance & Operations Committee on the hard work to prepare for today's rate hearing.

Announcements – Next meeting February 28, 2023

Adjournment – With no further business coming before the Board, Chair Stein declared the meeting adjourned at 10:42 am.

APPROVED BY:

____
Joseph DiSalvo, Secretary

Date: ________________________

Board Meeting Recorded by:

Allison S Hickok
Allison Hickok
Executive Staff Assistant

BOARD RESOLUTION 2023-18
May 28, 2023

A RESOLUTION OF THE JEA BOARD OF DIRECTORS TO HIGHLIGHT AND SUPPORT APRIL AS FLORIDA'S WATER CONSERVATION MONTH

WHEREAS, the State of Florida and its Water Management Districts and local government agencies, including JEA, are working together to increase public awareness about the importance of water conservation; and

WHEREAS, the State of Florida has designated April, typically a dry month when water demands are most acute, as Florida's Water Conservation Month in order to educate citizens about how they can help save Florida's precious water resources; and

WHEREAS, JEA is responsible for delivering an average of 120,000,000 gallons of clean, safe water to its customers each day while helping ensure our water supply is sustainable for the future; and

WHEREAS, JEA encourages and supports water conservation through various educational programs and special events and the One Water campaign; and

WHEREAS, through its conservation efforts, JEA has helped customers reduce their consumption of drinking water, resulting in billions of gallons of water savings; and

WHEREAS, JEA and every business, industry, school, and citizen can make a difference when it comes to conserving water.

NOW THEREFORE, BE IT RESOLVED by the JEA Board of Directors that:

The Board recognizes and supports the month of April as Water Conservation Month. JEA encourages its employees, customers, and area citizens to help protect our precious resource by practicing water saving measures and becoming more aware of the need to save and use water wisely.

Dated this 28th day of March 2023.

______________________________ JEA Board Chair

______________________________ JEA Board Secretary

Form Approved by

______________________________ Office of General Counsel

VOTE	
In Favor	
Opposed	
Abstained	

BOARD RESOLUTION No.: 2023-17
March 28, 2023

A RESOLUTION BY THE BOARD APPROVING AN INTERLOCAL AGREEMENT WITH THE JACKSONVILLE PORT AUTHORITY TO INCREASE THE HEIGHT OF TRANSMISSION LINES AT FULTON CUT CROSSING; AUTHORIZING THE CHIEF EXECUTIVE OFFICER/MANAGING DIRECTOR OR DESIGNEE TO EXECUTE ON BEHALF OF THE BOARD; PROVIDING FOR THE CORRECTION OF ERRORS; AND PROVIDING FOR AN EFFECTIVE DATE

RECITALS

WHEREAS, the Jacksonville Port Authority (JAXPORT), a body politic and corporate created under chapter 2001-319, Laws of Florida, as amended, is charged with operating, managing, and controlling the publicly owned seaport and ancillary facilities situated within the geographic boundaries of the City of Jacksonville (City); and

WHEREAS, JEA, a body politic and corporate created under chapter 78-538, Laws of Florida, as amended, and Article 21 of the City Charter, is vested with plenary authority to own, manage, and operate electric, waste, wastewater, natural gas, and other utility systems situated within and without the City in accordance with Article 21; and

WHEREAS, JEA owns and operates six (6) aerial high-voltage electric transmission lines that cross the St. Johns River at the Fulton Cut Crossing; and

WHEREAS, the transmission lines are currently carried by three (3) double circuit lattice towers located on each side of the crossing; and

WHEREAS, JAXPORT seeks to increase the height of JEA's transmission lines to improve conditions for the size and types of ships traversing Fulton Cut Crossing, thereby expanding navigation into and out of JAXPORT facilities as well as providing for more reliable, updated and resilient infrastructure; and

WHEREAS, JEA has confirmed the feasibility of replacing the existing lattice towers so as to increase or raise the height of JEA's transmission lines from a current air draft of approximately 175 feet to 225 feet (the "Project"); and

WHEREAS, on June 27, 2022, the JAXPORT and JEA (collectively "the Parties") entered into a Memorandum of Agreement ("MOA"), memorializing their respective commitments to carry out and complete the Project; and

WHEREAS, the MOA further provided for the Parties agreement to enter into a binding interlocal agreement for completion of the Project, contingent upon JAXPORT securing adequate funding; and

WHEREAS, JAXPORT has secured funding for the Project in the total amount of Forty-Five Million Dollars ($45,000,000) from the Florida Department of Transportation ("FDOT") and from the City to be disbursed to JAXPORT during the Project duration; and

WHEREAS, pursuant to Chapter 163.01, Florida Statutes, as amended, the Parties are authorized and empowered to cooperate with each other on a basis of mutual advantage to enter into interlocal agreements to make the most efficient use of their powers; and

WHEREAS, the Parties desire to enter into an interlocal agreement in substantially the same form and format as attached hereto as Attachment 1, and incorporated herein, detailing their respective duties and obligations in completing the Project; and

WHEREAS, based upon its review, the Board finds that entering into the proposed interlocal agreement to cooperate with JAXPORT to complete the Project provides mutual advantage and effective use of the Parties respective powers.

NOW, THEREFORE, BE IT RESOLVED by the JEA Board of Directors that:

1. The recitals stated above are hereby incorporated into and made part of this Resolution, and such recitals shall serve as findings of fact.

2. The Board hereby approves the terms, conditions, and provisions of the proposed interlocal agreement.

3. The Board authorizes the Chief Executive Officer/Managing Director, or designee, to execute an interlocal agreement in substantially the same form and format as attached hereto as Attachment 1, providing for completion of the Project.

4. To the extent that there are any typographical, administrative, and/or scrivener's errors contained herein that do not change the tone, tenor, or purpose of this Resolution, then such errors may be administratively corrected with no further action required by the Board.

5. This Resolution shall be effective upon approval by the Board.

Dated this 28th day of March 2023.

JEA Board Chair

JEA Board Secretary

Form Approved by

Office of General Counsel

VOTE	
In Favor	
Opposed	
Abstained	

Instrument Prepared By:

Harry M. Wilson IV
Assistant General Counsel
Office of General Counsel
117 W. Duval Street, Suite 480
Jacksonville, FL 32202

INTERLOCAL AGREEMENT
(Regarding the Fulton Cut Crossing Transmission Lines)

THIS INTERLOCAL AGREEMENT ("Agreement") is entered into this ____ day of _______________, 2023 (the "Effective Date"), between the **JACKSONVILLE PORT AUTHORITY** ("JAXPORT"), a body politic and corporate existing under the laws of the State of Florida, located at 2831 Talleyrand Avenue, Jacksonville, FL 32206, and **JEA**, a body politic and corporate existing under the laws of the State of Florida, located at 21 West Church Street, Jacksonville, FL 32202 (together, the "Parties").

RECITALS:

WHEREAS, JAXPORT, a body politic and corporate created under chapter 2001-319, Laws of Florida, as amended, is charged with operating, managing, and controlling the publicly owned seaport and ancillary facilities situated within the geographic boundaries of the City; and

WHEREAS, JEA, a body politic and corporate created under chapter 78-538, Laws of Florida, as amended, and Article 21 of the City Charter, is vested with plenary authority to own, manage and operate electric, waste, wastewater, natural gas, and other utility systems situated within and without the City in accordance with Article 21; and

WHEREAS, JEA owns and operates six (6) aerial high-voltage electric transmission lines that cross the St. Johns River at the Fulton Cut Crossing; and

WHEREAS, the transmission lines are currently carried by three (3) double circuit lattice towers located on each side of the crossing; and

WHEREAS, JAXPORT desires to increase the height of JEA's transmission lines to improve conditions for the size and types of ships traversing Fulton Cut Crossing, thereby expanding navigation into and out of JAXPORT facilities, and JEA desires to acquire more reliable, updated and resilient infrastructure to serve the area; and

WHEREAS, JEA has confirmed the feasibility of replacing the existing lattice towers so as to increase or raise the height of JEA's transmission lines from a current air draft of approximately 175 feet to 225 feet (the "Project"); and

WHEREAS, on June 27th, 2022, the Parties entered into a Memorandum of Agreement ("MOA") memorializing their commitment to carry out and complete the Project, and agreeing to enter into a binding interlocal agreement regarding the Project after JAXPORT had secured funding; and

WHEREAS, JAXPORT has secured funding for the Project in the total amount of Forty-Five Million Dollars ($45,000,000) from the Florida Department of Transportation ("FDOT") and from the City of Jacksonville ("City") to be disbursed to JAXPORT during the Project duration; and

WHEREAS, supplemental to their other powers, JAXPORT and JEA, pursuant to Chapter 163.01, *Florida Statutes*, as amended, are authorized and empowered to cooperate with each other on a basis of mutual advantage and governmental agencies are permitted to enter into interlocal agreements to make the most efficient use of their powers on the basis of mutual advantage, and JAXPORT and JEA desire to enter into this interlocal agreement for the mutual advantages to each party contemplated herein.

NOW THEREFORE, in consideration of the mutual covenants and promises contained herein, the sufficiency of which is hereby acknowledged, JAXPORT and JEA agree as follows:

1. **Incorporation of Recitals.** The Recitals set forth above are true and correct and incorporated into this Agreement.

2. **Term**. This Agreement shall commence on the Effective Date and shall remain in effect unless terminated by the mutual agreement of the parties or as otherwise provided in this Agreement.

3. **Project Scope and Administration.**

(a) JEA to Provide the Work. JEA shall perform, undertake, oversee, manage, and supervise all work required for the design, permitting, engineering, construction, quality control, and completion of the Project (the "Work"). Additionally, JEA shall ensure that the Project Work is performed in accordance with the Project schedule attached hereto as **Exhibit A** ("Project Schedule"). The Parties agree that the Project Schedule is preliminary and may be updated and amended by the Parties administratively during the term of this Agreement based on finalized permitting, design, and construction plans.

(b) Project Permitting; Project Design. JEA shall secure all federal, state, and local permits, licenses, and authorizations required for JEA to commence, undertake, and complete the Project, including, but not limited to, the permit authorizations regarding the Project issued by the United States Army Corps of Engineers (the "Permits"). JEA agrees to commence Project design as soon as reasonably practicable from the Effective Date. JAXPORT shall have an opportunity to review and comment on the Project engineering and design plans ("Plans") to ensure that the Plans comply with the FDOT grant requirements. JEA will ensure that the Project is completed in accordance with the final approved Plans approved by the Parties, the Agreement terms, and all applicable regulations, orders, permits, guidelines, and directives. JEA, at the reasonable request of JAXPORT, shall allow prompt access to the Project site subject to safety regulations.

(c) Guaranteed Maximum Price; Change Orders; Costs Overruns. Prior to commencement of Work, JAXPORT shall review and comment on the Guaranteed Maximum Price ("GMP") for the Project, as preliminarily agreed to by JEA and its contractor. JAXPORT agrees and acknowledges that JEA's performance of the Work may entail amendments or "change orders" to contracts JEA has entered with third party contractors. JEA shall have sole authority to accept all "change orders" submitted by its contractor, except that JAXPORT shall first authorize in writing those "change orders" which, if accepted, would increase the GMP by $10,000 or more. If no individual change order has exceeded $10,000, but, due to JEA's approval of cumulative change orders, the agreed-to GMP has increased so as to exceed $45,000,000, JAXPORT shall authorize in writing the approval of all additional change orders. JAXPORT shall be responsible for ordinary change orders related to the Project, including any change orders that would cause the entire Project to exceed $45,000,000. JEA shall be solely responsible for any Project costs or change orders that fall outside of the Plans, constitute upgrades or enhancements to the Plans, or are solely requested by JEA for its convenience. JAXPORT shall be solely responsible for securing additional funding and paying any Project related cost overruns. In such event, however, JEA will continue to timely pay Project related invoices and JAXPORT will reimburse JEA for the same in accordance with Section 5 below.

(d) Applicable Laws; Procurement. JEA shall procure all design, engineering, and construction services required for performance of the Work and completion of the Project, subject to applicable laws. In so doing JEA shall adhere to Florida public procurement law as applicable, including, but not limited to, Section 287.055, *Florida Statutes* (the "Competitive Consultants Negotiation Act "), applicable Grant Agreement terms, and the Disadvantaged Business Enterprise (DBE) Policy. To the extent JEA's normal procurement practices, including those involving DBE Policy and JSEB programs, conflict with Grant Agreement requirements, JEA shall follow those procurement practices that are consistent with the requirements of the Grant Agreement and Florida law.

(e) Project Completion Report; Project Certifications. JEA will submit a Project completion report to JAXPORT within ninety (90) days following completion of the Project. The report shall contain, at a minimum, the as-built drawings, surveys, and a certification from the engineer and contractor of record that the Project has been constructed in accordance with the Plans. JEA shall provide the report and certifications in writing to JAXPORT (i) at such time as JEA has raised the Fulton Cut transmission lines to a height of 225 feet or higher; and (ii) upon final completion of the Project, meaning the transmissions lines are raised to their required height, replacement towers are constructed, and JEA has formally closed all contracts related to performance of the Work ("Final Completion").

4. Project Funding.

(a) Generally. The Parties acknowledge and agree that JAXPORT has secured Project funding in the total amount of $45,000,000, with FDOT and City each providing half of the funds in the form of grants and loans. Accordingly, JAXPORT shall allocate the payment of Project costs on a pro-rata, 50/50 basis between the FDOT and City funding sources. In no event shall the FDOT funding exceed 50% of the total amount invoiced from JEA. Any unspent funds remaining after Final Completion (as defined herein) shall be divided on a pro-rata basis and returned, 50/50, to FDOT and City.

(b) FDOT Grant. Pursuant to the "Public Transportation Grant Agreement," between FDOT and JAXPORT, dated December 14, 2022 – Contract No. G2F55 (the "Grant Agreement"), the FDOT shall fund the Project in the form of a $22,5000,000 grant payable to JAXPORT on a reimbursement basis ("FDOT Funds"). While not a party to the Grant Agreement, JEA agrees and understands that JEA may be required to adhere to certain conditions and requirements set forth therein, including procurement matters and the terms of agreements JEA enters into with third party contractors on the Project. As a condition of receiving FDOT funds, JAXPORT may be required to certify that its contractors, to include JEA, are in compliance with certain terms of the Grant Agreement. JAXPORT represents and warrants that, prior to the Effective Date herein, it has informed JEA as to the FDOT requirements it must comply with, and JEA warrants that it understands it must adhere to these obligations under the Grant Agreement for JAXPORT to receive FDOT grant funding for the Project. In addition, JEA agrees to provide JAXPORT with information as needed to establish JEA's compliance with the Grant Agreement terms. JAXPORT shall not expend FDOT Funds on ineligible or disallowed grant expenditures, as determined by FDOT. The Grant Agreement has been provided to JEA and is incorporated into this Agreement by reference.

(c) City Funds. As approved by Ord. 2022-874-E described in that certain "Jacksonville Port Authority Fulton Cut Powerlines Raising Project Funding Agreement," dated ________, between City and JAXPORT, City shall provide funding to JAXPORT in the amount of $22,500,000, comprised of a $10,000,000 grant and a $12,5000,000 loan. In addition, City has provided JAXPORT with access to a $5,000,000 revolving line of credit facility to ensure prompt reimbursement to JEA of Project expenses. JAXPORT shall not expend City Funds on ineligible or disallowed expenditures, as determined by City. Additionally, the City requires a 15-day advanced notice on requests for disbursement.

(d) Replacement Funding Sources. To the extent the FDOT Funds and/or City Funds become unavailable during the Agreement term, JAXPORT shall promptly notify JEA and identify alternative or replacement funding sources to pay for the Project as provided herein.

5. Payment and Reimbursement. The Parties acknowledge and agree that JAXPORT's access to FDOT funding is contingent on prior payment by JEA of Project expenses. JAXPORT shall fund the Work and all Project costs by reimbursing JEA therefor. Accordingly, JEA shall timely pay all Project and Work-related invoices within ten (10) days of submission. Due to the City funding requirements outlined in Paragraph 4(c), JEA shall notify JAXPORT promptly upon receipt of any Work-related invoices. No later than twenty-four (24) hours after making payment on any such invoice, JEA shall provide the invoice and proof of payment to JAXPORT. Within twenty (20) days of receipt of the paid invoice, JAXPORT shall pay JEA the full amount due thereunder, drawing upon its funding sources in its sole discretion. JEA further agrees to cooperate with any reporting and invoicing requirements applicable to JEA, as contractor, under the Grant Agreement, with JAXPORT to inform JEA as to any such requirements. The funding for the Project will be encumbered via separate purchase orders and agreements with third-party contractors.

6. **Reporting**. In connection with its management and oversight of the Project, JEA shall keep JAXPORT informed as to the progress of the Work, including by furnishing written status reports to JAXPORT monthly. JEA will inform JAXPORT of any progress meetings with its prime contractor, and JAXPORT, through designated executives or staff, may attend such meetings in person or virtually. In addition, upon five (5) business days' request, the Chief Operating Officer of JAXPORT, or his or her designees, may conduct an in-person inspection of the Project no more than once every thirty (30) days.

7. **Cooperation**. The Parties recognize that planning and coordination among the Parties will ensure that responsibilities under this Agreement are carried out and accommodated in an efficient and timely manner so that the Project Schedule will not be unnecessarily delayed or compromised. JEA and JAXPORT shall work cooperatively to ensure the timely and cost-effective completion of the Project which will inure to the benefit of the Parties and City.

8. **Insurance**. The Parties agree and acknowledge that they are self-insured pursuant to Section 768.28, *Florida Statutes*. JEA shall require its contractors and sub-contractors performing Work on the Project to obtain insurance coverage satisfactory to JEA in its sole discretion. JEA shall require its contractors and sub-contractors to have all insurance required by JEA to be endorsed to the name of JEA and JAXPORT.

9. **Indemnity.** JEA shall require that its contractors and sub-contractors hold harmless, indemnify, and defend JEA and JAXPORT, its members, officers, officials, employees and agents (collectively, the "Indemnified Parties") from and against, without limitation, any and all claims, suits, actions, losses, damages, injuries, liabilities, fines, penalties, costs and expenses of whatsoever kind or nature, which may be incurred by, charged to or recovered from the Indemnified Parties related to the Project.

10. **Representations and Warranties**. JEA and JAXPORT represent, warrant and agree, one to the other as their respective interests may appear, as follows:

(a) JEA is a body politic and corporate under the laws of the State of Florida, and JAXPORT is a body politic and corporate under the laws of the State of Florida, respectively, and each is duly organized, validly existing and in good standing under the laws of the State of Florida, with full legal right, power and authority to conduct its operations substantially as presently conducted, and to execute, deliver and perform its obligations under this Agreement.

(b) After a duly called meeting of its respective governing body, at which a quorum was present and acting throughout, an ordinance or resolution, as applicable, authorizing the execution and delivery of this Agreement was duly enacted or adopted, as applicable, by the governing body of JEA or JAXPORT, respectively. Such ordinance or resolution remains in full force and effect and has not been revoked or modified in any respect.

(c) This Agreement is a legal, valid, and binding obligation of each of JEA and JAXPORT, respectively, enforceable against JEA and JAXPORT, respectively, in accordance with its terms, except as enforceability may be limited by equitable principles, or bankruptcy, insolvency, reorganization, moratorium, or other similar laws affecting the enforcement of creditors' rights generally.

(d) The execution and delivery of this Agreement and compliance with the provisions hereof will not conflict with or constitute a breach of or a default under the provisions of JEA Charter or JAXPORT Charter, respectively, the bylaws of JEA or bylaws of JAXPORT or any existing law, court or administrative regulation, judgment, decree or order, agreement, indenture, or other instrument to which JEA or JAXPORT, respectively, is a party.

11. Termination. Upon the occurrence of a default by a party, the non-defaulting party, at its sole and absolute election, may terminate this Agreement and exercise all rights and remedies it may have at law or in equity.

12. Notices. Whenever either party desires to give notice to the other, such notice must be in writing, sent by certified United States Mail, postage prepaid, return receipt requested, or by hand-delivery with a request for a written receipt of acknowledgement of delivery, addressed to the party for whom it is intended at the place last specified, except, as required by Paragraphs 4 above, JEA may provide paid invoices and proof of payment to JAXPORT via email. The place for giving notice shall remain the same as set forth herein until changed in writing in the manner provided in this section. For the present, the parties designate the following:

If to JAXPORT:

Nick Primrose
Chief of Regulatory Compliance
2831 Talleyrand Avenue
Jacksonville FL 32206
nicholas.primrose@jaxport.com
Phone: (904) 357-3132

If to JEA:

Jody L. Brooks
Chief Administrative Officer
21 West Church Street
Jacksonville FL 32202
broojl@jea.com
Phone: (904) 665-6384

With copies to:

Regina D. Ross, JEA Chief Legal Officer
Office of General Counsel

21 West Church Street
Jacksonville FL 32202
rossrd@jea.com
Phone (904) 665-6844

Harry M. Wilson, IV
Assistant General Counsel
Office of General Counsel
117 W. Duval Street, Suite 480
Jacksonville FL 32202
Phone: (904) 255-7763

A Party may change the recipient or address to which such communications are to be directed by giving written notice to the other Party in the manner provided in this paragraph.

13. **Severability**. If any word, phrase, sentence, part, subsection, section, or other portion of this Agreement, or any application thereof, to any person, or circumstances is declared void, unconstitutional, or invalid for any reason, then such word, phrase, sentence, part, subsection, other portion, or the proscribed application thereof, not having been declared void, unconstitutional, or invalid shall remain in full force, and effect.

14. **Entire Agreement**. This Agreement contains the entire agreement between the respective parties hereto relating to the subject matter hereof. No statement or representation of the respective parties hereto, their agents or employees, made outside of this Agreement, and not contained herein, shall form any part hereof or bind any respective party hereto. This Agreement shall not be supplemented, amended or modified except by written instrument signed by the respective parties hereto.

15. **Electronic execution; counterparts.** This Agreement may be executed electronically and in any number of counterparts, each of which when so executed and delivered shall be an original thereof.

16. **Survival**. All representations, warranties, indemnities and other covenants set forth herein shall be deemed continuing in nature and shall survive the expiration or early termination of this Agreement.

17. **Venue; Governing Law**. The parties acknowledge, consent and agree that all legal actions or proceedings arising out of or related to this Agreement shall be initiated in a state or federal court in Duval County, Florida having competent jurisdiction. This Agreement shall be governed by, construed, and enforced in accordance with the laws of the State of Florida.

[Remainder of page left blank intentionally. Signature pages follow.]

IN WITNESS WHEREOF, the parties, by and through their lawfully authorized representatives, have executed this Agreement on the day and year first above written.

JEA

By:____________________________
Jay Stowe, Chief Executive Officer

Form Approved (As to JEA)

By:_____________________
Office of General Counsel

STATE OF FLORIDA)

COUNTY OF DUVAL)

The foregoing instrument was acknowledged before me by means of ☐ physical presence or ☐ online notarization, this _____ day of ______________, 20__________, by ________________________, the ____________________ of ______________________________, a ________________________ _______, on behalf of said ____. Such person did not take an oath and: *(notary must check applicable box)*

☐ is/are personally known to me.

☐ produced a current _________________ driver's license as identification.

☐ produced _______________________ as identification.

{Notary Seal must be affixed}

____
Signature of Notary

____
Name of Notary (Typed, Printed or Stamped)
Commission Number (if not legible on seal):___________
My Commission Expires (if not legible on seal):_________

JACKSONVILLE PORT AUTHORITY

By:____________________________
Eric Green, Chief Executive Officer

Form Approved (As to JAXPORT)

By:______________________
Office of General Counsel

STATE OF FLORIDA)

COUNTY OF DUVAL)

The foregoing instrument was acknowledged before me by means of ☐ physical presence or ☐ online notarization, this _____ day of ______________, 20__________, by ______________________, the ____________________ of ____________________________, a _______________________ _______, on behalf of said ____. Such person did not take an oath and: *(notary must check applicable box)*

☐ is/are personally known to me.

☐ produced a current _________________ driver's license as identification.

☐ produced _______________________ as identification.

{Notary Seal must be affixed}

____
Signature of Notary

____
Name of Notary (Typed, Printed or Stamped)
Commission Number (if not legible on seal):____________
My Commission Expires (if not legible on seal):_________

Exhibit A

Project Schedule

Unless otherwise agreed to by the Parties, JEA agrees to complete the Project in various phases, spanning multiple fiscal years, using its best efforts to adhere to the following schedule:

Fiscal Year	Description of Work
October 1, 2022-September 30, 2023	Procure Engineering Services, Site Inspection, Project Design, Permitting
October 1, 2023-September 30, 2024	Procure Construction Services & Begin Construction of Tower Foundations
October 1, 2024-September 30, 2025	Tower Construction, Installation of Conductors
October 1, 2025-September 30, 2026	Complete Construction, Site Restoration

BOARD RESOLUTION: 2023-15
March 28, 2023

A RESOLUTION APPROVING THE MODIFICATIONS OF JEA'S OPEN ACCESS TRANSMISSION TARIFF TO SUPPORT JEA'S MEMBERSHIP IN THE SOUTHEAST ENERGY EXCHANGE MARKET.

WHEREAS, JEA is an owner of The Energy Authority, Inc. ("TEA"); and

WHEREAS, JEA was deemed eligible and was accepted as a member of the Southeast Energy Exchange Market (SEEM) effective January 1, 2023 pending fulfilling all the requirements of SEEM; and

WHEREAS, TEA will be trading on the SEEM platform on JEA's behalf after all the requirements of SEEM have been satisfied and the SEEM Participation Agreement has been executed by JEA; and

WHEREAS, the purpose of modifying JEA's Open Access Transmission Tariff (Tariff) is to provide for Non-Firm Energy Exchange Transmission Services for those Energy Exchanges that seek to utilize JEA's transmission system in accordance with SEEM requirements; and

WHEREAS, the Board's authorization is required for modification of the Tariff.

BE IT RESOLVED by the JEA Board of Directors that:

1. The JEA Board of Directors hereby approves the modifications to the Tariff in substantially the same form as attached hereto as Exhibit A and incorporated herein.

2. To the extent there are typographical, clerical, or administrative errors that do not affect the tone, tenor, or context of this resolution, such errors may be corrected without further authorization from the Board of Directors.

3. This Resolution shall be effective immediately upon passage.

Dated this 28th day of March 2023.

____________________________ ____________________________

JEA Board Chair JEA Board Secretary

Form Approved by ____________________________

Office of General Counsel

VOTE	
In Favor	
Opposed	
Abstained	

JEA OPEN ACCESS TRANSMISSION TARIFF

Issued By: Garry Baker
Revised: 01/24/2023 Effective Date: 01/1/1997

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I COMMON SERVICE PROVISIONS

1 Definitions

1.1 **Affiliate:** For the purposes of this Tariff, means The Energy Authority.

1.2 **Ancillary Services**: Those services that is necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 **Annual Network Transmission Service Rate**: The total annual rate for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider.

1.4 **Application**: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 **Arbitration Commitment Letter:** A letter requesting the submittal of disputed terms and conditions to arbitration as described in Sections 12.3 and 15.3.

1.6 **Commission**: The Federal Energy Regulatory Commission.

1.7 **Completed Application**: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.8 **Control Area**: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.9 **Curtailment**: A reduction in firm or nonfirm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.10 **Delivering Party**: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.11 **Designated Agent**: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.12 **Direct Assignment Facilities**: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct

Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer.

1.13 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that would be prohibited by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider. (ii) Any retail customer taking unbundled Transmission Service pursuant to a state requirement that the Transmission Provider offer the transmission service or pursuant to a voluntary offer of such service by the Transmission Provider is an Eligible Customer under the Tariff.

1.14 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications that will be required to provide the requested transmission service.

1.15 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.16 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.17 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.18 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve-month basis.

1.19 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.20 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.21 **Native Load Customers**: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.22 **Network Customer**: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.23 **Network Integration Transmission Service**: The transmission service provided under Part III of the Tariff.

1.24 **Network Load**: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.25 **Network Operating Agreement**: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.26 **Network Operating Committee**: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.27 **Network Resource**: Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.28 **Network Upgrades**: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.29 **Non-Firm Point-To-Point Transmission Service**: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.30 **Non-Firm Energy Exchange Transmission Service (NFEETS)**: The transmission service provided in accordance with Attachment N of the Tariff.

1.31 **Non-Firm Sale:** An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.32 **Open Access Same-Time Information System (OASIS)**: The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.33 **Part I**: Tariff Definitions and Common Service Provisions contained in Sections 1 through 12.

1.34 **Part II**: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.35 **Part III**: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.36 **Parties**: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.37 **Point(s) of Delivery**: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.38 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.39 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.40 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.41 Pre-Confirmed Application: An application that commits the Transmission Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.42 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.43 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.44 Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved

Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.45 **Service Agreement**: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.46 **Service Commencement Date**: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.47 **Short-Term Firm Point-To-Point Transmission Service**: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.48 **System Condition**: A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.49 **System Impact Study:** An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.50 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.51 Transmission Customer: Any Eligible Customer (or its Designated Agent) that executes a Service Agreement. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff. In addition, this term is used in Part I to include customers receiving Non-Firm Energy Exchange Transmission Service under Attachment N to the Tariff, unless specifically excluded in Attachment N.

1.52 Transmission Provider: The utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff. JEA is the Transmission Provider.

1.53 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.54 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.55 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority for Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of three years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to the longer of a competing request by any new Eligible Customer or three years and to pay the current just and reasonable rate for such service. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of three years or longer unless modified by the service agreement or violates other sections of the tariff. Service agreements subject to a right of first refusal entered into prior to the inclusion of the Transmission Provider's Attachment K, unless terminated, will become subject to the three year/one year requirement on the first rollover date after the inclusion of the Transmission Provider's Attachment K.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services:(i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve Supplemental, and (v) Generator Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the

Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 ,6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must by announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 9.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. § 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on its public OASIS website all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff.

5 Tax Exempt Bonds

5.1 Facilities Financed by Tax Exempt Bonds: Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if the provision of such Transmission Service would jeopardize the tax-exempt status of any bond(s) used to finance the Transmission Provider's facilities that would be used in providing such Transmission Service.

5.2 Opinions of Bond Counsel: Any request for service may require an opinion of JEA's bond counsel. The Internal Revenue Service is currently considering proposed regulations dealing with the effect of providing transmission service on tax-exempt bonds issued to finance transmission facilities. Pending the issuance of the regulations, JEA's bond counsel has advised that any new proposals for transmission service for more than 3 years, including extensions, should be reviewed by bond counsel to determine whether they would adversely affect the exclusion of interest on the bonds from gross income for Federal income tax purposes. Costs of obtaining any necessary letters or opinions from bond counsel will be borne by the Transmission Customer.

5.3 Termination of Service Agreements: The Transmission Provider may terminate any Service Agreement which it determines may jeopardize the tax-exempt status of its bonds. This includes Section 23 transactions.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO, Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds and be made by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall accrue and be payable at a rate equal to the interest rate paid by the Transmission Provider on its retail deposits. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment.

7.3 Customer Default and Termination of Service: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate procedures to terminate service. Prior to terminating service, the Transmission Provider shall provide written notice to the Transmission Customer of its intent to terminate service in 30 days. If the Transmission Customer does not request in writing to the Transmission Provider, within ten (10) calendar days of the Transmission Customer's receipt of notice, that the Transmission Provider initiate arbitration under the provisions of Section 12, the Transmission Provider shall terminate service on the date contained in its notice to the Customer. If the Transmission Customer requests in writing that the Transmission Provider initiate arbitration proceedings, the provisions of Sections 12.3 through 12.5 shall apply. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute according to the provisions of Section 12.2. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to terminate service.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below:

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expenses that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Changes to this Tariff by the Transmission Provider and Tariff Availability

9.1 Unilateral Right to Change: Notwithstanding any other provision in this Tariff or a Service Agreement, the Transmission Provider shall have the right unilaterally to make a change in rates, charges, classification of service, or any rule, regulation, or Service Agreement related thereto. The Transmission Provider will notify current Transmission Customers 30 days before a change becomes effective, unless the change is mutually agreeable to both parties.

9.2 Tariff Availability: Notwithstanding any other provision of this Tariff, the Transmission Provider may terminate this Tariff and all Service Agreements hereunder, effective immediately and without satisfying the requirements of any other provisions of this Tariff in its sole discretion. Further, nothing contained in this Tariff shall restrict the Transmission Provider's right unilaterally to withdraw the Tariff at any time. Except as otherwise provided in this Section 9.2, such withdrawal shall not affect existing Service Agreements for Firm Point-to-Point Transmission Service entered into under the Tariff. Upon such withdrawal of this Tariff, all Service Agreements for Non-Firm Point-to-Point Transmission Service shall terminate immediately, provided that the Transmission Provider shall complete Non-Firm Point-to-Point Transmission Service for specific scheduled Non-Firm Point-to-Point Transmission Service transactions prior to the date of termination of the Tariff (not to exceed service for three months). The Transmission Provider shall provide at least 30 days notice of its intent to terminate this Tariff to Transmission Customers that have entered into Service Agreements for Non-Firm Point-to-Point Transmission Service.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither the Transmission Provider nor the

Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider. For purposes of this Indemnification, the term "Transmission Provider" shall mean the JEA as a body politic and corporate and shall include its governing board, officers, employees, agents and assigns. This Indemnification shall survive the term of this Tariff.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures

12.1 Applicability of Section 12: The provisions of Section 12 shall be the exclusive basis by which to resolve all disputes arising under this Tariff or any Service Agreement.

12.2 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving Transmission Service under this Tariff (including disputes involving the Transmission Provider's proposed termination of service under Section 7.3, disputes regarding changes to the rates, rate methodologies, or non-rate terms and conditions in this Tariff or any Service Agreement entered into under the Tariff, and disputes regarding the Transmission Provider's proposed charges for Direct Assignment Facilities, Network Upgrades, stranded costs, and redispatch costs) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute shall be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.3 External Arbitration Procedures: Disputes may be submitted to arbitration upon request from the Transmission Customer in the form of an Arbitration Commitment Letter and provision of the required letter of credit or other form of security. Any arbitration initiated under this Section 12 shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any Party to the arbitration (other than previous arbitration experience). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Regional Transmission Group rules.

12.4 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision to disputes under this Section 12 within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons, therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court governed by the rules of the State of Florida.

12.5 **Costs**: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. the cost of the arbitrator chosen by the Party to sit on the three-member panel and one half of the cost of the third arbitrator chosen; or

2. one half the cost of the single arbitrator jointly chosen by the Parties.

II POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority:

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests with the same duration and pre-confirmation status (Pre-Confirmed or not confirmed), priority will be given to an Eligible Customer's request that offers the highest price, followed by the date and time of the request.

(iii) If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer-term request or equal duration service with a higher price before losing its reservation priority. A longer-term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point- To-Point Transmission Service. When a longer duration request preempts multiple shorter duration requests, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, pre-confirmation status, price and time of response will be used to determine the order by which the multiple shorter duration requests will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after January 1, 1997, or agreements executed prior to the aforementioned date that require unbundling. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-to-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-to-Point Transmission Service pursuant to the Tariff. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Service Agreement shall contain the process governing any changes to the curtailment conditions.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirement as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 **Curtailment of Firm Transmission Service**: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such System and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers, and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed after secondary service and before Non-Firm Point-To-Point Transmission Service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the

Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. E.P.T. (Eastern Prevailing Time) of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. E.P.T. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is less than 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such Party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer-term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a higher priority than Non-Firm Energy Exchange Transmission Service provided under Attachment N. Non-Firm Energy Exchange Transmission Service will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under agreements executed on or after January 1,1997 or agreements executed prior to the aforementioned date that require unbundling. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed twelve month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Except for Non-Firm Energy Exchange Transmission Service provided in accordance with Attachment N, schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. E.P.T. of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. E.P.T. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is less than 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 **Curtailment or Interruption of Service**: The Transmission Provider reserves the right to curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The

Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be curtailed or interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm

Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a higher priority than any Non-Firm Energy Exchange Transmission Service provided under Attachment N. Non-Firm Energy Exchange Transmission Service will have the lowest reservation priority under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability: A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Event of Disputed Terms and Conditions: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all of the terms and conditions of the Point-To-Point Service Agreement, upon written request from the Transmission Customer, the Transmission Provider and Transmission Customer shall submit the disputed terms and conditions to the dispute resolution procedures of Section 12. The written request from the Transmission Customer shall be in the form of an Arbitration Commitment Letter which specifies the terms of the Service Agreement which are not acceptable to the Transmission Customer. Attached to the Arbitration Commitment Letter shall be an executed Point-To-Point Service Agreement complete in all regards. The Transmission Provider shall commence providing Transmission Service under the Point-To-Point Service Agreement for the requested Transmission Service subject to the Transmission Customer agreeing in the Arbitration Commitment Letter to (a) compensate the Transmission Provider as determined by the outcome of Section 12, (b) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3 or providing a letter of credit as required by the Transmission Provider. The procedures in this section may also be used for applications for Network Service.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment:

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the

Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-to-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider may elect at its option to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. The Transmission Provider may consider redispatch arranged by the Transmission Customer from a third-party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider may elect at its option offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service or secondary service for JEA's native load for a specified number of hours per year or during System Condition(s).

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements may continue to receive transmission service under those agreements until such time as those agreements may be modified.

15.7 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Customer may elect to (1) supply the losses associated with all transmission service as calculated by the Transmission Provider or (2) have the Transmission Provider supply the losses (consistent with (1) above) at a rate equal to 100 percent of the Transmission Provider's forecasted average incremental cost after serving all other obligations (including economy and opportunity transactions). The applicable Real Power Loss factor is computed by May 1 of each year and is effective June 1 each year. The applicable Real Loss Factor and forecasted average incremental cost are posted on OASIS.

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has a pending Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to affect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: Director, Bulk Power Systems, JEA, 7720 Ramona Blvd., Jacksonville, FL 32221 (Internet: TSERVE@JEA.COM) at least 60 days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by electronic mail to the Internet address in this Section. This method will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number, facsimile number, and Internet address of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A Statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, i.e., will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information in a manner consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit: A Completed Application for requests for Firm Point-To-Point Transmission Service for reservations greater than one year shall also include a deposit of one month's charge for Reserved Capacity. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request for Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service.

If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service or deducted from the Transmission Customer’s first month billing if no facilities modifications were necessary as part of this request. Applicable interest shall accrue and be payable at a rate equal to the interest rate paid by the Transmission Provider on its retail deposits and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the

Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 **Response to a Completed Application**: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practical to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 **Execution of Service Agreement**: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or submit an

Arbitration Commitment Letter with a Service Agreement attached and provide the required letter of credit or other form of security pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If the Eligible Customer does not pay this non-refundable reservation fee within 15 days of notifying the Transmission Provider it intends to extend the commencement of service, the Eligible Customer’s application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by transmitting the required information to the Transmission Provider by electronic mail at the Internet address in Section 17.1. This method will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A Statement indication whether the Transmission Customer commits to a Pre-Confirmed Request, i.e., will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon E.P.T. the day before service is to commence. Except for requests for Non-Firm Energy Exchange Transmission Service that are governed by Attachment N, requests for service received later than 2:00 p.m. E.P.T. prior to the day service is scheduled to commence will be accommodated if practicable.

18.4 Determination of Available Transfer Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects not to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these option. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints identified with specificity by transmission element or flowgate, and (2) additional Direct Assignment Facilities or Network Upgrades required providing the requested service. At the Transmission Provider's option, the System Impact Study may identify (1) redispatch options, (when requested by a Transmission Customer) including an estimate of the cost of redispatch, (2) conditional curtailment options (when requested by a Transmission Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached and provide the required letter of credit or other form of security pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities

Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached pursuant to Section 15.3 and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 **Facilities Study Modifications**: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 **Due Diligence in Completing New Facilities**: The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 **Partial Interim Service**: If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding, and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists, and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest. However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and Non-Firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modifications on a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: Except for Non-Firm Energy Exchange Transmission Service provided in accordance with Attachment N, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall be at rates established by agreement with the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but, in any event, notification must be provided prior to any provision of service to the Assignee. The Reseller remains responsible to the Transmission Provider for the obligations under its Service Agreement, regardless of any sale or reassignment. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider’s OASIS on or before the date the reassigned services commence and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff consistent with the terms and conditions set forth for public utilities in FERC Order No. 888. However, the Transmission Provider's proposed stranded cost recovery shall be subject to the dispute resolution procedures of this Tariff.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources and the Transmission Provider agrees to accept the redispatch to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 **Network Integration Transmission Service**: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 **Secondary Service**: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 **Real Power Losses**: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factor is computed by May 1 of each year and is effective June 1 each year. The applicable Real Loss Factor is posted on OASIS.

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

29 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement in the form of Attachment F for service under Part III of the Tariff or submits an Arbitration Commitment Letter with a Service Agreement attached and provides the required letter of credit or other form of security pursuant to Section 15.3, and (iv) the Eligible Customer executes a

Network Operating Agreement with the Transmission Provider in the form of Attachment G.

29.2 Application Procedures: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by electronic mail at the Internet address in Section 17.1. This method will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number, facsimile number, and Internet address of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10-year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), for each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions:
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource,

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource

- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)
- Operating restriction, if any
    - Any periods of restricted operations throughout the year
    - Maintenance schedules
    - Minimum loading level of unit
    - Normal operating level of unit
    - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations.

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (e) above
- 10-year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year.

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

30 Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS by the following deadlines: (i) for periods of a day or longer, no later than the firm pre-schedule deadline, and (ii) for un-designation of less than one day, by a time established by the Transmission Provider, which shall be no later than 20 minutes before the first hour for which un-designation applies, as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2 or statement incorporating previous information as unchanged; and

(v) Identification of any related transmission service request to be evaluated concomitantly with the request for temporary termination, such that the requests for un-designation and the request for these related transmission service requests must be approved or denied as a single request. The evaluating of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected with The Transmission Provider: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission

Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load. .

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration, the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities added by the Network Customer subsequent to July 17, 2007, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement. Calculation of and credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected with the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g., the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required providing the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached and provide the required letter of credit or other form of security pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the

Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached pursuant to Section 15.3 and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that is reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission

Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries; the Parties shall curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

: The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying the Network Customer's monthly Network Load times the monthly Network Service Rate specified in Attachment H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) adjusted for losses coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this

Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 **Redispatch Charge**: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 **Stranded Cost Recovery**: The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms and conditions set forth for public utilities in FERC Order No. 888.

35 **Operating Arrangements**

35.1 **Operation under the Network Operating Agreement**: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 **Network Operating Agreement**: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement.

Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.

There is no charge for Scheduling, System Control and Dispatch Service at this time.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator. The charges for such service will be based on the rates set forth below.

Rate Treatment

The charge for Reactive Supply and Voltage Control from Generation Sources Service is no greater than:

Point-to-Point Service and Network Service

$0.78819 per kW-year,
$0.06568 per kW-month,
$0.01516 per kW-week,
$0.00303 per kW-day, provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or
$0.00019 per kW-hour, provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units

The rates above will be applied to the Network Customer's Monthly Network Load, or the capacity reserved for Point-to-Point Service Customers.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The amount of and charges for Regulation and Frequency Response Service are set forth below.

Rate Treatment

The charge for Regulation and Frequency Response Service is no greater than:

$2.51717 per kW-year
$0.20976 per kW-month,
$0.04841 per kW-week,

$0.00968 per kW-day; provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or

$0.00061 per kW-hour; provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units

For customers with load factors in the range of 87% to 100% within each hour, the rates above will be applied to the Network Customer's Monthly Network Load, or the capacity reserved for Point-to-Point Service Customers. The charges for customers with load factors less than 87% for each hour shall be based on the Transmission Customer's maximum deviation from the schedule within any hour. The rate shall be capped at $14.54 per kW-month.

Self-Supply of Service

A Transmission Customer that is located within the JEA's Control Area shall purchase Regulation and Frequency Response Service from the JEA unless it provides the service itself or purchases it from a third party through automatic generation control or dynamic scheduling.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under this Schedule for the same imbalance, but not both.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer’s scheduled transaction(s) will be settled financially, at the end of each month, at 1 and non-generation resources capable of providing this service that are 10 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost of 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The amount of and charges for Spinning Reserve Service are set forth below.

Rate Treatment

The charge for Operating Reserve Service - Spinning shall be the sum of the capacity and energy charges set forth below. These charges are not for providing backup service. These charges are to reimburse JEA for its costs incurred in meeting spinning reserve responsibilities.

A) Spinning Reservation Charge:

The charge for spinning reservation charge is no greater than:

$98.51872 per kW-year
$8.20989 per kW-month,
$1.89459 per kW-week,

$0.37892 per kW-day; provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or
$0.02368 per kW-hour; provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units:
The rates above will be applied to Network Customer's Monthly Network Load or the capacity reserved for Point-to-Point Service Customers, multiplied by the spinning reserve factor. The spinning reserve factor is 0.25for load within FRCC and 0.5 for load outside of FRCC.

Energy Use Charge:
These charges are applicable if the Transmission Customer's load is within the JEA's control area or the load is "metered into" JEA's control area.

A) Within 30 Minutes:

JEA will provide energy to the Transmission Customer for 30 minutes following a system contingency. The 30 minutes begin upon a schedule change due to the contingency. The energy delivered during these 30 minutes which exceeds the new scheduled amount is an energy imbalance. The charge for the energy imbalance will be $100/MWh or 110% of JEA's cost of providing such energy, whichever is higher.

B) After 30 Minutes:

If the Transmission Customer's schedule and load are not in balance after 30 minutes, then this is deemed an unauthorized use of capacity and energy. At its sole option, the JEA will either elect to separate the Transmission Customer's load from the JEA's system or it will provide the required energy and capacity. If JEA elects to supply the energy and capacity, the charges for such service will be equal to the rates stated for Imbalances Outside Deviation Band in Schedule 4, Energy Imbalance Service. For the purposes of this schedule, the capacity charge will be multiplied by the highest difference between scheduled and actual kW use during any 15-minute period until the schedule and the load are balanced.

Self-Supply of Service

A Transmission Customer that is located within the JEA's Control Area shall purchase Operating Reserve Service - Spinning from the JEA unless it provides comparable service from its own generators or from a third party. The provided Spinning Reserve Service must be available from on-line generation located within peninsular Florida in an amount equal to the reserve capability required of JEA. There must also be a firm transmission path between the generators providing the reserves and the Transmission Customer's loads for the period of transaction. The self-supply of service must be of such a nature that it relieves JEA of an appropriate amount of spinning reserve obligation. If it becomes apparent that self-supply of service is not comparable, the Transmission Customer must purchase this service from the JEA.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not necessarily available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The amount of and charges for Supplemental Reserve Service are set forth below.

Rate Treatment

The charge for Operating Reserve Service - Supplemental shall be the sum of the capacity and energy charges set forth below. These charges are not for providing backup service. These charges are to reimburse JEA for its costs incurred in meeting non-spinning reserve responsibilities.

A) Supplemental Reservation Charge:

The supplemental reservation charge is no greater than:

$63.30901 per kW-year
$5.27575 per kW-month,

$1.21748 per kW-week,
$0.24350 per kW-day; provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or
$0.01522 per kW-hour; provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units:
The rates above will be applied to Network Customer's Monthly Network Load or the capacity reserved for Point-to-Point Service Customers, multiplied by the operating reserve factor. The operating reserve factor is 0.75for load within FRCC and 0.5 for load outside of FRCC.

B) Energy Use Charge: These charges are applicable if the Transmission Customer's load is within the JEA's control area, or the load is "metered into" JEA's control area. These Energy Use Charges shall be waived if the Transmission Customer purchases Operating Reserve Service - Spinning from the JEA (in which case the energy use charges in the Operating Reserve Service - Spinning schedule will apply).

1) Within 30 Minutes:

JEA will provide energy to the Transmission Customer for 30 minutes following a system contingency. The 30 minutes begin upon a schedule change due to the contingency. The energy delivered during these 30 minutes which exceeds the new scheduled amount is an energy imbalance. The charge for the energy imbalance will be $100/MWh or 110% of JEA's cost of providing such energy, whichever is higher.

2) After 30 Minutes:

If the Transmission Customer's schedule and load are not in balance after 30 minutes, then this is deemed an unauthorized use of capacity and energy. At its sole option, the JEA will either elect to separate the Transmission Customer's load from the JEA's system or it will provide the required energy and capacity. If JEA elects to supply the energy and capacity, the charges for such service will be equal to the rates stated for Imbalances Outside Deviation Band in Schedule 4, Energy Imbalance Service. For the purposes of this schedule, the capacity charge will be multiplied by the highest difference between scheduled and actual kW use during any 15-minute period until the schedule and the load are balanced.

Self-Supply of Service

A Transmission Customer that is located within the JEA's Control Area shall purchase Operating Reserve Service - Supplemental from the JEA unless it provides comparable service from its own generators or from a third party. The provided Supplemental Reserve Service must be available from on-line, unloaded generation, quick-start generation or interruptible load located within peninsular Florida in an amount equal to the reserve capability required of JEA. There must also be a firm transmission path between the generators providing the reserves and the Transmission Customer's loads for the period of transaction. The self-supply of service must be of such a nature that it relieves JEA of an appropriate amount of non-spinning reserve obligation. If it becomes apparent that self-supply of service is not comparable, the Transmission Customer must purchase this service from the JEA.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

Rate Treatment

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity up to the sum of the applicable charges set forth below:

Yearly delivery:	\$15.96/kW of Reserved Capacity per year.
Monthly delivery:	\$1.33/kW of Reserved Capacity per month.
Weekly delivery:	\$0.31/kW of Reserved Capacity per week.
Daily delivery:	\$0.06/kW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for daily delivery, shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Discounts:

Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Excess use:

In the event that the Transmission Customer exceeds its firm reserved capacity at any Point of Receipt and/or Point of Delivery (except as otherwise specified in Section 22 of this Tariff), the Transmission Customer shall pay 150% of the Schedule 7 charge for the delivery period (i.e., yearly, monthly, weekly, or daily) for which the Transmission Customer is reserving capacity for the maximum amount that the Transmission Customer exceeds its firm reserved capacity at any Point of Receipt and/or Point of Delivery. In the event that the non-firm transmission service provided to the Transmission Customer for secondary receipt and delivery points exceeds the capacity reservation under which such services are provided, the Transmission Customer shall pay 150% of the applicable Schedule 8 transmission charge for the maximum amount that the Transmission Customer exceeds its capacity reservation.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

Rate Treatment

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

Monthly delivery:	\$1.33/kW of Reserved Capacity per month.
Weekly delivery:	\$0.31/kW of Reserved Capacity per week.
Daily delivery:	\$0.06/kW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for daily delivery, shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed \$3.84/MWH.

The total demand charge in any day, pursuant to a reservation for hourly delivery, shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Discounts:

Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Excess use:

In the event the Transmission Customer exceeds its reserved capacity at any Point of Receipt and/or Point of Delivery, the Transmission Customer shall pay 150% of the applicable transmission charge for the maximum amount that the Transmission Customer exceeds its capacity reservation.

SCHEDULE 9

Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission provider must offer this service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area Operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the same imbalance, but not both.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transactions(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent or (10 MW) of the schedule transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operator and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

ATTACHMENT A

Service Agreement

For Firm Point-To-Point

Transmission Service

1.0 This Service Agreement, dated as of ___________, 20__, is entered into, by and between JEA (formerly Jacksonville Electric Authority or the "Transmission Provider"), and ____, ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the JEA Open Access Transmission Tariff ("Tariff"). Said application is found in the "Application" for Firm Point-To-Point Transmission Service, which is attached hereto as Exhibit A, and by this reference is made a part hereof.

3.0 The Transmission Customer has provided to the Transmission Provider a Completed Application in accordance with the provisions of Section 17.1 of the Tariff and a deposit in the amount of $____________.

4.0 Service under this agreement shall commence on ____________ and shall terminate on ________________ based Transmission Customer's confirmation of Transaction ID # ______________ on JEA's Open Access Same-time Information System (OASIS) and the attached application.

5.0 The Transmission Provider agrees to provide, and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made in writing to the representative of the other Party as indicated below.

<u>JEA:</u>

Attention: Sr. Director, Energy Operations
JEA
7720 Ramona Blvd. West
Jacksonville, FL 32221

Internet e-mail: TSERVE@JEA.COM

Transmission Customer:

____

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

8.0 Such other terms and conditions that the Parties may agree on or may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

JEA:

By:______________________ Sr. Director Energy Operations _______________
Name Title Date

By:______________________ _____________________ ______________
Name Title Date

Exhibit A

Application For Firm Point-To-Point Transmission Service

l.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by JEA including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivering Party:____

4.0 Point(s) of Delivery:____

Receiving Party:____

5.0 The maximum amount of capacity and energy to be transmitted is__________based on Transmission Customer's confirmation of Transaction ID _________ on JEA's OASIS. ___

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charges are ______________based on Transmission Customer's confirmation of Transaction ID _________on JEA's OASIS.

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges are _______________ based on Transmission Customer's confirmation of Transaction ID ___________ on JEA's OASIS.

ATTACHMENT B

**SERVICE AGREEMENT
FOR NON-FIRM POINT-TO-POINT
TRANSMISSION SERVICE**

1.0 This Service Agreement, dated ________, is entered into, by and between JEA ("Transmission Provider"), and ______________________________. ("Transmission Customer").

2.0 The Transmission Customer has been determined by JEA to be a Transmission Customer under Part II of the JEA Open Access Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.1 of the JEA Open Access Tariff.

3.0 Service under this agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 Attached are listed the valid representatives of the Transmission Customer. Each Transmission Customer is liable for business conducted by the valid representative until the JEA receives notification that the aforementioned representative is no longer valid.

5.0 The Transmission Customer agrees to supply information JEA deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Transmission Provider agrees to provide, and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the JEA Open Access Tariff and this Service Agreement. Non-Firm Point-To-Point Transmission Service is recallable by the JEA. The Transmission Customer must relinquish service within ten minutes when service is recalled by JEA.

7.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

JEA:

Attention: Sr. Director, Energy Operations
JEA

7720 Ramona Blvd.
Jacksonville, FL 32221

Internet e-mail: TSERVE@JEA.COM

Transmission Customer:

____
____
____

8.0 The JEA Open Access Tariff is, by this reference, incorporated herein and made a part hereof, as if set out in its entirety.

9.0 The Parties may agree to such other terms and conditions as may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

JEA:

By:______________________ Sr. Director, Energy Operations ______________
Name Title Date

By:______________________ _________________ _________________
Name Title Date

ATTACHMENT C

Methodology to Access Available Transfer Capability

DEFINITIONS:
The JEA Open Access Tariff is, by this reference, incorporated herein and made a part hereof, as if set out in its entirety. The following definitions are based on the NERC "Available Transfer Capability Definitions and Determination document approved May 1996:

i) **Available Transfer Capability (ATC)** - The measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already committed uses.

ii) **Total Transfer Capability (TTC)** - The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post- contingency system conditions.

iii) **Transmission Reliability Margin (TRM)** - The amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

iv) **Capacity Benefit Margin (CBM)** - The amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

v) **Recallability** - The right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider's transmission service tariffs or contract provisions.

Methodology:
JEA will determine the Available Transmission Capability ("ATC") of its interfaces consistent with the “North American Electric Reliability Council” (“NERC”) Guidelines contained in “Transfer Capability; A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems” issued May, 1995 and “Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market”, issued May, 1996.

The "area-to-area" method will be used to determine the interface capabilities with other control areas. The Florida/Southern interface is a shared interface which is allocated among its interface owners pursuant to specific allocation agreements. Therefore, JEA will base its ATC calculations for the Florida/Southern interface on its allocated share of the TTC for the Florida/Southern interface.

Determination of ATC

The TTC will be determined using the most current load flow base cases with all facilities available, dispatching each area economically to meet their commitments and adjusted for projected system conditions (e.g., generating plants online, transmission facilities out of service, scheduled transactions). The criteria used will be consistent with JEA's latest FERC 715 filing.

The NRes will be determined by adding the CBM to the existing firm (nonrecallable) commitments (EC). i.e., NRes = CBM + EC.

The CBM will be determined by using reliability analyses (e.g., "Loss of Load Probability" ("LOLP") or other applicable analyses), and the appropriate amount of transmission interface capability will be reserved for CBM on a per interface basis.

The TRM will be determined by the difference between TTC, with all generating units available, and the amount of transfer capability with a critical generating unit to the particular interface being unavailable, plus the appropriate amount of "Operating Reserves" ("ORes") for that interface. TRM must recognize changing operating conditions that may occur in very short periods of time and cannot be definitely projected without the provision of a transfer capability margin. Therefore, a security margin may need to be a consideration as part of the TRM determination.

The ORes will be determined within Florida on an interface-by-interface basis by modeling each utility's allocated share of the statewide operating reserve requirements consistent with the latest FRCC Procedures for operating reserves or other methods which may be applicable in the future. ORes is only applicable to interfaces within Florida.

The "Nonrecallable Available Transfer Capability" ("NATC") will be determined by subtracting from the interface's TTC, its associated TRM and NRes. i.e., NATC = TTC - (TRM + NRes).

The “Recallable Available Transfer Capability” (“RATC”) will be determined by subtracting from the interface's TTC, the applicable portion of the TRM, NRes and "Recallable Reserved" ("RRes"). i.e., RATC = TTC - (aTRM + NRes + RRes), where

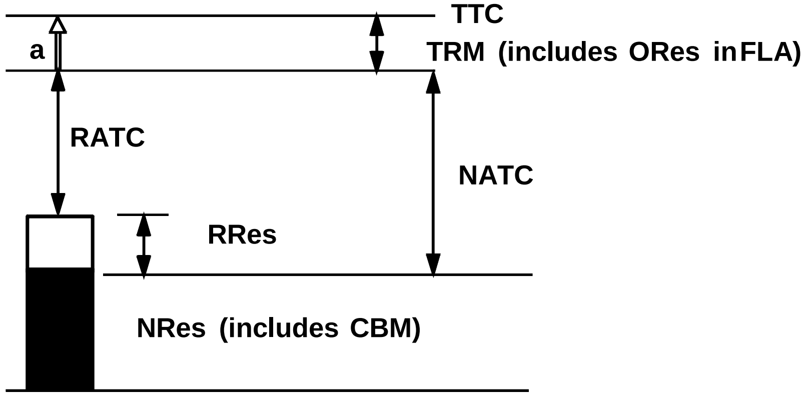

Figure 1.

$0 \leq a \leq 1$ determines the amount of TRM which can be made available to ATC on a recallable basis based on the system's reliability concerns.

Refer to Figure 1 for an illustration of the terms used above and assume for simplicity that the reserved amounts are equal to the actual scheduled amounts.

ATTACHMENT D

Methodology for Completing a System Impact Study

The JEA routinely conducts planning studies to determine the adequacy of its transmission lines to serve its native load. The criteria and processes used in these studies are documented in FERC Form No. 715, Annual Transmission Planning and Evaluation Report. This document is updated and filed each year by the JEA.

JEA will review each Application for transmission service. JEA will notify the customer within 30 days as to which condition exists:

1. More information is needed to assess the Application

JEA will ask the Transmission Customer to provide additional information or data relating to the requested transaction. The Application is not complete until this information is received.

2. Adequate transmission capacity exists

JEA will respond to the applicant that there is adequate transmission capacity. Documentation and information will be exchanged to develop a complete Service Agreement. This step may require more or less time depending on whether an opinion from JEA's Bond Counsel on the Private Use of Tax-Exempt Bonds is required. Failure of the Transmission Customer to execute and return the Service Agreement within fifteen (15) days after it is tendered by the JEA will be deemed a withdrawal and termination of the Application.

3. JEA is unsure about the amount of transmission capacity that exists for a particular transaction

JEA will contact the Transmission Customer and determine if the Transmission Customer wishes JEA to perform a System Impact Study.

4. Adequate transmission capacity does not exist

JEA will respond to the applicant with the amount of transmission capacity known to exist and determine if the prospective Transmission Customer wishes JEA to begin a Facilities Study.

The System Impact Study will evaluate the impact of the requested transaction on the JEA system. Consideration may be given to the impact on systems interconnected with JEA but JEA's findings will not be binding on any other system.

JEA will begin a System Impact Study by providing the Transmission Customer the following:

1. A list of assumptions;
2. The type of studies to be performed, e.g., load flows, stability, short circuit;
3. An estimate of the cost of the study;
4. An estimate of the cost of review by JEA's Bond Counsel, if appropriate;
5. An estimate of the schedule of time the JEA will need to perform the study.

EXHIBIT 1 TO ATTACHMENT D

FORM OF
SYSTEM IMPACT STUDY AGREEMENT
BETWEEN
JEA
AND
TRANSMISSION SERVICE CUSTOMER

THIS SYSTEM IMPACT STUDY AGREEMENT ("Study Agreement") between JEA ("Transmission Provider") and ____________________________________ ("Transmission Customer") is made and entered into this ______ day of ___________, _______.

WITNESSETH

WHEREAS, Transmission Customer, has requested that JEA provide it with Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service under JEA's Open Access Transmission Tariff;

WHEREAS, in order to conduct the System Impact Study ("Study") that will analyze the impact of the type of transmission service requested by the Transmission Customer on JEA's transmission system, the Transmission Customer has provided JEA certain information as may be required to perform the Study; and

NOW, THEREFORE, in consideration of the foregoing premises and of the benefits to be obtained from the covenants herein, JEA and the Transmission Customer agree as follows:

1. This Study Agreement shall not be used by either Party for any purpose other than enforcement of the terms of the Study Agreement.

2. JEA and the Transmission Customer agree that any data provided pursuant to this Study Agreement and designated confidential by the providing Party will be kept confidential, and that neither Party will disclose such designated data; provided, however, that either Party may disclose such confidential designated data in any manner consistent with a written consent to such disclosure obtained from the providing Party prior to such disclosure.

3. In the event that one Party is required by a state or federal regulatory authority or court to disclose data previously provided under the Study by the other Party under a confidentiality designation, the Party subject to such requirement shall exercise reasonable best efforts to obtain a confidentiality agreement or appropriate protective order with such state or federal regulatory authority or court, as applicable, to preserve the confidentiality of the designated data to be

disclosed. Further, upon receipt of such a demand for the data, the receiving Party shall immediately notify the other Party.

4. JEA and the Transmission Customer agree that the purpose of the Study will be to identify any impacts which the Transmission Service requested by the Transmission Customer could reasonably be anticipated to have on the operation and reliability of JEA's Transmission System. The System Impact Study shall identify any system constraints, additional Direct Assignment Facilities or Network Upgrades required to provide the requested Transmission Service.

5. Appendix No. 1 of this Study Agreement sets out the informational data to be provided by the Transmission Customer upon which the Study will be based. Part I of Appendix No. 1 sets out the principal information required to be provided by the Transmission Customer for the Study in response to a Point-To-Point Transmission Service request; Part II of Appendix No. 1 sets out the principal information required to be provided by the Transmission Customer in response to a Network Integration Transmission Service request.

6. Appendix No. 2 of this Study Agreement sets out the criteria and a description of the principal procedures to be employed by JEA in performing the Study.

7. JEA shall provide the Study results to the Transmission Customer no later than sixty (60) days following the latter of 1) the execution of this Study Agreement, or 2) the Transmission Customer having provided JEA the data specified in Appendix No. 1 to this Study. To the extent JEA completes the Study in a shorter period of time; JEA will provide the Transmission Customer with the results of this Study as soon as it is completed.

8. After JEA presents the Study results to the Transmission Customer: 1) if the Study indicates that JEA can provide all the requested service from existing capacity, JEA will provide the Transmission Customer an executable Service Agreement, or 2) if the Study indicates that JEA will be required to construct and/or install incremental facilities, and if the Transmission Customer so requests, JEA will provide the Transmission Customer within thirty (30) days a Facilities Study Agreement, the form of which is incorporated as Exhibit 2 to this Attachment D.

9. The actual cost of the Study is estimated by JEA to be_____________ ____________dollars ($). The Transmission Customer will be responsible for such cost. The Transmission Customer will deposit with JEA dollars ($) within fifteen (15) days of the date of execution of this Study Agreement. The actual cost of the Study, less the dollars ($)

deposit, will be billed to the Transmission Customer, subject to JEA providing the Transmission Customer with the results of the Study. Payment by the Transmission Customer to JEA of such cost will be due no later than twenty (20) days from the date of mailing (as determined by postmark) of the bill. JEA will provide the Transmission Customer with documentation of the costs at the time JEA bills the Transmission Customer for the Study.

10. In the event JEA is unable to complete the Study within the time period specified above, JEA shall notify the Transmission Customer and shall provide an estimate completion date along with an explanation of the reasons why additional time is required to complete the Study.

IN WITNESS WHEREOF, the Parties hereto have caused this Study Agreement to be executed by their duly authorized officers effective as of the date first written above.

JEA

Date:_____________________ **By:_______________________________**

Title:______________________________

TRANSMISSION CUSTOMER

Date:_____________________ **By:________________________________**

Title:______________________________

APPENDIX NO. 1
TO
EXHIBIT 1
TO
ATTACHMENT D
INFORMATION TO BE PROVIDED BY TRANSMISSION CUSTOMER

PART I

To be provided by the Transmission Customer when a System Impact Study is performed in response to a Long-Term Firm Point-To-point Transmission Service request.

Informational Data:

The informational data provided pursuant to Section 18.2 of JEA's Open Access Transmission Tariff and any other pertinent information necessary to properly analyze the Transmission Customer's request for Long-Term Firm Point-To-Point Transmission Service shall be specifically delineated in this Appendix and agreed to between JEA and the Transmission Customer.

PART II

To be provided by Transmission Customer when a System Impact Study is performed in response to a Network Integration Transmission Service request.

Informational Data:

The informational data provided pursuant to Section 29.2 of JEA's Open Access Transmission Tariff and any other pertinent information necessary to properly analyze the Transmission Customer's request for Network Integration Transmission Service shall be specifically delineated in this Appendix and agreed to between JEA and the Transmission Customer. More specifically, the following are the typical types of information that will be needed to be provided to JEA by the Transmission Customer in paper summary and in electronic format, as applicable.

LOAD: Coincident (with the Transmission Customer's load) and non-coincident load projection for the term of the transmission service for each delivery point along with the corresponding power factor.

GENERATION: Capacity plan along with the capability of each generating unit (i.e., real and reactive power) and heat rate curves and/or sufficient data to dispatch the Transmission Customer's resources.

On Peak /Off Peak cases will be analyzed.

INTERCHANGE SCHEDULE: Long-term firm transactions, specifying receipt and delivery points, duration of transactions, and underlying agreements.

STUDY HORIZON: Expected system conditions for planning horizon will be represented in the Study. It may be necessary to represent other years beyond the planning horizon depending on the results of the Study.

MODEL: Latest transmission model for utility and/or member systems, including, but not limited to, compensating devices, line impedances, transformers, and other pertinent data. Also, transient stability and short circuit data for generators.

**APPENDIX NO. 2
TO
EXHIBIT 1
TO
ATTACHMENT D
CRITERIA AND STUDY PROCEDURE**

CRITERIA:

Criteria will be in conformance with criteria in JEA's latest Form 715 filing.

STUDY PROCEDURE:

Task 1.0: Case Development

The FRCC data bank for years _______________ will be used as a basis with the necessary detailed data added for the Study.

Task 2.0: Analyses

Load flow analyses for the JEA system will be performed. Thermal and reactive limitations will be identified.

Transient Stability Analysis will be performed as required to determine reliability impact of request on the JEA system. Cases will be used with worst but probable dispatches.

Short Circuit Analysis will be performed as required to determine reliability impact on the JEA system.

In addition, JEA may perform other special studies as may be necessary.

Task 3.0: Documentation of Results

Document in report form the assumptions, methodology, and results of the study.

APPENDIX NO. 2
TO
ATTACHMENT D
FORM OF
FACILITIES STUDY AGREEMENT
BETWEEN
JEA
AND
TRANSMISSION SERVICE CUSTOMER

THIS FACILITIES STUDY AGREEMENT ("Facilities Agreement") between JEA ("Transmission Provider") and ____ ("Transmission Customer") is made and entered into this ____ day of ___________ , ______ .

WITNESSETH

WHEREAS, Transmission Customer has requested that JEA provide it with Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service under JEA's Open Access Transmission Tariff;

WHEREAS, in order to provide the requested transmission service JEA has conducted a System Impact Study as requested by the Transmission Customer, and the results of such Study have determined that JEA will be required to construct and/or install incremental facilities; and

NOW, THEREFORE, in consideration of the foregoing premises and of the benefits to be obtained from the covenants herein, JEA and the Transmission Customer agree as follows:

1. This Facilities Agreement shall not be used by either Party for any purpose other than enforcement of the terms of the Facilities Agreements.
2. JEA and the Transmission Customer agree that any data provided pursuant to this Facilities Agreement and designated confidential by the providing Party will be kept confidential, and that neither Party will disclose such designated data; provided, however, that either Party may disclose such confidential designated data in any manner consistent with a written consent to such disclosure obtained from the providing Party prior to such disclosure.
3. In the event that one Party is required by a state or federal regulatory authority or court to disclose data previously provided under the Facilities Agreement by the other Party under a confidentiality designation, the Party subject to such requirement shall exercise reasonable best efforts to obtain a confidentiality agreement or appropriate protective order with such state or federal regulatory authority or court, as applicable, to preserve the confidentiality of the designated data to be disclosed.

Further, upon receipt of such a demand for the data, the receiving Party shall immediately notify the other Party.

4. JEA and the Transmission Customer agree that the purpose of the Facilities Study is to identify what specific incremental facilities, including enhancements, modifications, additions or deletions that will be required in order for JEA to provide the requested Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service and the associated costs thereof.

5. JEA shall provide the Facilities Study results no later than sixty (60) days following the latter of 1) execution of this Facilities Agreement, or 2) the Transmission Customer having provided JEA any information requested by JEA in order to complete the Facilities Study. To the extent JEA completes the Facilities Study in a shorter period of time, JEA will provide the Transmission Customer with the results of this Facilities Study as soon as completed. To the extent JEA is unable to complete the Facilities Study within the time frame specified above, JEA will notify the Transmission Customer and provide an estimate of the time needed to complete the Facilities Study.

6. The results of the Facilities Study will include a good faith estimate of 1) the cost of the Direct Assignment Facilities to be charged to the Transmission Customer, 2) JEA's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and 3) the time required to complete such construction and initiate the requested Transmission Service.

7. The actual cost of the Facilities Study is estimated by JEA to be ________ dollars ($). The Transmission Customer will be responsible for such cost. The Transmission Customer will deposit with JEA dollars ($) within fifteen (15) days of the date of execution of this Facilities Agreement. The actual cost of the Facilities Study, less the dollars ($) deposit, will be billed to the Transmission Customer, subject to JEA providing the Transmission Customer with copies of the results of the Facilities Study. Payment by the Transmission Customer to JEA of such cost will be due no later than twenty (20) days from the date of mailing (as determined by postmark) of the Facilities Study bill. JEA will provide the Transmission Customer with documentation of the costs at the time JEA bills the Transmission Customer for the Facilities Study.

8. Upon completion of the Facilities Study and at the request of the Transmission Customer, JEA shall provide the customer an executable Service Agreement. The Transmission Customer shall have thirty (30) days to execute the Service Agreement.

9. At the time the Transmission Customer executes the Service Agreement, and prior to the commencement of any construction and other activities attendant thereto, the Transmission Customer shall provide JEA with an unconditional and irrevocable letter of credit or other form of security acceptable to JEA equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the

Uniform Commercial Code that protects JEA against the risk of non-payment for such costs.

IN WITNESS WHEREOF, the Parties hereto have caused this Facilities Agreement to be executed by their duly authorized officers effective as of the date first written above.

JEA

Date: _______________

By: ______________________________________

Title: ______________________________________

TRANSMISSION CUSTOMER

Date: ________________

By: ______________________________________

Title: ______________________________________

ATTACHMENT E

Index of Point-To-Point Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT F

Form of Service Agreement for Network Integration Transmission Service

This Service Agreement, dated as of ___________________________, is entered into by and between JEA ("Transmission Provider") and __________________________________ ("Network Customer").

1.0 The Network Customer is ______________________________________ and has been determined by JEA to have submitted a complete Application for Network Integration Transmission Service under Part III of the Tariff.

2.0 Service under this Service Agreement shall commence on the later of: (1) 0001 hours on _________________, 19 ____, or (2) the date on which construction of transmission facilities and/or Network Upgrades identified by the System Impact Study are completed.

3.0 JEA agrees to provide, and the Network Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of the Tariff and this Service Agreement. Any notice or request made to or by any Party regarding this Service Agreement shall be made in writing and shall be delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

JEA:

Attention: Sr. Director, Energy Operations
JEA
7720 Ramona Blvd.
Jacksonville, FL 32221

NETWORK CUSTOMER:

____
____
____
____

5.0 The amount of credit, if any, for a Network Customer's owned transmission facilities that meet the requirements of Section 30.9 of the Tariff is as follows:

____
____
____

6.0 Such other terms and conditions that the Parties may agree on or may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized representatives as of the date first above written.

JEA

By:_____________________________________

NETWORK CUSTOMER

By:_____________________________________

SPECIFICATIONS FOR NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 Term of Network Integration Transmission Service:

Start Date:

Termination Date:

2.0 Description of capacity and/or energy to be transmitted by Transmission Provider across the Transmission Provider's Transmission System (including electric control area in which the transaction originates).

3.0 Network Resources

(1) Transmission Customer Generation Owned:

Resource Capacity Capacity Designated

(2) Transmission Customer Generation Purchased:

Source Capacity

Total Network Resources: (1)+(2) = ____________

4.0 Network Load

(1) Transmission Customer Network Load:

Network Load Transmission Voltage Level

(2) Member Systems Loads Designated as Network Load:

Member System Load Transmission Voltage Level

Total Network Load (Estimated): (1)+(2) = _________

ATTACHMENT G

Form of a Network Operating Agreement

THIS NETWORK OPERATING AGREEMENT ("Operating Agreement") between JEA ("Transmission Provider") and the Network Customer ("Network Customer") is made and entered into this ______ day of ________, 19___.

WITNESSETH

WHEREAS, the Network Customer has requested and JEA has agreed to provide Network Integration Transmission Service under Part III of the Tariff; and

WHEREAS JEA and the Network Customer have agreed to enter into this Operating Agreement to set forth certain operating understandings in order for JEA to provide the requested network service.

NOW, THEREFORE, in consideration of the foregoing premises and of the benefits to be obtained from the covenants herein, JEA and the Network Customer agree as follows:

ARTICLE 1 – Definitions

Along with the definitions set forth below, the definitions in the Tariff are hereby incorporated into this Operating Agreement.

1.1 **Data Acquisition Equipment:** Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of the Tariff.

1.2 **Data Link:** The direct communications link between the Network Customer's energy control center and JEA's control center that will enable JEA's control center to receive real time telemetry and data from the Customer's energy control center and the Customer's energy control center to receive real time telemetry and data from JEA's control center.

1.3 **Metering Equipment:** High accuracy, solid state kW, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, meter recording devices (e.g., Solid State Data Receivers), telephone circuits, signal or pulse dividers, transducers, pulse accumulators, and any other metering equipment necessary to implement the provisions of the Tariff.

1.4 **Member System:** An Eligible Customer operating as a part of a lawful combination, partnership, association or joint action agency composed exclusively of Eligible Customers.

1.5 **Power Factor Requirements (PFR) On-Peak Hours:** The PFR On-Peak hours are the hours during the PFR On Peak Period; the PFR On Peak Period is (1) from December 1 through March 31 during the hours from 6 a.m. to 10 a.m., and 6 p.m. to 10 p.m. and; (2) from April 1 through November 30 during the hours from 10 a.m. to 10 p.m., unless and until otherwise changed by mutual agreement of the Operating Committee.

1.6 **Power Factor Requirements (PFR) Off-Peak Hours:** All other hours besides the PFR "On-Peak hours".

1.7 **Protective Equipment:** Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Tariff.

ARTICLE 2 - Term of Service

2.1 The term of this Operating Agreement between JEA and the Network Customer shall be concurrent with the Service Agreement.

ARTICLE 3 - Network Customer Control Area

3.1 **Network Customer's Control Area:** The Network Customer shall include its designated Network Resources and Network Load and operate as a single independent Control Area ("Network Customer Control Area") and shall plan, construct, operate and maintain the Network Customer's Control Area in accordance with Good Utility Practice, which shall include, but not be limited to, all applicable guidelines of the North American Electrical Reliability Council, the Southeastern Electric Reliability Council, and the Florida Regional Reliability Council, or their successor; provided, however, that JEA will not require adherence to any such applicable guidelines to the extent that JEA does not adhere to such applicable guideline.

3.1.1 The Network Customer may contract with another entity to provide Control Area services to the Network Customer, in which event such entity shall be required to meet all of the control area requirements set forth in this Article.

3.1.2 If the Network Customer desires to merge the Network Customer's Control Area with another entity's Control Area such that a common control scheme is applied to the Network Customer's and the other entity's generation and load (i.e., a pooling arrangement) then the Network Customer must submit a new Application for service under the Tariff.

3.1.3 The Network Customer shall provide and operate automatic generation control equipment (or contract with a third party to perform these services) in accordance with Good Utility Practice so as to avoid burdening demands upon JEA's system or the systems of others.

3.2 **Control Area Operations:** JEA and the Network Customer shall operate and maintain their respective Control Areas in a manner that will allow JEA to safely and reliably operate the Transmission System in accordance with the Tariff and with Good Utility Practice, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of the Tariff, JEA shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Transmission System.

3.3 **Control Area Equipment:** The Network Customer shall be responsible for the purchase, installation, upgrading, operation, maintenance and replacement of all Data Acquisition Equipment, Metering Equipment, Protection Equipment, and any other associated equipment and software, which may be required by either Party for the Network Customer to operate a Control Area in accordance with Good Utility Practice. JEA shall have the right to review and approve such equipment and software as may be required to ensure conformance with Good Utility Practices, prior to its installation.

3.4 **Control Area Data:** The Network Customer shall incorporate the information obtained from the Network Customer's Metering Equipment and Data Acquisition Equipment into the Network Customer's energy control center as the Parties determine to be necessary to incorporate the Member Systems into a single Control Area operating within the JEA Transmission System consistent with the terms and conditions of the Tariff.

3.5 **Regulation:** The Network Customer shall be responsible for operating in a manner to provide for its Network Load at all times, and to hold deviations from frequency-biased net interchange schedules to a minimum in accordance with the North American Electric Reliability Council, Southeastern Electric Reliability Council, and the Florida Regional Reliability Council, or their successor requirements.

3.6 **Data Link Operations:** The selection of real time telemetry and data to be received by JEA and the Network Customer shall be as necessary for reliability, security, economics, and/or monitor-ing of real-time condition that affect JEA's Transmission System. This telemetry shall include, but is not limited to, loads, line flows, voltages, generator output, and breaker status at any of the Network Customer's transmission and generation facilities (See Exhibit 2 to this Operating Agreement). To the extent that JEA or the Network Customer requires data that are not available from existing equipment, the Network Customer shall, at its own expense, install any Metering Equipment, Data Acquisition Equipment, or other equipment and software necessary for the telemetry to be received by JEA or the Network Customer via the Data Link. JEA shall have the right to inspect equipment and software associated with the Data Link in order to assure conformance Good Utility Practice.

3.7 **Computer Modifications:** Each Party shall be responsible for implementing any computer modifications or changes required to its own computer system(s) as necessary to implement the provisions of the Tariff.

3.8 **Metering:** The Network Load shall be metered on an hourly integrated basis in accordance with JEA's standards or practices for similarly determining JEA's load. The actual hourly Network Load during each calendar month shall be provided to JEA by the Network Customer by the seventh day of the following calendar month.

3.9 **Voltage Support:** The Network Customer will use reasonable best efforts to have in the shortest practicable time, but under no circumstances greater than one (1) year after service begins under the Tariff, sufficient reactive compensation and control to meet the power factor requirements specified below (such range to be adhered to except for momentary deviations or at JEA's written consent) at each interconnection or point of delivery with each Member System. If the Network Customer does not provide the necessary reactive compensation and control to comply with the objectives described in this Section, JEA shall have the unilateral right to install such equipment to meet these standards at the Network Customer's expense.

POWER FACTOR REQUIREMENTS	
On-Peak Hours	**.95 (lagging) to 0.95 (leading)**
Off-Peak Hours	**.90 (lagging) to 1.00 (unity)**

3.10 **Real Time System Data Requirements:** The Network Customer shall provide JEA via the Data Link, at least once every one minute (this time interval is subject to modification as agreed to by the Network Operating Committee), loads, line flows, voltages, generator outputs, breaker status, etc. as necessary for JEA to provide service under the Tariff and ensuring the security and reliability of the JEA Transmission System.

3.11 **Disturbances:** Each Party shall, insofar as practicable, protect, operate and maintain its system and facilities so as to avoid or minimize the likelihood of disturbances which might cause impairment of or jeopardy to service to the customers of the other Party, or to other interconnected systems.

3.12 **Notification:** The Network Customer shall notify and coordinate with JEA prior to the commencement of any work by the Network Customer, Member System, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Network

Customer's or JEA's Control Area, the Data Link, or the reliability of the JEA Transmission System.

3.13 **Maintenance of Equipment:** The Network Customer shall, on a regular basis or at JEA's request, and at the Network Customer's own expense, test, calibrate, verify and validate the Metering Equipment, Data Acquisition Equipment, and other equipment or software used to determine Network Load. JEA shall have the right to inspect such tests, calibrations, verifications and validations of the Metering Equipment, Data Acquisition Equipment, and other equipment or software used to determine the Network Load. Upon JEA's request, the Network Customer will provide JEA a copy of the installation, test and calibration records of the Metering Equipment, Data Acquisition Equipment, and other equipment or software. JEA shall, at the Network Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any Metering Equipment, Data Acquisition Equipment, and other equipment or software used to determine the Network Load.

3.14 **Control Area Costs:** The Network Customer shall be responsible for all costs to establish, operate and maintain the Network Customer's Control Area, including, but not limited to, engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, relocation of equipment, or software.

ARTICLE 4 - Network Operating Committee

4.1 **Network Operating Committee:** Each Party shall in writing appoint a member(s) and an alternate(s) to a Network Operating Committee and to notify the other Party of such appointment(s). Such appointments may be changed at any time by similar written notice. The Network Operating Committee shall meet as necessary and review the duties set forth herein. The Network Operating Committee shall hold meetings at the request of either Party, at a time and place agreed upon by the members of the Network Operating Committee. The Network Operating Committee shall meet once each year to discuss the information provided pursuant to Article V and the information exchanged pursuant to this Section. Each member and alternate shall be a responsible person working with the day-to-day operations of each respective power system. The Network Operating Committee shall represent the Parties in all opera-tonal matters that may be delegated to it by mutual agreement of the Parties hereto. The duties of the Network Operating

Committee shall include those specifically referred to elsewhere in the Tariff, including but not limited to, the following:

(1) The coordination of operation and maintenance schedules;

(2) The exchange of information regarding each party's long range transmission plans;

(3) Establishment of maintenance control and operating procedures consistent with the provisions of the Tariff;

(4) Establishment of data requirements necessary for JEA to provide Network Integration Service as delineated in the Tariff;

(5) Review of Metering Equipment, Data Acquisition Equip-mint, Protection Equipment, and any other equipment or software requirements, standards and procedures; and

(6) Such other duties as may be conferred upon it by mutual agreement of the Parties hereto.

4.2 **Network Operating Committee Agreements:** Each Party shall cooperate in providing to the Network Operating Committee all information required in the performance of the Network Operating Committee's duties. All decisions and agreements, if any, made by the Network Operating Committee shall be evidenced in writing and shall be in accordance with the Tariff.

ARTICLE 5 - Technical Data

5.1 **Annual Load Forecast:** The Network Customer shall provide JEA by November 1st of each year the Network Customer's best forecast of the following calendar year's (i) monthly coincident peak Network Load of the Member Systems expressed in kW along with the power factor of each of the Member Systems at such time and, (ii) each individual Member System's monthly non-coincident peak loads expressed in kW along with the power factor of each of the Member Systems at such time. Such forecast shall be made using prudent forecasting techniques available and generally deemed acceptable in the electric utility industry.

5.2 **Annual Network Resource Availability Forecast:** The Network Customer shall provide to JEA by November 1st of each year the Network Customer's best forecast of the following calendar year's planned Network Resource availability forecast (e.g., all planned resource outages, including off-line and on-line dates). Such forecast shall be made using prudent forecasting techniques available and generally deemed acceptable in the electric utility industry. The Network Customer shall inform JEA, in a timely manner, of any changes to Network Customer's planned Network Resource Availability Forecast.

5.3 **Annual Operating Conflicts:** In the event that JEA determines that the annual Network Resource Availability Forecast cannot be accommodated due to a transmission constraint on the JEA Transmission System, and such constraint may jeopardize the security of the JEA Transmission System or adversely affect the economic operation of either JEA or the Network Customer, to the extent possible, the Network Operating Committee will coordinate the annual Operating Network Resource Availability Forecast of both Parties to mitigate the transmission constraint.

5.4 **Daily Operating Forecast:** The Network Customer shall provide JEA, at least 36 hours in advance of every calendar day, the Network Customer's best hourly forecast for the calendar day of the (i) maximum non-coincident flow (both import and export) at each of the JEA interfaces with the Network Customer and/or the Member Systems, (ii) first contingency maximum non-coincident flow (both import and export) at each of the JEA interfaces with each Member System, (iii) any planned transmission or generation outage(s) on the system of any of the Member Systems or on a system other than that of JEA where a Network Resource is located, (iv) the individual coincident

Member Systems loads along with the commitment/dispatch of the Network Resources at peak operating period(s) (the peak operating period(s) will be determined by JEA operating personnel and may be changed from time-to-time as necessary), and (v) and any other information that JEA's operating personnel reasonably deem appropriate to safely and reliability operate the JEA Transmission System. The Network Customer shall keep JEA informed in a timely manner, of any changes to its current Daily Operating Forecast.

5.5 **Daily Operating Conflicts:** In the event that JEA determines that the Daily Operating Forecast cannot be accommodated due to a transmission constraint on the JEA Transmission System, and such constraint may jeopardize the security and reliability of the JEA Transmission System or adversely affect the economic operation of either JEA or the Network Customer, the load curtailment provisions of the Tariff will be implemented in accordance with Exhibit 1 of this Operating Agreement.

5.6 **Network Planning Information:** In order for JEA to plan, on an ongoing basis, to meet the Network Customer's firm-long term requirements for Network Integration Transmission Service the Network Customer shall provide JEA with the information set forth in Sections 5.7 - 5.10. This type of information is consistent with JEA's information requirements for planning to serve JEA's Native Load Network Customers and is consistent with JEA's ten (10) year planning process.

5.7 **Annual Planning Network Load Forecast:** The Network Customer shall provide JEA by November 1st of each year the Network Customer's best forecast of the following ten (10) calendar years' (i) monthly coincident Network Load and non-coincident Member Systems' Network Loads expressed in kW and, (ii) each individual Member System's monthly coincident and non-coincident loads expressed in kW along with the respective power factor. Such forecast shall be made using prudent forecasting techniques available and generally deemed acceptable in the electric utility industry.

5.8 **Annual Planning Network Resource Forecast:** The Network Customer shall provide to JEA by November 1st of each year (i) the Network Customer's best forecast of the next ten (10) years' planned Network Resources and all pertinent information regarding such Network Resources, (ii) a copy of the Network Customer's most current firm purchased power commitments (including the underlying agreement for purchased power) for the next ten (10) years on a unit specific basis for any Network Resource(s) which is a firm unit specific purchased power resource, and (iii) for purchased power commitments that are non-unit specific, any information necessary for JEA (including the underlying agreement for purchased power) to model how the purchased power commitment would be dispatched by the Network Customer to meet the Network Load; provided, however, that the information provided by the Network Customer pursuant to this Section 5.8 shall not be deemed a substitute for written notice required for designating new Network Resources.

5.9 **Annual Planning Network Transmission Facilities:** The Network Customer shall provide JEA any planned internal transmission facilities on the Network Customer and/or each Member Systems' system (lines, transformers, reactive equipment, etc.) for each of the subsequent ten (10) calendar years.

5.10 **Technical Data Format:** The Network Customer shall provide JEA the best available data associated with Network Resources and transmission facilities, for modeling purposes in an electronic format specified by JEA. The electronic format specified by JEA shall be a format commonly used in the electric utility industry.

5.11 Such other terms and conditions that the Parties may agree on or may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties hereto have caused this Operating Agreement to be executed by their duly authorized officers effective as of the date first written above.

JEA

Date: ________________________

By: ____

Title: ____

[Network Customer]

Date: ________________________

By: ____

Title: ____

EXHIBIT 1 TO ATTACHMENT G
Out of dispatch Cost Methodology

JEA's system operations will determine the least-cost re-dispatch for both JEA and the Network Customers that would relieve the constraint, without regard to resource ownership. Both JEA and the Network Customer will be required to redispatch their resources (including reducing purchases and sales) in accordance with the results produced by JEA's system operations until the constraint has been removed. JEA's system operations will then determine JEA's, and the Network Customer's total combined additional costs incurred to alleviate the constraint.

This total combined cost will be shared by JEA and all Network Customers such that the Network Customer will be responsible for its load ratio share of that cost.

Out of dispatch Costs Computation Methodology:

PC_{JEA} - JEA's total production costs, including sales and purchases, before the constraint procedures are implemented.

PC_{TC} - The Network Customer's total production costs, including sales and purchases, before the constraint procedures are implemented.

PC_{JEA}' - JEA's total production costs, including sales and purchases, after the constraint procedures are implemented.

PC_{TC}' - The Network Customer's total production costs, including sales and purchases, after the constraint procedures are implemented.

LRP_{TC} - The load ratio percentage of the Network Customer.

PC - The total incremental production costs to relieve the constraint or defined as $PC = (PC_{JEA}' + PC_{TC}') - (PC_{JEA} + PC_{TC})$.

CR_{TC} - The cost responsibility of the Network Customer for the total incremental production costs to relieve the constraint or defined as $CR_{TC} =$ □PC * $LRP_{TC.}$

AC_{TC} - The incremental costs/saving incurred by the Network Customer to relieve the constraint or defined as $AC_{TC} = (PC_{TC}' - PC_{TC})$.

OCC - The Out of Dispatch charge (negative) or credit (positive) to the Network Customer bill or defined as $OCC = AC_{TC} - CR_{TC}$

EXHIBIT 2 TO ATTACHMENT G
OF THE NETWORK OPERATING AGREEMENT

General Requirements

1. Periodicity of data sent to JEA will be compatible with JEA's own, i.e., as required by JEA's EMS.

2. If a data link is used, ICCP protocol will be used. If the communication is direct from RTU's, it will be 44 - 500 protocol.

3. Forecast data, i.e., system load, unit outage, etc. will be communicated to the system operators.

4. The Network Customer will provide to JEA all their independent schedules into and out of network.

Specific Data Requirements

The list below shows the required data that the Network Customer must provide to JEA. Real time data updated at least every 2 minutes is required in order to guarantee that the information is current when a data snapshot is taken by the security applications. This time is currently about half of the periodicity of these applications. In the future this data snapshot will be required at a faster rate to match expected reduced run times for these applications:

1. The Network Customer will provide to JEA all their independent schedules into & out of the network

2. Network Load
   A. Instantaneous - MW, MVAR
   B. Hourly - MWHr, refresh hourly for day

3. Generation
   A. Instantaneous - MW, MVAR, Voltage, Dynamic schedules for Jointly Owned Units
   B. Hourly - MWHr, refresh hourly for day
   C. Dispatch Data, Efficiency, Fuel Cost, High and Low Limits

D. Availability of Network Resources

4. Actual Net Interchange (for all ties)

A. Instantaneous - MW, MVAR

B. Hourly - MWHr, refresh hourly for day

5. Data for Transmission Facilities key to JEA's Security Assessment

A. Status

B. MW, MVAR, AMPS loading

C. Voltages

D. MVA, AMP ratings

E. Settings (i.e., capacitor banks and auto transformers)

F. Distribution load per station

G. Transmission facilities modeling data

6. Forecasted Data

A. 36 hour forecasted load

B. Unit maintenance / deration

C. Projected hourly loss schedule for next day

D. Line and equipment outages

7. Information sufficient to determine uses of the Network Resources for purposes other than serving Network Load.

ATTACHMENT H

Annual Network Transmission Service Rate

The Annual Network Transmission Service Rate shall be $18.12/kW-year. This rate shall be applied by multiplying $1.51/kW-month times the Customer's monthly Network Load. All quantities used in calculating the Network Customer's monthly Network Load shall be adjusted to the transmission system input level, i.e., shall include the transmission capacity associated with any applicable losses.

ATTACHMENT I

Index of Network Integration Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT J

Procedures for Addressing Parallel Flows

The North American Electric Reliability Council's (NERC) Transmission Loading Relief ("TLR") Procedures as may be amended from time to time.

ATTACHMENT K

Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop transmission plans;

(iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;

(v) The obligation of and methods for customers to submit data to the transmission provider;

(vi) The dispute resolution process;

(vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(viii) The relevant cost allocation procedures or principles.

ATTACHMENT L

Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) a summary of the procedure for determining the level of secured and unsecured credit;
(2) a list of the acceptable types of collateral/security;
(3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;
(4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;
(5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and
(6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

ATTACHMENT N

NON-FIRM ENERGY EXCHANGE TRANSMISSION SERVICE

Section 1. Scope and Application

1.1 This Attachment N applies solely to the provision of Non-Firm Energy Exchange Transmission Service by the Transmission Provider.

1.2 Any capitalized terms not defined specifically herein have the meaning ascribed to them in Part I of the Tariff.

1.3 To the extent any provision of the Tariff conflicts with this Attachment, this Attachment controls as to the provision of Non-Firm Energy Exchange Transmission Service.

Section 2. Definitions

2.1 "ENERGY EXCHANGE" is the "Energy Exchange" as that term is defined in the Energy Exchange Agreement.

2.2 "ENERGY EXCHANGE PARTICIPANT" is a "Participant" as that term is defined in the Energy Exchange Agreement.

2.3 ENERGY EXCHANGE MEMBER" is a "Member" as that term is defined in the Energy Exchange Agreement.

2.4 "ENERGY EXCHANGE SYSTEM" is the "Southeast EEM System" as that term is defined in the Energy Exchange Agreement.

2.5 "ENERGY EXCHANGE AGREEMENT" means the "Southeast Energy Exchange Market Agreement on file with Commission, as it may be amended from time to time.

2.6 "NON-FIRM ENERGY EXCHANGE TRANSMISSION SERVICE CUSTOMER" means a Transmission Customer taking Non-Firm Energy Exchange Transmission Service provided in accordance with this Attachment N of this Tariff pursuant to an executed Service Agreement for Non-Firm Energy Exchange Transmission Service, Attachment N-1 to this Tariff.

Section 3. Nature of Non-Firm Energy Exchange Transmission Service

3.1 Term. Non-Firm Energy Exchange Transmission Service will be available on an as-available basis for 15-minute Energy Exchanges.

3.2 Reservation Priority. Non-Firm Energy Exchange Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term Firm, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service and Secondary Point-to-Point Transmission Service. Non-Firm Energy Exchange Transmission Service will have the lowest reservation priority under the Tariff.

3.3 Scheduling and Reservation. Non-Firm Energy Exchange Transmission Service may only be reserved, scheduled, and tagged through the reservation, scheduling and e-tagging functions of the Energy Exchange System, rather than directly through the Transmission Provider's OASIS.

3.4 Availability. Non-Firm Energy Exchange Transmission Service will be made available for Energy Exchanges from Available Transfer Capability after procurement and scheduling deadlines have passed for the next operating hour, taking into account other higher priority confirmed reservations and the limitations of the Transmission System of the Transmission Provider. Additional Non-Firm Energy Exchange Transmission Service may be made available for Energy Exchanges considering capacity from unscheduled reservations.

3.5 Curtailment and Interruption. The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Energy Exchange Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System, or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Energy Exchange Transmission Service provided under the Tariff to accommodate (1) transmission service for Network Customers, (2) Transmission Service for Firm Point-to-Point Transmission Service; or (3) Transmission Service for Non-Firm Point-to-Point Transmission Service. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Energy Exchange Transmission Service shall be subordinate to all other types of transmission service provided under this Tariff.

3.6 Transmission Losses. Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Non-Firm Energy Exchange Transmission Service Customer is responsible for replacing losses associated with all transmission service as calculated by Transmission Provider and pursuant to Section 6.1.2 of this Attachment N.

3.7 Transmission Provider's Obligations.

3.7.1 Transmission Provider will provide the Energy Exchange System with all information required by Participating Transmission Providers, as that term is defined in Appendix B of the Energy Exchange Agreement.

3.7.2 Transmission Provider is not obligated to (i) plan, construct, or maintain its Transmission System for the benefit of any Energy Exchange Participant; (ii) provide Non-Firm Energy Exchange Transmission Service in a manner that is contrary to the terms of this Tariff, or contrary to Good Utility Practice, each as determined in the sole judgement of the Transmission Provider; (iii) provide Non-Firm Energy Exchange Transmission Service to any Transmission Customer who is not an Energy Exchange Participant; (iv) provide Non-Firm Energy Exchange Transmission Service following Transmission Provider's removal or withdrawal from the Energy Exchange Agreement; or (v) file its Tariff with FERC if the Tariff is not already required to be filed with FERC.

3.7.3 Transmission Provider's participation in the Energy Exchange System is voluntary and may be terminated at any time in accordance with the provisions of the Energy Exchange Agreement. It is therefore expressly understood, and a condition of service, that Non-Firm Energy Exchange Transmission Service Customer has no reliance interest in provision of Non-Firm Energy Exchange Transmission Service and has no right to rely on Transmission Provider continuing to provide Non-Firm Energy Exchange Transmission Service.

Section 4. Initiation of Non-Firm Energy Exchange Transmission Service

4.1 Non-Firm Energy Exchange Transmission Service is available only to Eligible Customers that:

4.1.1 Are in good financial standing with the Transmission Provider.

4.1.2 Have submitted a Completed Application for Non-Firm Energy Exchange Transmission Service to the Transmission Provider:

JEA
Sr. Director, Energy Operations
7720 Ramona Blvd
Jacksonville, FL 32221

Internet e-mail: TSERVE@JEA.COM

4.1.2.1 A Completed Application for Non-Firm Energy Exchange Transmission Service must include:

(i) The identity, address, telephone number and email address of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer;

(iii) A statement that the entity requesting service is, or will be upon commencement of service, an Energy Exchange Participant; and

(iv) The service commencement date of the requested Non-Firm Energy Exchange Transmission Service.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

4.1.3 Meet the creditworthiness criteria set forth in Part I, Section 11 of the Tariff.

4.1.4 Have executed a Service Agreement for Non-Firm Energy Exchange Transmission Service, Attachment N-1 of this Tariff.

Section 5. Limitations on Usage of Non-Firm Energy Exchange Transmission Service

5.1 Non-Firm Energy Exchange Transmission Service can be used solely for Energy Exchanges.

5.2 Non-Firm Energy Exchange Transmission Service may not be reassigned, redirected, or sold by the Non-Firm Energy Exchange Transmission Service Customer.

Section 6. Charges for Non-Firm Energy Exchange Transmission Service

6.1 The Non-Firm Energy Exchange Transmission Service Customer shall compensate the Transmission Provider for Non-Firm Energy Exchange Transmission Service as follows:

6.1.1 Rate for Non-Firm Energy Exchange Transmission Service: The rate for intra-hourly delivery shall be $0/MW of Reserved Capacity per 15-minute increment.

6.1.2 Charges for Real Power Losses: The charges for Real Power Losses shall be based on the applicable Real Power Loss Factor and the Real Power Loss Rate applied to deliveries of Non-Firm Energy Exchange Transmission Service.

6.1.2.1 The applicable Real Power Loss factor shall be the same as specified in Section 15.7 of the Tariff.

6.1.2.2 The Real Power Loss Rate shall be a rate equal to 100 percent of the

Transmission Provider's forecasted average incremental cost after serving all other obligations (including economy and opportunity transactions).

6.1.3 Ancillary Services: As described in Section 6.2.1, the charge for Schedule 1 or Schedule 2 Ancillary Services is $0.

6.2 Ancillary Services

6.2.1 Notwithstanding the requirements in Tariff Section 3, the Non-Firm Energy Exchange Transmission Service Customer shall pay for the following Ancillary Services at the rate established in Section 6.1.3 of Attachment N: (a) Scheduling, System Control and Dispatch, and (b) Reactive Supply and Voltage Control from Generation or Other Sources.

6.2.2 The Non-Firm Energy Exchange Transmission Service Customer serving load within the Transmission Provider's Control Area must demonstrate that it already has made alternate arrangements for the following Ancillary Services, or it must acquire them from the Transmission Provider, from a third party, or by self-supply: (i) Regulation and Frequency Response, (ii) Energy Imbalance. A Non-Firm Energy Exchange Transmission Service Customer delivering power from a generator in Transmission Provider's Control Area off system must demonstrate that it already has made alternate arrangements for the following Ancillary Services, or it must acquire them from the Transmission Provider, from a third party, or by self-supply: (i) Regulation and Frequency Response and (ii) Generator Imbalance.

ATTACHMENT N-1

Form of Service Agreement for Non-Firm Energy Exchange Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between _______________ (the "Transmission Provider"), and ____________ ("Non-Firm Energy Exchange Transmission Service Customer").

2.0 The Non-Firm Energy Exchange Transmission Service Customer has been determined by the Transmission Provider to be an Eligible Customer under Part I of the Tariff and an Energy Exchange Participant as defined in Attachment N of the Tariff, and as has submitted a Completed Application for Non-Firm Energy Exchange Transmission Service in accordance with Section 4 of Attachment N of the Tariff.

3.0 Service under this Service Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Non-Firm Energy Exchange Transmission Service Customer and subject to the scheduling procedures outlined in the Energy Exchange Agreement.

4.0 Non-Firm Energy Exchange Transmission Service Customer has all the rights and obligations of a Transmission Customer as set forth in Part I of the Tariff, except as specifically excluded in Attachment N to the Tariff.

5.0 The Non-Firm Energy Exchange Transmission Service Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for the Transmission Provider to provide the requested service.

6.0 The Transmission Provider agrees to provide, and the Non-Firm Energy Exchange Transmission Service Customer agrees to take and pay for Non-Firm Energy Exchange Transmission Service in accordance with the provisions of Attachment N of the Tariff and this Service Agreement.

7.0 The Non-Firm Energy Exchange Transmission Service Customer is responsible for replacing Real Power Losses associated with all Non-Firm Energy Exchange Transmission Service. Transmission Provider will supply, and the Non-Firm Energy Exchange Transmission Service Customer will pay for such Real Power Losses in accordance with Section 3.6 of Attachment N.

8.0 The Non-Firm Energy Exchange Transmission Service Customer or the Transmission Provider can cancel this Service Agreement at any time.

9.0 Transmission Provider's participation in the Energy Exchange System is voluntary and may be terminated at any time in accordance with the provisions of the Energy Exchange Agreement. It is therefore expressly understood, and a condition of service, that Non-Firm Energy Exchange Transmission Service Customer has no reliance interest in provision of Non-Firm Energy Exchange Transmission Service and has no right to rely on Transmission Provider continuing to provide Non-Firm Energy Exchange Transmission Service. Accordingly, if the Transmission Provider terminates its participation in the Energy Exchange System, the Transmission Provider can cancel this Service Agreement.

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____
____
____

Non-Firm Energy Exchange Transmission Service Customer:

____
____
____

11.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ______________________ ______________________ ______________
Name Title Date

Non-Firm Energy Exchange Transmission Service Customer:

By: ______________________ ______________________ ______________
Name Title Date

JEA OPEN ACCESS TRANSMISSION TARIFF

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I COMMON SERVICE PROVISIONS

1 Definitions

1.1 Affiliate: For the purposes of this Tariff, means The Energy Authority.

1.2 Ancillary Services: Those services that is necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Network Transmission Service Rate: The total annual rate for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider.

1.4 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Arbitration Commitment Letter: A letter requesting the submittal of disputed terms and conditions to arbitration as described in Sections 12.3 and 15.3.

1.6 Commission: The Federal Energy Regulatory Commission.

1.7 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.8 Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.9 Curtailment: A reduction in firm or nonfirm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.10 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.11 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.12 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct

Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer.

1.13 **Eligible Customer:** (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that would be prohibited by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider. (ii) Any retail customer taking unbundled Transmission Service pursuant to a state requirement that the Transmission Provider offer the transmission service or pursuant to a voluntary offer of such service by the Transmission Provider is an Eligible Customer under the Tariff.

1.14 **Facilities Study**: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications that will be required to provide the requested transmission service.

1.15 **Firm Point-To-Point Transmission Service**: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.16 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.17 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.18 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve-month basis.

1.19 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.20 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.21 **Native Load Customers**: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.22 **Network Customer**: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.23 **Network Integration Transmission Service**: The transmission service provided under Part III of the Tariff.

1.24 **Network Load**: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.25 **Network Operating Agreement**: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.26 **Network Operating Committee**: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.27 **Network Resource**: Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.28 **Network Upgrades**: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.29 **Non-Firm Point-To-Point Transmission Service**: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.30 Non-Firm Energy Exchange Transmission Service (NFEETS): The transmission service provided in accordance with Attachment N of the Tariff.

1.31~~0~~ Non-Firm Sale: An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.32~~1~~ Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.33~~2~~ Part I: Tariff Definitions and Common Service Provisions contained in Sections 1 through 12.

1.34~~3~~ Part II: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.35~~4~~ Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.36~~5~~ Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.37~~6~~ Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.38~~7~~ Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.39~~8~~ Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.40~~39~~ Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.41~~0~~ Pre-Confirmed Application: An application that commits the Transmission Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.42~~1~~ Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.43~~2~~ Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.44~~3~~ Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved

Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.45~~4~~ **Service Agreement**: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.46~~5~~ **Service Commencement Date**: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.47~~6~~ **Short-Term Firm Point-To-Point Transmission Service**: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.48~~7~~ **System Condition**: A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.49~~8~~ **System Impact Study:** An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.50~~49~~ **Third-Party Sale**: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.51~~0~~ Transmission Customer: Any Eligible Customer (or its Designated Agent) that executes a Service Agreement. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff. In addition, this term is used in Part I to include customers receiving Non-Firm Energy Exchange Transmission Service under Attachment N to the Tariff, unless specifically excluded in Attachment N.

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1.52~~1~~ Transmission Provider: The utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff. JEA is the Transmission Provider.

1.53~~2~~ Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.54~~3~~ Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.55~~4~~ Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority for Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of three years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to the longer of a competing request by any new Eligible Customer or three years and to pay the current just and reasonable rate for such service. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of three years or longer unless modified by the service agreement or violates other sections of the tariff. Service agreements subject to a right of first refusal entered into prior to the inclusion of the Transmission Provider's Attachment K, unless terminated, will become subject to the three year/one year requirement on the first rollover date after the inclusion of the Transmission Provider's Attachment K.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services:(i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve Supplemental, and (v) Generator Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the

Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 ,6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must by announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 9.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. § 38 of the Commission’s regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on its public OASIS website all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff.

5 Tax Exempt Bonds

5.1 Facilities Financed by Tax Exempt Bonds: Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if the provision of such Transmission Service would jeopardize the tax-exempt status of any bond(s) used to finance the Transmission Provider's facilities that would be used in providing such Transmission Service.

5.2 Opinions of Bond Counsel: Any request for service may require an opinion of JEA’s bond counsel. The Internal Revenue Service is currently considering proposed regulations dealing with the effect of providing transmission service on tax-exempt bonds issued to finance transmission facilities. Pending the issuance of the regulations, JEA’s bond counsel has advised that any new proposals for transmission service for more than 3 years, including extensions, should be reviewed by bond counsel to determine whether they would adversely affect the exclusion of interest on the bonds from gross income for Federal income tax purposes. Costs of obtaining any necessary letters or opinions from bond counsel will be borne by the Transmission Customer.

5.3 Termination of Service Agreements: The Transmission Provider may terminate any Service Agreement which it determines may jeopardize the tax-exempt status of its bonds. This includes Section 23 transactions.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO, Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds and be made by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall accrue and be payable at a rate equal to the interest rate paid by the Transmission Provider on its retail deposits. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment.

7.3 Customer Default and Termination of Service: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate procedures to terminate service. Prior to terminating service, the Transmission Provider shall provide written notice to the Transmission Customer of its intent to terminate service in 30 days. If the Transmission Customer does not request in writing to the Transmission Provider, within ten (10) calendar days of the Transmission Customer's receipt of notice, that the Transmission Provider initiate arbitration under the provisions of Section 12, the Transmission Provider shall terminate service on the date contained in its notice to the Customer. If the Transmission Customer requests in writing that the Transmission Provider initiate arbitration proceedings, the provisions of Sections 12.3 through 12.5 shall apply. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute according to the provisions of Section 12.2. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to terminate service.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below:

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expenses that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Changes to this Tariff by the Transmission Provider and Tariff Availability

9.1 Unilateral Right to Change: Notwithstanding any other provision in this Tariff or a Service Agreement, the Transmission Provider shall have the right unilaterally to make a change in rates, charges, classification of service, or any rule, regulation, or Service Agreement related thereto. The Transmission Provider will notify current Transmission Customers 30 days before a change becomes effective, unless the change is mutually agreeable to both parties.

9.2 Tariff Availability: Notwithstanding any other provision of this Tariff, the Transmission Provider may terminate this Tariff and all Service Agreements hereunder, effective immediately and without satisfying the requirements of any other provisions of this Tariff in its sole discretion. Further, nothing contained in this Tariff shall restrict the Transmission Provider's right unilaterally to withdraw the Tariff at any time. Except as otherwise provided in this Section 9.2, such withdrawal shall not affect existing Service Agreements for Firm Point-to-Point Transmission Service entered into under the Tariff. Upon such withdrawal of this Tariff, all Service Agreements for Non-Firm Point-to-Point Transmission Service shall terminate immediately, provided that the Transmission Provider shall complete Non-Firm Point-to-Point Transmission Service for specific scheduled Non-Firm Point-to-Point Transmission Service transactions prior to the date of termination of the Tariff (not to exceed service for three months). The Transmission Provider shall provide at least 30 days notice of its intent to terminate this Tariff to Transmission Customers that have entered into Service Agreements for Non-Firm Point-to-Point Transmission Service.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither the Transmission Provider nor the

Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 **Indemnification**: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider. For purposes of this Indemnification, the term “Transmission Provider” shall mean the JEA as a body politic and corporate and shall include its governing board, officers, employees, agents and assigns. This Indemnification shall survive the term of this Tariff.

11 **Creditworthiness**

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures

12.1 Applicability of Section 12: The provisions of Section 12 shall be the exclusive basis by which to resolve all disputes arising under this Tariff or any Service Agreement.

12.2 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving Transmission Service under this Tariff (including disputes involving the Transmission Provider's proposed termination of service under Section 7.3, disputes regarding changes to the rates, rate methodologies, or non-rate terms and conditions in this Tariff or any Service Agreement entered into under the Tariff, and disputes regarding the Transmission Provider's proposed charges for Direct Assignment Facilities, Network Upgrades, stranded costs, and redispatch costs) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute shall be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.3 **External Arbitration Procedures**: Disputes may be submitted to arbitration upon request from the Transmission Customer in the form of an Arbitration Commitment Letter and provision of the required letter of credit or other form of security. Any arbitration initiated under this Section 12 shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any Party to the arbitration (other than previous arbitration experience). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Regional Transmission Group rules.

12.4 **Arbitration Decisions**: Unless otherwise agreed, the arbitrator(s) shall render a decision to disputes under this Section 12 within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons, therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court governed by the rules of the State of Florida.

12.5 **Costs**: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. the cost of the arbitrator chosen by the Party to sit on the three-member panel and one half of the cost of the third arbitrator chosen; or

2. one half the cost of the single arbitrator jointly chosen by the Parties.

II POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority:

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests with the same duration and pre-confirmation status (Pre-Confirmed or not confirmed), priority will be given to an Eligible Customer's request that offers the highest price, followed by the date and time of the request.

(iii) If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer-term request or equal duration service with a higher price before losing its reservation priority. A longer-term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point- To-Point Transmission Service. When a longer duration request preempts multiple shorter duration requests, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, pre-confirmation status, price and time of response will be used to determine the order by which the multiple shorter duration requests will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after January 1, 1997, or agreements executed prior to the aforementioned date that require unbundling. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-to-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-to-Point Transmission Service pursuant to the Tariff. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Service Agreement shall contain the process governing any changes to the curtailment conditions.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirement as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 **Curtailment of Firm Transmission Service**: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such System and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers, and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed after secondary service and before Non-Firm Point-To-Point Transmission Service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the

Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. E.P.T. (Eastern Prevailing Time) of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. E.P.T. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is less than 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such Party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer-term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service.

Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a higher priority than Non-Firm Energy Exchange Transmission Service provided under Attachment N. Non-Firm Energy Exchange Transmission Service will have the lowest reservation priority under the Tariff.

~~Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.~~

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14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under agreements executed on or after January 1,1997 or agreements executed prior to the aforementioned date that require unbundling. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed twelve month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Except for Non-Firm Energy Exchange Transmission Service provided in accordance with Attachment N, s~~S~~chedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. E.P.T. of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. E.P.T. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is less than 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider’s Transmission System.

Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be curtailed or interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a ~~lower~~higher priority than any Non-Firm ~~Point-To-Point~~Energy Exchange Transmission Service provided under ~~the Tariff~~Attachment N. Non-Firm Energy Exchange Transmission Service will have the lowest reservation priority under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability: A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Event of Disputed Terms and Conditions: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all of the terms and conditions of the Point-To-Point Service Agreement, upon written request from the Transmission Customer, the Transmission Provider and Transmission Customer shall submit the disputed terms and conditions to the dispute resolution procedures of Section 12. The written request from the Transmission Customer shall be in the form of an Arbitration Commitment Letter which specifies the terms of the Service Agreement which are not acceptable to the Transmission Customer. Attached to the Arbitration Commitment Letter shall be an executed Point-To-Point Service Agreement complete in all regards. The Transmission Provider shall commence providing Transmission Service under the Point-To-Point Service Agreement for the requested Transmission Service subject to the Transmission Customer agreeing in the Arbitration Commitment Letter to (a) compensate the Transmission Provider as determined by the outcome of Section 12, (b) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3 or providing a letter of credit as required by the Transmission Provider. The procedures in this section may also be used for applications for Network Service.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment:

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its

Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-to-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider may elect at its option to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. The Transmission Provider may consider redispatch arranged by the Transmission Customer from a third-party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider may elect at its option offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service or secondary service for JEA's native load for a specified number of hours per year or during System Condition(s).

15.5 **Deferral of Service**: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 **Other Transmission Service Schedules**: Eligible Customers receiving transmission service under other agreements may continue to receive transmission service under those agreements until such time as those agreements may be modified.

15.7 **Real Power Losses**: Real Power Losses are associated with all transmission service. The Transmission Customer may elect to (1) supply the losses associated with all transmission service as calculated by the Transmission Provider or (2) have the Transmission Provider supply the losses (consistent with (1) above) at a rate equal to 100 percent of the Transmission Provider's forecasted average incremental cost after serving all other obligations (including economy and opportunity transactions). The applicable Real Power Loss factor is computed by May 1 of each year and is effective June 1 each year. The applicable Real Loss Factor and forecasted average incremental cost are posted on OASIS.

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has a pending Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to affect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service.

The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: Director, Bulk Power Systems, JEA, 7720 Ramona Blvd., Jacksonville, FL 32221 (Internet: TSERVE@JEA.COM) at least 60 days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by electronic mail to the Internet address in this Section. This method will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number, facsimile number, and Internet address of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A Statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, i.e., will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider’s planning process established in Attachment K.

The Transmission Provider shall treat this information in a manner consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit: A Completed Application for requests for Firm Point-To-Point Transmission Service for reservations greater than one year shall also include a deposit of one month's charge for Reserved Capacity. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request for Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the

Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service or deducted from the Transmission Customer's first month billing if no facilities modifications were necessary as part of this request. Applicable interest shall accrue and be payable at a rate equal to the interest rate paid by the Transmission Provider on its retail deposits and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practical to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached and provide the required letter of credit or other form of security pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If the Eligible Customer does not pay this non-refundable reservation fee within 15 days of notifying the Transmission Provider it intends to extend the commencement of service, the Eligible Customer's application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission

Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by transmitting the required information to the Transmission Provider by electronic mail at the Internet address in Section 17.1. This method will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A Statement indication whether the Transmission Customer commits to a Pre-Confirmed Request, i.e., will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon E.P.T. the day before service is to commence. Except for requests for Non-Firm Energy Exchange Transmission Service that are governed by Attachment N, r~~R~~equests for service received later than 2:00 p.m. E.P.T. prior to the day service is scheduled to commence will be accommodated if practicable.

18.4 Determination of Available Transfer Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects not to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these option. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints identified with specificity by transmission element or flowgate, and (2) additional Direct Assignment Facilities or Network Upgrades required providing the requested service. At the Transmission Provider's option, the System Impact Study may identify (1) redispatch options, (when requested by a Transmission Customer) including an estimate of the cost of redispatch, (2) conditional curtailment options (when requested by a Transmission Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached and provide the required letter of credit or other form of security pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service.

The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached pursuant to Section 15.3 and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities: The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service: If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding, and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its

Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists, and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest. However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and Non-Firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm

Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modifications on a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: Except for Non-Firm Energy Exchange Transmission Service provided in accordance with Attachment N, a~~A~~ Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall be at rates established by agreement with the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service

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for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but, in any event, notification must be provided prior to any provision of service to the Assignee. The Reseller remains responsible to the Transmission Provider for the obligations under its Service Agreement, regardless of any sale or reassignment. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned services commence and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales.

The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff consistent with the terms and conditions set forth for public utilities in FERC Order No. 888. However, the Transmission Provider's proposed stranded cost recovery shall be subject to the dispute resolution procedures of this Tariff**.**

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources and the Transmission Provider agrees to accept the redispatch to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement.

Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network

Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 **Network Integration Transmission Service**: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 **Secondary Service**: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network

Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factor is computed by May 1 of each year and is effective June 1 each year. The applicable Real Loss Factor is posted on OASIS.

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

29 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide

Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement in the form of Attachment F for service under Part III of the Tariff or submits an Arbitration Commitment Letter with a Service Agreement attached and provides the required letter of credit or other form of security pursuant to Section 15.3, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider in the form of Attachment G.

29.2 **Application Procedures**: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by electronic mail at the Internet address in Section 17.1. This method will provide a time-stamped record for establishing the service priority of the Application. A Completed

Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number, facsimile number, and Internet address of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10-year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), for each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions:
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations

- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource,

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)
- Operating restriction, if any
    - Any periods of restricted operations throughout the year
    - Maintenance schedules
    - Minimum loading level of unit
    - Normal operating level of unit

  - o Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations.

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (e) above
- 10-year projection of system expansions or upgrades

- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year.

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider’s planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network

Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

30 Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service

Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 **Designation of New Network Resources**: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 **Termination of Network Resources**: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS by the following deadlines: (i) for periods of a day or longer, no later than the firm pre-schedule deadline, and (ii) for un-designation of less than one day, by a time established by the Transmission Provider, which shall be no later than 20 minutes before the first hour for which un-designation applies, as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2 or statement incorporating previous information as unchanged; and

(v) Identification of any related transmission service request to be evaluated concomitantly with the request for temporary termination, such that the requests for un-designation and the request for these related transmission service requests must be approved or denied as a single request. The evaluating of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 **Operation of Network Resources**: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider’s Control Area such that the output of those facilities exceeds its designated Network Load plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer’s Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider’s Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource’s capacity, as specified in the Network Customer’s Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 **Network Customer Redispatch Obligation**: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 **Transmission Arrangements for Network Resources Not Physically Interconnected with The Transmission Provider**: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 **Limitation on Designation of Network Resources**: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 **Use of Interface Capacity by the Network Customer**: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load. .

30.9 **Network Customer Owned Transmission Facilities**: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration, the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities added by the Network Customer subsequent to July 17, 2007, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement. Calculation of and credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected with the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section

31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g., the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission

Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a

Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required providing the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached and provide the required letter of credit or other form of security pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

32.4 **Facilities Study Procedures**: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or submit an Arbitration Commitment Letter with a Service Agreement attached pursuant to Section 15.3 and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission

Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 **Transmission Constraints**: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that is reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 **Cost Responsibility for Relieving Transmission Constraints**: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 **Curtailments of Scheduled Deliveries**: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries; the Parties shall curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 **Allocation of Curtailments**: The Transmission Provider shall, on a non-discriminatory basis, curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would curtail the Transmission Provider's schedules under similar circumstances.

33.6 **Load Shedding**: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 **System Reliability**: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission

Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

: The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying the Network Customer's monthly Network Load times the monthly Network Service Rate specified in Attachment H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) adjusted for losses coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms and conditions set forth for public utilities in FERC Order No. 888.

35 Operating Arrangements

35.1 Operation under the Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability

Organization (ERO) as defined in 18 C.F.R. 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.

There is no charge for Scheduling, System Control and Dispatch Service at this time.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator. The charges for such service will be based on the rates set forth below.

Rate Treatment

The charge for Reactive Supply and Voltage Control from Generation Sources Service is no greater than:

Point-to-Point Service and Network Service

$0.78819 per kW-year,
$0.06568 per kW-month,
$0.01516 per kW-week,
$0.00303 per kW-day, provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or
$0.00019 per kW-hour, provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units

The rates above will be applied to the Network Customer's Monthly Network Load, or the capacity reserved for Point-to-Point Service Customers.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The amount of and charges for Regulation and Frequency Response Service are set forth below.

Rate Treatment

The charge for Regulation and Frequency Response Service is no greater than:

$2.51717 per kW-year
$0.20976 per kW-month,
$0.04841 per kW-week,

$0.00968 per kW-day; provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or

$0.00061 per kW-hour; provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units

For customers with load factors in the range of 87% to 100% within each hour, the rates above will be applied to the Network Customer's Monthly Network Load, or the capacity reserved for Point-to-Point Service Customers. The charges for customers with load factors less than 87% for each hour shall be based on the Transmission Customer's maximum deviation from the schedule within any hour. The rate shall be capped at $14.54 per kW-month.

Self-Supply of Service

A Transmission Customer that is located within the JEA's Control Area shall purchase Regulation and Frequency Response Service from the JEA unless it provides the service itself or purchases it from a third party through automatic generation control or dynamic scheduling.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under this Schedule for the same imbalance, but not both.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer’s scheduled transaction(s) will be settled financially, at the end of each month, at 1 and non-generation resources capable of providing this service that are 10 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost of 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The amount of and charges for Spinning Reserve Service are set forth below.

Rate Treatment

The charge for Operating Reserve Service - Spinning shall be the sum of the capacity and energy charges set forth below. These charges are not for providing backup service. These charges are to reimburse JEA for its costs incurred in meeting spinning reserve responsibilities.

A) Spinning Reservation Charge:

The charge for spinning reservation charge is no greater than:

$98.51872 per kW-year
$8.20989 per kW-month,
$1.89459 per kW-week,

$0.37892 per kW-day; provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or
$0.02368 per kW-hour; provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units:
The rates above will be applied to Network Customer's Monthly Network Load or the capacity reserved for Point-to-Point Service Customers, multiplied by the spinning reserve factor. The spinning reserve factor is 0.25for load within FRCC and 0.5 for load outside of FRCC.

Energy Use Charge:
These charges are applicable if the Transmission Customer's load is within the JEA's control area or the load is "metered into" JEA's control area.

A) Within 30 Minutes:

JEA will provide energy to the Transmission Customer for 30 minutes following a system contingency. The 30 minutes begin upon a schedule change due to the contingency. The energy delivered during these 30 minutes which exceeds the new scheduled amount is an energy imbalance. The charge for the energy imbalance will be $100/MWh or 110% of JEA's cost of providing such energy, whichever is higher.

B) After 30 Minutes:

If the Transmission Customer's schedule and load are not in balance after 30 minutes, then this is deemed an unauthorized use of capacity and energy. At its sole option, the JEA will either elect to separate the Transmission Customer's load from the JEA's system or it will provide the required energy and capacity. If JEA elects to supply the energy and capacity, the charges for such service will be equal to the rates stated for Imbalances Outside Deviation Band in Schedule 4, Energy Imbalance Service. For the purposes of this schedule, the capacity charge will be multiplied by the highest difference between scheduled and actual kW use during any 15-minute period until the schedule and the load are balanced.

Self-Supply of Service

A Transmission Customer that is located within the JEA's Control Area shall purchase Operating Reserve Service - Spinning from the JEA unless it provides comparable service from its own generators or from a third party. The provided Spinning Reserve Service must be available from on-line generation located within peninsular Florida in an amount equal to the reserve capability required of JEA. There must also be a firm transmission path between the generators providing the reserves and the Transmission Customer's loads for the period of transaction. The self-supply of service must be of such a nature that it relieves JEA of an appropriate amount of spinning reserve obligation. If it becomes apparent that self-supply of service is not comparable, the Transmission Customer must purchase this service from the JEA.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not necessarily available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The amount of and charges for Supplemental Reserve Service are set forth below.

Rate Treatment

The charge for Operating Reserve Service - Supplemental shall be the sum of the capacity and energy charges set forth below. These charges are not for providing backup service. These charges are to reimburse JEA for its costs incurred in meeting non-spinning reserve responsibilities.

A) Supplemental Reservation Charge:

The supplemental reservation charge is no greater than:

$63.30901 per kW-year
$5.27575 per kW-month,

$1.21748 per kW-week,

$0.24350 per kW-day; provided that the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service, or

$0.01522 per kW-hour; provided that the maximum charge in any day shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Billing Units:
The rates above will be applied to Network Customer's Monthly Network Load or the capacity reserved for Point-to-Point Service Customers, multiplied by the operating reserve factor. The operating reserve factor is 0.75for load within FRCC and 0.5 for load outside of FRCC.

B) Energy Use Charge: These charges are applicable if the Transmission Customer's load is within the JEA's control area, or the load is "metered into" JEA's control area. These Energy Use Charges shall be waived if the Transmission Customer purchases Operating Reserve Service - Spinning from the JEA (in which case the energy use charges in the Operating Reserve Service - Spinning schedule will apply).

1) Within 30 Minutes:

JEA will provide energy to the Transmission Customer for 30 minutes following a system contingency. The 30 minutes begin upon a schedule change due to the contingency. The energy delivered during these 30 minutes which exceeds the new scheduled amount is an energy imbalance. The charge for the energy imbalance will be $100/MWh or 110% of JEA's cost of providing such energy, whichever is higher.

2) After 30 Minutes:

If the Transmission Customer's schedule and load are not in balance after 30 minutes, then this is deemed an unauthorized use of capacity and energy. At its sole option, the JEA will either elect to separate the Transmission Customer's load from the JEA's system or it will provide the required energy and capacity. If JEA elects to supply the energy and capacity, the charges for such service will be equal to the rates stated for Imbalances Outside Deviation Band in Schedule 4, Energy Imbalance Service. For the purposes of this schedule, the capacity charge will be multiplied by the highest difference between scheduled and actual kW use during any 15-minute period until the schedule and the load are balanced.

Self-Supply of Service
A Transmission Customer that is located within the JEA's Control Area shall purchase Operating Reserve Service - Supplemental from the JEA unless it provides comparable service from its own generators or from a third party. The provided Supplemental Reserve Service must be available from on-line, unloaded generation, quick-start generation or interruptible load located within peninsular Florida in an amount equal to the reserve capability required of JEA. There must also be a firm transmission path between the generators providing the reserves and the Transmission Customer's loads for the period of transaction. The self-supply of service must be of such a nature that it relieves JEA of an appropriate amount of non-spinning reserve obligation. If it becomes apparent that self-supply of service is not comparable, the Transmission Customer must purchase this service from the JEA.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

Rate Treatment

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity up to the sum of the applicable charges set forth below:

Yearly delivery:	$15.96/kW of Reserved Capacity per year.
Monthly delivery:	$1.33/kW of Reserved Capacity per month.
Weekly delivery:	$0.31/kW of Reserved Capacity per week.
Daily delivery:	$0.06/kW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for daily delivery, shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Discounts:

Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Excess use:

In the event that the Transmission Customer exceeds its firm reserved capacity at any Point of Receipt and/or Point of Delivery (except as otherwise specified in Section 22 of this Tariff), the Transmission Customer shall pay 150% of the Schedule 7 charge for the delivery period (i.e., yearly, monthly, weekly, or daily) for which the Transmission Customer is reserving capacity for the maximum amount that the Transmission Customer exceeds its firm reserved capacity at any Point of Receipt and/or Point of Delivery. In the event that the non-firm transmission service provided to the Transmission Customer for secondary receipt and delivery points exceeds the capacity reservation under which such services are provided, the Transmission Customer shall pay 150% of the applicable Schedule 8 transmission charge for the maximum amount that the Transmission Customer exceeds its capacity reservation.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

Rate Treatment

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

Monthly delivery:	\$1.33/kW of Reserved Capacity per month.
Weekly delivery:	\$0.31/kW of Reserved Capacity per week.
Daily delivery:	\$0.06/kW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for daily delivery, shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed \$3.84/MWH.

The total demand charge in any day, pursuant to a reservation for hourly delivery, shall be no greater than the product of the maximum service reserved in any hour in that day and the maximum charge for daily service; and the maximum charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall be no greater than the product of the maximum service reserved in any day in that week and the maximum charge for weekly service.

Discounts:

Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Excess use:

In the event the Transmission Customer exceeds its reserved capacity at any Point of Receipt and/or Point of Delivery, the Transmission Customer shall pay 150% of the applicable transmission charge for the maximum amount that the Transmission Customer exceeds its capacity reservation.

SCHEDULE 9

Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission provider must offer this service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area Operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the same imbalance, but not both.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transactions(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent or (10 MW) of the schedule transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operator and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

ATTACHMENT A

Service Agreement

For Firm Point-To-Point

Transmission Service

1.0 This Service Agreement, dated as of ___________, 20__, is entered into, by and between JEA (formerly Jacksonville Electric Authority or the "Transmission Provider"), and ____, ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the JEA Open Access Transmission Tariff ("Tariff"). Said application is found in the "Application" for Firm Point-To-Point Transmission Service, which is attached hereto as Exhibit A, and by this reference is made a part hereof.

3.0 The Transmission Customer has provided to the Transmission Provider a Completed Application in accordance with the provisions of Section 17.1 of the Tariff and a deposit in the amount of $____________.

4.0 Service under this agreement shall commence on ____________ and shall terminate on ________________ based Transmission Customer's confirmation of Transaction ID # ______________ on JEA's Open Access Same-time Information System (OASIS) and the attached application.

5.0 The Transmission Provider agrees to provide, and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made in writing to the representative of the other Party as indicated below.

<u>JEA:</u>

Attention: Sr. Director, ~~Bulk Power Systems~~Energy Operations
JEA
7720 Ramona Blvd. West
Jacksonville, FL 32221

Internet e-mail: TSERVE@JEA.COM

Transmission Customer:

____

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

8.0 Such other terms and conditions that the Parties may agree on or may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

JEA:

By:______________________ Sr. Director ~~Bulk Power Systems~~Energy Operations
____

Name Title Date

By:______________________ ______________________ ______________

Name	Title	Date

Exhibit A

Application For Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by JEA including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivering Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 The maximum amount of capacity and energy to be transmitted is_________based on Transmission Customer's confirmation of Transaction ID _________ on JEA's OASIS. ___

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

7.0 Name(s) of any intervening systems providing transmission service:
____
____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charges are ____________based on Transmission Customer's confirmation of Transaction ID ________on JEA's OASIS.

8.2 System Impact and/or Facilities Study Charge(s):
____
____

8.3 Direct Assignment Facilities Charge:
____
____

8.4 Ancillary Services Charges are _____________ based on Transmission Customer's confirmation of Transaction ID __________ on JEA's OASIS.

ATTACHMENT B

**SERVICE AGREEMENT
FOR NON-FIRM POINT-TO-POINT
TRANSMISSION SERVICE**

1.0 This Service Agreement, dated ________, is entered into, by and between JEA ("Transmission Provider"), and ______________________________. ("Transmission Customer").

2.0 The Transmission Customer has been determined by JEA to be a Transmission Customer under Part II of the JEA Open Access Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.1 of the JEA Open Access Tariff.

3.0 Service under this agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 Attached are listed the valid representatives of the Transmission Customer. Each Transmission Customer is liable for business conducted by the valid representative until the JEA receives notification that the aforementioned representative is no longer valid.

5.0 The Transmission Customer agrees to supply information JEA deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Transmission Provider agrees to provide, and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the JEA Open Access Tariff and this Service Agreement. Non-Firm Point-To-Point Transmission Service is recallable by the JEA. The Transmission Customer must relinquish service within ten minutes when service is recalled by JEA.

7.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

JEA:

Attention: Sr. Director, ~~Bulk Power Systems~~Energy Operations
JEA

7720 Ramona Blvd.
Jacksonville, FL 32221

Internet e-mail: TSERVE@JEA.COM

Transmission Customer:

____
____
____

8.0 The JEA Open Access Tariff is, by this reference, incorporated herein and made a part hereof, as if set out in its entirety.

9.0 The Parties may agree to such other terms and conditions as may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

JEA:

By:______________________ Sr. Director, ~~Bulk Power Systems~~Energy Operations ___ ____________
Name Title Date

By:______________________ _________________ _________________
Name Title Date

ATTACHMENT C

Methodology to Access Available Transfer Capability

DEFINITIONS:

The JEA Open Access Tariff is, by this reference, incorporated herein and made a part hereof, as if set out in its entirety. The following definitions are based on the NERC "Available Transfer Capability Definitions and Determination document approved May 1996:

i) **Available Transfer Capability (ATC)** - The measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already committed uses.

ii) **Total Transfer Capability (TTC)** - The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post- contingency system conditions.

iii) **Transmission Reliability Margin (TRM)** - The amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

iv) **Capacity Benefit Margin (CBM)** - The amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

v) **Recallability** - The right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider's transmission service tariffs or contract provisions.

Methodology:

JEA will determine the Available Transmission Capability ("ATC") of its interfaces consistent with the "North American Electric Reliability Council" ("NERC") Guidelines contained in "Transfer Capability; A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems" issued May, 1995 and "Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market", issued May, 1996.

The "area-to-area" method will be used to determine the interface capabilities with other control areas. The Florida/Southern interface is a shared interface which is allocated among its interface owners pursuant to specific allocation agreements. Therefore, JEA will base its ATC calculations for the Florida/Southern interface on its allocated share of the TTC for the Florida/Southern interface.

Determination of ATC

The TTC will be determined using the most current load flow base cases with all facilities available, dispatching each area economically to meet their commitments and adjusted for projected system conditions (e.g., generating plants online, transmission facilities out of service, scheduled transactions). The criteria used will be consistent with JEA's latest FERC 715 filing.

The NRes will be determined by adding the CBM to the existing firm (nonrecallable) commitments (EC). i.e., NRes = CBM + EC.

The CBM will be determined by using reliability analyses (e.g., "Loss of Load Probability" ("LOLP") or other applicable analyses), and the appropriate amount of transmission interface capability will be reserved for CBM on a per interface basis.

The TRM will be determined by the difference between TTC, with all generating units available, and the amount of transfer capability with a critical generating unit to the particular interface being unavailable, plus the appropriate amount of "Operating Reserves" ("ORes") for that interface. TRM must recognize changing operating conditions that may occur in very short periods of time and cannot be definitely projected without the provision of a transfer capability margin. Therefore, a security margin may need to be a consideration as part of the TRM determination.

The ORes will be determined within Florida on an interface-by-interface basis by modeling each utility's allocated share of the statewide operating reserve requirements consistent with the latest FRCC Procedures for operating reserves or other methods which may be applicable in the future. ORes is only applicable to interfaces within Florida.

The "Nonrecallable Available Transfer Capability" ("NATC") will be determined by subtracting from the interface's TTC, its associated TRM and NRes. i.e., NATC = TTC - (TRM + NRes).

The “Recallable Available Transfer Capability” (“RATC”) will be determined by subtracting from the interface's TTC, the applicable portion of the TRM, NRes and "Recallable Reserved" ("RRes"). i.e., RATC = TTC - (aTRM + NRes + RRes), where

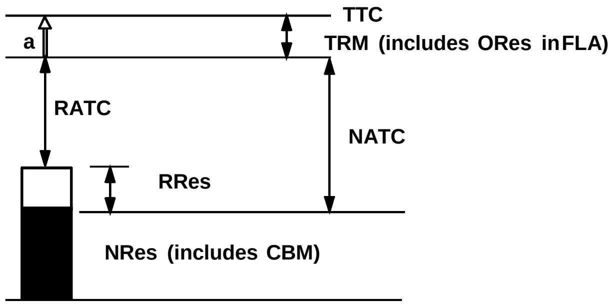

Figure 1.

0 $\leq$ a $\leq$ 1 determines the amount of TRM which can be made available to ATC on a recallable basis based on the system's reliability concerns.

Refer to Figure 1 for an illustration of the terms used above and assume for simplicity that the reserved amounts are equal to the actual scheduled amounts.

ATTACHMENT D

Methodology for Completing a System Impact Study

The JEA routinely conducts planning studies to determine the adequacy of its transmission lines to serve its native load. The criteria and processes used in these studies are documented in FERC Form No. 715, Annual Transmission Planning and Evaluation Report. This document is updated and filed each year by the JEA.

JEA will review each Application for transmission service. JEA will notify the customer within 30 days as to which condition exists:

1. **More information is needed to assess the Application**
   JEA will ask the Transmission Customer to provide additional information or data relating to the requested transaction. The Application is not complete until this information is received.

2. **Adequate transmission capacity exists**
   JEA will respond to the applicant that there is adequate transmission capacity. Documentation and information will be exchanged to develop a complete Service Agreement. This step may require more or less time depending on whether an opinion from JEA's Bond Counsel on the Private Use of Tax-Exempt Bonds is required. Failure of the Transmission Customer to execute and return the Service Agreement within fifteen (15) days after it is tendered by the JEA will be deemed a withdrawal and termination of the Application.

3. **JEA is unsure about the amount of transmission capacity that exists for a particular transaction**
   JEA will contact the Transmission Customer and determine if the Transmission Customer wishes JEA to perform a System Impact Study.

4. **Adequate transmission capacity does not exist**
   JEA will respond to the applicant with the amount of transmission capacity known to exist and determine if the prospective Transmission Customer wishes JEA to begin a Facilities Study.

The System Impact Study will evaluate the impact of the requested transaction on the JEA system. Consideration may be given to the impact on systems interconnected with JEA but JEA's findings will not be binding on any other system.

JEA will begin a System Impact Study by providing the Transmission Customer the following:

1. A list of assumptions;
2. The type of studies to be performed, e.g., load flows, stability, short circuit;
3. An estimate of the cost of the study;
4. An estimate of the cost of review by JEA's Bond Counsel, if appropriate;
5. An estimate of the schedule of time the JEA will need to perform the study.

EXHIBIT 1 TO ATTACHMENT D

FORM OF
SYSTEM IMPACT STUDY AGREEMENT
BETWEEN
JEA
AND
TRANSMISSION SERVICE CUSTOMER

THIS SYSTEM IMPACT STUDY AGREEMENT ("Study Agreement") between JEA ("Transmission Provider") and ____________________________________ ("Transmission Customer") is made and entered into this ______ day of ___________, _______.

WITNESSETH

WHEREAS, Transmission Customer, has requested that JEA provide it with Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service under JEA's Open Access Transmission Tariff;

WHEREAS, in order to conduct the System Impact Study ("Study") that will analyze the impact of the type of transmission service requested by the Transmission Customer on JEA's transmission system, the Transmission Customer has provided JEA certain information as may be required to perform the Study; and

NOW, THEREFORE, in consideration of the foregoing premises and of the benefits to be obtained from the covenants herein, JEA and the Transmission Customer agree as follows:

1. This Study Agreement shall not be used by either Party for any purpose other than enforcement of the terms of the Study Agreement.

2. JEA and the Transmission Customer agree that any data provided pursuant to this Study Agreement and designated confidential by the providing Party will be kept confidential, and that neither Party will disclose such designated data; provided, however, that either Party may disclose such confidential designated data in any manner consistent with a written consent to such disclosure obtained from the providing Party prior to such disclosure.

3. In the event that one Party is required by a state or federal regulatory authority or court to disclose data previously provided under the Study by the other Party under a confidentiality designation, the Party subject to such requirement shall exercise reasonable best efforts to obtain a confidentiality agreement or appropriate protective order with such state or federal regulatory authority or court, as applicable, to preserve the confidentiality of the designated data to be

disclosed. Further, upon receipt of such a demand for the data, the receiving Party shall immediately notify the other Party.

4. JEA and the Transmission Customer agree that the purpose of the Study will be to identify any impacts which the Transmission Service requested by the Transmission Customer could reasonably be anticipated to have on the operation and reliability of JEA's Transmission System. The System Impact Study shall identify any system constraints, additional Direct Assignment Facilities or Network Upgrades required to provide the requested Transmission Service.

5. Appendix No. 1 of this Study Agreement sets out the informational data to be provided by the Transmission Customer upon which the Study will be based. Part I of Appendix No. 1 sets out the principal information required to be provided by the Transmission Customer for the Study in response to a Point-To-Point Transmission Service request; Part II of Appendix No. 1 sets out the principal information required to be provided by the Transmission Customer in response to a Network Integration Transmission Service request.

6. Appendix No. 2 of this Study Agreement sets out the criteria and a description of the principal procedures to be employed by JEA in performing the Study.

7. JEA shall provide the Study results to the Transmission Customer no later than sixty (60) days following the latter of 1) the execution of this Study Agreement, or 2) the Transmission Customer having provided JEA the data specified in Appendix No. 1 to this Study. To the extent JEA completes the Study in a shorter period of time; JEA will provide the Transmission Customer with the results of this Study as soon as it is completed.

8. After JEA presents the Study results to the Transmission Customer: 1) if the Study indicates that JEA can provide all the requested service from existing capacity, JEA will provide the Transmission Customer an executable Service Agreement, or 2) if the Study indicates that JEA will be required to construct and/or install incremental facilities, and if the Transmission Customer so requests, JEA will provide the Transmission Customer within thirty (30) days a Facilities Study Agreement, the form of which is incorporated as Exhibit 2 to this Attachment D.

9. The actual cost of the Study is estimated by JEA to be_____________ ____________dollars ($). The Transmission Customer will be responsible for such cost. The Transmission Customer will deposit with JEA dollars ($) within fifteen (15) days of the date of execution of this Study Agreement. The actual cost of the Study, less the dollars ($)

deposit, will be billed to the Transmission Customer, subject to JEA providing the Transmission Customer with the results of the Study. Payment by the Transmission Customer to JEA of such cost will be due no later than twenty (20) days from the date of mailing (as determined by postmark) of the bill. JEA will provide the Transmission Customer with documentation of the costs at the time JEA bills the Transmission Customer for the Study.

10. In the event JEA is unable to complete the Study within the time period specified above, JEA shall notify the Transmission Customer and shall provide an estimate completion date along with an explanation of the reasons why additional time is required to complete the Study.

IN WITNESS WHEREOF, the Parties hereto have caused this Study Agreement to be executed by their duly authorized officers effective as of the date first written above.

JEA

Date:_____________________ **By:______________________________**

Title:______________________________

TRANSMISSION CUSTOMER

Date:_____________________ **By:______________________________**

Title:______________________________

APPENDIX NO. 1
TO
EXHIBIT 1
TO
ATTACHMENT D
INFORMATION TO BE PROVIDED BY TRANSMISSION CUSTOMER

PART I

To be provided by the Transmission Customer when a System Impact Study is performed in response to a Long-Term Firm Point-To-point Transmission Service request.

Informational Data:

The informational data provided pursuant to Section 18.2 of JEA's Open Access Transmission Tariff and any other pertinent information necessary to properly analyze the Transmission Customer's request for Long-Term Firm Point-To-Point Transmission Service shall be specifically delineated in this Appendix and agreed to between JEA and the Transmission Customer.

PART II

To be provided by Transmission Customer when a System Impact Study is performed in response to a Network Integration Transmission Service request.

Informational Data:

The informational data provided pursuant to Section 29.2 of JEA's Open Access Transmission Tariff and any other pertinent information necessary to properly analyze the Transmission Customer's request for Network Integration Transmission Service shall be specifically delineated in this Appendix and agreed to between JEA and the Transmission Customer. More specifically, the following are the typical types of information that will be needed to be provided to JEA by the Transmission Customer in paper summary and in electronic format, as applicable.

LOAD: Coincident (with the Transmission Customer's load) and non-coincident load projection for the term of the transmission service for each delivery point along with the corresponding power factor.

GENERATION: Capacity plan along with the capability of each generating unit (i.e., real and reactive power) and heat rate curves and/or sufficient data to dispatch the Transmission Customer's resources.

On Peak /Off Peak cases will be analyzed.

INTERCHANGE SCHEDULE: Long-term firm transactions, specifying receipt and delivery points, duration of transactions, and underlying agreements.

STUDY HORIZON: Expected system conditions for planning horizon will be represented in the Study. It may be necessary to represent other years beyond the planning horizon depending on the results of the Study.

MODEL: Latest transmission model for utility and/or member systems, including, but not limited to, compensating devices, line impedances, transformers, and other pertinent data. Also, transient stability and short circuit data for generators.

**APPENDIX NO. 2
TO
EXHIBIT 1
TO
ATTACHMENT D
CRITERIA AND STUDY PROCEDURE**

CRITERIA:

Criteria will be in conformance with criteria in JEA's latest Form 715 filing.

STUDY PROCEDURE:

Task 1.0: Case Development

The FRCC data bank for years _______________ will be used as a basis with the necessary detailed data added for the Study.

Task 2.0: Analyses

Load flow analyses for the JEA system will be performed. Thermal and reactive limitations will be identified.

Transient Stability Analysis will be performed as required to determine reliability impact of request on the JEA system. Cases will be used with worst but probable dispatches.

Short Circuit Analysis will be performed as required to determine reliability impact on the JEA system.

In addition, JEA may perform other special studies as may be necessary.

Task 3.0: Documentation of Results

Document in report form the assumptions, methodology, and results of the study.

APPENDIX NO. 2
TO
ATTACHMENT D
FORM OF
FACILITIES STUDY AGREEMENT
BETWEEN
JEA
AND
TRANSMISSION SERVICE CUSTOMER

THIS FACILITIES STUDY AGREEMENT ("Facilities Agreement") between JEA ("Transmission Provider") and ____ ("Transmission Customer") is made and entered into this ____ day of ___________ , ______ .

WITNESSETH

WHEREAS, Transmission Customer has requested that JEA provide it with Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service under JEA's Open Access Transmission Tariff;

WHEREAS, in order to provide the requested transmission service JEA has conducted a System Impact Study as requested by the Transmission Customer, and the results of such Study have determined that JEA will be required to construct and/or install incremental facilities; and

NOW, THEREFORE, in consideration of the foregoing premises and of the benefits to be obtained from the covenants herein, JEA and the Transmission Customer agree as follows:

1. This Facilities Agreement shall not be used by either Party for any purpose other than enforcement of the terms of the Facilities Agreements.
2. JEA and the Transmission Customer agree that any data provided pursuant to this Facilities Agreement and designated confidential by the providing Party will be kept confidential, and that neither Party will disclose such designated data; provided, however, that either Party may disclose such confidential designated data in any manner consistent with a written consent to such disclosure obtained from the providing Party prior to such disclosure.
3. In the event that one Party is required by a state or federal regulatory authority or court to disclose data previously provided under the Facilities Agreement by the other Party under a confidentiality designation, the Party subject to such requirement shall exercise reasonable best efforts to obtain a confidentiality agreement or appropriate protective order with such state or federal regulatory authority or court, as applicable, to preserve the confidentiality of the designated data to be disclosed.

Further, upon receipt of such a demand for the data, the receiving Party shall immediately notify the other Party.

4. JEA and the Transmission Customer agree that the purpose of the Facilities Study is to identify what specific incremental facilities, including enhancements, modifications, additions or deletions that will be required in order for JEA to provide the requested Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service and the associated costs thereof.

5. JEA shall provide the Facilities Study results no later than sixty (60) days following the latter of 1) execution of this Facilities Agreement, or 2) the Transmission Customer having provided JEA any information requested by JEA in order to complete the Facilities Study. To the extent JEA completes the Facilities Study in a shorter period of time, JEA will provide the Transmission Customer with the results of this Facilities Study as soon as completed. To the extent JEA is unable to complete the Facilities Study within the time frame specified above, JEA will notify the Transmission Customer and provide an estimate of the time needed to complete the Facilities Study.

6. The results of the Facilities Study will include a good faith estimate of 1) the cost of the Direct Assignment Facilities to be charged to the Transmission Customer, 2) JEA's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and 3) the time required to complete such construction and initiate the requested Transmission Service.

7. The actual cost of the Facilities Study is estimated by JEA to be ________ dollars ($). The Transmission Customer will be responsible for such cost. The Transmission Customer will deposit with JEA dollars ($) within fifteen (15) days of the date of execution of this Facilities Agreement. The actual cost of the Facilities Study, less the dollars ($) deposit, will be billed to the Transmission Customer, subject to JEA providing the Transmission Customer with copies of the results of the Facilities Study. Payment by the Transmission Customer to JEA of such cost will be due no later than twenty (20) days from the date of mailing (as determined by postmark) of the Facilities Study bill. JEA will provide the Transmission Customer with documentation of the costs at the time JEA bills the Transmission Customer for the Facilities Study.

8. Upon completion of the Facilities Study and at the request of the Transmission Customer, JEA shall provide the customer an executable Service Agreement. The Transmission Customer shall have thirty (30) days to execute the Service Agreement.

9. At the time the Transmission Customer executes the Service Agreement, and prior to the commencement of any construction and other activities attendant thereto, the Transmission Customer shall provide JEA with an unconditional and irrevocable letter of credit or other form of security acceptable to JEA equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the

Uniform Commercial Code that protects JEA against the risk of non-payment for such costs.

IN WITNESS WHEREOF, the Parties hereto have caused this Facilities Agreement to be executed by their duly authorized officers effective as of the date first written above.

JEA

Date: ______________

By: ____________________________________

Title: ____________________________________

TRANSMISSION CUSTOMER

Date: _______________

By: ____________________________________

Title: ____________________________________

ATTACHMENT E

Index of Point-To-Point Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT F

Form of Service Agreement for Network Integration Transmission Service

This Service Agreement, dated as of ___________________________, is entered into by and between JEA ("Transmission Provider") and __________________________________ ("Network Customer").

1.0 The Network Customer is ______________________________________ and has been determined by JEA to have submitted a complete Application for Network Integration Transmission Service under Part III of the Tariff.

2.0 Service under this Service Agreement shall commence on the later of: (1) 0001 hours on _________________, 19 ____, or (2) the date on which construction of transmission facilities and/or Network Upgrades identified by the System Impact Study are completed.

3.0 JEA agrees to provide, and the Network Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of the Tariff and this Service Agreement. Any notice or request made to or by any Party regarding this Service Agreement shall be made in writing and shall be delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

JEA:

Attention: Sr. Director, ~~Bulk Power Systems~~Energy Operations
JEA
7720 Ramona Blvd.
Jacksonville, FL 32221

NETWORK CUSTOMER:

____
____
____
____

5.0 The amount of credit, if any, for a Network Customer's owned transmission facilities that meet the requirements of Section 30.9 of the Tariff is as follows:

____
____
____

6.0 Such other terms and conditions that the Parties may agree on or may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized representatives as of the date first above written.

JEA

By:______________________________________

NETWORK CUSTOMER

By:______________________________________

SPECIFICATIONS FOR NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 Term of Network Integration Transmission Service:

Start Date:

Termination Date:

2.0 Description of capacity and/or energy to be transmitted by Transmission Provider across the Transmission Provider's Transmission System (including electric control area in which the transaction originates).

3.0 Network Resources

(1) Transmission Customer Generation Owned:

Resource	Capacity	Capacity Designated

(2) Transmission Customer Generation Purchased:

Source	Capacity

Total Network Resources: (1)+(2) = ___________

4.0 Network Load

(1) Transmission Customer Network Load:

Network Load	Transmission Voltage Level

(2) Member Systems Loads Designated as Network Load:

Member System Load	Transmission Voltage Level

Total Network Load (Estimated): (1)+(2) = ________

Issued By: Garry Baker
Revised: 0~~7~~1/~~1~~24~~7~~/20~~07~~23 Effective Date: 01/1/1997

ATTACHMENT G

Form of a Network Operating Agreement

THIS NETWORK OPERATING AGREEMENT ("Operating Agreement") between JEA ("Transmission Provider") and the Network Customer ("Network Customer") is made and entered into this ______ day of ________, 19___.

WITNESSETH

WHEREAS, the Network Customer has requested and JEA has agreed to provide Network Integration Transmission Service under Part III of the Tariff; and

WHEREAS JEA and the Network Customer have agreed to enter into this Operating Agreement to set forth certain operating understandings in order for JEA to provide the requested network service.

NOW, THEREFORE, in consideration of the foregoing premises and of the benefits to be obtained from the covenants herein, JEA and the Network Customer agree as follows:

ARTICLE 1 – Definitions

Along with the definitions set forth below, the definitions in the Tariff are hereby incorporated into this Operating Agreement.

1.1 **Data Acquisition Equipment:** Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of the Tariff.

1.2 **Data Link:** The direct communications link between the Network Customer's energy control center and JEA's control center that will enable JEA's control center to receive real time telemetry and data from the Customer's energy control center and the Customer's energy control center to receive real time telemetry and data from JEA's control center.

1.3 **Metering Equipment:** High accuracy, solid state kW, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, meter recording devices (e.g., Solid State Data Receivers), telephone circuits, signal or pulse dividers, transducers, pulse accumulators, and any other metering equipment necessary to implement the provisions of the Tariff.

1.4 **Member System:** An Eligible Customer operating as a part of a lawful combination, partnership, association or joint action agency composed exclusively of Eligible Customers.

1.5 **Power Factor Requirements (PFR) On-Peak Hours:** The PFR On-Peak hours are the hours during the PFR On Peak Period; the PFR On Peak Period is (1) from December 1 through March 31 during the hours from 6 a.m. to 10 a.m., and 6 p.m. to 10 p.m. and; (2) from April 1 through November 30 during the hours from 10 a.m. to 10 p.m., unless and until otherwise changed by mutual agreement of the Operating Committee.

1.6 **Power Factor Requirements (PFR) Off-Peak Hours:** All other hours besides the PFR "On-Peak hours".

1.7 **Protective Equipment:** Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Tariff.

ARTICLE 2 - Term of Service

2.1 The term of this Operating Agreement between JEA and the Network Customer shall be concurrent with the Service Agreement.

ARTICLE 3 - Network Customer Control Area

3.1 **Network Customer's Control Area:** The Network Customer shall include its designated Network Resources and Network Load and operate as a single independent Control Area ("Network Customer Control Area") and shall plan, construct, operate and maintain the Network Customer's Control Area in accordance with Good Utility Practice, which shall include, but not be limited to, all applicable guidelines of the North American Electrical Reliability Council, the Southeastern Electric Reliability Council, and the Florida Regional Reliability Council, or their successor; provided, however, that JEA will not require adherence to any such applicable guidelines to the extent that JEA does not adhere to such applicable guideline.

3.1.1 The Network Customer may contract with another entity to provide Control Area services to the Network Customer, in which event such entity shall be required to meet all of the control area requirements set forth in this Article.

3.1.2 If the Network Customer desires to merge the Network Customer's Control Area with another entity's Control Area such that a common control scheme is applied to the Network Customer's and the other entity's generation and load (i.e., a pooling arrangement) then the Network Customer must submit a new Application for service under the Tariff.

3.1.3 The Network Customer shall provide and operate automatic generation control equipment (or contract with a third party to perform these services) in accordance with Good Utility Practice so as to avoid burdening demands upon JEA's system or the systems of others.

3.2 **Control Area Operations:** JEA and the Network Customer shall operate and maintain their respective Control Areas in a manner that will allow JEA to safely and reliably operate the Transmission System in accordance with the Tariff and with Good Utility Practice, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of the Tariff, JEA shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Transmission System.

3.3 **Control Area Equipment:** The Network Customer shall be responsible for the purchase, installation, upgrading, operation, maintenance and replacement of all Data Acquisition Equipment, Metering Equipment, Protection Equipment, and any other associated equipment and software, which may be required by either Party for the Network Customer to operate a Control Area in accordance with Good Utility Practice. JEA shall have the right to review and approve such equipment and software as may be required to ensure conformance with Good Utility Practices, prior to its installation.

3.4 **Control Area Data:** The Network Customer shall incorporate the information obtained from the Network Customer's Metering Equipment and Data Acquisition Equipment into the Network Customer's energy control center as the Parties determine to be necessary to incorporate the Member Systems into a single Control Area operating within the JEA Transmission System consistent with the terms and conditions of the Tariff.

3.5 **Regulation:** The Network Customer shall be responsible for operating in a manner to provide for its Network Load at all times, and to hold deviations from frequency-biased net interchange schedules to a minimum in accordance with the North American Electric Reliability Council, Southeastern Electric Reliability Council, and the Florida Regional Reliability Council, or their successor requirements.

3.6 **Data Link Operations:** The selection of real time telemetry and data to be received by JEA and the Network Customer shall be as necessary for reliability, security, economics, and/or monitor-ing of real-time condition that affect JEA's Transmission System. This telemetry shall include, but is not limited to, loads, line flows, voltages, generator output, and breaker status at any of the Network Customer's transmission and generation facilities (See Exhibit 2 to this Operating Agreement). To the extent that JEA or the Network Customer requires data that are not available from existing equipment, the Network Customer shall, at its own expense, install any Metering Equipment, Data Acquisition Equipment, or other equipment and software necessary for the telemetry to be received by JEA or the Network Customer via the Data Link. JEA shall have the right to inspect equipment and software associated with the Data Link in order to assure conformance Good Utility Practice.

3.7 **Computer Modifications:** Each Party shall be responsible for implementing any computer modifications or changes required to its own computer system(s) as necessary to implement the provisions of the Tariff.

3.8 **Metering:** The Network Load shall be metered on an hourly integrated basis in accordance with JEA's standards or practices for similarly determining JEA's load. The actual hourly Network Load during each calendar month shall be provided to JEA by the Network Customer by the seventh day of the following calendar month.

3.9 **Voltage Support:** The Network Customer will use reasonable best efforts to have in the shortest practicable time, but under no circumstances greater than one (1) year after service begins under the Tariff, sufficient reactive compensation and control to meet the power factor requirements specified below (such range to be adhered to except for momentary deviations or at JEA's written consent) at each interconnection or point of delivery with each Member System. If the Network Customer does not provide the necessary reactive compensation and control to comply with the objectives described in this Section, JEA shall have the unilateral right to install such equipment to meet these standards at the Network Customer's expense.

POWER FACTOR REQUIREMENTS	
On-Peak Hours	**.95 (lagging) to 0.95 (leading)**
Off-Peak Hours	**.90 (lagging) to 1.00 (unity)**

3.10 **Real Time System Data Requirements:** The Network Customer shall provide JEA via the Data Link, at least once every one minute (this time interval is subject to modification as agreed to by the Network Operating Committee), loads, line flows, voltages, generator outputs, breaker status, etc. as necessary for JEA to provide service under the Tariff and ensuring the security and reliability of the JEA Transmission System.

3.11 **Disturbances:** Each Party shall, insofar as practicable, protect, operate and maintain its system and facilities so as to avoid or minimize the likelihood of disturbances which might cause impairment of or jeopardy to service to the customers of the other Party, or to other interconnected systems.

3.12 **Notification:** The Network Customer shall notify and coordinate with JEA prior to the commencement of any work by the Network Customer, Member System, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Network

Customer's or JEA's Control Area, the Data Link, or the reliability of the JEA Transmission System.

3.13 **Maintenance of Equipment:** The Network Customer shall, on a regular basis or at JEA's request, and at the Network Customer's own expense, test, calibrate, verify and validate the Metering Equipment, Data Acquisition Equipment, and other equipment or software used to determine Network Load. JEA shall have the right to inspect such tests, calibrations, verifications and validations of the Metering Equipment, Data Acquisition Equipment, and other equipment or software used to determine the Network Load. Upon JEA's request, the Network Customer will provide JEA a copy of the installation, test and calibration records of the Metering Equipment, Data Acquisition Equipment, and other equipment or software. JEA shall, at the Network Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any Metering Equipment, Data Acquisition Equipment, and other equipment or software used to determine the Network Load.

3.14 **Control Area Costs:** The Network Customer shall be responsible for all costs to establish, operate and maintain the Network Customer's Control Area, including, but not limited to, engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, relocation of equipment, or software.

ARTICLE 4 - Network Operating Committee

4.1 **Network Operating Committee:** Each Party shall in writing appoint a member(s) and an alternate(s) to a Network Operating Committee and to notify the other Party of such appointment(s). Such appointments may be changed at any time by similar written notice. The Network Operating Committee shall meet as necessary and review the duties set forth herein. The Network Operating Committee shall hold meetings at the request of either Party, at a time and place agreed upon by the members of the Network Operating Committee. The Network Operating Committee shall meet once each year to discuss the information provided pursuant to Article V and the information exchanged pursuant to this Section. Each member and alternate shall be a responsible person working with the day-to-day operations of each respective power system. The Network Operating Committee shall represent the Parties in all opera-tonal matters that may be delegated to it by mutual agreement of the Parties hereto. The duties of the Network Operating

Committee shall include those specifically referred to elsewhere in the Tariff, including but not limited to, the following:

(1) The coordination of operation and maintenance schedules;

(2) The exchange of information regarding each party's long range transmission plans;

(3) Establishment of maintenance control and operating procedures consistent with the provisions of the Tariff;

(4) Establishment of data requirements necessary for JEA to provide Network Integration Service as delineated in the Tariff;

(5) Review of Metering Equipment, Data Acquisition Equip-mint, Protection Equipment, and any other equipment or software requirements, standards and procedures; and

(6) Such other duties as may be conferred upon it by mutual agreement of the Parties hereto.

4.2 **Network Operating Committee Agreements:** Each Party shall cooperate in providing to the Network Operating Committee all information required in the performance of the Network Operating Committee's duties. All decisions and agreements, if any, made by the Network Operating Committee shall be evidenced in writing and shall be in accordance with the Tariff.

ARTICLE 5 - Technical Data

5.1 **Annual Load Forecast:** The Network Customer shall provide JEA by November 1st of each year the Network Customer's best forecast of the following calendar year's (i) monthly coincident peak Network Load of the Member Systems expressed in kW along with the power factor of each of the Member Systems at such time and, (ii) each individual Member System's monthly non-coincident peak loads expressed in kW along with the power factor of each of the Member Systems at such time. Such forecast shall be made using prudent forecasting techniques available and generally deemed acceptable in the electric utility industry.

5.2 **Annual Network Resource Availability Forecast:** The Network Customer shall provide to JEA by November 1st of each year the Network Customer's best forecast of the following calendar year's planned Network Resource availability forecast (e.g., all planned resource outages, including off-line and on-line dates). Such forecast shall be made using prudent forecasting techniques available and generally deemed acceptable in the electric utility industry. The Network Customer shall inform JEA, in a timely manner, of any changes to Network Customer's planned Network Resource Availability Forecast.

5.3 **Annual Operating Conflicts:** In the event that JEA determines that the annual Network Resource Availability Forecast cannot be accommodated due to a transmission constraint on the JEA Transmission System, and such constraint may jeopardize the security of the JEA Transmission System or adversely affect the economic operation of either JEA or the Network Customer, to the extent possible, the Network Operating Committee will coordinate the annual Operating Network Resource Availability Forecast of both Parties to mitigate the transmission constraint.

5.4 **Daily Operating Forecast:** The Network Customer shall provide JEA, at least 36 hours in advance of every calendar day, the Network Customer's best hourly forecast for the calendar day of the (i) maximum non-coincident flow (both import and export) at each of the JEA interfaces with the Network Customer and/or the Member Systems, (ii) first contingency maximum non-coincident flow (both import and export) at each of the JEA interfaces with each Member System, (iii) any planned transmission or generation outage(s) on the system of any of the Member Systems or on a system other than that of JEA where a Network Resource is located, (iv) the individual coincident

Member Systems loads along with the commitment/dispatch of the Network Resources at peak operating period(s) (the peak operating period(s) will be determined by JEA operating personnel and may be changed from time-to-time as necessary), and (v) and any other information that JEA's operating personnel reasonably deem appropriate to safely and reliability operate the JEA Transmission System. The Network Customer shall keep JEA informed in a timely manner, of any changes to its current Daily Operating Forecast.

5.5 **Daily Operating Conflicts:** In the event that JEA determines that the Daily Operating Forecast cannot be accommodated due to a transmission constraint on the JEA Transmission System, and such constraint may jeopardize the security and reliability of the JEA Transmission System or adversely affect the economic operation of either JEA or the Network Customer, the load curtailment provisions of the Tariff will be implemented in accordance with Exhibit 1 of this Operating Agreement.

5.6 **Network Planning Information:** In order for JEA to plan, on an ongoing basis, to meet the Network Customer's firm-long term requirements for Network Integration Transmission Service the Network Customer shall provide JEA with the information set forth in Sections 5.7 - 5.10. This type of information is consistent with JEA's information requirements for planning to serve JEA's Native Load Network Customers and is consistent with JEA's ten (10) year planning process.

5.7 **Annual Planning Network Load Forecast:** The Network Customer shall provide JEA by November 1st of each year the Network Customer's best forecast of the following ten (10) calendar years' (i) monthly coincident Network Load and non-coincident Member Systems' Network Loads expressed in kW and, (ii) each individual Member System's monthly coincident and non-coincident loads expressed in kW along with the respective power factor. Such forecast shall be made using prudent forecasting techniques available and generally deemed acceptable in the electric utility industry.

5.8 **Annual Planning Network Resource Forecast:** The Network Customer shall provide to JEA by November 1st of each year (i) the Network Customer's best forecast of the next ten (10) years' planned Network Resources and all pertinent information regarding such Network Resources, (ii) a copy of the Network Customer's most current firm purchased power commitments (including the underlying agreement for purchased power) for the next ten (10) years on a unit specific basis for any Network Resource(s) which is a firm unit specific purchased power resource, and (iii) for purchased power commitments that are non-unit specific, any information necessary for JEA (including the underlying agreement for purchased power) to model how the purchased power commitment would be dispatched by the Network Customer to meet the Network Load; provided, however, that the information provided by the Network Customer pursuant to this Section 5.8 shall not be deemed a substitute for written notice required for designating new Network Resources.

5.9 **Annual Planning Network Transmission Facilities:** The Network Customer shall provide JEA any planned internal transmission facilities on the Network Customer and/or each Member Systems' system (lines, transformers, reactive equipment, etc.) for each of the subsequent ten (10) calendar years.

5.10 **Technical Data Format:** The Network Customer shall provide JEA the best available data associated with Network Resources and transmission facilities, for modeling purposes in an electronic format specified by JEA. The electronic format specified by JEA shall be a format commonly used in the electric utility industry.

5.11 Such other terms and conditions that the Parties may agree on or may be required by the nature of the service requested.

IN WITNESS WHEREOF, the Parties hereto have caused this Operating Agreement to be executed by their duly authorized officers effective as of the date first written above.

JEA

Date: ______________________

By: ______________________________________

Title: ______________________________________

[Network Customer]

Date: ______________________

By: ______________________________________

Title: ______________________________________

EXHIBIT 1 TO ATTACHMENT G
Out of dispatch Cost Methodology

JEA's system operations will determine the least-cost re-dispatch for both JEA and the Network Customers that would relieve the constraint, without regard to resource ownership. Both JEA and the Network Customer will be required to redispatch their resources (including reducing purchases and sales) in accordance with the results produced by JEA's system operations until the constraint has been removed. JEA's system operations will then determine JEA's, and the Network Customer's total combined additional costs incurred to alleviate the constraint.

This total combined cost will be shared by JEA and all Network Customers such that the Network Customer will be responsible for its load ratio share of that cost.

Out of dispatch Costs Computation Methodology:

PC_{JEA} - JEA's total production costs, including sales and purchases, before the constraint procedures are implemented.

PC_{TC} - The Network Customer's total production costs, including sales and purchases, before the constraint procedures are implemented.

PC_{JEA}' - JEA's total production costs, including sales and purchases, after the constraint procedures are implemented.

PC_{TC}' - The Network Customer's total production costs, including sales and purchases, after the constraint procedures are implemented.

LRP_{TC} - The load ratio percentage of the Network Customer.

PC - The total incremental production costs to relieve the constraint or defined as $PC = (PC_{JEA}' + PC_{TC}') - (PC_{JEA} + PC_{TC})$.

CR_{TC} - The cost responsibility of the Network Customer for the total incremental production costs to relieve the constraint or defined as $CR_{TC} = \square PC * LRP_{TC.}$

AC_{TC} - The incremental costs/saving incurred by the Network Customer to relieve the constraint or defined as $AC_{TC} = (PC_{TC}' - PC_{TC})$.

OCC - The Out of Dispatch charge (negative) or credit (positive) to the Network Customer bill or defined as $OCC = AC_{TC} - CR_{TC}$

**EXHIBIT 2 TO ATTACHMENT G
OF THE NETWORK OPERATING AGREEMENT**

General Requirements

1. Periodicity of data sent to JEA will be compatible with JEA's own, i.e., as required by JEA's EMS.

2. If a data link is used, ICCP protocol will be used. If the communication is direct from RTU's, it will be 44 - 500 protocol.

3. Forecast data, i.e., system load, unit outage, etc. will be communicated to the system operators.

4. The Network Customer will provide to JEA all their independent schedules into and out of network.

Specific Data Requirements

The list below shows the required data that the Network Customer must provide to JEA. Real time data updated at least every 2 minutes is required in order to guarantee that the information is current when a data snapshot is taken by the security applications. This time is currently about half of the periodicity of these applications. In the future this data snapshot will be required at a faster rate to match expected reduced run times for these applications:

1. The Network Customer will provide to JEA all their independent schedules into & out of the network

2. Network Load
   A. Instantaneous - MW, MVAR
   B. Hourly - MWHr, refresh hourly for day

3. Generation
   A. Instantaneous - MW, MVAR, Voltage, Dynamic schedules for Jointly Owned Units
   B. Hourly - MWHr, refresh hourly for day
   C. Dispatch Data, Efficiency, Fuel Cost, High and Low Limits

D. Availability of Network Resources

4. Actual Net Interchange (for all ties)

   A. Instantaneous - MW, MVAR

   B. Hourly - MWHr, refresh hourly for day

5. Data for Transmission Facilities key to JEA's Security Assessment

   A. Status

   B. MW, MVAR, AMPS loading

   C. Voltages

   D. MVA, AMP ratings

   E. Settings (i.e., capacitor banks and auto transformers)

   F. Distribution load per station

   G. Transmission facilities modeling data

6. Forecasted Data

   A. 36 hour forecasted load

   B. Unit maintenance / deration

   C. Projected hourly loss schedule for next day

   D. Line and equipment outages

7. Information sufficient to determine uses of the Network Resources for purposes other than serving Network Load.

ATTACHMENT H

Annual Network Transmission Service Rate

The Annual Network Transmission Service Rate shall be $18.12/kW-year. This rate shall be applied by multiplying $1.51/kW-month times the Customer's monthly Network Load. All quantities used in calculating the Network Customer's monthly Network Load shall be adjusted to the transmission system input level, i.e., shall include the transmission capacity associated with any applicable losses.

ATTACHMENT I

Index of Network Integration Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT J

Procedures for Addressing Parallel Flows

The North American Electric Reliability Council's (NERC) Transmission Loading Relief ("TLR") Procedures as may be amended from time to time.

ATTACHMENT K

Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop transmission plans;

(iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;

(v) The obligation of and methods for customers to submit data to the transmission provider;

(vi) The dispute resolution process;

(vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(viii) The relevant cost allocation procedures or principles.

ATTACHMENT L

Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) a summary of the procedure for determining the level of secured and unsecured credit;
(2) a list of the acceptable types of collateral/security;
(3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;
(4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;
(5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and
(6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

ATTACHMENT N

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NON-FIRM ENERGY EXCHANGE TRANSMISSION SERVICE

Section 1. Scope and Application

1.1 This Attachment N applies solely to the provision of Non-Firm Energy Exchange Transmission Service by the Transmission Provider.

1.2 Any capitalized terms not defined specifically herein have the meaning ascribed to them in Part I of the Tariff.

1.3 To the extent any provision of the Tariff conflicts with this Attachment, this Attachment controls as to the provision of Non-Firm Energy Exchange Transmission Service.

Section 2. Definitions

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2.1 "ENERGY EXCHANGE" is the "Energy Exchange" as that term is defined in the Energy Exchange Agreement.

2.2 "ENERGY EXCHANGE PARTICIPANT" is a "Participant" as that term is defined in the Energy Exchange Agreement.

2.3 ENERGY EXCHANGE MEMBER" is a "Member" as that term is defined in the Energy Exchange Agreement.

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2.4 "ENERGY EXCHANGE SYSTEM" is the "Southeast EEM System" as that term is defined in the Energy Exchange Agreement.

2.5 "ENERGY EXCHANGE AGREEMENT" means the "Southeast Energy Exchange Market Agreement on file with Commission, as it may be amended from time to time.

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2.6 "NON-FIRM ENERGY EXCHANGE TRANSMISSION SERVICE CUSTOMER" means a Transmission Customer taking Non-Firm Energy Exchange Transmission Service provided in accordance with this Attachment N of this Tariff pursuant to an executed Service Agreement for Non-Firm Energy Exchange Transmission Service, Attachment N-1 to this Tariff.

Section 3. Nature of Non-Firm Energy Exchange Transmission Service

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3.1 Term. Non-Firm Energy Exchange Transmission Service will be available on an as-available basis for 15-minute Energy Exchanges.

3.2 Reservation Priority. Non-Firm Energy Exchange Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term Firm, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service and Secondary Point-to-Point Transmission Service. Non-Firm Energy Exchange Transmission Service will have the lowest reservation priority under the Tariff.

3.3 Scheduling and Reservation. Non-Firm Energy Exchange Transmission Service may only be reserved, scheduled, and tagged through the reservation, scheduling and e-tagging functions of the Energy Exchange System, rather than directly through the Transmission Provider's OASIS.

3.4 Availability. Non-Firm Energy Exchange Transmission Service will be made available for Energy Exchanges from Available Transfer Capability after procurement and scheduling deadlines have passed for the next operating hour, taking into account other higher priority confirmed reservations and the limitations of the Transmission System of the Transmission Provider. Additional Non-Firm Energy Exchange Transmission Service may be made available for Energy Exchanges considering capacity from unscheduled reservations.

3.5 Curtailment and Interruption. The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Energy Exchange Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System, or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Energy Exchange Transmission Service provided under the Tariff to accommodate (1) transmission service for Network Customers, (2) Transmission Service for Firm Point-to-Point Transmission Service; or (3) Transmission Service for Non-Firm Point-to-Point Transmission Service. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Energy Exchange Transmission Service shall be subordinate to all other types of transmission service provided under this Tariff.

3.6 Transmission Losses. Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Non-Firm Energy Exchange Transmission Service Customer is responsible for replacing losses associated with all transmission service as calculated by Transmission Provider and pursuant to Section 6.1.2 of this Attachment N.

3.7 Transmission Provider's Obligations.

3.7.1 Transmission Provider will provide the Energy Exchange System with all

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3.7.2 Transmission Provider is not obligated to (i) plan, construct, or maintain its Transmission System for the benefit of any Energy Exchange Participant; (ii) provide Non-Firm Energy Exchange Transmission Service in a manner that is contrary to the terms of this Tariff, or contrary to Good Utility Practice, each as determined in the sole judgement of the Transmission Provider; (iii) provide Non-Firm Energy Exchange Transmission Service to any Transmission Customer who is not an Energy Exchange Participant; (iv) provide Non-Firm Energy Exchange Transmission Service following Transmission Provider's removal or withdrawal from the Energy Exchange Agreement; or (v) file its Tariff with FERC if the Tariff is not already required to be filed with FERC.

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3.7.3 Transmission Provider's participation in the Energy Exchange System is voluntary and may be terminated at any time in accordance with the provisions of the Energy Exchange Agreement. It is therefore expressly understood, and a condition of service, that Non-Firm Energy Exchange Transmission Service Customer has no reliance interest in provision of Non-Firm Energy Exchange Transmission Service and has no right to rely on Transmission Provider continuing to provide Non-Firm Energy Exchange Transmission Service.

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Section 4. Initiation of Non-Firm Energy Exchange Transmission Service

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4.1 Non-Firm Energy Exchange Transmission Service is available only to Eligible Customers that:

4.1.1 Are in good financial standing with the Transmission Provider.

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4.1.2 Have submitted a Completed Application for Non-Firm Energy Exchange Transmission Service to the Transmission Provider:

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JEA
Sr. Director, Energy Operations
7720 Ramona Blvd
Jacksonville, FL 32221

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Internet e-mail: TSERVE@JEA.COM

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4.1.2.1 A Completed Application for Non-Firm Energy Exchange Transmission Service must include:

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(i) The identity, address, telephone number and email address of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer;

(iii) A statement that the entity requesting service is, or will be upon commencement of service, an Energy Exchange Participant; and

(iv) The service commencement date of the requested Non-Firm Energy Exchange Transmission Service.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

4.1.3 Meet the creditworthiness criteria set forth in Part I, Section 11 of the Tariff.

4.1.4 Have executed a Service Agreement for Non-Firm Energy Exchange Transmission Service, Attachment N-1 of this Tariff.

Section 5. Limitations on Usage of Non-Firm Energy Exchange Transmission Service

5.1 Non-Firm Energy Exchange Transmission Service can be used solely for Energy Exchanges.

5.2 Non-Firm Energy Exchange Transmission Service may not be reassigned, redirected, or sold by the Non-Firm Energy Exchange Transmission Service Customer.

Section 6. Charges for Non-Firm Energy Exchange Transmission Service

6.1 The Non-Firm Energy Exchange Transmission Service Customer shall compensate the Transmission Provider for Non-Firm Energy Exchange Transmission Service as follows:

6.1.1 Rate for Non-Firm Energy Exchange Transmission Service: The rate for intra-hourly delivery shall be $0/MW of Reserved Capacity per 15-minute increment.

6.1.2 Charges for Real Power Losses: The charges for Real Power Losses shall be based on the applicable Real Power Loss Factor and the Real Power Loss Rate applied to deliveries of Non-Firm Energy Exchange Transmission Service.

6.1.2.1 The applicable Real Power Loss factor shall be the same as specified in Section 15.7 of the Tariff.

6.1.2.2 The Real Power Loss Rate shall be a rate equal to 100 percent of the

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Transmission Provider's forecasted average incremental cost after serving all other obligations (including economy and opportunity transactions).

6.1.3 Ancillary Services: As described in Section 6.2.1, the charge for Schedule 1 or Schedule 2 Ancillary Services is $0.

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6.2 Ancillary Services

6.2.1 Notwithstanding the requirements in Tariff Section 3, the Non-Firm Energy Exchange Transmission Service Customer shall pay for the following Ancillary Services at the rate established in Section 6.1.3 of Attachment N: (a) Scheduling, System Control and Dispatch, and (b) Reactive Supply and Voltage Control from Generation or Other Sources.

6.2.2 The Non-Firm Energy Exchange Transmission Service Customer serving load within the Transmission Provider's Control Area must demonstrate that it already has made alternate arrangements for the following Ancillary Services, or it must acquire them from the Transmission Provider, from a third party, or by self-supply: (i) Regulation and Frequency Response, (ii) Energy Imbalance. A Non-Firm Energy Exchange Transmission Service Customer delivering power from a generator in Transmission Provider's Control Area off system must demonstrate that it already has made alternate arrangements for the following Ancillary Services, or it must acquire them from the Transmission Provider, from a third party, or by self-supply: (i) Regulation and Frequency Response and (ii) Generator Imbalance.

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ATTACHMENT N-1

Form of Service Agreement for Non-Firm Energy Exchange Transmission Service

1.0 This Service Agreement, dated as of ________________, is entered into, by and between __________________ (the "Transmission Provider"), and _____________ ("Non-Firm Energy Exchange Transmission Service Customer").

2.0 The Non-Firm Energy Exchange Transmission Service Customer has been determined by the Transmission Provider to be an Eligible Customer under Part I of the Tariff and an Energy Exchange Participant as defined in Attachment N of the Tariff, and as has submitted a Completed Application for Non-Firm Energy Exchange Transmission Service in accordance with Section 4 of Attachment N of the Tariff.

3.0 Service under this Service Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Non-Firm Energy Exchange Transmission Service Customer and subject to the scheduling procedures outlined in the Energy Exchange Agreement.

4.0 Non-Firm Energy Exchange Transmission Service Customer has all the rights and obligations of a Transmission Customer as set forth in Part I of the Tariff, except as specifically excluded in Attachment N to the Tariff.

5.0 The Non-Firm Energy Exchange Transmission Service Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for the Transmission Provider to provide the requested service.

6.0 The Transmission Provider agrees to provide, and the Non-Firm Energy Exchange Transmission Service Customer agrees to take and pay for Non-Firm Energy Exchange Transmission Service in accordance with the provisions of Attachment N of the Tariff and this Service Agreement.

7.0 The Non-Firm Energy Exchange Transmission Service Customer is responsible for replacing Real Power Losses associated with all Non-Firm Energy Exchange Transmission Service. Transmission Provider will supply, and the Non-Firm Energy Exchange Transmission Service Customer will pay for such Real Power Losses in accordance with Section 3.6 of Attachment N.

8.0 The Non-Firm Energy Exchange Transmission Service Customer or the Transmission Provider can cancel this Service Agreement at any time.

9.0 Transmission Provider's participation in the Energy Exchange System is voluntary and may be terminated at any time in accordance with the provisions of

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the Energy Exchange Agreement. It is therefore expressly understood, and a condition of service, that Non-Firm Energy Exchange Transmission Service Customer has no reliance interest in provision of Non-Firm Energy Exchange Transmission Service and has no right to rely on Transmission Provider continuing to provide Non-Firm Energy Exchange Transmission Service. Accordingly, if the Transmission Provider terminates its participation in the Energy Exchange System, the Transmission Provider can cancel this Service Agreement.

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____
____
____

Non-Firm Energy Exchange Transmission Service Customer:

____
____
____

11.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ____________________ ____________________ _____________
Name Title Date

Non-Firm Energy Exchange Transmission Service Customer:

By: ____________________ ____________________ _____________
Name Title Date

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BOARD RESOLUTION: 2023-12
March 28, 2023

A RESOLUTION BY THE BOARD APPROVING THE DELEGATION OF AUTHORITY TO JEA REPRESENTATIVES TO APPROVE AND EXECUTE CERTAIN FLORIDA DEPARTMENT OF TRANSPORTATION DOCUMENTATION; PROVIDING FOR THE CORRECTION OF ERRORS; AND PROVIDING FOR AN EFFECTIVE DATE

RECITALS

WHEREAS, from time to time, JEA is required to seek permitting from and to enter into agreements with the Florida Department of Transportation (FDOT) to conduct activities and transactions associated with operation of the utilities systems; and

WHEREAS, in efforts to effectively and efficiently do so, JEA may appoint and delegate authority to individuals to approve and execute specified documents on behalf of JEA; and

WHEREAS, based upon its review, the Board has determined that approving execution of the completed FDOT Delegation and Special Power of Attorney form (Delegation) to authorize certain individuals to act as provided therein best serves the interests of JEA. A copy of the Delegation is attached hereto as Attachment 1 and incorporated herein by this reference.

NOW THEREFORE, BE IT RESOLVED by the JEA Board of Directors that:

1. The recitals stated above are incorporated into this Resolution and adopted as findings of fact.
2. The Board hereby approves the Delegation and authorizes the Chair to execute it on behalf of JEA.
3. The Board further authorizes those individuals serving in the positions listed in the Delegation to approve and execute the specified document type(s) as provided therein, including all other necessary supplemental documents, agreements, and instruments.
4. To the extent that there are any typographical, administrative, and/or scrivener's errors contained in the Delegation or in this Resolution that do not change the tone, tenor, or purpose thereof, then such errors may be corrected with no further action required by the Board.
5. This Resolution shall be effective upon approval by the Board.

Dated this 28th day of March 2023.

JEA Board Chair

JEA Board Secretary

Form Approved:

Office of General Counsel

VOTE	
In Favor	
Opposed	
Abstained	

STATE OF FLORIDA DEPARTMENT OF TRANSPORTATION

710-010-51
UTILITIES
10/04

DELEGATION AND SPECIAL POWER OF ATTORNEY

JEA, HEREINAFTER REFERRED TO AS THE UAO, HEREBY TAKES THE FOLLOWING ACTION:

1. The positions, the title of which appears in the chart below, are hereby delegated the authority, and the persons, the name of whom appears in the chart below, are hereby appointed as attorney-in-fact for the **UAO**, to approve and execute on behalf of and in the name of the **UAO**, any specified document type listed in the chart below next to that position or person between the **UAO** and the **STATE OF FLORIDA, DEPARTMENT OF TRANSPORTATION** (hereinafter referred to as the **FDOT**) and all other documents, agreements and instruments which are necessary in connection with the document type specified. In the event that All is checked or specified, there shall be no limitation on the authority of that position or person to approve and execute documents between the **UAO** and the **FDOT**.

2. This delegation and appointment shall remain in full force and effect, and the **FDOT** shall be entitled to rely upon this delegation and appointment, until written notice of the modification, rescission, or revocation of this delegation and appointment, in whole or in part, has been actually delivered to the State Utility Engineer of the **FDOT** at its Central Office in Tallahassee, Florida, with copies to the District Utility Engineer of each District of the **FDOT**. No such modification, rescission, or revocation shall, in any event, be effective with respect to any documents executed or actions taken pursuant to this delegation and appointment prior to the actual delivery of written notice of such modification, rescission, or revocation to the **FDOT** as specified above.

3. This delegation and appointment shall not be exclusive and shall not be deemed to limit the authority of any other position or person which may otherwise have authority for the **UAO**.

Name of Representative (If by NAME Please Type or Print approved names)	**Title of Representative** (If by TITLE Please Type or Print approved titles)	**Approved to Sign** (Please check or specify type)	
		All	**Specified Document Type**
	Managing Dir/CEO	☒	
	Chief Operating Officer	☒	
	VP Electric Systems	☒	
	Sr. Mgr Distribution Const. & Maint.	☐	Utility Permits
	Dir Preventative Maint. & Contract Mgmt	☐	Utility Permits
	Mgr Energy Construction & Maintenance	☐	Utility Permits
	Mgr Energy Contract Management	☐	Utility Permits
	Mgr T&D Preventative Maintenance	☐	Utility Permits
	Dir W/WW Reuse Delivery & Collection	☐	Utility Permits
	Mgr Delivery & Collection Engineering	☐	Utility Permits
	Water Wastewater Engineer	☐	Utility Permits
	Staff Engineer	☐	Utility Permits
	Water/Wastewater Planner	☐	Utility Permits
	Maintenance Specialist	☐	Utility Permits
	Service Technician	☐	Utility Permits
	Staff Technician	☐	Utility Permits
	Associate Staff Technician	☐	Utility Permits
	Mgr O&M Construction & Maintenance	☐	Utility Permits
	Mgr Water & Reuse Operation & Maint.	☐	Utility Permits
	Mgr Sewer Operation &	☐	Utility Permits

STATE OF FLORIDA DEPARTMENT OF TRANSPORTATION

DELEGATION AND SPECIAL POWER OF ATTORNEY

710-010-51
UTILITIES
10/04

Name of Representative (If by NAME Please Type or Print approved names)	Title of Representative (If by TITLE Please Type or Print approved titles)	Approved to Sign (Please check or specify type)	
		All	Specified Document Type
	Maintenance		
	Mgr W/WW System Ops. & Cust. Response	☐	Utility Permits
	Mgr Water & Sewer Preventative Maint.	☐	Utility Permits
	VP Water Wastewater Systems	☒	
	VP Planning Engineering & Construction	☒	
	Sr Dir Engineering & Projects	☐	Utility Permits
	Manager Project Management	☐	Utility Permits
	Mgr Transmission & Substation Projects	☐	Utility Permits
	Mgr System Protection & Control Projects	☐	Utility Permits
	Dir Energy Project Management	☐	Utility Permits
	Mgr Energy & Development Projects	☐	Utility Permits
	Mgr Distribution Projects	☐	Utility Prmts; UWHCA <$300k; Escrow Agrm
	Electric Systems Engineer	☐	Utility Permits
	Dir W/WW Project Engineering & Const.	☐	Utility Prmts; UWHCA <$300k; Escrow Agrm
	Senior Manager Project Management	☐	Utility Prmts; UWHCA <$300k; Escrow Agrm
	Mgr W/WW Project Management	☐	Utility Prmts; UWHCA <$300k; Escrow Agrm
	Dir W/WW Planning & Development	☐	Utility Permits
	Mgr. W/WW Development	☐	Utility Permits
	VP Supply Chain & Operations Support	☐	General Agreements
	Dir Procurement Services	☐	General Agreements
	Mgr Procurement Contract Administration	☐	General Agreements
	VP Economic Development	☐	All Real Estate Documents & Instruments
	Director, Real Estate	☐	All Real Estate Documents & Instruments
	Dir Network & Telecommunication Services	☐	Utility Permits
	Mgr Telecom Sales & Services	☐	Utility Permits
		☐	

Dated this 28th day of February, year of 2023.

STATE OF FLORIDA DEPARTMENT OF TRANSPORTATION

DELEGATION AND SPECIAL POWER OF ATTORNEY

710-010-51
UTILITIES
10/04

JEA
(Print Name of UAO on line above)

By: ______________________

Name: Robert Stein

Title: Chair, JEA Board of Directors

Attest: ______________________

Name: Melissa Charleroy

Title: Board Services Manager

BOARD RESOLUTION: 2023-14
March 28, 2023

REVISIONS TO PROCUREMENT CODE

WHEREAS, the JEA Procurement Code was adopted via a JEA Board resolution in 1996 as a comprehensive purchasing code for use in governing all JEA purchases and related administrative activities. The Procurement Code provides a solid foundation for JEA's procurement activities and has been amended over the years to remain current with industry best practices; and

WHEREAS, the JEA Chief Procurement Officer is responsible for updating JEA's Procurement Code and ensuring it is in compliance with all applicable laws and regulations; and

WHEREAS, the last significant Procurement Code revision was made in 2021 following the completion of the Procurement Best Practice Study and an update to the JEA Charter in 2020; and

WHEREAS, the JEA Chief Procurement Officer performed the biannual review in accordance with Article 21 – JEA Charter, requiring Board of Directors approval.

BE IT RESOLVED by the JEA Board of Directors that:

1. The Board of Directors grants JEA approval for the revisions to the JEA Procurement Code.

2. To the extent there are typographical, clerical, or administrative errors that do not change the tone, tenor, or context of this resolution, such errors may be revised without subsequent approval by the JEA Board of Directors.

3. This resolution shall be effective immediately upon passage.

Dated this 28th day of March 2023.

JEA Board Chair

JEA Board Secretary

Form Approved by

Office of General Counsel

VOTE	
In Favor	
Opposed	
Abstained	

Amended and Restated JEA Procurement Code

Effective April 1, 2023

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DEFINITIONS

Addendum means a document issued by JEA which modifies a Solicitation.

Appeal shall have the meaning set forth in Section 4-106 of this Code.

Award means the written approval of the JEA Awards Committee with the written concurrence of the Chief Executive Officer that a Formal Purchase will be in accordance with this Code and the best interest of JEA.

Awards Committee means the body appointed by the Chief Executive Officer in accordance with Section 2-106 of this Code.

Best and Final Offer or *BAFO* means a Vendor's final offer following the conclusion of contract negotiations in connection with an Invitation to Negotiate.

Bid means a Vendor's offer to provide Services or Supplies in response to an Invitation for Bid.

Bidder means a Vendor submitting a Bid in response to an Invitation to Bid.

Business Day is any day except any Saturday, any Sunday or any holiday observed by JEA's Procurement office.

Chief Procurement Officer or *CPO* means the person holding the position appointed in accordance with Section 2-103 of this Code.

Code means this Amended and Restated JEA Procurement Code.

Construction means the process of building, altering, repairing, improving, or demolishing any structure or building, or other improvements of any kind to any real property. It does not include the routine operation, routine repair, or routine maintenance of existing structures, buildings, or real property.

Construction Management Entity means a licensed general contractor or a licensed building contractor, as defined in Section 489.105, Florida Statutes, as amended, who coordinates and supervises a Construction project from the conceptual development stage through final Construction, including the scheduling, selection, contracting with, and directing of specialty trade contractors, and the value engineering of a project.

Construction Manager at Risk or CMAR shall have the meaning set forth in Section 3-109 of this Code.

Consultants' Competitive Negotiation Act or CCNA means Section 287.055, Florida Statutes, as amended, relating to the Procurement of certain architectural, engineering, landscape architectural, and mapping and surveying Services.

Contract means all types of agreements for the Procurement of Supplies or Services, regardless of what these agreements may be called, and shall include, but not be limited to, a Purchase Order issued by JEA and accepted by a Vendor.

Contract Amendment means a written amendment executed after the execution of the Contract formalizing any revisions to the Contract.

Collaborative Procurement means a Procurement undertaken by JEA in accordance with Section 3115 of this Code.

Data means recorded information, regardless of form or characteristic.

Design-Build Contract means a single Contract with a Design-Build Firm for the design and Construction of a Construction project as defined in CCNA.

Designee has the meaning set forth in Section 4-302 of this Code.

Determination means a finding or decision by JEA made in the course of the process of procuring Supplies or Services under this Code.

Emergency shall have the meaning set forth in Section 3-113 of this Code.

Ex Parte Communication has the meaning set forth in Section 1-107 of this Code.

Florida's Open Meetings Laws means the laws found in Chapter 286, Florida Statutes, as amended.

Formal Purchase shall have the meaning set forth in Section 3-101 of this Code.

Governmental Entity means any state or territory of the United States, or any county, city, town or other subdivision of any state or territory of the United States, or any public agency, public authority, educational, health, or other institution of such subdivision.

Informal Purchase shall have the meaning set forth in Section 3-102 of this Code.

Intent to Award means JEA's announcement via an email, posting of the Awards Committee agenda, or issuance of an Addendum stating its intent to award a Formal or Informal Contract.

Invitation for Bid or *IFB* means a type of Solicitation requesting price offers and qualification information for defined Supplies or Services.

Invitation to Negotiate or ITN means a type of Solicitation requesting competitive sealed replies with the intent to select one or more Vendors with which to commence negotiations for the procurement of Supplies or Services, and usually concluding with a Best and Final Offer from Respondents.

JEA means that body politic and corporate created and established in Article 21 of the Charter of the City of Jacksonville.

JEA Board means the members of the JEA appointed to serve as provided by Section 21.03 of the JEA Charter.

JEA Charter means Article 21 of the Charter of the City of Jacksonville, as amended from time to time.

Letter of Credit means a commitment, usually made by a commercial bank, to honor demands for payment of an obligation upon compliance with conditions and/or the occurrence of certain events specified under the terms of the commitment.

Office of General Counsel means the City of Jacksonville's Office of the General Counsel.

Operational Procedures means the written process and procedures applicable to JEA Procurements and Procurement activities that have been promulgated in accordance with this Code.

Organizational Element means any subdivision of JEA — for example, a team, area, activity, department, group, business unit. — that utilizes Supplies or Services procured under this Code.

Organizational Element Manager means the person designated by the Chief Executive Officer to have responsibility for Procurement policies and procedures for certain categories of Supplies and Services under Section 2-102 of this Code.

Pre-Source Selection Methods means the pre-source selection methods described in Section 3-103 of this Code.

Pilot Project shall have the meaning set forth in Section 3-118 of this Code.

Post, Posting or Posted means placing documents or information on JEA's centralized internet website in the manner and location in which similar documents or information are typically posted.

Procurement means purchasing, renting, leasing, or otherwise acquiring; or selling, renting, leasing or otherwise disposing of any Supplies or Services, including, but not limited to, all functions that pertain to such activities – e.g., description of requirements, selection and solicitation of sources, and preparation and Award.

Procurement Appeals Board means the body comprised of at least three members of the Awards Committee as designated in this Code to hear Appeals regarding Procurement actions in accordance with Article 5 of this Code.

Professional Services shall have the meaning set forth in the CCNA.

JEA Project Manager shall have the meaning set forth in Section 3-122.

Proposer means a Vendor submitting a Proposal in response to a Request for Proposals.

Proposal means a Vendor's submittal of its offer in response to a Request for Proposals.

Protest shall have the meaning set forth in Section 4-101 of this Code.

Protestant means a Vendor who files a timely and proper Protest in accordance with Article 5 of this Code.

Purchase Order means a document issued by JEA requesting that a Vendor provide specified Supplies and Services to JEA and may contain additional terms and conditions related to the provision of such Supplies and Services.

Real Estate means land, including buildings and improvements, its natural assets, easements or a permanent interest therein.

Request for Information has the meaning set forth in Section 3-103 of this Code.

Request for Proposals means a type of competitive Solicitation requesting offers that includes qualifications, methods or other information, and may or may not include price, in the form of a Proposal.

Request for Qualifications or RFQ has the meaning set forth in Section 3-103 of this Code.

Response means a Vendor's submittal of its qualifications and price to in response to an ITN or other Solicitation.

Respondent means a Vendor submitting a Response to an ITN or other Solicitation.

Responsible Bidder (or Responsible Proposer or Responsible Respondent) means a Vendor that, in the Chief Procurement Officer's Determination, has the business judgment, experience, facilities and capability in all respects to perform fully the Solicitation requirements, and the integrity and reliability that will assure good faith performance.

Responsive Bidder (or Proposer or Respondent) means a Vendor that, in the Chief Procurement Officer's Determination, has submitted a Bid, Response or Proposal that conforms in all material respects to a Solicitation.

Reverse Auction means a type of auction in which sellers bid for the prices at which they are willing to sell their Supplies or Services.

Services means the furnishing of labor, time or effort by a Vendor, and includes, but is not limited to, work performed on Construction projects and the receipt, delivery and transmission of electric power, fuel, by-products or thermal energy, work customarily rendered by attorneys, certified public accountants, insurance agents, financial advisors, personnel consultants, health care providers and consultants, systems consultants, software or technology consultants, temporary staffing providers, and management consultants, and administrative, maintenance, repair, installation and other technical services. This term shall not include employment agreements or collective bargaining agreements.

Single Source has the meaning set forth in Section 3-112 of this Code.

Solicitation means a document (which may be electronic) issued by JEA for the Formal Purchase of Supplies, Services, or Real Estate.

Source Selection means the type of Solicitation advertised or Procurement method JEA utilizes to obtain responses from Vendors to provide Services or Supplies (e.g., Invitation for Bids, Request for Proposals, Invitation to Negotiate)

Specifications means any description of the physical or functional characteristics, or of the nature of an item of Supply or Service. It may include a description of any requirement for inspecting or testing an item of Supply or Service or preparing such item for delivery. Also commonly referred to as Technical Specifications.

Supplies means all property, including but not limited to, equipment, materials, repair parts, consumables, tools, printing, and leases of real property.

Utility Industry Partner means a publicly-owned or privately-owned utility, utility industry trade association; exempt wholesale generator; co-generator or small power producer, or other entity whose business purpose is the generation or transmission or distribution or the promotion of the efficient use of electricity or water, approved by the Chief Procurement Officer, with whom JEA may legally engage in a Collaborative Procurement provided in Section 3-115 of this Code or a Joint Project as provided in Section 3-117 of this Code.

Vendor means any person or legal entity that provides, agrees to provide, or is interested in providing, Supplies or Services to JEA.

ARTICLE 1- GENERAL PROVISIONS

1-101 Purposes, Rules of Construction

(1) *Interpretation.* This Code shall be construed to be consistent with the guiding principles and to promote its underlying purposes and policies set forth in this Section 1-101.

(2) *Guiding Principles*. This Code shall at all times be subject to the provisions of the JEA Charter found in Article 21 (JEA), Charter of the City of Jacksonville and the following guiding principles:

(a) *Open and Fair Competition*. To the greatest extent reasonably possible, JEA shall use fair, competitive, and generally accepted government Procurement methods that seek to encourage the most competition and best price for the purchase of supplies, construction, professional and other contractual services. JEA should adhere to all applicable state procurement laws, including but not limited to laws governing the purchase of construction services and professional design services.

(b) *Transparency in Procurement processes*. This Code and all Procurement policies, Operational Procedures, rules, directives, standards, and other procurement governing documents, including any amendments thereto, shall be posted on JEA's website in a conspicuous manner for the public to view. All records of JEA Procurement activities shall be subject to disclosure under

Florida's public records laws, including, but not limited to those laws codified in Section 119, Florida Statutes, as amended.

(c) *Use of certain agreements.* The use of confidentiality, nondisclosure or similar agreements by government agencies are contrary to open and transparent government. Except regarding information or records deemed by JEA to be confidential or exempt information or records by law, JEA should not enter into confidentiality or nondisclosure agreements with third parties and should use confidentiality, nondisclosure or similar agreements sparingly in the conduct and operation of its Procurement activities. Additionally, JEA shall not require a member, officer or employee to maintain the confidentiality of information or records that is not confidential or exempt by law.

(3) *Purposes and Policies*. The underlying purposes and policies of this Code are:

(a) to provide for increased public confidence and consistency in the procedures followed in JEA Procurement;

(b) to ensure the fair and equitable treatment of all persons who deal with the JEA Procurement system;

(c) to maximize, to the fullest extent practicable, the purchasing value of JEA funds;

(d) to foster effective, broad-based competition among vendors purchasing good and services from JEA;

(e) to provide safeguards for the maintenance of the quality and integrity of the JEA Procurement system, and

(f) to ensure JEA's Procurement activities comply with all applicable Florida Statutes.

(4) *Singular-Plural and Gender Rules*. In this Code, unless the context requires otherwise, words in the singular include the plural, and those in the plural include the singular.

(5) *Use of Capitals in Text*. Capitalized terms used in this Code shall have the meanings given to them in the Definitions section of this Code.

(6) *Job Titles*. If a JEA job title used in this Code is changed in the future due to JEA organizational changes, this Code shall be construed by substituting the appropriate successor job title.

(7) *Interpretation*: Where the word "shall" is used, it connotes a mandatory requirement. Where the word "may" is used, it connotes a permissive requirement.

1-102 Application of this Code

(1) *General Application.* This Code applies to Procurement activities conducted by JEA and repeals and replaces all previously adopted versions of the JEA Procurement Code. Notwithstanding the foregoing, nothing herein shall affect the validity of Procurement activities conducted in compliance with the version of the Code in effect at the time such activities were conducted.

(2) *Application to JEA Procurement.* This Code shall apply to all expenditures of public funds under Contract by JEA, irrespective of their source. It shall also apply to the sale or other disposal of JEA property and Supplies.

(3) *Application of City of Jacksonville Procurement Code.* If the Code is silent on a specific procurement procedures, JEA may defer to the City of Jacksonville Code where addressed.

1-103 Determinations

Written Determinations required by this Code shall be retained in the appropriate official Procurement or Contract file maintained in accordance with promulgated by the Chief Procurement Officer.

1-104 Policy of Continuous Improvement

Suggestions for Improvements. The JEA Board intends for this Code to be a dynamic document comprising the best available public sector Procurement practices. To this end, the Chief Executive Officer encourages employees of JEA and others who deal with the JEA Procurement system to submit to the Chief Procurement Officer any ideas or suggestions for improvements to this Code.

1-105 Jacksonville Small Emerging Business (JSEB) Program; Minority Business Enterprises

JEA shall adhere to the City of Jacksonville's Small Emerging Business (JSEB) Program, or successor city program, in its Procurement procedures. Subject to applicable federal, state and local laws, with the JEA Board's approval, JEA is authorized to implement and to take all actions necessary to administer a race-conscious purchasing and Procurement program to remedy the present effects of past discrimination by JEA, if any, in the awarding of Contracts. Any such race-conscious program implemented by JEA to remedy the present effects of past discrimination by JEA, if any, in the awarding of Contracts must be supported by evidence and based on the required criteria and standards as set forth in applicable federal and state laws.

1-106 General Counsel of the City of Jacksonville; Engagement of Legal Services

The General Counsel of the City of Jacksonville has the responsibility for providing all legal Services to JEA, including, but not limited to, legal Services relating to Procurement matters. The General Counsel may employ, supervise and terminate assistant counsels to assist with the efficient provision of legal Services for JEA. The General Counsel may authorize JEA to engage outside counsel upon certification by the General Counsel of compliance with the City of Jacksonville's Charter and JEA's authority, and a written finding of necessity by the General Counsel. The General Counsel shall consult with JEA before the General Counsel selects outside counsel. The provision of all outside legal Services to JEA shall be in accordance with the terms of an engagement letter authorized and approved by the General Counsel, including, but not limited to, the scope of the services provided and the maximum indebtedness of JEA's obligations in connection with the engagement.

The provision of legal Services as contemplated by this Section 1-106 shall include all legal related services, e.g., court reporters, expert consultants or witnesses, and Real Estate property appraisers. Legal counsel engaged by JEA shall have the authority to engage such related legal Services only to the extent that the vendor of such related legal Services and the maximum indebtedness of JEA's obligations in connection with such services is approved in by the General Counsel and described in the engagement letter for such legal counsel. The engagement of related legal Services by outside counsel shall not be used as a means to circumvent the competitive bidding requirements or any other provisions of this Code.

1-107 Ex Parte Communication Prohibited

Adherence to procedures that ensure a fair open and impartial Procurement process is essential to the maintenance of public confidence in the value and soundness of the important process of public Procurement. Therefore, except as provided in subsection (3) of this Section 1-107, employees, agents and all other representatives of a Vendor shall be strictly prohibited from communicating, directly or indirectly, with any of the JEA representatives described in subsection (1) below during a period described in subsection (2) below.

(1) *Persons covered*. The prohibitions of this Section 1-107 shall apply to all JEA Board members, employees, agents, and other representatives if such persons are involved in JEA's Procurement process, or have any decision-making authority with respect to an Award.

(2) *Periods.* Ex Parte Communications are prohibited during the following periods:

(a) from the advertisement of a Solicitation through the Award of a Contract or cancellation of the Solicitation prior to Award; and

(b) from the initiation of a Protest through final resolution of such Protest under this Code.

(3) *Exclusions*. This Section 1-107 shall not prohibit:

(a) communications concerning process and questions regarding a Solicitation addressed to the JEA Procurement staff member designated in a Solicitation to answer questions about the Solicitation, including, but not limited to, communications initiated by such staff member in order to clarify aspects of a Bid, Proposal or Response;

(b) communications during public meetings held in accordance with Florida's Open Meetings Laws, for the purpose of discussing a Solicitation or an evaluation or selection process including, but not limited to, substantive aspects of the Solicitation document (Such public meetings may include, but are not limited to, pre-Bid, pre-Proposal or pre-Response meetings, site visits to JEA's or a Vendor's facilities, interviews or negotiation sessions as part of the selection process, and other presentations by Bidders, Proposers, or Respondents. Exempted communications at such public meetings shall be limited to those consistent with the advertised purpose of the meeting and shall be communicated in a manner which can be heard by all those present at the meeting.);

(c) communications during negotiation sessions with Vendors to the extent exempt under Section 286.0113(2), Florida Statutes, as amended;

(d) Awards Committee and the

(e) Procurement Appeals Board meetings advertised and conducted pursuant to Florida's Open Meetings Laws;

(f) contact by a Vendor currently under Contract with JEA, but only regarding work under that Contract and unrelated to the Solicitation or Protest currently in process; or

(g) communications between a Vendor and the Chief Procurement Officer, or JEA's legal counsel in accordance with the requirements of Article 5 of this Code.

(4) Violation of this Section 1-107 by a Vendor or any of its employees, agents or other representatives may be grounds for any one or more of the following: (i) disqualification of the Vendor from eligibility for an Award; (ii) rescission of any Award to the Vendor; (iii) termination of any Contract with the Vendor; or (iv) a decision to suspend or debar the Vendor.

1-108 Retention of Procurement Records

All Procurement records shall be retained, made available, and disposed of in accordance with the requirements of all applicable laws, including but not limited to Chapter 119, Florida Statutes (Florida's Public Records Laws), as amended, and the rules and regulations promulgated by the Division of Library and Information Services of the Florida Department of State.

1-109 Collection of Data Concerning JEA Procurement; Annual Vendor Survey

The Chief Procurement Officer shall prepare and maintain statistical Data concerning the Procurement, usage, and disposition of all Supplies and Services, except for Procurements exempt under Section 2-102 of this Code and not procured under a process overseen by the Chief Procurement Officer. Organizational Element Managers overseeing Procurements exempt under Section 2-102 shall furnish such reports as the Chief Procurement Officer may require concerning usage and needs, and the Chief Procurement Officer shall have authority to prescribe forms to be used by such Organizational Element Managers in requisitioning, ordering, and reporting of Supplies and Services.

The Chief Procurement Officer shall annually conduct a survey of actual, interested and prospective Bidders, Proposers, Respondents, and Vendors to obtain feedback on JEA's Procurement process. Such survey shall be on a form approved by the JEA Board and participation in the survey shall be open to actual, interested and prospective Bidders, Respondents, and Vendors. survey topics may include, without limitation, various aspects of JEA's Procurement process such as information transparency and accessibility, preconferences, bid submittal packages, evaluations, and Awards. The Chief Procurement Officer shall report the results of such survey to the JEA Board and the JEA Board shall consider such survey results during the JEA Board's biennial review of this Code.

1-110 Record of Procurement Actions

The Chief Procurement Officer shall prepare and deliver a written report to the JEA Board on or before the JEA Board's last regularly scheduled meeting held in each calendar year summarizing all Awards made during the immediately preceding fiscal year. Such written report shall contain at a minimum the following information:

(a) The number of Awards for the reporting fiscal year;

(b) A detailed listing of all Awards categorized by service type (e.g., Construction, Professional Services, Supplies, etc.), Award type (e.g., Single Source, Emergency, Request for Proposals, Invitation to Negotiate, piggyback, etc.) and a brief description of each Award containing the Vendor name, Contract amount and Contract term;

(c) The number of JSEB Awards categorized by service type (e.g., Construction, Professional Services, Supplies, etc.), Award type (e.g., Single Source, Emergency, Request for Proposals, Invitation to Negotiate, piggyback, etc.), and a brief description of each Award containing the JSEB contractor name, Contract amount and Contract term;

(d) The number of Protests for the reporting fiscal year and the outcome of each Protest (i.e., whether JEA prevailed); and

(e) The annual survey results pursuant to the survey requirement in Section 1-109 of this Code.

After providing such written report to the JEA Board, the Chief Procurement Officer shall deliver the report to the Jacksonville City Council and the Mayor and post the report on JEA's website in a conspicuous manner for the public to view.

ARTICLE 2 - PROCUREMENT AUTHORITY & DESIGNATIONS, AND COMMITTEES

2-101 Procurement Authority and Duties of the JEA Board

Pursuant to Article 21 of the Charter of the City of Jacksonville, the JEA Board shall review and approve this Code and all amendments to this Code. The JEA Board may not delegate its approval of this Code, including any amendments thereto, to the Chief Executive Officer or any other officer, employee or agent of JEA.

The Chief Procurement Officer shall periodically review this Code and JEA's other Procurement procedures in accordance with the JEA Charter, and shall report to the JEA Board on the results of such review including any recommendations for changes the Chief Procurement Officer deems appropriate.

2-102 Procurement Code Exemptions

(1) Due to the nature of the following Supplies and Services, such Supplies and Services need not be procured through the Chief Procurement Officer and are not subject to approval by the Awards Committee, but may be procured using Procurement policies and procedures established by an Organizational Element Manager designated by the Chief Executive Officer for that category of Supplies and Services:

(a) Generation Fuels, Emission Allowances, and Associated Transport;

(b) Byproducts;

(c) Purchase or Sale of Electric Energy, Electric Generation Capacity, Electric Transmission Capacity and Transmission Services – Short- and Long-Term Transactions;

(d) Sale of JEA Owned Transmission and Ancillary Services, including applicable Enabling Agreements;

(e) Environmental Allowances;

(f) Real Estate, including easements;

(g) Community Outreach Procurements; and

(h) Financial Instruments and Services

The Operational Procedures shall provide more detail concerning the procedures on how to procure the above listed exempt categories of Supplies and Services.

(2) Prior to the Procurement of Supplies or Services by an Organizational Element Manager, the Organizational Element Manager shall obtain all appropriate approvals required by the Procurement Exemption for the specific procurement which can be found in the Operational Procedures and verify there are no conflicts of interest between JEA and the vendor.

(3) In the absence of an Organizational Element Manager for a category of Supplies and Services exempt under subsection (1) of this Section 2-102, the Supplies and Services shall be procured through the Chief Procurement Officer in accordance with this Code and Operational Procedures.

(4) Property and casualty insurance, and Human Resource Benefits may be awarded through the broker or consultant for those services with ultimate approval by the Awards Committee.

2-103 Appointment and Authority of the Chief Procurement Officer

(1) *Central Procurement Officer of JEA.* The Chief Executive Officer shall appoint a Chief Procurement Officer. The Chief Procurement Officer shall be a full-time, appointed employee of JEA with demonstrated executive and organizational ability. The Chief Procurement Officer shall serve as the central point of contact for JEA Procurement matters.

(2) *Operational Procedures*. The Chief Procurement Officer shall promulgate Operational Procedures governing JEA Procurement activities that are consistent with the provisions of this Code. Whenever practicable, the Operational Procedures shall be updated to incorporate the use of new technologies, best practices, and streamlined procedures for continuous improvement of JEA's Procurement activities. Material revisions to the Operational Procedures shall be approved by the Office of General Counsel prior to the revisions becoming effective.

(3) *Duties.* Except as otherwise specifically provided in this Code, the Chief Procurement Officer duties shall include, but are not limited to:

(a) supervise and coordinate the Procurement of all Supplies and Services by JEA;

(b) make Determinations as to what constitutes a minor irregularity in Bids, Proposals and Responses and when Bids, Proposals and Responses should be rejected as unresponsive;

(c) conduct or coordinate training on JEA's Procurement policies and processes and related matters;

(d) develop and maintain the standard contract language for Solicitations, Contracts and other documents used in the JEA's Procurement process in consultation with the Office of General Counsel; and

(e) exercise the duties given to the Chief Procurement Officer in Article 5 of this Code.

2-104 Delegation of Authority by the Chief Procurement Officer

The Chief Procurement Officer may delegate any duty or authority given to the Chief Procurement Officer under this Code in writing to one or more designees.

2-105 Procurement Document Review

The Chief Procurement Officer shall create a process and procedures to ensure all Solicitations and other documents used in JEA's Procurement process are reviewed to ensure compliance with this Code, the Operational Procedures and all applicable laws and regulations. The process and procedures for review of all Solicitations shall be set forth in the Operational Procedures.

2-106 Awards Committee

(1) *Awards Committee Membership*. The JEA Awards Committee shall consist of three Vice Presidents or other senior Officers of JEA appointed by the Chief Executive Officer. Members of the Awards Committee shall serve a two-year term, or until their successors have been appointed. Multiple terms are permitted. The Chief Executive Officer will appoint an Awards Committee member to be the chair of the committee who will run the meeting. Members of the Awards Committee may be removed at any time with or without cause by the Chief Executive Officer. If an Awards Committee member shall cease to be qualified to serve, then the member's term shall be vacant until the Chief Executive Officer appoints a replacement.

(2) *Liaisons*. There shall be three permanent liaisons present at all meetings of the Awards Committee which shall include the Chief Procurement Officer, a representative from the Budget Organizational Element designated by the Chief Executive Officer and a representative from the Office of General Counsel. These liaisons shall not be considered voting members of the Awards Committee for purposes of Florida's Open Meetings Laws.

(3) *Quorum*. The presence of at least two voting members of the Awards Committee shall constitute a quorum. If a quorum is not present or any one of the three Liaisons is not in attendance, the meeting shall be cancelled. If a voting member of the Awards Committee or a liaison is unable to attend a meeting of the Awards Committee, that voting member or liaison may designate an alternate to serve for that meeting, and the alternate shall for all purposes (including, but not limited to satisfying quorum requirements and voting) be considered a member or liaison, as the case may be, for that meeting.

2-107 Awards Committee Procedures

All meetings of the Awards Committee shall be held in accordance with this Code and the requirements of Florida's Open Meetings Laws and shall be properly noticed, and minutes shall be taken. The voting members of the Awards Committee shall not discuss any matter which foreseeably could come before the Awards Committee with another voting member of the Awards Committee unless such discussions take place in a duly noticed meeting held in accordance with Florida's Open Meetings Laws.

Each voting member of the Awards Committee shall have one vote. It shall take a majority of the voting members of the Awards Committee for an item to be approved. Items may be presented to the Awards Committee as part of a regular or a consent agenda. Items placed on the consent agenda shall be those items that do not require discussion or explanation prior to committee action. An individual Awards Committee member may remove items from the consent agenda prior to the vote on the consent agenda. An item removed from the consent agenda shall be discussed and acted upon separately following the consideration of the consent agenda. Such items may be taken up immediately following approval of the consent agenda or placed later on the agenda at the Chair's discretion. Except as otherwise provided herein, once an Award Item is reviewed and approved by the Awards Committee, JEA is authorized to proceed with executing a Contract. Items that are moved from the consent agenda to the regular agenda shall require the approval of the Chief Executive Officer before the Award is finalized.

The Chief Procurement Officer shall conduct all meetings of the Awards Committee and shall present each Award item placed on the regular agenda to the Committee for its consideration. The Chair shall have the authority to determine the presence of a quorum and whether any voting requirement has been met. The Chief Procurement Officer shall be responsible for all administrative matters relating to the conduct of the Committee's business including, but not limited to, ensuring that proper notice is given, and minutes are taken.

2-108 Duties of the Awards Committee

(1) *Scope of Review.* The Awards Committee shall review each Award item presented to the Committee, by way of regular or consent agenda, and shall consider whether the proposed item is in compliance with this Code and in the best interest of JEA.

(2) *Required Approvals.* The following Procurements of Supplies and Services by JEA shall require approval by the Awards Committee:

(a) Formal Purchases of Supplies and Services by JEA as provided in Section 3-101, unless exempt under Section 2-102 (Procurement Code Exemptions) or specifically provided otherwise in this Code;

(b) changes to, and renewals of, any Contracts executed in connection with an Award approved by the Awards Committee if:

(i) the financial impact of the change or renewal exceeds 10% of the amount of the most recent Award approved by the Awards Committee;

(ii) the financial impact of the change or renewal exceeds $1,000,000;

(iii) the change or renewal causes an Informal Purchase to exceed the threshold for a Formal Purchases set forth in Section 3-101 of this Code;

(iv) the change or renewal, in the opinion of the Chief Procurement Officer, changes the Award approved by the Awards Committee in any material respect.

(c) sales of Supplies or Services by JEA that exceed $300,000 or annual spend in excess of $300,000 for continuing services contracts, including, but not limited to the sale of any surplus items;

(d) Procurements exempt under Section 2-102 (Procurement Code Exemptions) of this Code if required by the Procurement processes and procedures established by the applicable Organizational Manager; and

(e) ratification of all Formal Purchases procured under Section 3-113 (Emergency Procurements) of this Code.

(3) Availability of Funding for Procurement Items. The Awards Committee shall approve Awards items only after receiving confirmation as provided in this Section 2-108(4) that sufficient funds are available for the Award. Prior to presentation to the Awards Committee, each Award item shall be reviewed and approved by the Budget Organizational Element to determine whether sufficient funding is available for the Award.

(4) Effect of Approval. Once an Award item is reviewed and approved by the Awards Committee, and the Chief Executive Officer as needed, JEA is authorized to proceed with actions to finalize the Procurement of the Supplies or Services consistent with the Award, including but not limited to, execution of a Contract, issuance of a Purchase Order and notice to proceed, and acceptance of delivery of Supplies and Services, subject to lawfully appropriated funds. An Award may be rejected if, in the judgment of the Chief Executive Officer, the Award does not comply with the requirements of the JEA Procurement Code, Operational Procedures, or other applicable law.

ARTICLE 3 – SOURCE SELECTION AND CONTRACT FORMATION

3-101 Formal Purchases

(1) Unless exempt under Section 2-102 of this Code, the following Procurements shall be considered Formal Purchases under this Code:

(a) the Procurement of Supplies or Services where the estimated aggregate costs and fees for the Procurement exceed $300,000 annually;

(b) the Procurement of Capital and O&M projects where the estimated total project costs and fees for the Procurement exceed $300,000;

(c) “Public construction works” required to be competitively awarded under Section 255.20, Florida Statutes, as amended;

(d) "Electrical work" required to be competitively awarded under Section 255.20, Florida Statutes, as amended; and

(e) "Professional Services" required to be publicly announced under Section 287.055, Florida Statutes, as amended.

(2) Formal Purchases shall be procured using the process and procedures for Formal Purchases detailed in the Operational Procedures.

3-102 Informal Purchases

(1) Unless exempt under Section 2-102 of this Code, all Procurements not considered to be Formal Purchases under Section 3-101 of this Code shall be considered Informal Purchases.

(2) Informal Purchases may be made in accordance with Operational Procedures.

(3) Procurements shall not be artificially divided to constitute an Informal Purchase under this Section 3-102.

(4) Unless the Procurement is otherwise exempt under this Code, the Operational Procedures for Informal Purchases shall require, at a minimum, the following kind and number of quotations from prospective Vendors:

(a) one properly documented quotation for Informal Purchases of $10,000 or less; or

(b) three properly documented quotations for Informal Purchases exceeding $10,000; provided, however that if JEA fails to receive 3 quotations despite using all reasonable efforts to obtain 3 quotations, the Chief Procurement Officer may waive this requirement.

(5) Informal Purchases exceeding $50,000 shall be Posted for 7 to 10 calendar days.

(6) Architectural, engineering, landscape architectural, or registered surveying and mapping services considered "Professional Services" under the CCNA in the amount of $35,000 or less shall be exempt from competitive bidding under this Code. JEA may procure such services directly without competition.

3-103 Methods of Pre-Source Selection

The Chief Procurement Officer may authorize any one or more of the following Pre-Source Selection Methods:

(1) A Request for Information ("RFI") is a Pre-Source Selection Method that requests written information about the capabilities of Bidders, Proposers or Respondents and may prepare interested Vendors for participation in future Solicitations. The publication of an RFI does not obligate JEA to make the purchases referred to in the RFI. JEA may use information obtained from RFIs to develop scopes of work for future Solicitations.

(2) A Request for Qualifications ("RFQ") is a Pre-Source Selection Method used to qualify a pool of two or more Vendors which will be eligible to respond to future Solicitations.

(3) An Intent to Bid is a Pre-Source Selection Method intended to provide notice and information to potential Vendors of JEA's intent to issue a Solicitation for Supplies or Services. The Intent to Bid may request a response from Bidders confirming their intent to submit a Bid, Proposal or Response to a future JEA Solicitation. The publication of an Intent to Bid does not obligate JEA to make the purchases referred to in the Intent to Bid.

3-104 Methods of Source Selection

Unless exempt under Section 2-102 of this Code, all Formal Purchases shall be procured using one of the following Methods of Source Selection:

(a) Section 3-105 (Invitation for Bids (IFB));
(b) Section 3-106 (Request for Proposals (RFP));
(c) Section 3-107 (Consultants' Competitive Negotiation Act (CCNA) (Architectural, Engineering, Landscape Architectural, or Surveying & Mapping Services));
(d) Section 3-108 (Design-Build Contracts);
(e) Section 3-109 (Construction Management and Program Management);
(f) Section 3-110 (Multi-Step Competitive Bidding);
(g) (g) Section 3-111 (Invitation to Negotiate (ITN))
(h) Section 3-112 (Single Source);
(i) Section 3-113 (Emergency Procurements);
(j) Section 3-114 (Public Private Ventures);
(k) Section 3-115 (Collaborative Procurements);
(l) Section 3-116 (Joint Projects);
(m) Section 3-117 (Use of Publicly Procured Contracts);
(n) Section 3-118 (Pilot Projects);
(o) Section 3-119 (Use of Reverse Auctions);

The Chief Procurement Officer may elect to use any one of the Methods of Source Selection listed in this Section 3-104 if the Method of Source Selection is deemed by the Chief Procurement Officer to be in the best interest of JEA consistent with the purposes and guiding principles set forth in Section 1-101 of this Code. Notwithstanding the foregoing, the Method of Source Selection shall comply with the requirements of this Code, the provisions of any grant or other funding or cooperative agreements to which JEA is a party, and all applicable laws and regulations, including but not limited to, statutory requirements for the Procurement of Professional Services subject to the CCNA and Construction services meeting certain statutory thresholds. The Operational Procedures shall establish a process and procedures for each Method of Source Selection.

3-105 Invitation For Bids (IFB)

An IFB may be used when JEA is capable of defining the Specifications for a Supply or Service. An Award generally will be made to the Responsive and Responsible Bidder who submits the lowest Bid in a sealed competitive bidding process. Notwithstanding the foregoing, the Chief Procurement may waive minor irregularities in a Bid and may reject all Bids if the Chief Procurement Officer deems such actions to be in the best interest of JEA.

3-106 Request for Proposal (RFP)

An RFP may be used when the Chief Procurement Officer determines that a Solicitation should include selection criteria in addition to price. Various combinations or versions of Supplies or Services may be proposed by a Vendor to meet the Specifications in the RFP.

An RFP may be used to procure Construction Services to the extent permitted by Section 255.20(1)(d)(2), Florida Statutes.

3-107 Consultants' Competitive Negotiation Act (CCNA) (Architectural, Engineering, Landscape Architectural, or Surveying & Mapping Services)

Architectural, engineering, landscape architectural, or registered surveying and mapping services considered "Professional Services" under the CCNA shall be procured in accordance with the requirements of the CCNA.

3-108 Design-Build Contracts

A Design-Build Contract may be used when the general design and construction requirements are known, but the detailed design and engineering has not been completed. Design-build contracts as defined in Section 287.055(2)(i), Florida Statutes, shall be procured in accordance with the CCNA and the Operational Procedures.

3-109 Construction Management and Program Management

Services may be procured from Construction Management Entities and program management entities in accordance with the provisions of Section 255.103, Florida Statutes. After selection and competitive negotiations, a Construction Management Entity may be required to offer a guaranteed maximum price and a guaranteed completion date or a lump-sum price and a guaranteed completion date as a construction manager "at risk" in accordance with the provisions of Section 255.103, Florida Statutes (a "Construction Manager at Risk" or a "CMAR").

3-110 Multi-Step Competitive Bidding

The Multi-Step Bidding Method of Source Selection involves a two-phase process in which Bidders first submit proposed revisions to both the commercial and technical terms of the Solicitation. During the second phase of the process, Bidders submit a bid price based on a revised Solicitation issued by JEA. An Award is based solely on the price of the Bid and does not include additional discussions or negotiations of material terms and conditions with Bidders after Bids are received. Multi-Step Competitive Bidding allows JEA to obtain Vendor feedback before finalizing commercial and technical terms to be used in an Invitation for Bids.

3-111 Invitation to Negotiate (ITN)

The Invitation to Negotiate is a Method of Source Selection that allows JEA to directly negotiate with Vendors to obtain best overall value for JEA. Under the ITN, JEA first evaluates initial Proposals with the intent to identify one or more Responsive and Responsible Respondent with which JEA may enter into one or more rounds of negotiations. Negotiations may result in modifications to the scope of work and terms and conditions of the ITN, submission of revised Bids or Responses, and may conclude with the submission of Best and Final Offers from one or more Vendors. The procedures for conducting an Invitation to Negotiate shall be described in the ITN Solicitation and the Operational Procedures.

ITNs may provide best value for JEA when establishing master contracts or definite delivery contracts for complex Supplies or Services, or when determining or refining scope, methods, or other nonprice aspects of a Solicitation.

For each use of the ITN Method of Source Selection, prior to issuance of the ITN, the Chief Procurement Officer shall document the reasons an ITN will produce the best value for JEA compared to an IFB or RFP. In addition to negotiating price, additional reasons must be stated as to why negotiations are needed to realize best value for JEA. Examples of such reasons are “the ITN method allows refining approaches, methods, tools, requirements, deliverables, and systems;” or, “identifying and incorporating value added services offered by Vendors into final requirements.”

3-112 Single Source

A Contract may be awarded for Supplies or Services as a Single Source when, pursuant to the Operational Procedures, the Chief Procurement Officer determines that:

(a) there is only one justifiable source for the required Supplies or Services;

(b) the Supplies or Services must be a certain type, brand, make or manufacturer due to the criticality of the item or compatibility within a JEA utility system, and such Supplies or Services may not be obtained from multiple sources such as distributors;

(c) the Services are a follow-up of Services that may only be done efficiently and effectively by the Vendor that rendered the initial Services to JEA, provided the Procurement of the initial Services was competitive;

(d) at the conclusion of a Pilot Project under Section 3-118 of this Code, the Procurement of Supplies or Services tested during the Pilot Project, provided the Vendor was competitively selected for the Pilot Project.

3-113 Emergency Procurements

In the event of an Emergency, the Chief Procurement Officer, or Designee, may make or authorize an Emergency Procurement, provided that Emergency Procurements shall be made with as much competition as practicable under the circumstances. A written Determination of the basis for the Emergency and for the selection of the particular Vendor shall be included in the Procurement file.

For purposes of this Section 3-113, an "Emergency" means any one of the following:

(a) a reasonably unforeseen breakdown in machinery;

(b) an interruption in the delivery of an essential governmental service or the development of a circumstance causing a threatened curtailment, diminution, or termination of an essential service;

(c) the development of a dangerous condition causing an immediate danger to the public health, safety, or welfare or other substantial loss to JEA;

(d) an immediate danger of loss of public or private property;

(e) the opportunity to secure significant financial gain for JEA, to avoid delays to any Governmental Entity, or avoid significant financial loss through immediate or timely action; or

(f) a declared federal, state, or local state of emergency, or a valid public emergency certified by the Chief Executive Officer.

The Chief Procurement Officer, or Designee, shall submit all Formal Purchases made under this Section 3-113 to the Awards Committee for ratification as soon as reasonably practicable after the Formal Purchase is made.

3-114 Public-Private Partnerships

JEA may receive unsolicited proposals or may solicit proposals for a qualifying project and may thereafter enter into a comprehensive agreement with a private entity, or a consortium of private entities, for the building, upgrading, operating, ownership, or financing of JEA's facilities in accordance with the provisions of Section 255.065, Florida Statutes, as may be amended from time to time. The Operational

Procedures shall set forth a process and procedures for the receipt and solicitation of such proposals that meet the requirements of Section 255.065, Florida Statutes, as amended from time to time.

3-115 Collaborative Procurements

JEA may participate in, sponsor, conduct, or administer a Collaborative Procurement for the Procurement of any Supplies or Services or Real Estate with one or more Governmental Entities, utility industry partners, nonprofit organizations or purchasing alliances in accordance with the terms of an agreement entered into between the participants. Such Procurements shall be in accordance with this Code and the Operational Procedures.

JEA shall not participate in, sponsor, conduct, or administer a Collaborative Procurement agreement for the purpose of circumventing this Code.

3-116 Joint Projects

Except where doing so is to circumvent the purpose of this Code, JEA may enter into joint projects with public or utility industry partners, the City of Jacksonville and its other independent agencies, political subdivisions or other Governmental Entities (e.g., the United States Navy, the Florida Department of Transportation, etc.). Joint projects may include, but shall not be limited to, combined water, sewer, drainage and road projects with the City of Jacksonville and Florida Department of Transportation.

Notwithstanding the foregoing, the Procurement of Supplies and Services by JEA in a Joint Procurement shall be consistent with the guiding principles and purposes of this Code set forth in Section 1101.

3-117 Use of Publicly Procured Contracts

JEA may procure Supplies or Services by using or "piggybacking" on contracts of the City of Jacksonville or its independent agencies, political subdivisions, other city and state or governmental agencies, school board districts, community colleges, federal agencies, Governmental Entities, or public colleges or universities, provided that the contracts of such other entities were competitively procured and the terms and conditions of JEA's Contract are at least as favorable as the terms and conditions of the contract on which JEA is piggybacking. Formal Purchases using this Method of Source Selection shall be awarded through the Awards Committee.

3-118 Pilot Projects

A Pilot Project allows JEA to procure Supplies or Services on a trial basis in limited amounts and for a limited period of time in order to determine whether to proceed with a Formal Solicitation for the Procurement of such Supplies or Services.

If the estimated aggregate cost of Supplies and Services to be procured during a Pilot Project do not exceed $100,000, and the term of the Contract for the Pilot Project does not exceed two years, the selection of a Vendor to participate in the Pilot Project is not required to be selected using a competitive solicitation process unless required by applicable law. However, after the conclusion of the Pilot Project, the Supplies or Services evaluated during the Pilot Project shall be procured using one of the other Methods of Source Selection provided in Section 3-104 of this Code.

Where the cost to JEA of the Supplies and Services during the Pilot Project is $100,000 or more, JEA shall publicly advertise the Pilot Project so that Vendors may submit their qualifications to provide such Supplies or Services. Based on the qualifications submitted by Vendors in response to such public advertisement, JEA will select one or more Vendors to participate in the Pilot Project. Once the Pilot Project is complete, the Chief Procurement Officer will determine whether JEA will initiate a competitive bidding process to obtain the Supplies or Services.

3-119 Use of Reverse Auctions

When the Chief Procurement Officer determines that procurement by a Reverse Auction is in the best interest of JEA, the Chief Procurement Officer may procure Supplies or Services by Reverse Auction. Reverse Auctions may be used with the following Solicitation types:

(a) Invitation for Bids (IFB) – With Reverse Auction

(b) Request for Proposals (RFP) – With Reverse Auction

(c) Invitation to Negotiate (ITN) – With Reverse Auction

Reverse Actions are to be used solely for obtaining lowest pricing. Prior to conducting a Reverse Auction, the following must be established for each Bidder, Proposer or Respondent:

(a) Invitation for Bids –Bidders must provide documentation that they meet the minimum qualifications and any other requirements set forth in the IFB.

(b) Request for Proposals – The Proposers must provide fully responsive Proposals. JEA shall evaluate Proposals and select at the top three, or more, ranked Proposers to participate in a Reverse Auction to establish pricing.

(c) Invitation to Negotiate – At the conclusion of the negotiation process for an ITN, where all terms other than price have been agreed, JEA may choose to use a Reverse Auction to establish pricing.

3-120 Form of Contract Documents

The Office of General Counsel shall approve as to form all Contract documents for Formal Purchases. Contract Amendments do not require OGC form approval, unless otherwise provided in the Operational Procedures.

Purchase Orders may be used to form a Contract for Informal Purchases and Formal Purchases when the Chief Procurement Officer determines that a Formal Contract is not necessary. Purchase Orders shall be on a form that incorporates general terms and conditions reviewed and approved by the Office of General Counsel. If a Contract other than a Purchase Order is executed for an Informal Purchase, the Contract does not require form approval by the Office of General Counsel, unless specifically requested by the CPO, or unless such Contract contains terms materially different than JEA's standard terms and conditions. .

In accordance with the JEA Charter, unless otherwise provided in the JEA Charter or by law, all Contracts of any kind, and in any form entered into by JEA, including, but not limited to, Procurement Contracts, Joint Project Contracts, interlocal agreements, and Purchase Orders for Informal Purchases shall contain a provision clearly specifying a fixed, maximum monetary indebtedness of JEA thereunder.

3-121 Execution of Contract Documents

The Chief Executive Officer shall execute all Contracts. The Chief Executive Officer may delegate to the Chief Procurement Officer the authority to execute Contracts. Contracts and Purchase Orders may be executed by electronic means.

3-122 JEA Project Manager

All Contracts shall provide for a JEA Project Manager who will have the responsibility for overseeing all Work under the Contract and all payments made by JEA under the Contract. The Operational Procedures shall contain additional details concerning the responsibilities of JEA's Project and Contract Managers.

3-123 Continuing Services Contracts

Continuing services contracts, and continuation contracts based on unit prices, may be utilized for recurring Procurements of Supplies and Services that are projected to be made over a period of time. The total amount of all Procurements issued under a continuing services contract shall not exceed JEA's maximum indebtedness set forth in the Contract or the amount as authorized by Florida Statutes for the specific category of work, if any, and shall comply with all other applicable laws.

3-124 Contract Pricing Terms

Contract pricing terms are required in all Contracts and are the basis for payment approvals. The appropriate type of pricing terms will depend on the type of Contract and work being performed. The Operational Procedures may contain additional guidance concerning the type of pricing terms what are appropriate for certain types of Contracts.

3-125 Compliance with Federal and State Procurement Requirements

To the extent that a conflict exists between the provisions of this Code and the provisions of federal or state procurement requirements necessary to receive and expend grant funding, the CPO, in consultation with the Office of General Counsel, is authorized to waive any such conflicting Code provision and comply with the federal or state procurement requirement. In the event a Code provision is waived pursuant to this section, upon final approval of the contract award, the CPO shall notify the Chief Executive Officer.

ARTICLE 4 - ADMINISTRATIVE REMEDIES

4-101 Protests

(1) *Guiding Principles*. It is important that actual or prospective Bidders, Proposers and Respondents have confidence in JEA's Procurement process and procedures. One method of maintaining this confidence is to provide Vendors with an opportunity to file Protests relating to Solicitations and Awards and Intent to Award as provided in this Section 4-101. The provisions of this Article shall apply only to Formal Procurement actions as defined in Article 3-101 as provided herein. All other disputes will be resolved by the CPO as provided in the Operational Procedures. The provisions of this Article may not be used in connection with any Contract dispute, determination of Vendor performance, or Contract termination.

(2) *Right to Protest Procurement Actions.* Any Vendor who is adversely affected by an Award or an Intent to Award may submit a written Protest meeting all of the requirements of subsections (3) and (4) of this Section 4-101. Protests in connection with the requirements of a Solicitation or a Determination made in connection with a Solicitation shall include, but not be limited to, Protests concerning any event or aspect of the Procurement process that followed the issuance of the Solicitation and led to the Award or Intent to Award, Protests relating to the rejection of a Bid, Proposal or Response, including, but not limited to, whether a Bidder, Proposer or Respondent is Responsible or Responsive, and Protests relating to any ranking, scoring, or short-listing of Proposers or Respondents. Protests shall not include challenges to minimum qualifications, the Technical Specifications, the chosen procurement method, the evaluation criteria, the relative weight of the evaluation criteria, or the formula specified for assigning points to the evaluation criteria.

(3) *Protest Requirements.* Protests shall:

(i) be submitted in writing in a letter or email addressed to the Chief Procurement Officer;

(ii) identify the Solicitation, Award, or Intent to Award, by number and title or other language sufficient to enable the Chief Procurement Officer to identify the Solicitation, Award, or Intent to Award;

(iii) demonstrate the timeliness of the Protest;

(iv) state the Protestant's complete legal name and legal standing to protest; and

(v) clearly state with particularity the issues and material facts supporting the Protest, and any legal authority upon which the Protest is based; with requested remedy.

Contact information for the Chief Procurement Officer can be found at jea.com under the Procurement section of the website.

(4) *Timeliness.*

(i) All Protests concerning an Award or an Intent to Award, or a Determination made in connection with a Solicitation, must be received by the Chief Procurement Officer within two Business Days after the Posting or other written notification of JEA's decision or intended decision, whichever is earlier. Without limitation, the Posting of the Awards Committee agenda on JEA's website, or JEA's issuance of an Addendum or email to all Bidders, Proposers or Respondents stating its Intent to Award or establishing the short list of Respondents or Proposers, shall constitute notification of an Award or Intent to Award, or other Determination. The period for filing a Protest under this subsection (ii) shall begin at the time of the Posting or other such notification.

(ii) At the time of filing a timely Protest, a Protestant may request an extension of three Business Days after the date its Protest is timely received, in which to provide supplemental Protest materials. Such extension may be granted or denied in JEA's sole discretion. Failure to submit a request for extension or to timely submit the supplemental Protest materials shall constitute a waiver of any right to supplement the Protest. All written information, documents, materials and legal authority the Protestant will provide to the Chief Procurement Officer must be received by the deadline established by the Chief Procurement Officer in a notice provided to the Protestant.

(5) Protests failing to meet the requirements of subsections (3) and (4) shall be rejected and shall constitute a waiver of all rights of the Protestant to file a Protest with respect to that subject matter. A Determination of whether a Protest meets the requirements of subsections (3) and (4) shall be made by the Chief Procurement Officer and is not subject to Protest or Appeal to the Procurement Appeals Board.

(6) JEA shall have the right to cancel, or rescind and re-issue, all Solicitations of any type, at any time until the time JEA executes a Contract under the Solicitation. Such right shall include the right to rescind an Award or an Intent to Award. After a Contract is executed, the terms of the Contract shall govern the parties to the Contract. Such cancelations and rescissions are not subject to Protest.

(7) *Protest Bond.* Within 48 hours from a submitting a Protest, the Protestant is required to submit a protest bond, or alternate security approved by JEA, the amount of 1% of Protestant's submitted Bid/ Proposal/Response amount or $10,000, whichever is less. If the Protestant does not submit the protest bond within the specified timeframe, the protest will be void and waives the right to further protest JEA's decision. If the Protest is successful, the protest bond shall be returned in full to the Protestant within a reasonable time.

However, if JEA prevails, JEA shall retain the protest bond, in full or in part, in order to cover any administrative costs associated with addressing the protest.

(8) *Notice of Protest to Affected Third Parties.* Upon receipt of a timely and proper Protest, JEA will notify Vendors known to JEA to be directly affected by the outcome of the Protest. All information, documents, materials and legal authority relating to the Protest that any such Vendor will provide to the Chief Procurement Officer must be received by the deadline established by the Chief Procurement Officer in such notice.

(9) *Protest Hearings.* Protestants shall not be entitled to a hearing of any kind prior to a decision of the Chief Procurement Officer concerning a Protest. The Chief Procurement Officer may conduct a hearing before making a decision. The Chief Procurement Officer shall be entitled to establish procedures for the conduct of any hearing and may set forth some or all of such procedures in the Operational Procedures or in the notice of the hearing. The Chief Procurement Officer or Designee shall provide Vendors known to JEA to be directly affected by the outcome of the Protest with a notice of the hearing providing the time, date, location and manner of the hearing.

(10) *Decision by Chief Procurement Officer.* After receipt of a Protest, and following a hearing, if any, and any period of time the Chief Procurement Officer may allow for other interested parties to respond to the Protest, the Chief Procurement Officer shall issue a written decision on the Protest. The written decision shall identify the Protestant, recite relevant facts material to the decision, and state the decision and briefly summarize the Chief Procurement Officer's reasoning leading to the decision. The Chief Procurement Officer's review of a Protest shall be limited to material contained in the Protestant's response to the Solicitation that is the subject of the Protest, and the Chief Procurement Officer's decision shall be based on whether the Procurement action being protested was arbitrary, capricious, or clearly erroneous, In the event the decision is subject to review by the Procurement Appeals Board under this Article 4, the written decision of the Chief Procurement Officer shall inform the Protestant of this right with a reference to the Sections of this Code and Operational Procedures outlining the procedures for Appeals.

(11) *Appeal Rights.* Protest decisions made by the Chief Procurement Officer may be appealed to the JEA Procurement Appeals Board pursuant to Section 4-106 below. Notwithstanding the foregoing, a Protestant shall not have the right to appeal a Determination by the Chief Procurement Officer about whether a Protest met the requirements of subsections (3) and (4) of this Section.

(12) *Stay of Procurement During Protests and Appeals.* During the pendency of a Protest meeting the requirements of subsections (3) and (4) or an Appeal properly filed under Subsection (10) above, JEA shall not proceed further with the Solicitation or with the Award unless the Chief Procurement Officer, after consultation with the Organizational Element Manager, makes a Determination that proceeding with the Solicitation or Award without delay is necessary to protect substantial interests of JEA.

(13) Nothing in this Article 4 shall affect the ability of the Office of General Counsel to settle Protests pending the outcome of decisions by the Chief Procurement Officer, the Procurement Appeals Board, or the courts.

4-102 Suspensions and Debarments

(1) *Authority.* The Chief Procurement Officer, after consultation with the Organizational Element Manager, shall have authority to suspend or debar a Vendor from consideration for participation in any Procurement undertaken by JEA.

(2) *Causes for Suspension or Debarment*. In making a decision of whether to suspend or debar a Vendor, and the length of any suspension or debarment, the Chief Procurement Officer shall consider the seriousness of the facts leading to the suspension or debarment. The causes for suspension or debarment may include, but not be limited to, the following:

(a) conviction of a Public Entity Crime and inclusion on the State of Florida Convicted Vendor List pursuant to Section 287.133, Florida Statutes, as amended;

(b) violation of the terms or requirements of a Contract in a manner that is regarded by the Chief Procurement Officer to be so serious as to justify a suspension or debarment decision, including, but not limited to, the following:

(i) a failure, without good cause, to perform in accordance with a Contract, Specifications, performance levels, warranty provisions, bonding and insurance requirements, or to comply within the time limits provided in the Contract, or

(ii) failure to timely pay subcontractors or materialmen; or

(iii) continued failure to perform or of unsatisfactory performance in accordance with the terms of one or more Contracts, provided that the failure to perform or unsatisfactory performance was not caused by acts beyond the control of the Vendor; or

(c) suspension or debarment by another Governmental Entity including, but not limited to, the City of Jacksonville;

(d) actions by the Vendor that are determined by the Chief Procurement Officer to be fraudulent or in bad faith;

(e) violation of JEA's or the City of Jacksonville's Ethics Code;

(f) violation of provisions of this Code relating to Ex Parte Communications;

(g) existence of delinquent obligations of the Vendor to JEA, including claims by JEA for liquidated damages under any Contract; and

(h) any other cause the Chief Procurement Officer determines to be so serious and compelling as to justify a Vendor's suspension or debarment.

(3) *Suspension/Debarment Timeframes.* The Chief Procurement Officer, in concurrence with the Chief of the Business Organizational Element, shall consider the causes set forth in (2) above in determining the length of a Vendor's suspension or debarment. Suspensions shall be subject to the maximum length as set forth below:

a First Offense – up to 2 years suspension of bidding privileges

b Second Offense – up to 5 years suspension of bidding privileges

c Third Offense – Vendor is debarred and bidding privileges are suspended permanently.

(4) *Effect of Suspension or Debarment*. A Vendor that is suspended or debarred under this Section 4-102 shall be ineligible to participate in Procurements or as otherwise specified by the CPO. The suspension or debarment may extend to all entities with common ownership or common management as the Vendor that has been suspended or debarred and may include work undertaken by the debarred Vendor (or such related entity) as a subcontractor or materialman, as determined by the CPO on a case by case basis. JEA has the option to debar a Vendor at any time depending on the egregiousness of their actions, and is not required to issue a First or Second offense as described above.

(5) *Decision*. The Chief Procurement Officer shall issue a written letter to the Vendor informing it of the decision to suspend or debar that Vendor. The decision shall:

(a) recite relevant facts material to the Chief Procurement Officer's decision;

(b) state the reasons for the decision;

(c) state whether the Vendor is a suspension or debarment;

(d) state the timeframe for suspension or debarment; and

(e) inform the suspended or debarred Vendor involved of any rights to administrative review as provided in this Article 5.

(5) *Finality of Decision*. A suspension or debarment decision by the Chief Procurement Officer shall be final and conclusive, unless appealed.

4-103 Creation of the Procurement Appeals Board

The Chief Executive Officer shall appoint a Procurement Appeals Board composed of a chair and two other members of the Awards Committee who shall serve until their successors are appointed by the Chief Executive Officer. A representative from the Office of General Counsel shall serve as counsel to the Procurement Appeals Board. The chair and two other members of the Procurement Appeals Board must be present to constitute a quorum of the Procurement Appeals Board.

4-104 Procurement Appeals Board Procedures

(1) Meetings of the Procurement Appeals Board shall be held in accordance with Florida's Open Meetings Laws. Accordingly, meetings will be publicly noticed, minutes will be taken, and a member of the Procurement Appeals Board shall not discuss with another member any matter which foreseeably may

come before the Procurement Appeals Board unless the discussion occurs in a meeting held in accordance with Florida's Open Meeting Laws.

(2) Each member of the Procurement Appeals Board shall have one vote. A decision by the Procurement Appeals Board shall require a majority vote of the members of the Procurement Appeals Board.

(3) The chair of the Procurement Appeals Board shall have the authority to establish procedures for the Procurement Appeals Board and its meetings, provided that such process and procedures are consistent with this Code and the Operational Procedures.

4-105 Authority of Procurement Appeals Board

The Procurement Appeals Board is authorized to review and make a final decision on any Appeal of a written decision issued by the Chief Procurement Officer under:

(a) Section 4-101 (Protests) of this Code; or
(b) Section 4-102 (Suspensions and Debarments) of this Code.

The Procurement Appeals Board is not authorized to intercede in, or hear Appeals relating to, Determinations made in connection with Vendor disputes regarding performance under a Contract, other than the authority granted to review and make decisions regarding Appeals of Suspensions or Debarments as provided in Section 4-102 of this Code.

4-106 Appeals

(1) *Appeal Submittal*. A Vendor seeking to appeal a decision of the Chief Procurement Officer under Section 4-101 or 4-102 of this Code shall submit its appeal in writing by letter or email to the Chief Procurement Officer in accordance with the timeliness and other requirements set forth in this Section 4-106 (an "Appeal"). The Appeal shall clearly state the following:

(a) the grounds, relevant facts and legal authority supporting the Appeal; and
(b) acts supporting the Vendor's standing to Appeal.

(2) *Timeliness and Standing.* An Appeal relating to a decision of the Chief Procurement Officer under Section 4-101 of this Code must be received by the Chief Procurement Officer no later than three Business Days after issuance of a written decision by the Chief Procurement Officer. An Appeal relating to a decision of the Chief Procurement Officer under Section 4-102 of this Code must be received by the Chief Procurement Officer no later than 15 days after issuance of a decision by the Chief Procurement Officer under Section 4-102. To have standing to Appeal, a Vendor must have been adversely affected by such decision.

(3) Failure to submit a timely Appeal or to have standing to Appeal under subsections (1) and (2) of this Section 4-106 shall result in dismissal of the Appeal and constitute a waiver of all rights to appeal a decision of the Chief Procurement Officer. A Determination of whether an Appeal meets the requirements

of subsections (1) and (2) shall be made by the chair of the Procurement Appeals Board and is not subject to appeal to the Procurement Appeals Board.

(4) All written information, documents, materials and legal authority the Vendor making an Appeal desires to provide to the Procurement Appeals Board must be sent to the Chief Procurement Officer and received by the deadline established by the chair of the Procurement Appeals Board in the notice of hearing provided to the Vendor making the Appeal.

(5) Upon receipt of a timely and proper Appeal, the Chief Procurement Officer will notify Vendors known to JEA to be directly affected by the outcome of the Appeal. Any information, materials and legal authority relating to the Appeal that any such Vendor desires to provide to the Procurement Appeals Board must be received by the deadline established by the Chief Procurement Officer in such notice.

4-107 Review of Appeals

(1) Upon receipt of an Appeal, the Chief Procurement Officer shall forward the Appeal to the Procurement Appeals Board and, if the Appeal is determined by the chair of the Procurement Appeals Board to be proper and timely, a meeting of the Procurement Appeals Board to consider the Appeal shall be scheduled.

(2) Representatives of the Vendor appealing the decision, will be afforded an opportunity to present the merits of the Appeal based solely upon the grounds, facts and legal authority contained in its written Appeal submitted to the Chief Procurement Officer. Representatives of any other Vendors adversely affected by the resolution of the Appeal will also be given an opportunity to be heard and to present information before the Procurement Appeals Board. The Chief Procurement Officer and the Chief Procurement Officer's legal counsel shall also be given an opportunity to respond to the Appeal and the presentations to the Procurement Appeals Board. Formal rules of evidence, including, but not limited to, those found in the Florida Evidence Code, do not apply to presentations made at meetings of the Procurement Appeals Board. The Chair of the Procurement Appeals Board may impose reasonable limitations on the amount of time each Vendor has to present, allow members of the Procurement Appeals Board to ask questions of any party at any time, and may impose other reasonable requirements relating to all presentations and the conduct of the meeting. The chair of the Procurement Appeals Board shall have the authority to make all Determinations and resolve any disputes concerning the process and procedures for Appeals and the conduct of the meeting.

4-108 Standard of Review for Procurement Appeals Board

(1) The standard of review used by the Procurement Appeals Board in making its decision shall be whether the Chief Procurement Officer's decision is:

(i) in conflict with this Code and the Operational Procedures;

(ii) arbitrary;
(iii) capricious;
(iv) dishonest;
(v) fraudulent;
(vi) clearly erroneous;
(vii) illegal; or
(viii) without any basis in fact or otherwise must be reversed based on applicable law.

(2) The burden shall be on the Vendor appealing the Chief Procurement Officer's decision to demonstrate that the standard of review is met.

(3) A majority vote of the members of the Procurement Appeals Board shall be required to render a decision.

(4) The Procurement Appeals Board shall deliberate at the meeting held to consider the Appeal and announce its decision prior to adjourning the meeting. The decision of the Procurement Appeals Board shall be final and binding. Following the adjournment of the meeting, the Procurement Appeals Board will issue a written decision within three (3) business days.

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Amended and Restated JEA Procurement Code

Effective April ~~27, 2021~~1, 2023

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DEFINITIONS

Addendum means a document issued by JEA which modifies a Solicitation.

Appeal shall have the meaning set forth in Section ~~5~~4-106 of this Code.

Award means the written approval of the JEA Awards Committee with the written concurrence of the Chief Executive Officer that a Formal Purchase will be in accordance with this Code and the best interest of JEA.

Awards Committee means the body appointed by the Chief Executive Officer in accordance with Section 2-106 of this Code.

Best and Final Offer or *BAFO* means a Vendor's final offer following the conclusion of contract negotiations in connection with an Invitation to Negotiate.

Bid means a Vendor's offer to provide Services or Supplies in response to an Invitation for Bid.

Bidder means a Vendor submitting a Bid in response to an Invitation to Bid.

~~*Bond Insurance* means an agreement supplied by an insurance company in conjunction with a debt issue that provides for the guarantee of payment of principal and interest to the debt holder.~~

Business Day is any day except any Saturday, any Sunday or any holiday observed by JEA's Procurement office.

~~*Cap* means an agreement obligating the seller of the Cap to make payments to the buyer of the Cap, each payment under which is based on the amount, if any, by which a reference price or level or the performance or value of one or more underlying interests exceeds a predetermined number, sometimes called the strike/Cap rate or price.~~

Chief Procurement Officer or *CPO* means the person holding the position appointed in accordance with Section 2-103 of this Code.

Code means this Amended and Restated JEA Procurement Code.

~~*Collar* means an agreement to receive payments as the buyer of an Option, Cap, or Floor, and to make payments as the seller of the Collar of a different Option, Cap, or Floor.~~

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Construction means the process of building, altering, repairing, improving, or demolishing any structure or building, or other improvements of any kind to any real property. It does not include the routine operation, routine repair, or routine maintenance of existing structures, buildings, or real property.

Construction Management Entity means a licensed general contractor or a licensed building contractor, as defined in Section 489.105, Florida Statutes, as amended, who coordinates and supervises a Construction project from the conceptual development stage through final Construction, including the scheduling, selection, contracting with, and directing of specialty trade contractors, and the value engineering of a project.

Construction Manager at Risk or CMAR shall have the meaning set forth in Section 3-109 of this Code.

Consultants' Competitive Negotiation Act or CCNA means Section 287.055, Florida Statutes, as amended, relating to the Procurement of certain architectural, engineering, landscape architectural, and mapping and surveying Services.

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Contract means all types of agreements for the Procurement of Supplies or Services, regardless of what these agreements may be called, and shall include, but not be limited to, a Purchase Order issued by JEA and accepted by a Vendor.

Contract Amendment means a written amendment executed after the execution of the Contract formalizing any revisions to the Contract.

Collaborative Procurement means a Procurement undertaken by JEA in accordance with Section 3115 of this Code.

Data means recorded information, regardless of form or characteristic.

Design-Build Contract means a single Contract with a Design-Build Firm for the design and Construction of a Construction project as defined in CCNA.

Designee has the meaning set forth in Section 4-302 of this Code.

Determination means a finding or decision by JEA made in the course of the process of procuring Supplies or Services under this Code.

Emergency shall have the meaning set forth in Section 3-113 of this Code.

Ex Parte Communication has the meaning set forth in Section 1-107 of this Code.

[illegible]

Formal Purchase shall have the meaning set forth in Section 3-101 of this Code.

Governmental Entity means any state or territory of the United States, or any county, city, town or other subdivision of any state or territory of the United States, or any public agency, public authority, educational, health, or other institution of such subdivision.

[illegible]

Intent to Award means JEA's announcement via an email, posting of the Awards Committee agenda, or issuance of an Addendum stating its intent to award a Formal or Informal Contract.

Invitation for Bid or *IFB* means a type of Solicitation requesting price offers and qualification information for defined Supplies or Services.

Invitation to Negotiate or ITN means a type of Solicitation requesting competitive sealed replies with the intent to select one or more Vendors with which to commence negotiations for the procurement of Supplies or Services, and usually concluding with a Best and Final Offer from Respondents.

JEA means that body politic and corporate created and established in Article 21 of the Charter of the City of Jacksonville.

JEA Board means the members of the JEA appointed to serve as provided by Section 21.03 of the JEA Charter.

JEA Charter means Article 21 of the Charter of the City of Jacksonville, as amended from time to time.

Letter of Credit means a commitment, usually made by a commercial bank, to honor demands for payment of an obligation upon compliance with conditions and/or the occurrence of certain events specified under the terms of the commitment.

[illegible]

Operational Procedures means the written process and procedures applicable to JEA Procurements and Procurement activities that have been promulgated in accordance with this Code.

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[illegible] department, group, business unit. — that utilizes Supplies or Services procured under this Code.

Organizational Element Manager means the person designated by the Chief Executive Officer to have responsibility for Procurement policies and procedures for certain categories of Supplies and Services under Section 2-102 of this Code.

Pre-Source Selection Methods means the pre-source selection methods described in Section 3-103 of this Code.

Pilot Project shall have the meaning set forth in Section 3-118 of this Code.

Post, Posting or Posted means placing documents or information on JEA's centralized internet website in the manner and location in which similar documents or information are typically posted.

Procurement means purchasing, renting, leasing, or otherwise acquiring; or selling, renting, leasing or otherwise disposing of any Supplies or Services, including, but not limited to, all functions that pertain to such activities – e.g., description of requirements, selection and solicitation of sources, and preparation and Award.

Procurement Appeals Board means the body comprised of at least three members of the Awards Committee as designated in this Code to hear Appeals regarding Procurement actions in accordance with Article 5 of this Code.

Professional Services shall have the meaning set forth in the CCNA.

JEA Project Manager shall have the meaning set forth in Section 3-122.

Proposer means a Vendor submitting a Proposal in response to a Request for Proposals.

Proposal means a Vendor's submittal of its offer in response to a Request for Proposals.

Protest shall have the meaning set forth in Section ~~5~~4-101 of this Code.

Protestant means a Vendor who files a timely and proper Protest in accordance with Article 5 of this Code.

Purchase Order means a document issued by JEA requesting that a Vendor provide specified Supplies and Services to JEA and may contain additional terms and conditions related to the provision of such Supplies and Services.

Real Estate means land, including buildings and improvements, its natural assets, easements or a permanent interest therein.

[illegible]

Request for Proposals means a type of competitive Solicitation requesting offers that includes qualifications, methods or other information, and may or may not include price, in the form of a Proposal.

Request for Qualifications or RFQ has the meaning set forth in Section 3-103 of this Code.

Response means a Vendor's submittal of its qualifications and price to in response to an ITN or other Solicitation.

Respondent means a Vendor submitting a Response to an ITN or other Solicitation.

Responsible Bidder (or Responsible Proposer or Responsible Respondent) means a Vendor that, in the Chief Procurement Officer's Determination, has the business judgment, experience, facilities and capability in all respects to perform fully the Solicitation requirements, and the integrity and reliability that will assure good faith performance.

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Responsive Bidder (or Proposer or Respondent) means a Vendor that, in the Chief Procurement Officer's Determination, has submitted a Bid, Response or Proposal that conforms in all material respects to a Solicitation.

Reverse Auction means a type of auction in which sellers bid for the prices at which they are willing to sell their Supplies or Services.

[illegible]

Services means the furnishing of labor, time or effort by a Vendor, and includes, but is not limited to, work performed on Construction projects and the receipt, delivery and transmission of electric power, fuel, by-products or thermal energy, work customarily rendered by attorneys, certified public accountants, insurance agents, financial advisors, personnel consultants, health care providers and consultants, systems consultants, software or technology consultants, temporary staffing providers, and management consultants, and administrative, maintenance, repair, installation and other technical services. This term shall not include employment agreements or collective bargaining agreements.

Single Source has the meaning set forth in Section 3-112 of this Code.

Solicitation means a document (which may be electronic) issued by JEA for the Formal Purchase of Supplies, Services, or Real Estate.

Source Selection means the type of Solicitation advertised or Procurement method JEA utilizes to obtain responses from Vendors to provide Services or Supplies (e.g., Invitation for Bids, Request for Proposals, Invitation to Negotiate)

Specifications means any description of the physical or functional characteristics, or of the nature of an item of Supply or Service. It may include a description of any requirement for inspecting or testing an item of Supply or Service or preparing such item for delivery. Also commonly referred to as Technical Specifications.

Supplies means all property, including but not limited to, equipment, materials, repair parts, consumables, tools, printing, and leases of real property.

[illegible]

association; exempt wholesale generator; co-generator or small power producer, or other entity whose business purpose is the generation or transmission or distribution or the promotion of the efficient use of electricity or water, approved by the Chief Procurement Officer, with whom JEA may legally engage in a Collaborative Procurement provided in Section 3-115 of this Code or a Joint Project as provided in Section 3-117 of this Code.

Vendor means any person or legal entity that provides, agrees to provide, or is interested in providing, Supplies or Services to JEA.

ARTICLE 1- GENERAL PROVISIONS

1-101 Purposes, Rules of Construction

(1) *Interpretation.* This Code shall be construed to be consistent with the guiding principles and to promote its underlying purposes and policies set forth in this Section 1-101.

(2) *Guiding Principles*. This Code shall at all times be subject to the provisions of the JEA Charter found in Article 21 (JEA), Charter of the City of Jacksonville and the following guiding principles:

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(a) *Open and Fair Competition*. To the greatest extent reasonably possible, JEA shall use fair, competitive, and generally accepted government Procurement methods that seek to encourage the most competition and best price for the purchase of supplies, construction, professional and other contractual services. JEA should adhere to all applicable state procurement laws, including but not limited to laws governing the purchase of construction services and professional design services.

(b) *Transparency in Procurement processes*. This Code and all Procurement policies, Operational Procedures, rules, directives, standards, and other procurement governing documents, including any amendments thereto, shall be posted on JEA's website in a conspicuous manner for the public to view. All records of JEA Procurement activities shall be subject to disclosure under Florida's public records laws, including, but not limited to those laws codified in Section 119, Florida Statutes, as amended.

(c) *Use of certain agreements.* The use of confidentiality, nondisclosure or similar agreements by government agencies are contrary to open and transparent government. Except regarding information or records deemed by JEA to be confidential or exempt information or records by law, JEA should not enter into confidentiality or nondisclosure agreements with third parties and should use confidentiality, nondisclosure or similar agreements sparingly in the conduct and operation of its Procurement activities. Additionally, JEA shall not require a member, officer or employee to maintain the confidentiality of information or records that is not confidential or exempt by law.

(3) *Purposes and Policies*. The underlying purposes and policies of this Code are:

(a) to provide for increased public confidence and consistency in the procedures followed in JEA Procurement;

(b) to ensure the fair and equitable treatment of all persons who deal with the JEA Procurement system;

(c) to maximize, to the fullest extent practicable, the purchasing value of JEA funds;

(d) to foster effective, broad-based competition among vendors purchasing good and services from JEA;

(e) to provide safeguards for the maintenance of the quality and integrity of the JEA Procurement system, and

(f) to ensure JEA's Procurement activities comply with all applicable Florida Statutes.

(4) *Singular-Plural and Gender Rules*. In this Code, unless the context requires otherwise, words in the singular include the plural, and those in the plural include the singular.

(5) *Use of Capitals in Text*. Capitalized terms used in this Code shall have the meanings given to them in the Definitions section of this Code.

(6) *Job Titles*. If a JEA job title used in this Code is changed in the future due to JEA organizational changes, this Code shall be construed by substituting the appropriate successor job title.

(7) *Interpretation*: Where the word "shall" is used, it connotes a mandatory requirement. Where the word "may" is used, it connotes a permissive requirement.

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1-102 Application of this Code

(1) [illegible] repeals and replaces all previously adopted versions of the JEA Procurement Code. Notwithstanding the foregoing, nothing herein shall affect the validity of Procurement activities conducted in compliance with the version of the Code in effect at the time such activities were conducted.

(2) *Application to JEA Procurement.* This Code shall apply to all expenditures of public funds under Contract by JEA, irrespective of their source. It shall also apply to the sale or other disposal of JEA property and Supplies.

(3) *Application of City of Jacksonville Procurement Code.* If the Code is silent on a specific procurement procedures, JEA may defer to the City of Jacksonville Code where addressed.

1-103 Determinations

Written Determinations required by this Code shall be retained in the appropriate official Procurement or Contract file maintained in accordance with promulgated by the Chief Procurement Officer.

1-104 Policy of Continuous Improvement

Suggestions for Improvements. The JEA Board intends for this Code to be a dynamic document comprising the best available public sector Procurement practices. To this end, the Chief Executive Officer encourages employees of JEA and others who deal with the JEA Procurement system to submit to the Chief Procurement Officer any ideas or suggestions for improvements to this Code.

1-105 Jacksonville Small Emerging Business (JSEB) Program; Minority Business Enterprises

JEA shall adhere to the City of Jacksonville's Small Emerging Business (JSEB) Program, or successor city program, in its Procurement procedures. Subject to applicable federal, state and local laws, with the JEA Board's approval, JEA is authorized to implement and to take all actions necessary to administer a race-conscious purchasing and Procurement program to remedy the present effects of past discrimination by JEA, if any, in the awarding of Contracts. Any such race-conscious program implemented by JEA to remedy the present effects of past discrimination by JEA, if any, in the awarding of Contracts must be supported by evidence and based on the required criteria and standards as set forth in applicable federal and state laws.

1-106 General Counsel of the City of Jacksonville; Engagement of Legal Services

The General Counsel of the City of Jacksonville has the responsibility for providing all legal Services to JEA, including, but not limited to, legal Services relating to Procurement matters. The General Counsel may employ, supervise and terminate assistant counsels to assist with the efficient provision of legal Services

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for JEA. The General Counsel may authorize JEA to engage outside counsel upon certification by the General Counsel of compliance with the City of Jacksonville's Charter and JEA's authority, and a written finding of necessity by the General Counsel. The General Counsel shall consult with JEA before the General Counsel selects outside counsel. The provision of all outside legal Services to JEA shall be in accordance with the terms of an engagement letter authorized and approved by the General Counsel, including, but not limited to, the scope of the services provided and the maximum indebtedness of JEA's obligations in connection with the engagement.

The provision of legal Services as contemplated by this Section 1-106 shall include all legal related services, e.g., court reporters, expert consultants or witnesses, and Real Estate property appraisers. Legal counsel engaged by JEA shall have the authority to engage such related legal Services only to the extent that the vendor of such related legal Services and the maximum indebtedness of JEA's obligations in connection with such services is approved in by the General Counsel and described in the engagement letter for such legal counsel. The engagement of related legal Services by outside counsel shall not be used as a means to circumvent the competitive bidding requirements or any other provisions of this Code.

1-107 Ex Parte Communication Prohibited

Adherence to procedures that ensure a fair open and impartial Procurement process is essential to the maintenance of public confidence in the value and soundness of the important process of public Procurement. Therefore, except as provided in subsection (3) of this Section 1-107, employees, agents and all other representatives of a Vendor shall be strictly prohibited from communicating, directly or indirectly, with any of the JEA representatives described in subsection (1) below during a period described in subsection (2) below.

(1) *Persons covered*. The prohibitions of this Section 1-107 shall apply to all JEA Board members, employees, agents, and other representatives if such persons are involved in JEA's Procurement process, or have any decision-making authority with respect to an Award.

(2) *Periods.* Ex Parte Communications are prohibited during the following periods:

(a) from the advertisement of a Solicitation through the Award of a Contract or cancellation of the Solicitation prior to Award; and

(b) from the initiation of a Protest through final resolution of such Protest under this Code.

(3) *Exclusions*. This Section 1-107 shall not prohibit:

(a) communications concerning process and questions regarding a Solicitation addressed to the JEA Procurement staff member designated in a Solicitation to answer questions about the Solicitation, including, but not limited to, communications initiated by such staff member in order to clarify aspects of a Bid, Proposal or Response;

(b) communications during public meetings held in accordance with Florida's Open Meetings Laws, for the purpose of discussing a Solicitation or an evaluation or selection process including, but not limited to, substantive aspects of the Solicitation document (Such public meetings may include, but are not limited to, pre-Bid, pre-Proposal or pre-Response meetings, site visits to JEA's or a Vendor's facilities, interviews or negotiation sessions as part of the selection process, and other presentations by Bidders, Proposers, or Respondents. Exempted communications at such public

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meetings shall be limited to those consistent with the advertised purpose of the meeting and shall be communicated in a manner which can be heard by all those present at the meeting.);

(c) communications during negotiation sessions with Vendors to the extent exempt under Section 286.0113(2), Florida Statutes, as amended;

(d) Awards Committee and the

~~(d)~~(e) Procurement Appeals Board ~~at~~ meetings advertised and conducted pursuant to Florida's Open Meetings Laws;

~~(e)~~(f) contact by a Vendor currently under Contract with JEA, but only regarding work under that Contract and unrelated to the Solicitation or Protest currently in process; or

~~(f)~~(g) communications between a Vendor and the Chief Procurement Officer, or JEA's legal counsel in accordance with the requirements of Article 5 of this Code.

(4) Violation of this Section 1-107 by a Vendor or any of its employees, agents or other representatives may be grounds for any one or more of the following: (i) disqualification of the Vendor from eligibility for an Award; (ii) rescission of any Award to the Vendor; (iii) termination of any Contract with the Vendor; or (iv) a decision to suspend or debar the Vendor.

1-108 Retention of Procurement Records

All Procurement records shall be retained, made available, and disposed of in accordance with the requirements of all applicable laws, including but not limited to Chapter 119, Florida Statutes (Florida's Public Records Laws), as amended, and the rules and regulations promulgated by the Division of Library and Information Services of the Florida Department of State.

1-109 Collection of Data Concerning JEA Procurement; Annual Vendor Survey

The Chief Procurement Officer shall prepare and maintain statistical Data concerning the Procurement, usage, and disposition of all Supplies and Services, except for Procurements exempt under Section 2-102 of this Code and not procured under a process overseen by the Chief Procurement Officer. Organizational Element Managers overseeing Procurements exempt under Section 2-102 shall furnish such reports as the Chief Procurement Officer may require concerning usage and needs, and the Chief Procurement Officer shall have authority to prescribe forms to be used by such Organizational Element Managers in requisitioning, ordering, and reporting of Supplies and Services.

The Chief Procurement Officer shall annually conduct a survey of actual, interested and prospective Bidders, Proposers, Respondents, and Vendors to obtain feedback on JEA's Procurement process. Such survey shall be on a form approved by the JEA Board and participation in the survey shall be open to actual, interested and prospective Bidders, Respondents, and Vendors. survey topics may include, without limitation, various aspects of JEA's Procurement process such as information transparency and accessibility, preconferences, bid submittal packages, evaluations, and Awards. The Chief Procurement Officer shall report the results of such

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survey to the JEA Board and the JEA Board shall consider such survey results during the JEA Board's biennial review of this Code.

1-110 Record of Procurement Actions

The Chief Procurement Officer shall prepare and deliver a written report to the JEA Board on or before the JEA Board's last regularly scheduled meeting held in each calendar year summarizing all Awards made during the immediately preceding fiscal year. Such written report shall contain at a minimum the following information:

(a) The number of Awards for the reporting fiscal year;

(b) A detailed listing of all Awards categorized by service type (e.g., Construction, Professional Services, Supplies, etc.), Award type (e.g., Single Source, Emergency, Request for Proposals, Invitation to Negotiate, piggyback, etc.) and a brief description of each Award containing the Vendor name, Contract amount and Contract term;

(c) The number of JSEB Awards categorized by service type (e.g., Construction, Professional Services, Supplies, etc.), Award type (e.g., Single Source, Emergency, Request for Proposals, Invitation to Negotiate, piggyback, etc.), and a brief description of each Award containing the JSEB contractor name, Contract amount and Contract term;

(d) The number of Protests for the reporting fiscal year and the outcome of each Protest (i.e., whether JEA prevailed); and

(e) The annual survey results pursuant to the survey requirement in Section 1-109 of this Code.

After providing such written report to the JEA Board, the Chief Procurement Officer shall deliver the report to the Jacksonville City Council and the Mayor and post the report on JEA's website in a conspicuous manner for the public to view.

DESIGNATIONS, AND COMMITTEES

2-101 Procurement Authority and Duties of the JEA Board

Pursuant to Article 21 of the Charter of the City of Jacksonville, the JEA Board shall review and approve this Code and all amendments to this Code. The JEA Board may not delegate its approval of this Code, including any amendments thereto, to the Chief Executive Officer or any other officer, employee or agent of JEA.

The Chief Procurement Officer shall ~~biennially~~periodically review this Code and JEA's other Procurement procedures in accordance with the JEA Charter, and shall report to the JEA Board on the results of such review including any recommendations for changes the Chief Procurement Officer deems appropriate.

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2-102 Procurement Code Exemptions

(1) Due to the nature of the following Supplies and Services, such Supplies and Services need not be procured through the Chief Procurement Officer and are not subject to approval by the Awards Committee, but may be procured using Procurement policies and procedures established by an Organizational Element Manager designated by the Chief Executive Officer for that category of Supplies and Services:

(a) Generation Fuels, Emission Allowances, and Associated Transport;

(b) Byproducts;

(c) Purchase or Sale of Electric Energy, Electric Generation Capacity, Electric Transmission Capacity and Transmission Services – Short- and Long-Term Transactions;

(d) Sale of JEA Owned Transmission and Ancillary Services, including applicable Enabling Agreements;

(e) Environmental Allowances; ~~(f)~~

(f) Real Estate, including easements; ~~and (g)~~

~~(e)~~(g) Community Outreach Procurements~~.~~; and

The Operational Procedures shall provide more detail concerning the ~~types of Supplies and Services included within~~ procedures on how to procure the above listed exempt categories of ~~Procurements listed above.~~ Supplies and Services.

(2) Prior to the Procurement of Supplies or Services by an Organizational Element Manager, the Organizational Element Manager shall ~~establish Procurement policies and procedures for the exempt category of Supplies and Services and~~ obtain all appropriate approvals required by the Procurement Exemption for the specific procurement which can be found in the Operational Procedures and verify there are no conflicts of interest between JEA and the vendor.

(3) In the absence of an Organizational Element Manager for a category of Supplies and Services exempt under subsection (1) of this Section 2-102, the Supplies and Services shall be procured through the Chief Procurement Officer in accordance with this Code and Operational Procedures.

(4) Property and casualty insurance, and Human Resource Benefits may be awarded through the broker or consultant for those services with ultimate approval by the Awards Committee.

2-103 Appointment and Authority of the Chief Procurement Officer

(1) *Central Procurement Officer of JEA.* The Chief Executive Officer shall appoint a Chief Procurement Officer. The Chief Procurement Officer shall be a full-time, appointed employee of JEA with demonstrated executive and organizational ability. The Chief Procurement Officer shall serve as the central point of contact for JEA Procurement matters.

(2) *Operational Procedures*. The Chief Procurement Officer shall promulgate Operational Procedures governing JEA Procurement activities that are consistent with the provisions of this Code. Whenever practicable, the Operational Procedures shall be updated to incorporate the use of new technologies, best practices, and streamlined procedures for continuous improvement of JEA's Procurement activities. Material revisions to the Operational Procedures shall be approved by the Office of General Counsel prior to the revisions becoming effective.

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(3) *Duties.* Except as otherwise specifically provided in this Code, the Chief Procurement Officer duties shall include, but are not limited to:

(a) supervise and coordinate the Procurement of all Supplies and Services by JEA;

(b) make Determinations as to what constitutes a minor irregularity in Bids, Proposals and Responses and when Bids, Proposals and Responses should be rejected as unresponsive;

(c) conduct or coordinate training on JEA's Procurement policies and processes and related matters;

(d) develop and maintain the standard contract language for Solicitations, Contracts and other documents used in the JEA's Procurement process in consultation with the Office of General Counsel; and

(e) exercise the duties given to the Chief Procurement Officer in Article 5 of this Code.

2-104 Delegation of Authority by the Chief Procurement Officer

The Chief Procurement Officer may delegate any duty or authority given to the Chief Procurement Officer under this Code in writing to one or more designees.

2-105 Procurement Document Review

The Chief Procurement Officer shall create a process and procedures to ensure all Solicitations and other documents used in JEA's Procurement process are reviewed to ensure compliance with this Code, the Operational Procedures and all applicable laws and regulations. The process and procedures for review of all Solicitations shall be set forth in the Operational Procedures.

2-106 Awards Committee

(1) *Awards Committee Membership*. The JEA Awards Committee shall consist of three ~~to five~~ Vice Presidents or other senior Officers of JEA appointed by the Chief Executive Officer. Members of the Awards Committee shall serve a two-year term, or until their successors have been appointed. Multiple terms are permitted. The Chief Executive Officer will appoint an Awards Committee member to be the chair of the committee who will run the meeting. Members of the Awards Committee may be removed at any time with or without cause by the Chief Executive Officer. If an Awards Committee member shall cease to be qualified to serve, then the member's term shall be vacant until the Chief Executive Officer appoints a replacement.

(2) *Liaisons*. There shall be three permanent liaisons present at all meetings of the Awards Committee which shall include the Chief Procurement Officer, a representative from the Budget Organizational Element designated by the Chief Executive Officer and a representative from the Office of General Counsel. These liaisons shall not be considered voting members of the Awards Committee for purposes of Florida's Open Meetings Laws.

(3) *Quorum*. The presence of at least ~~three~~two voting members of the Awards Committee shall constitute a quorum. If a quorum is not present or any one of the three Liaisons is not in attendance, the meeting shall be

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cancelled. If a voting member of the Awards Committee or a liaison is unable to attend a meeting of the Awards Committee, that voting member or liaison may designate an alternate to serve for that meeting, and the alternate shall for all purposes (including, but not limited to satisfying quorum requirements and voting) be considered a member or liaison, as the case may be, for that meeting.

2-107 Awards Committee Procedures

All meetings of the Awards Committee shall be held in accordance with this Code and the requirements of Florida's Open Meetings Laws and shall be properly noticed, and minutes shall be taken. The voting members of the Awards Committee shall not discuss any matter which foreseeably could come before the Awards Committee with another voting member of the Awards Committee unless such discussions take place in a duly noticed meeting held in accordance with Florida's Open Meetings Laws.

Each voting member of the Awards Committee shall have one vote. It shall take a majority of the voting members of the Awards Committee for an item to be approved. Items may be presented to the Awards Committee as part of a regular or a consent agenda. Items placed on the consent agenda shall be those items that do not require discussion or explanation prior to committee action. An individual Awards Committee member may remove items from the consent agenda prior to the vote on the consent agenda. An item removed from the consent agenda shall be discussed and acted upon separately following the consideration of the consent agenda. Such items may be taken up immediately following approval of the consent agenda or placed later on the agenda at the Chair's discretion. Except as otherwise provided herein, once an Award Item is reviewed and approved by the Awards Committee, JEA is authorized to proceed with executing a Contract. Items that are moved from the consent agenda to the regular agenda shall require the approval of the Chief Executive Officer before the Award is finalized.

The Chief Procurement Officer shall conduct all meetings of the Awards Committee and shall present each Award item placed on the regular agenda to the Committee for its consideration. The ~~Chief Procurement Officer~~Chair shall have the authority to determine the presence of a quorum and whether any voting requirement has been met ~~and~~. The Chief Procurement Officer shall be responsible for all administrative matters relating to the conduct of the Committee's business including, but not limited to, ensuring that proper notice is given, and minutes are taken.

2-108 Duties of the Awards Committee

(1) *Scope of Review.* The Awards Committee shall review each Award item presented to the Committee, by way of regular or consent agenda, and shall consider whether the proposed item is in compliance with this Code and in the best interest of JEA.

(2) *Required Approvals.* The following Procurements of Supplies and Services by JEA shall require approval ~~of, or ratification by,~~by the Awards Committee:

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Formal Purchases of Supplies and Services by JEA as provided in Section 3-101, unless exempt under Section 2-102 Code;

~~rescissions of Formal Solicitations and rejection all Bids, Proposals and Responses after Bids,~~

~~(c)~~(b) changes to, and renewals of, any Contracts executed in connection with an Award approved by the Awards Committee if:

(i) the financial impact of the change or renewal exceeds 10% of the amount of the most recent Award approved by the Awards Committee;

(ii) the financial impact of the change or renewal exceeds $1,000,000;

(iii) the change or renewal causes an Informal Purchase to exceed the threshold for a Formal Purchases set forth in Section 3-101 of this Code;

[illegible]

~~(v)~~(iv) the change or renewal, in the opinion of the Chief Procurement Officer, changes the Award approved by the Awards Committee in any material respect.

~~(d)~~(c) sales of Supplies or Services by JEA that exceed $300,000 or annual spend in excess of $300,000 for continuing services contracts, including, but not limited to the sale of any surplus items;

~~(e)~~(d) Procurements exempt under Section 2-102 (Procurement Code Exemptions) of this Code if required by the Procurement processes and procedures established by the applicable Organizational Manager; and

~~(f)~~(e) ratification of all Formal Purchases procured under Section 3-113 (Emergency Procurements) of this Code.

(3) *Availability of Funding for Procurement Items*. The Awards Committee shall approve Awards items only after receiving confirmation as provided in this Section 2-108(4) that sufficient funds are available for the Award. Prior to presentation to the Awards Committee, each Award item shall be reviewed and approved by the Budget

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(4) *Effect of Approval.* Once an Award item is reviewed and approved by the Awards Committee, and the Chief Executive Officer as needed, JEA is authorized to proceed with actions to finalize the Procurement of the Supplies or Services consistent with the Award, including but not limited to, execution of a Contract, issuance of a Purchase Order and notice to proceed, and acceptance of delivery of Supplies and Services, subject to lawfully appropriated funds. An Award may be rejected if, in the judgment of the Chief Executive Officer, the Award does not comply with the requirements of the JEA Procurement Code, Operational Procedures, or other applicable law.

ARTICLE 3 – SOURCE SELECTION AND CONTRACT FORMATION

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3-101 Formal Purchases

(1) Unless exempt under Section 2-102 of this Code, the following Procurements shall be considered Formal Purchases under this Code:

(a) the Procurement of Supplies or Services where the estimated aggregate costs and fees for the Procurement exceed $300,000 annually;

(b) the Procurement of Capital and O&M projects where the estimated total project costs and fees for the Procurement exceed $300,000;

~~(a)~~ "Public construction works" required to be competitively awarded under Section 255.20,

~~(a)~~ "Electrical work" required to be competitively awarded under Section 255.20, Florida

~~(b)~~(c) "Professional Services" required to be publicly announced under Section 287.055, Florida Statutes, as amended.

(2) Formal Purchases shall be procured using the process and procedures for Formal Purchases detailed in the Operational Procedures.

3-102 Informal Purchases

(1) Unless exempt under Section 2-102 of this Code, all Procurements not considered to be Formal Purchases under Section 3-101 of this Code shall be considered Informal Purchases.

(2) Informal Purchases may be made in accordance with Operational Procedures.

(3) Procurements shall not be artificially divided to constitute an Informal Purchase under this Section 3-102.

(4) Unless the Procurement is otherwise exempt under this Code, the Operational Procedures for Informal Purchases shall require, at a minimum, the following kind and number of quotations from prospective Vendors:

(a) one properly documented quotation for Informal Purchases of $10,000 or less; or

(b) three properly documented quotations for Informal Purchases exceeding $10,000; provided, however that if JEA fails to receive 3 quotations despite using all reasonable efforts to obtain 3 quotations, the Chief Procurement Officer may waive this requirement.

(5) Informal Purchases exceeding $50,000 shall be Posted for 7 to 10 calendar days.

(6) Architectural, engineering, landscape architectural, or registered surveying and mapping services considered "Professional Services" under the CCNA in the amount of $35,000 or less shall be exempt from competitive bidding under this Code. JEA may procure such services directly without competition.

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3-103 Methods of Pre-Source Selection

The Chief Procurement Officer may authorize any one or more of the following Pre-Source Selection Methods:

(1) A Request for Information ("RFI") is a Pre-Source Selection Method that requests written information about the capabilities of Bidders, Proposers or Respondents and may prepare interested Vendors for participation in future Solicitations. The publication of an RFI does not obligate JEA to make the purchases referred to in the RFI. JEA may use information obtained from RFIs to develop scopes of work for future Solicitations.

~~(1)~~ A Request for Qualifications ("RFQ") is a Pre-Source Selection Method used to qualify a pool

~~(2)~~(3) An Intent to Bid is a Pre-Source Selection Method intended to provide notice and information to potential Vendors of JEA's intent to issue a Solicitation for Supplies or Services. The Intent to Bid may request a response from Bidders confirming their intent to submit a Bid, Proposal or Response to a future JEA Solicitation. The publication of an Intent to Bid does not obligate JEA to make the purchases referred to in the Intent to Bid.

3-104 Methods of Source Selection

Unless exempt under Section 2-102 of this Code, all Formal Purchases shall be procured using one of the following Methods of Source Selection:

(a) Section 3-105 (Invitation for Bids (IFB));
(b) Section 3-106 (Request for Proposals (RFP));
(c) Section 3-107 (Consultants' Competitive Negotiation Act (CCNA) (Architectural, Engineering, Landscape Architectural, or Surveying & Mapping Services));
(d) Section 3-108 (Design-Build Contracts);
(e) Section 3-109 (Construction Management and Program Management);
(f) Section 3-110 (Multi-Step Competitive Bidding);
~~(f)~~(g) (g) Section 3-111 (Invitation to Negotiate (ITN))
~~(g)~~(h) Section 3-112 (Single Source);
~~(h)~~(i) Section 3-113 (Emergency Procurements);
~~(i)~~(j) Section 3-114 (Public Private Ventures);
~~(j)~~(k) Section 3-115 (Collaborative Procurements);
~~(k)~~(l) Section 3-116 (Joint Projects);
~~(l)~~(m) Section 3-117 (Use of Publicly Procured Contracts);
~~(m)~~(n) Section 3-118 (Pilot Projects);
~~(n)~~(o) Section 3-119 (Use of Reverse Auctions);

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~~Article 4 (Procurement of Financial Instruments and Services).~~

The Chief Procurement Officer may elect to use any one of the Methods of Source Selection listed in this Section 3-104 if the Method of Source Selection is deemed by the Chief Procurement Officer to be in the best interest of JEA consistent with the purposes and guiding principles set forth in Section 1-101 of this Code. Notwithstanding the foregoing, the Method of Source Selection shall comply with the requirements of this Code, the provisions of any grant or other funding or cooperative agreements to which JEA is a party, and all applicable laws and regulations, including but not limited to, statutory requirements for the Procurement of Professional Services subject to the CCNA and Construction services meeting certain statutory thresholds. The Operational Procedures shall establish a process and procedures for each Method of Source Selection.

3-105 Invitation For Bids (IFB)

An IFB may be used when JEA is capable of defining the Specifications for a Supply or Service. An Award generally will be made to the Responsive and Responsible Bidder who submits the lowest Bid in a sealed competitive bidding process. Notwithstanding the foregoing, the Chief Procurement may waive minor irregularities in a Bid and may reject all Bids if the Chief Procurement Officer deems such actions to be in the best interest of JEA.

3-106 Request for Proposal (RFP)

An RFP may be used when the Chief Procurement Officer determines that a Solicitation should include selection criteria in addition to price. Various combinations or versions of Supplies or Services may be proposed by a Vendor to meet the Specifications in the RFP.

An RFP may be used to procure Construction Services to the extent permitted by Section 255.20(1)(d)(2), Florida Statutes.

3-107 Consultants' Competitive Negotiation Act (CCNA) (Architectural, Engineering, Landscape Architectural, or Surveying & Mapping Services)

Architectural, engineering, landscape architectural, or registered surveying and mapping services considered "Professional Services" under the CCNA shall be procured in accordance with the requirements of the CCNA.

3-108 Design-Build Contracts

A Design-Build Contract may be used when the general design and construction requirements are known, but the detailed design and engineering has not been completed. Design-build contracts as defined in Section 287.055(2)(i), Florida Statutes, shall be procured in accordance with the CCNA and the Operational Procedures.

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3-109 Construction Management and Program Management

Services may be procured from Construction Management Entities and program management entities in accordance with the provisions of Section 255.103, Florida Statutes. After selection and competitive negotiations, a Construction Management Entity may be required to offer a guaranteed maximum price and a guaranteed completion date or a lump-sum price and a guaranteed completion date as a construction manager "at risk" in accordance with the provisions of Section 255.103, Florida Statutes (a "Construction Manager at Risk" or a "CMAR").

3-110 Multi-Step Competitive Bidding

The Multi-Step Bidding Method of Source Selection involves a two-phase process in which Bidders first submit proposed revisions to both the commercial and technical terms of the Solicitation. During the second phase of the process, Bidders submit a bid price based on a revised Solicitation issued by JEA. An Award is based solely on the price of the Bid and does not include additional discussions or negotiations of material terms and conditions with Bidders after Bids are received. Multi-Step Competitive Bidding allows JEA to obtain Vendor feedback before finalizing commercial and technical terms to be used in an Invitation for Bids.

3-111 Invitation to Negotiate (ITN)

The Invitation to Negotiate is a Method of Source Selection that allows JEA to directly negotiate with Vendors to obtain best overall value for JEA. Under the ITN, JEA first evaluates initial Proposals with the intent to identify one or more Responsive and Responsible Respondent with which JEA may enter into one or more rounds of negotiations. Negotiations may result in modifications to the scope of work and terms and conditions of the ITN, submission of revised Bids or Responses, and may conclude with the submission of Best and Final Offers from one or more Vendors. The procedures for conducting an Invitation to Negotiate shall be described in the ITN Solicitation and the Operational Procedures.

ITNs may provide best value for JEA when establishing master contracts or definite delivery contracts for complex Supplies or Services, or when determining or refining scope, methods, or other nonprice aspects of a Solicitation.

For each use of the ITN Method of Source Selection, prior to issuance of the ITN, the Chief Procurement Officer shall document the reasons an ITN will produce the best value for JEA compared to an IFB or RFP. In addition to negotiating price, additional reasons must be stated as to why negotiations are needed to realize best value for JEA. Examples of such reasons are "the ITN method allows refining approaches, methods, tools, requirements, deliverables, and systems;" or, "identifying and incorporating value added services offered by Vendors into final requirements."

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3-112 Single Source

A Contract may be awarded for Supplies or Services as a Single Source when, pursuant to the Operational Procedures, the Chief Procurement Officer determines that:

(a) there is only one justifiable source for the required Supplies or Services;

(b) the Supplies or Services must be a certain type, brand, make or manufacturer due to the criticality of the item or compatibility within a JEA utility system, and such Supplies or Services may not be obtained from multiple sources such as distributors;

(c) the Services are a follow-up of Services that may only be done efficiently and effectively by the Vendor that rendered the initial Services to JEA, provided the Procurement of the initial Services was competitive;

(d) at the conclusion of a Pilot Project under Section 3-118 of this Code, the Procurement of Supplies or Services tested during the Pilot Project, provided the Vendor was competitively selected for the Pilot Project~~-~~.

3-113 Emergency Procurements

In the event of an Emergency, the Chief Procurement Officer, or Designee, may make or authorize an Emergency Procurement, provided that Emergency Procurements shall be made with as much competition as practicable under the circumstances. A written Determination of the basis for the Emergency and for the selection of the particular Vendor shall be included in the Procurement file.

For purposes of this Section 3-113, an "Emergency" means any one of the following:

(a) a reasonably unforeseen breakdown in machinery;

(b) an interruption in the delivery of an essential governmental service or the development of a circumstance causing a threatened curtailment, diminution, or termination of an essential service;

(c) the development of a dangerous condition causing an immediate danger to the public health, safety, or welfare or other substantial loss to JEA;

(d) an immediate danger of loss of public or private property;

(e) the opportunity to secure significant financial gain for JEA, to avoid delays to any Governmental Entity, or avoid significant financial loss through immediate or timely action; or ~~(f) a valid public emergency certified by the Chief Executive Officer.~~

(f) a declared federal, state, or local state of emergency, or a valid public emergency certified by the Chief Executive Officer.

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The Chief Procurement Officer, or Designee, shall submit all Formal Purchases made under this Section 3-113 to the Awards Committee for ratification as soon as reasonably practicable after the Formal Purchase is made.

3-114 Public-Private Partnerships

JEA may receive unsolicited proposals or may solicit proposals for a qualifying project and may thereafter enter into a comprehensive agreement with a private entity, or a consortium of private entities, for the building, upgrading, operating, ownership, or financing of JEA's facilities in accordance with the provisions of Section 255.065, Florida Statutes, as may be amended from time to time. The Operational Procedures shall set forth a process and procedures for the receipt and solicitation of such proposals that meet the requirements of Section 255.065, Florida Statutes, as amended from time to time.

3-115 Collaborative Procurements

JEA may participate in, sponsor, conduct, or administer a Collaborative Procurement for the Procurement of any Supplies or Services or Real Estate with one or more Governmental Entities, utility industry partners, nonprofit organizations or purchasing alliances in accordance with the terms of an agreement entered into between the participants. Such Procurements shall be in accordance with this Code and the Operational Procedures.

JEA shall not participate in, sponsor, conduct, or administer a Collaborative Procurement agreement for the purpose of circumventing this Code.

3-116 Joint Projects

Except where doing so is to circumvent the purpose of this Code, JEA may enter into joint projects with public or utility industry partners, the City of Jacksonville and its other independent agencies, political subdivisions or other Governmental Entities (e.g., the United States Navy, the Florida Department of Transportation, etc.). Joint projects may include, but shall not be limited to, combined water, sewer, drainage and road projects with the City of Jacksonville and Florida Department of Transportation.

Notwithstanding the foregoing, the Procurement of Supplies and Services by JEA in a Joint Procurement shall be consistent with the guiding principles and purposes of this Code set forth in Section 1101.

3-117 Use of Publicly Procured Contracts

JEA may procure Supplies or Services by using or "piggybacking" on contracts of the City of Jacksonville or its independent agencies, political subdivisions, other city and state or governmental agencies, school board districts, community colleges, federal agencies, Governmental Entities, or public colleges or universities, provided that the contracts of such other entities were competitively procured and the terms and conditions of JEA's

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Contract are at least as favorable as the terms and conditions of the contract on which JEA is piggybacking. Formal Purchases using this Method of Source Selection shall be awarded through the Awards Committee.

3-118 Pilot Projects

A Pilot Project allows JEA to procure Supplies or Services on a trial basis in limited amounts and for a limited period of time in order to determine whether to proceed with a Formal Solicitation for the Procurement of such Supplies or Services.

If the estimated aggregate cost of Supplies and Services to be procured during a Pilot Project do not exceed $100,000, and the term of the Contract for the Pilot Project does not exceed two years, the selection of a Vendor to participate in the Pilot Project is not required to be selected using a competitive solicitation process unless required by applicable law. However, after the conclusion of the Pilot Project, the Supplies or Services evaluated during the Pilot Project shall be procured using one of the other Methods of Source Selection provided in Section 3-104 of this Code.

Where the cost to JEA of the Supplies and Services during the Pilot Project is $100,000 or more, JEA shall publicly advertise the Pilot Project so that Vendors may submit their qualifications to provide such Supplies or Services. Based on the qualifications submitted by Vendors in response to such public advertisement, JEA will select one or more Vendors to participate in the Pilot Project. Once the Pilot Project is complete, the Chief Procurement Officer will determine whether JEA will initiate a competitive bidding process to obtain the Supplies or Services.

3-119 Use of Reverse Auctions

When the Chief Procurement Officer determines that procurement by a Reverse Auction is in the best interest of JEA, the Chief Procurement Officer may procure Supplies or Services by Reverse Auction. Reverse Auctions may be used with the following Solicitation types:

(a) Invitation for Bids (IFB) – With Reverse Auction

(b) Request for Proposals (RFP) – With Reverse Auction

(c) Invitation to Negotiate (ITN) – With Reverse Auction

Reverse Actions are to be used solely for obtaining lowest pricing. Prior to conducting a Reverse Auction, the following must be established for each Bidder, Proposer or Respondent:

(a) Invitation for Bids –Bidders must provide documentation that they meet the minimum qualifications and any other requirements set forth in the IFB.

(b) Request for Proposals – The Proposers must provide fully responsive Proposals. JEA shall evaluate Proposals and select at the top three, or more, ranked Proposers to participate in a Reverse Auction to establish pricing.

(c) Invitation to Negotiate – At the conclusion of the negotiation process for an ITN, where all terms other than price have been agreed, JEA may choose to use a Reverse Auction to establish pricing.

3-120 Form of Contract Documents

The Office of General Counsel shall approve as to form all Contract documents for Formal Purchases. Contract Amendments do not require OGC form approval, unless otherwise provided in the Operational Procedures.

Purchase Orders may be used to form a Contract for Informal Purchases and Formal Purchases when the Chief Procurement Officer determines that a Formal Contract is not necessary. Purchase Orders shall be on a form that incorporates general terms and conditions reviewed and approved by the Office of General Counsel. If a Contract other than a Purchase Order is executed for an Informal Purchase, the Contract does not require form approval by the Office of General Counsel, unless specifically requested by ~~JEA~~the CPO, or unless such Contract contains terms materially different than JEA's standard terms and conditions~~, and can be executed as set forth in the Operational Procedures.~~.

In accordance with the JEA Charter, unless otherwise provided in the JEA Charter or by law, all Contracts of any kind, and in any form entered into by JEA, including, but not limited to, Procurement Contracts, Joint Project Contracts, interlocal agreements, and Purchase Orders for Informal Purchases shall [illegible]

3-121 Execution of Contract Documents

The Chief Executive Officer shall execute all Contracts. The Chief Executive Officer may delegate to the Chief Procurement Officer the authority to execute Contracts. Contracts and Purchase Orders may be executed by electronic means~~ or by facsimile signatures.~~.

3-122 JEA Project Manager

All Contracts shall provide for a JEA Project Manager who will have the responsibility for overseeing all Work under the Contract and all payments made by JEA under the Contract. The Operational Procedures shall contain additional details concerning the responsibilities of JEA's Project and Contract Managers.

3-123 Continuing Services Contracts

Continuing services contracts, and continuation contracts based on unit prices, may be utilized for recurring Procurements of Supplies and Services that are projected to be made over a period of time. The total amount of all Procurements issued under a continuing services contract shall not exceed JEA's maximum indebtedness set forth in the Contract or the amount as authorized by Florida Statutes for the specific category of work, if any, and shall comply with all other applicable laws.

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3-124 Contract Pricing Terms

Contract pricing terms are required in all Contracts and are the basis for payment approvals. The appropriate type of pricing terms will depend on the type of Contract and work being performed. The Operational Procedures may contain additional guidance concerning the type of pricing terms what are appropriate for certain types of Contracts.

3-125 Compliance with Federal and ~~Services~~

To the extent that ~~market commercial paper, variable rate demand obligations or other variable rate debt issued under the above resolutions;~~ [illegible] with the Office of General Counsel~~.~~ with the federal or state procurement requirement. In the event a Code ~~without further approval by the JEA Board.~~ provision is waived pursuant to this section, upon final approval of the contract award, the CPO shall notify the Chief Executive Officer.

ARTICLE ~~5~~4 - ADMINISTRATIVE REMEDIES

~~5~~4-101 Protests

(1) *Guiding Principles*. It is important that actual or prospective Bidders, Proposers and Respondents have confidence in JEA's Procurement process and procedures. One method of maintaining this confidence is to provide Vendors with an opportunity to file Protests relating to Solicitations and Awards ~~as provided in this Section 5-101.~~ and Intent to Award as provided in this Section 4-101. The provisions of this Article shall apply only to Formal Procurement actions as defined in Article 3-101 as provided herein. All other disputes will be resolved by the CPO as provided in the Operational Procedures. The provisions of this Article may not be used in connection with any Contract dispute, determination of Vendor performance, or Contract termination.

(2) *Right to Protest* *Procurement Actions*. Any Vendor who is adversely affected by [illegible] an Award or an Intent to Award may submit a written Protest meeting all of the requirements of subsections (3) and (4) of this Section ~~5~~4-101. Protests in connection with the requirements of a Solicitation or a Determination made in connection with a Solicitation shall include, but not be limited to, Protests concerning any event or aspect of the Procurement process that followed the issuance of the Solicitation and led to the Award or Intent to Award, Protests relating to the rejection of a Bid, Proposal or Response, including, but not limited to, whether a Bidder, Proposer or Respondent is Responsible or Responsive, and Protests relating to any ranking, scoring, or short-listing of Proposers or Respondents. Protests shall not include challenges to minimum qualifications, the Technical Specifications, the chosen procurement method, the evaluation criteria, the relative weight of the evaluation criteria, or the formula specified for assigning points to the evaluation criteria.

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(3) *Protest Requirements.* Protests shall:

(i) be submitted in writing in a letter or email addressed to the Chief Procurement Officer;

(ii) identify the Solicitation, Award, or Intent to Award, by number and title or other language sufficient to enable the Chief Procurement Officer to identify the Solicitation, Award, or Intent to Award;

(iii) demonstrate the timeliness of the Protest;

(iv) state the Protestant's complete legal name and legal standing to protest; and

(v) clearly state with particularity the issues and material facts supporting the Protest, and any legal authority upon which the Protest is based~~.~~; with requested remedy.

Contact information for the Chief Procurement Officer can be found at jea.com under the Procurement section of the website.

(4) *Timeliness.*

~~[illegible]~~

~~(ii)~~(i) All Protests concerning an Award or an Intent to Award, or a Determination made in connection with a Solicitation, must be received by the Chief Procurement Officer within two Business Days after the Posting or other written notification of JEA's decision or intended decision, whichever is earlier. Without limitation, the Posting of the Awards Committee agenda on JEA's website, or JEA's issuance of an Addendum or email to all Bidders, Proposers or Respondents stating its Intent to Award or establishing the short list of Respondents or Proposers, shall constitute notification of an Award or Intent to Award, or other Determination. The period for filing a Protest under this subsection (ii) shall begin at the time of the Posting or other such notification.

~~(iii)~~(ii) At the time of filing a timely Protest, a Protestant may request an extension of three Business Days after the date its Protest is timely received, in which to provide supplemental Protest materials. ~~Failure to do so~~Such extension may be granted or denied in JEA's sole discretion. Failure to submit a request for extension or to timely submit the supplemental Protest materials shall constitute a waiver of any right to supplement the Protest. All written information, documents, materials and legal authority the Protestant will provide to the Chief Procurement Officer must be received by the deadline established by the Chief Procurement Officer in a notice provided to the Protestant.

(5) Protests failing to meet the requirements of subsections (3) and (4) shall be rejected and shall constitute a waiver of all rights of the Protestant to file a Protest with respect to that subject matter. A Determination of whether a Protest meets the requirements of subsections (3) and (4) shall be made by the Chief Procurement Officer and is not subject to Protest or Appeal to the Procurement Appeals Board.

(6) JEA shall have the right to cancel, or rescind and re-issue, all Solicitations of any type, at any time until the time JEA executes a Contract under the Solicitation. Such right shall include the right to rescind an Award or an Intent to Award. After a Contract is executed, the terms of the Contract shall govern the parties to the Contract. Such cancelations and rescissions are not subject to Protest.

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(7) *Protest Bond.* Within 48 hours from a submitting a Protest, the Protestant is required to submit a protest bond, or alternate security approved by JEA, the amount of 1% of Protestant's submitted Bid/ Proposal/Response amount or $10,000, whichever is less. If the Protestant does not submit the protest bond within the specified timeframe, the protest will be void and waives the right to further protest JEA's decision. If the Protest is successful, the protest bond shall be returned in full to the Protestant within a reasonable time. However, if JEA prevails, JEA shall retain the protest bond, in full or in part, in order to cover any administrative costs associated with addressing the protest.

~~(7)~~(8) *Notice of Protest to Affected Third Parties.* Upon receipt of a timely and proper Protest, JEA will notify Vendors known to JEA to be directly affected by the outcome of the Protest. All information, documents, materials and legal authority relating to the Protest that any such Vendor will provide to the Chief Procurement Officer must be received by the deadline established by the Chief Procurement Officer in such notice.

~~(8)~~(9) *Protest Hearings.* Protestants shall not be entitled to a hearing of any kind prior to a decision of the Chief Procurement Officer concerning a Protest. The Chief Procurement Officer may conduct a hearing before making a decision. The Chief Procurement Officer shall be entitled to establish procedures for the conduct of any hearing and may set forth some or all of such procedures in the Operational Procedures or in the notice of the hearing. The Chief Procurement Officer or Designee shall provide Vendors known to JEA to be directly affected by the outcome of the Protest with a notice of the hearing providing the time, date, location and manner of the hearing.

~~(9)~~(10) *Decision by Chief Procurement Officer.* After receipt of a Protest, and following a hearing, if any, and any period of time the Chief Procurement Officer may allow for other interested parties to respond to the Protest, the Chief Procurement Officer shall issue a written decision on the Protest. The written decision shall identify the Protestant, recite relevant facts material to the decision, and state the decision and briefly summarize the Chief Procurement Officer's reasoning leading to the decision. The Chief Procurement Officer's review of a Protest shall be limited to material contained in the Protestant's response to the Solicitation that is the subject of the Protest, and the Chief Procurement Officer's decision shall be based on whether the Procurement action being protested was arbitrary, capricious, or clearly erroneous, In the event the decision is subject to review by the Procurement Appeals Board under this Article ~~5~~4, the written decision of the Chief Procurement Officer shall inform the Protestant of this right with a reference to the Sections of this Code and Operational Procedures outlining the procedures for Appeals.

~~(10)~~(11) *Appeal Rights.* Protest decisions made by the Chief Procurement Officer may be appealed to the JEA Procurement Appeals Board pursuant to Section ~~5~~4-106 below. Notwithstanding the foregoing, a Protestant shall not have the right to appeal a Determination by the Chief Procurement Officer about whether a Protest met the requirements of subsections (3) and (4) of this Section.

~~(11)~~(12) *Stay of Procurement During Protests and Appeals.* During the pendency of a Protest meeting the requirements of subsections (3) and (4) or an Appeal properly filed under Subsection (10) above,

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JEA shall not proceed further with the Solicitation or with the Award unless the Chief Procurement Officer, after consultation with the Organizational Element Manager, makes a Determination that proceeding with the Solicitation or Award without delay is necessary to protect substantial interests of JEA.

~~(12)~~(13) Nothing in this Article ~~5~~4 shall affect the ability of the Office of General Counsel to settle Protests pending the outcome of decisions by the Chief Procurement Officer, the Procurement Appeals Board, or the courts.

~~5~~4-102 Suspensions and Debarments

(1) *Authority*. The Chief Procurement Officer, after consultation with the Organizational Element Manager, shall have authority to suspend or debar a Vendor from consideration for participation in any [illegible]

(2) *Causes for Suspension or Debarment*. In making a decision of whether to suspend or debar a Vendor, and the length of any suspension or debarment, the Chief Procurement Officer shall consider the seriousness of the facts leading to the suspension or debarment. The causes for suspension or debarment may include, but not be limited to, the following:

(a) conviction of a Public Entity Crime and inclusion on the State of Florida Convicted Vendor List pursuant to Section 287.133, Florida Statutes, as amended;

(b) violation of the terms or requirements of a Contract in a manner that is regarded by the Chief Procurement Officer to be so serious as to justify a suspension or debarment decision, including, but not limited to, the following:

(i) a failure, without good cause, to perform in accordance with a Contract, Specifications, performance levels, warranty provisions, bonding and insurance requirements, or to comply within the time limits provided in the Contract, or

(ii) failure to timely pay subcontractors or materialmen; or

(iii) continued failure to perform or of unsatisfactory performance in accordance with the terms of one or more Contracts, provided that the failure to perform or unsatisfactory performance was not caused by acts beyond the control of the Vendor; or

(c) suspension or debarment by another Governmental Entity including, but not limited to, the City of Jacksonville;

(d) actions by the Vendor that are determined by the Chief Procurement Officer to be fraudulent or in bad faith;

(e) violation of JEA's or the City of Jacksonville's Ethics Code;

(f) violation of provisions of this Code relating to Ex Parte Communications;

(g) existence of delinquent obligations of the Vendor to JEA, including claims by JEA for liquidated damages under any Contract; and

(h) any other cause the Chief Procurement Officer determines to be so serious and compelling as to justify a Vendor's suspension or debarment.

(3) *Suspension/Debarment Timeframes.* The Chief Procurement Officer, in concurrence with the Chief of the Business Organizational Element, shall consider the causes set forth in (2) above in determining the length of a Vendor's suspension or debarment. Suspensions shall be subject to the maximum length as set forth below:

a First Offense – up to 2 years suspension of bidding privileges

b Second Offense – up to 5 years suspension of bidding privileges

c Third Offense – Vendor is debarred and bidding privileges are suspended permanently.

~~(3)~~(4) *Effect of Suspension or Debarment*. A Vendor that is suspended or debarred under this Section ~~5~~4-102 shall be ineligible to participate in ~~any manner in any Procurement undertaken~~ Procurements or as otherwise specified by ~~JEA~~ the CPO. The suspension or debarment ~~shall~~may extend to all entities with common ownership or common management as the Vendor that has been suspended or debarred and ~~shall~~may include work undertaken by the debarred Vendor (or such related entity) as a subcontractor or materialman~~.~~, as determined by the CPO on a case by case basis. JEA has the option to debar a Vendor at any time depending on the egregiousness of their actions, and is not required to issue a First or Second offense as described above.

~~(4)~~(5) *Decision*. The Chief Procurement Officer shall issue a written letter to the Vendor informing it of the decision to suspend or debar that Vendor. The decision shall:

~~(a)~~

(a) recite relevant facts material to the Chief Procurement Officer's decision; ~~(b)~~

(b) state the reasons for the decision;

(c) state whether the Vendor is a suspension or debarment;

(d) state the timeframe for suspension or debarment; and

(e) inform the suspended or debarred Vendor involved of any rights to administrative review as provided in this Article 5.

(5) *Finality of Decision*. A suspension or debarment decision by the Chief Procurement Officer shall be final and conclusive, unless appealed.

~~5~~4-103 Creation of the Procurement Appeals Board

The Chief Executive Officer shall appoint a Procurement Appeals Board composed of a chair and two other members of the Awards Committee who shall serve until their successors are appointed by the Chief Executive Officer. A representative from the Office of General Counsel shall serve as counsel to the Procurement Appeals Board. The chair and two other members of the Procurement Appeals Board must be present to constitute a quorum of the Procurement Appeals Board.

~~5~~4-104 Procurement Appeals Board Procedures

(1) Meetings of the Procurement Appeals Board shall be held in accordance with Florida's Open Meetings Laws. Accordingly, meetings will be publicly noticed, minutes will be taken, and a member

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of the Procurement Appeals Board shall not discuss with another member any matter which foreseeably may come before the Procurement Appeals Board unless the discussion occurs in a meeting held in accordance with Florida's Open Meeting Laws.

(2) Each member of the Procurement Appeals Board shall have one vote. A decision by the Procurement Appeals Board shall require a majority vote of the members of the Procurement Appeals Board.

(3) The chair of the Procurement Appeals Board shall have the authority to establish procedures for the Procurement Appeals Board and its meetings, provided that such process and procedures are consistent with this Code and the Operational Procedures.

~~5~~4-105 Authority of Procurement Appeals Board

The Procurement Appeals Board is authorized to review and make a final decision on any Appeal of a written decision issued by the Chief Procurement Officer under:

(a) Section ~~5~~4-101 (Protests) of this Code; or

(b) Section ~~5~~4-102 (Suspensions and Debarments) of this Code.

The Procurement Appeals Board is not authorized to intercede in, or hear Appeals relating to, Determinations made in connection with Vendor disputes regarding performance under a Contract, other than the authority granted to review and make decisions regarding Appeals of Suspensions or Debarments as provided in Section 4-102 of this Code.

~~5~~4-106 Appeals

(1) *Appeal Submittal*. A Vendor seeking to appeal a decision of the Chief Procurement Officer under Section ~~5~~4-101 or ~~5~~4-102 of this Code shall submit its appeal in writing by letter or email to the Chief Procurement Officer in accordance with the timeliness and other requirements set forth in this Section ~~5~~4-106 (an "Appeal"). The Appeal shall clearly state the following:

(a) the grounds, relevant facts and legal authority supporting the Appeal; and

(b) acts supporting the Vendor's standing to Appeal.

(2) *Timeliness and Standing.* An Appeal relating to a decision of the Chief Procurement Officer under Section ~~5~~4-101 of this Code must be received by the Chief Procurement Officer no later than three Business Days after issuance of a written decision by the Chief Procurement Officer. An Appeal relating to a decision of the Chief Procurement Officer under Section ~~5~~4-102 of this Code must be received by the Chief Procurement Officer no later than ~~30~~15 days after issuance of a decision by the Chief Procurement Officer under Section ~~5~~4-102. To have standing to Appeal, a Vendor must have been adversely affected by such decision.

(3) Failure to submit a timely Appeal or to have standing to Appeal under subsections (1) and (2) of this Section ~~5~~4-106 shall result in dismissal of the Appeal and constitute a waiver of all rights to appeal

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a decision of the Chief Procurement Officer. A Determination of whether an Appeal meets the requirements of subsections (1) and (2) shall be made by the chair of the Procurement Appeals Board and is not subject to appeal to the Procurement Appeals Board.

(4) All written information, documents, materials and legal authority the Vendor making an Appeal desires to provide to the Procurement Appeals Board must be sent to the Chief Procurement Officer and received by the deadline established by the chair of the Procurement Appeals Board in the notice of hearing provided to the Vendor making the Appeal.

(5) Upon receipt of a timely and proper Appeal, the Chief Procurement Officer will notify Vendors known to JEA to be directly affected by the outcome of the Appeal. Any information, materials and legal authority relating to the Appeal that any such Vendor desires to provide to the Procurement Appeals Board must be received by the deadline established by the Chief Procurement Officer in such notice.

~~5~~4-107 Review of Appeals

(1) Upon receipt of an Appeal, the Chief Procurement Officer shall forward the Appeal to the Procurement Appeals Board and, if the Appeal is determined by the chair of the Procurement Appeals Board to be proper and timely, a meeting of the Procurement Appeals Board to consider the Appeal shall be scheduled.

(2) Representatives of the Vendor appealing the decision, will be afforded an opportunity to present the merits of the Appeal based solely upon the grounds, facts and legal authority contained in its written Appeal submitted to the Chief Procurement Officer. Representatives of any other Vendors adversely affected by the resolution of the Appeal will also be given an opportunity to be heard and to present information before the Procurement Appeals Board. The Chief Procurement Officer and the Chief Procurement Officer's legal counsel shall also be given an opportunity to respond to the Appeal and the presentations to the Procurement Appeals Board. Formal rules of evidence, including, but not limited to, those found in the Florida Evidence Code, do not apply to presentations made at meetings of the Procurement Appeals Board. The Chair of the Procurement Appeals Board may impose reasonable limitations on the amount of time each Vendor has to present, allow members of the Procurement Appeals Board to ask questions of any party at any time, and may impose other reasonable requirements relating to all presentations and the conduct of the meeting. The chair of the Procurement Appeals Board shall have the authority to make all Determinations and resolve any disputes concerning the process and procedures for Appeals and the conduct of the meeting.

4-108 Standard of Review for Procurement Appeals Board

(1) The standard of review used by the Procurement Appeals Board in making its decision shall be whether the Chief Procurement Officer's decision is:

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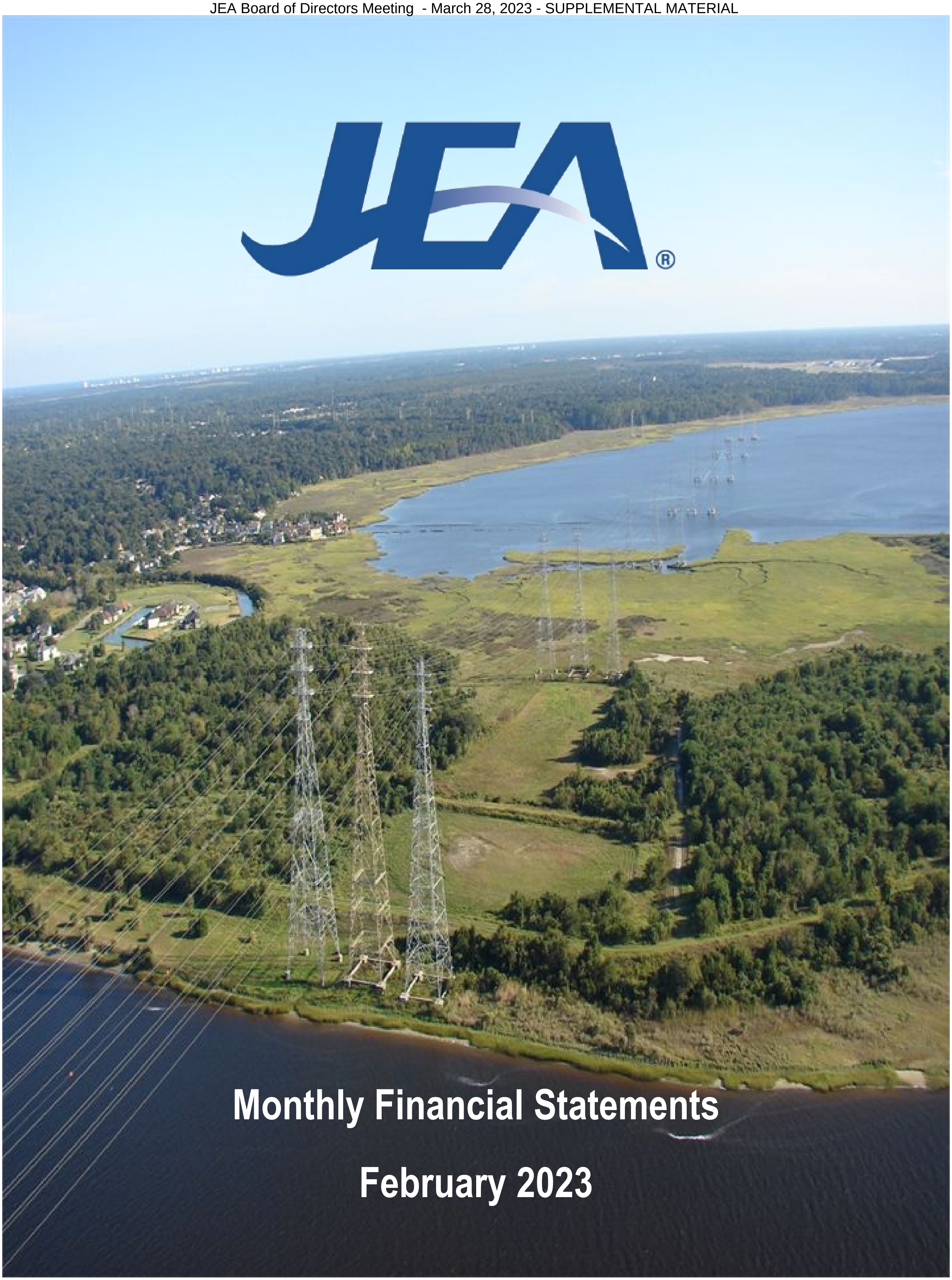
(i) in conflict with this Code and the Operational Procedures;
(ii) arbitrary;
(iii) capricious;
(iv) dishonest;
(v) fraudulent;
(vi) clearly erroneous; ~~(vii)~~
~~(vi)~~(vii) illegal; or
(viii) without any basis in fact or otherwise must be reversed based on applicable law.

(2) The burden shall be on the Vendor appealing the Chief Procurement Officer's decision to demonstrate that the standard of review is met.

~~(5)~~(3) A majority vote of the members of the Procurement Appeals Board shall be required to render a decision.

~~(6)~~(4) The Procurement Appeals Board shall deliberate at the meeting held to consider the Appeal and announce its decision prior to adjourning the meeting. The decision of the Procurement Appeals Board shall be final and binding. Following the adjournment of the meeting, the Procurement Appeals Board will issue a written decision within three (3) business days.



Monthly Financial Statements

February 2023

Monthly Financial Statements

February 2023

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JEA
Statements of Net Position
(in thousands)

	February 2023 (unaudited)	September 2022
Assets		
Current assets:		
Cash and cash equivalents	$ 234,350	$ 245,337
Investments	54,833	278
Customer accounts receivable, net of allowance ($731 and $679, respectively)	238,147	314,362
Inventories:		
Materials and supplies	88,281	67,064
Fuel	55,691	52,483
Prepaid assets	18,731	31,774
Other current assets	8,443	22,987
Total current assets	698,476	734,285
Noncurrent assets:		
Restricted assets:		
Cash and cash equivalents	12,016	275,353
Investments	431,810	306,650
Other restricted assets	52	215
Total restricted assets	443,878	582,218
Costs to be recovered from future revenues	797,066	814,161
Hedging derivative instruments	123,920	267,807
Other assets	61,313	60,137
Total noncurrent assets	1,426,177	1,724,323
Capital assets:		
Land and easements	218,291	218,244
Plant in service	12,957,653	12,670,690
Less accumulated depreciation	(8,157,677)	(7,995,820)
Plant in service, net	5,018,267	4,893,114
Construction work in progress	503,798	571,383
Net capital assets	5,522,065	5,464,497
Total assets	7,646,718	7,923,105
Deferred outflows of resources		
Unrealized pension contributions and losses	131,651	131,651
Accumulated decrease in fair value of hedging derivatives	51,894	39,582
Unamortized deferred losses on refundings	77,481	80,372
Unrealized asset retirement obligations	36,673	42,931
Unrealized OPEB contributions and losses	11,029	11,029
Total deferred outflows of resources	308,728	305,565
Total assets and deferred outflows of resources	$ 7,955,446	$ 8,228,670

JEA
Statements of Net Position
(in thousands)

	February 2023 (unaudited)	September 2022
Liabilities		
Current liabilities:		
Accounts and accrued expenses payable	$ 64,054	$ 117,105
Customer deposits and prepayments	88,921	89,690
Billings on behalf of state and local governments	24,008	33,764
Compensation and benefits payable	17,273	14,306
City of Jacksonville payable	10,336	10,245
Asset retirement obligations	1,944	2,254
Total current liabilities	206,536	267,364
Current liabilities payable from restricted assets:		
Debt due within one year	89,375	74,070
Interest payable	40,146	48,950
Construction contracts and accounts payable	52,939	90,627
Renewal and replacement reserve	3,222	4,252
Total current liabilities payable from restricted assets	185,682	217,899
Noncurrent liabilities:		
Long-term debt:		
Debt payable, less current portion	2,574,510	2,659,885
Unamortized premium, net	162,484	171,753
Fair value of debt management strategy instruments	35,785	38,231
Total long-term debt	2,772,779	2,869,869
Net pension liability	646,112	646,112
Asset retirement obligations	34,729	40,677
Compensation and benefits payable	36,563	34,726
Net OPEB liability	1,802	1,642
Other liabilities	33,123	18,701
Total noncurrent liabilities	3,525,108	3,611,727
Total liabilities	3,917,326	4,096,990
Deferred inflows of resources		
Revenues to be used for future costs	181,689	141,722
Accumulated increase in fair value of hedging derivatives	123,920	267,807
Unrealized OPEB gains	18,599	18,599
Unrealized pension gains	118,660	118,660
Total deferred inflows of resources	442,868	546,788
Net position		
Net investment in capital assets	2,988,113	2,830,411
Restricted for:		
Capital projects	254,978	347,929
Debt service	38,185	73,635
Other purposes	(5,204)	2,473
Unrestricted	319,180	330,444
Total net position	3,595,252	3,584,892
Total liabilities, deferred inflows of resources, and net position	$ 7,955,446	$ 8,228,670

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Statements of Revenues, Expenses, and Changes in Net Position
(in thousands - unaudited)

	Month February 2023	Month February 2022	Year-to-Date February 2023	Year-to-Date February 2022
Operating revenues				
Electric - base	$ 60,595	$ 49,782	$ 277,314	$ 322,355
Electric - fuel and purchased power	56,037	42,735	263,785	213,363
Water and sewer	39,997	35,791	205,949	192,942
District energy system	860	597	4,504	3,131
Other operating revenues	5,569	3,227	15,475	16,090
Total operating revenues	163,058	132,132	767,027	747,881
Operating expenses				
Operations and maintenance:				
Maintenance and other operating expenses	35,929	31,038	189,962	193,069
Fuel	39,314	29,972	198,800	168,294
Purchased power	13,742	19,850	99,342	82,260
Depreciation	35,848	32,350	173,823	271,927
State utility and franchise taxes	6,521	6,355	34,454	29,767
Recognition of deferred costs and revenues, net	13,800	2,443	21,900	(12,738)
Total operating expenses	145,154	122,008	718,281	732,579
Operating income	17,904	10,124	48,746	15,302
Nonoperating revenues (expenses)				
Interest on debt	(8,637)	(8,606)	(43,781)	(47,600)
Earnings from The Energy Authority	(132)	1,189	6,226	14,783
Allowance for funds used during construction	1,775	932	8,952	4,451
Other nonoperating income, net	535	545	2,733	2,732
Investment income	1,863	365	10,924	986
Other interest, net	(249)	(4)	(2,145)	21
Total nonoperating expenses, net	(4,845)	(5,579)	(17,091)	(24,627)
Income before contributions	13,059	4,545	31,655	(9,325)
Contributions (to) from				
General Fund, City of Jacksonville, Florida	(10,202)	(10,100)	(51,010)	(50,505)
Developers and other	8,764	6,617	42,469	36,620
Reduction of plant cost through contributions	(4,230)	(3,587)	(23,889)	(23,683)
Total contributions, net	(5,668)	(7,070)	(32,430)	(37,568)
Special item	-	-	11,135	100,000
Change in net position	7,391	(2,525)	10,360	53,107
Net position, beginning of period	3,587,861	3,523,086	3,584,892	3,467,454
Net position, end of period	$ 3,595,252	$ 3,520,561	$ 3,595,252	$ 3,520,561

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Statement of Cash Flows
(in thousands - unaudited)

	Year-to-Date February 2023	Year-to-Date February 2022
Operating activities		
Receipts from customers	$ 867,228	$ 711,699
Payments to suppliers	(459,664)	(350,422)
Payments for salaries and benefits	(122,459)	(116,593)
Other operating activities	29,281	115,575
Net cash provided by operating activities	314,386	360,259
Noncapital and related financing activities		
Contribution to General Fund, City of Jacksonville, Florida	(50,909)	(50,405)
Net cash used in noncapital and related financing activities	(50,909)	(50,405)
Capital and related financing activities		
Acquisition and construction of capital assets	(267,695)	(152,685)
Defeasance of debt	-	(74,885)
Interest paid on debt	(58,620)	(60,512)
Repayment of debt principal	(74,070)	(91,535)
Capital contributions	18,581	12,938
Revolving credit agreement withdrawals	4,000	1,000
Other capital financing activities	3,497	4,366
Net cash used in capital and related financing activities	(374,307)	(361,313)
Investing activities		
Proceeds from sale and maturity of investments	115,674	95,725
Purchase of investments	(292,330)	(232,318)
Distributions from The Energy Authority	6,420	4,448
Investment income	6,742	1,382
Net cash used in investing activities	(163,494)	(130,763)
Net change in cash and cash equivalents	(274,324)	(182,222)
Cash and cash equivalents at beginning of year	520,690	713,113
Cash and cash equivalents at end of period	$ 246,366	$ 530,891
Reconciliation of operating income to net cash provided by operating activities		
Operating income	$ 48,746	$ 15,302
Adjustments:		
Depreciation and amortization	173,823	272,202
Recognition of deferred costs and revenues, net	21,900	(12,738)
Other nonoperating income, net	8,992	100,056
Changes in noncash assets and noncash liabilities:		
Accounts receivable	76,215	9,873
Inventories	(24,426)	(16,028)
Other assets	26,668	(1,737)
Accounts and accrued expenses payable	(60,589)	26,576
Current liabilities payable from restricted assets	(2,261)	(124)
Other noncurrent liabilities and deferred inflows	45,318	(33,123)
Net cash provided by operating activities	$ 314,386	$ 360,259
Noncash activity		
Contribution of capital assets from developers	$ 23,889	$ 23,683
Unrealized investment fair market value changes, net	$ 3,060	$ (785)

JEA
Combining Statement of Net Position
(in thousands - unaudited) February 2023

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Total JEA
Assets							
Current assets:							
Cash and cash equivalents	$ 202,249	$ 2,940	$ -	$ 205,189	27,595	$ 1,566	$ 234,350
Investments	32,281	897	-	33,178	21,655	-	54,833
Customer accounts receivable, net of allowance ($731)	183,471	-	-	183,471	54,085	591	238,147
Inventories:							
Materials and supplies	2,269	-	-	2,269	86,012	-	88,281
Fuel	55,691	-	-	55,691	-	-	55,691
Prepaid assets	17,795	28	-	17,823	894	14	18,731
Other current assets	4,277	(12)	(412)	3,853	4,590	-	8,443
Total current assets	498,033	3,853	(412)	501,474	194,831	2,171	698,476
Noncurrent assets:							
Restricted assets:							
Cash and cash equivalents	110	11,884	-	11,994	207	(185)	12,016
Investments	304,456	3,328	-	307,784	124,026	-	431,810
Other restricted assets	28	24	-	52	-	-	52
Total restricted assets	304,594	15,236	-	319,830	124,233	(185)	443,878
Costs to be recovered from future revenues	421,937	79,556	-	501,493	295,304	269	797,066
Hedging derivative instruments	123,920	-	-	123,920	-	-	123,920
Other assets	34,869	31,178	(4,765)	61,282	31	-	61,313
Total noncurrent assets	885,320	125,970	(4,765)	1,006,525	419,568	84	1,426,177
Capital assets:							
Land and easements	127,100	6,660	-	133,760	81,480	3,051	218,291
Plant in service	6,295,421	1,316,043	-	7,611,464	5,280,403	65,786	12,957,653
Less accumulated depreciation	(4,048,590)	(1,314,369)	-	(5,362,959)	(2,759,167)	(35,551)	(8,157,677)
Plant in service, net	2,373,931	8,334	-	2,382,265	2,602,716	33,286	5,018,267
Construction work in progress	89,018	-	-	89,018	406,960	7,820	503,798
Net capital assets	2,462,949	8,334	-	2,471,283	3,009,676	41,106	5,522,065
Total assets	3,846,302	138,157	(5,177)	3,979,282	3,624,075	43,361	7,646,718
Deferred outflows of resources							
Unrealized pension contributions and losses	71,715	10,100	-	81,815	49,836	-	131,651
Accumulated decrease in fair value of hedging derivatives	46,145	-	-	46,145	5,749	-	51,894
Unamortized deferred losses on refundings	43,804	1,131	-	44,935	32,406	140	77,481
Unrealized asset retirement obligations	36,636	37	-	36,673	-	-	36,673
Unrealized OPEB contributions and losses	6,507	-	-	6,507	4,522	-	11,029
Total deferred outflows of resources	204,807	11,268	-	216,075	92,513	140	308,728
Total assets and deferred outflows of resources	$ 4,051,109	$ 149,425	$ (5,177)	$ 4,195,357	$ 3,716,588	$ 43,501	$ 7,955,446

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Combining Statement of Net Position
(in thousands - unaudited) February 2023

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Total JEA
Liabilities							
Current liabilities:							
Accounts and accrued expenses payable	$ 51,029	$ (19)	$ 19	$ 51,029	$ 12,995	$ 30	$ 64,054
Customer deposits and prepayments	58,862	-	-	58,862	30,059	-	88,921
Billings on behalf of state and local governments	20,398	-	-	20,398	3,610	-	24,008
Compensation and benefits payable	12,503	-	-	12,503	4,732	38	17,273
City of Jacksonville payable	8,081	-	-	8,081	2,255	-	10,336
Asset retirement obligations	1,907	37	-	1,944	-	-	1,944
Total current liabilities	152,780	18	19	152,817	53,651	68	206,536
Current liabilities payable from restricted assets:							
Debt due within one year	19,275	15,865	-	35,140	52,365	1,870	89,375
Interest payable	19,192	1,433	-	20,625	19,035	486	40,146
Construction contracts and accounts payable	9,233	441	(431)	9,243	42,971	725	52,939
Renewal and replacement reserve	-	3,222	-	3,222	-	-	3,222
Total current liabilities payable from restricted assets	47,700	20,961	(431)	68,230	114,371	3,081	185,682
Noncurrent liabilities:							
Long-term debt:							
Debt payable, less current portion	1,330,015	76,850	-	1,406,865	1,134,690	32,955	2,574,510
Unamortized premium (discount), net	85,661	55	-	85,716	76,780	(12)	162,484
Fair value of debt management strategy instruments	30,036	-	-	30,036	5,749	-	35,785
Total long-term debt	1,445,712	76,905	-	1,522,617	1,217,219	32,943	2,772,779
Net pension liability	381,206	-	-	381,206	264,906	-	646,112
Asset retirement obligations	34,729	-	-	34,729	-	-	34,729
Compensation and benefits payable	26,138	-	-	26,138	10,324	101	36,563
Net OPEB liability	1,060	-	-	1,060	742	-	1,802
Other liabilities	33,123	4,765	(4,765)	33,123	-	-	33,123
Total noncurrent liabilities	1,921,968	81,670	(4,765)	1,998,873	1,493,191	33,044	3,525,108
Total liabilities	2,122,448	102,649	(5,177)	2,219,920	1,661,213	36,193	3,917,326
Deferred inflows of resources							
Revenues to be used for future costs	146,317	16,931	-	163,248	18,441	-	181,689
Accumulated increase in fair value of hedging derivatives	123,920	-	-	123,920	-	-	123,920
Unrealized OPEB gains	10,973	-	-	10,973	7,626	-	18,599
Unrealized pension gains	58,457	19,581	-	78,038	40,622	-	118,660
Total deferred inflows of resources	339,667	36,512	-	376,179	66,689	-	442,868
Net position							
Net investment in (divestment of) capital assets	1,155,583	(850)	-	1,154,733	1,827,402	5,978	2,988,113
Restricted for:							
Capital projects	230,835	-	-	230,835	25,594	(1,451)	254,978
Debt service	7,712	6,647	-	14,359	23,046	780	38,185
Other purposes	(6,497)	595	431	(5,471)	267	-	(5,204)
Unrestricted	201,361	3,872	(431)	204,802	112,377	2,001	319,180
Total net position	1,588,994	10,264	-	1,599,258	1,988,686	7,308	3,595,252
Total liabilities, deferred inflows of resources, and net position	$ 4,051,109	$ 149,425	$ (5,177)	$ 4,195,357	$ 3,716,588	$ 43,501	$ 7,955,446

JEA
Combining Statement of Net Position
(in thousands) September 2022

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Total JEA
Assets							
Current assets:							
Cash and cash equivalents	$ 173,076	$ 3,031	$ -	$ 176,107	$ 67,889	$ 1,341	$ 245,337
Investments	-	278	-	278	-	-	278
Customer accounts receivable, net of allowance ($679)	257,894	-	-	257,894	56,145	323	314,362
Inventories:							
Materials and supplies	2,342	-	-	2,342	64,722	-	67,064
Fuel	52,483	-	-	52,483	-	-	52,483
Prepaid assets	31,385	1	-	31,386	382	6	31,774
Other current assets	18,418	3	(372)	18,049	4,938	-	22,987
Total current assets	535,598	3,313	(372)	538,539	194,076	1,670	734,285
Noncurrent assets:							
Restricted assets:							
Cash and cash equivalents	154,657	21,833	-	176,490	95,393	3,470	275,353
Investments	193,653	3,811	-	197,464	109,186	-	306,650
Other restricted assets	-	40	-	40	175	-	215
Total restricted assets	348,310	25,684	-	373,994	204,754	3,470	582,218
Costs to be recovered from future revenues	428,479	85,968	-	514,447	299,544	170	814,161
Hedging derivative instruments	267,807	-	-	267,807	-	-	267,807
Other assets	33,689	31,178	(4,765)	60,102	35	-	60,137
Total noncurrent assets	1,078,285	142,830	(4,765)	1,216,350	504,333	3,640	1,724,323
Capital assets:							
Land and easements	127,100	6,660	-	133,760	81,433	3,051	218,244
Plant in service	6,135,345	1,316,043	-	7,451,388	5,154,090	65,212	12,670,690
Less accumulated depreciation	(3,960,409)	(1,314,198)	-	(5,274,607)	(2,686,812)	(34,401)	(7,995,820)
Plant in service, net	2,302,036	8,505	-	2,310,541	2,548,711	33,862	4,893,114
Construction work in progress	169,195	-	-	169,195	398,824	3,364	571,383
Net capital assets	2,471,231	8,505	-	2,479,736	2,947,535	37,226	5,464,497
Total assets	4,085,114	154,648	(5,137)	4,234,625	3,645,944	42,536	7,923,105
Deferred outflows of resources							
Unrealized pension contributions and losses	71,715	10,100	-	81,815	49,836	-	131,651
Accumulated decrease in fair value of hedging derivatives	32,855	-	-	32,855	6,727	-	39,582
Unamortized deferred losses on refundings	45,710	1,227	-	46,937	33,290	145	80,372
Unrealized asset retirement obligations	42,879	52	-	42,931	-	-	42,931
Unrealized OPEB contributions and losses	6,507	-	-	6,507	4,522	-	11,029
Total deferred outflows of resources	199,666	11,379	-	211,045	94,375	145	305,565
Total assets and deferred outflows of resources	$ 4,284,780	$ 166,027	$ (5,137)	$ 4,445,670	$ 3,740,319	$ 42,681	$ 8,228,670

JEA
Combining Statement of Net Position
(in thousands) September 2022

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Total JEA
Liabilities							
Current liabilities:							
Accounts and accrued expenses payable	$ 105,033	$ 281	$ -	$ 105,314	$ 11,717	$ 74	$ 117,105
Customer deposits and prepayments	57,113	-	-	57,113	32,577	-	89,690
Billings on behalf of state and local governments	29,873	2	-	29,875	3,889	-	33,764
Compensation and benefits payable	10,573	-	-	10,573	3,706	27	14,306
City of Jacksonville payable	8,008	-	-	8,008	2,237	-	10,245
Asset retirement obligations	2,202	52	-	2,254	-	-	2,254
Total current liabilities	212,802	335	-	213,137	54,126	101	267,364
Current liabilities payable from restricted assets:							
Debt due within one year	47,120	15,285	-	62,405	9,850	1,815	74,070
Interest payable	23,504	2,029	-	25,533	22,811	606	48,950
Construction contracts and accounts payable	15,783	1,670	(372)	17,081	70,563	2,983	90,627
Renewal and replacement reserve	-	4,252	-	4,252	-	-	4,252
Total current liabilities payable from restricted assets	86,407	23,236	(372)	109,271	103,224	5,404	217,899
Noncurrent liabilities:							
Long-term debt:							
Debt payable, less current portion	1,349,290	92,715	-	1,442,005	1,187,055	30,825	2,659,885
Unamortized premium (discount), net	89,763	123	-	89,886	81,882	(15)	171,753
Fair value of debt management strategy instruments	31,504	-	-	31,504	6,727	-	38,231
Total long-term debt	1,470,557	92,838	-	1,563,395	1,275,664	30,810	2,869,869
Net pension liability	381,206	-	-	381,206	264,906	-	646,112
Asset retirement obligations	40,677	-	-	40,677	-	-	40,677
Compensation and benefits payable	24,725	-	-	24,725	9,907	94	34,726
Net OPEB liability	969	-	-	969	673	-	1,642
Other liabilities	18,701	4,765	(4,765)	18,701	-	-	18,701
Total noncurrent liabilities	1,936,835	97,603	(4,765)	2,029,673	1,551,150	30,904	3,611,727
Total liabilities	2,236,044	121,174	(5,137)	2,352,081	1,708,500	36,409	4,096,990
Deferred inflows of resources							
Revenues to be used for future costs	98,697	16,931	-	115,628	26,094	-	141,722
Accumulated increase in fair value of hedging derivatives	267,807	-	-	267,807	-	-	267,807
Unrealized OPEB gains	10,973	-	-	10,973	7,626	-	18,599
Unrealized pension gains	58,457	19,581	-	78,038	40,622	-	118,660
Total deferred inflows of resources	435,934	36,512	-	472,446	74,342	-	546,788
Net position							
Net investment in (divestment of) capital assets	1,110,851	(10,215)	-	1,100,636	1,727,842	1,933	2,830,411
Restricted for:							
Capital projects	233,129	-	-	233,129	113,751	1,049	347,929
Debt service	46,386	15,321	-	61,707	10,113	1,815	73,635
Other purposes	-	203	372	575	1,898	-	2,473
Unrestricted	222,436	3,032	(372)	225,096	103,873	1,475	330,444
Total net position	1,612,802	8,341	-	1,621,143	1,957,477	6,272	3,584,892
Total liabilities, deferred inflows of resources, and net position	$ 4,284,780	$ 166,027	$ (5,137)	$ 4,445,670	$ 3,740,319	$ 42,681	$ 8,228,670

JEA

Combining Statement of Revenues, Expenses, and Changes in Net Position
(in thousands - unaudited) for the month ended February 2023

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Eliminations	Total JEA
Operating revenues								
Electric - base	$ 61,267	$ -	$ -	$ 61,267	$ -	$ -	$ (672)	$ 60,595
Electric - fuel and purchased power	57,239	1,777	(1,777)	57,239	-	-	(1,202)	56,037
Water and sewer	-	-	-	-	40,020	-	(23)	39,997
District energy system	-	-	-	-	-	921	(61)	860
Other operating revenues	4,572	-	-	4,572	1,473	-	(476)	5,569
Total operating revenues	123,078	1,777	(1,777)	123,078	41,493	921	(2,434)	163,058
Operating expenses								
Operations and maintenance:								
Maintenance and other operating expenses	21,610	201	-	21,811	16,193	359	(2,434)	35,929
Fuel	39,314	-	-	39,314	-	-	-	39,314
Purchased power	15,519	-	(1,777)	13,742	-	-	-	13,742
Depreciation	18,257	34	-	18,291	17,327	230	-	35,848
State utility and franchise taxes	5,673	-	-	5,673	848	-	-	6,521
Recognition of deferred costs and revenues, net	10,089	1,272	-	11,361	2,439	-	-	13,800
Total operating expenses	110,462	1,507	(1,777)	110,192	36,807	589	(2,434)	145,154
Operating income	12,616	270	-	12,886	4,686	332	-	17,904
Nonoperating revenues (expenses)								
Interest on debt	(4,694)	(303)	-	(4,997)	(3,512)	(128)	-	(8,637)
Earnings from The Energy Authority	(132)	-	-	(132)	-	-	-	(132)
Allowance for funds used during construction	303	-	-	303	1,445	27	-	1,775
Other nonoperating income, net	313	19	-	332	203	-	-	535
Investment income	1,384	11	-	1,395	468	-	-	1,863
Other interest, net	(252)	-	-	(252)	3	-	-	(249)
Total nonoperating expenses, net	(3,078)	(273)	-	(3,351)	(1,393)	(101)	-	(4,845)
Income before contributions	9,538	(3)	-	9,535	3,293	231	-	13,059
Contributions (to) from								
General Fund, City of Jacksonville, Florida	(7,958)	-	-	(7,958)	(2,244)	-	-	(10,202)
Developers and other	552	-	-	552	8,212	-	-	8,764
Reduction of plant cost through contributions	(552)	-	-	(552)	(3,678)	-	-	(4,230)
Total contributions, net	(7,958)	-	-	(7,958)	2,290	-	-	(5,668)
Change in net position	1,580	(3)	-	1,577	5,583	231	-	7,391
Net position, beginning of period	1,587,414	10,267	-	1,597,681	1,983,103	7,077	-	3,587,861
Net position, end of period	$ 1,588,994	$ 10,264	$ -	$ 1,599,258	$ 1,988,686	$ 7,308	$ -	$ 3,595,252

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Combining Statement of Revenues, Expenses, and Changes in Net Position
(in thousands - unaudited) for the month ended February 2022

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Eliminations	Total JEA
Operating revenues								
Electric - base	$ 50,456	$ -	$ -	$ 50,456	$ -	$ -	$ (674)	$ 49,782
Electric - fuel and purchased power	43,618	2,183	(2,183)	43,618	-	-	(883)	42,735
Water and sewer	-	-	-	-	35,804	-	(13)	35,791
District energy system	-	-	-	-	-	618	(21)	597
Other operating revenues	1,837	-	-	1,837	1,581	-	(191)	3,227
Total operating revenues	95,911	2,183	(2,183)	95,911	37,385	618	(1,782)	132,132
Operating expenses								
Operations and maintenance:								
Maintenance and other operating expenses	18,077	493	-	18,570	13,965	285	(1,782)	31,038
Fuel	29,972	-	-	29,972	-	-	-	29,972
Purchased power	22,033	-	(2,183)	19,850	-	-	-	19,850
Depreciation	17,735	34	-	17,769	14,366	215	-	32,350
State utility and franchise taxes	5,530	-	-	5,530	825	-	-	6,355
Recognition of deferred costs and revenues, net	691	1,239	-	1,930	513	-	-	2,443
Total operating expenses	94,038	1,766	(2,183)	93,621	29,669	500	(1,782)	122,008
Operating income	1,873	417	-	2,290	7,716	118	-	10,124
Nonoperating revenues (expenses)								
Interest on debt	(4,615)	(695)	-	(5,310)	(3,193)	(103)	-	(8,606)
Earnings from The Energy Authority	1,189	-	-	1,189	-	-	-	1,189
Allowance for funds used during construction	222	-	-	222	700	10	-	932
Other nonoperating income, net	319	22	-	341	204	-	-	545
Investment income	168	12	-	180	184	1	-	365
Other interest, net	(4)	-	-	(4)	-	-	-	(4)
Total nonoperating expenses, net	(2,721)	(661)	-	(3,382)	(2,105)	(92)	-	(5,579)
Income before contributions	(848)	(244)	-	(1,092)	5,611	26	-	4,545
Contributions (to) from								
General Fund, City of Jacksonville, Florida	(7,878)	-	-	(7,878)	(2,222)	-	-	(10,100)
Developers and other	505	-	-	505	6,112	-	-	6,617
Reduction of plant cost through contributions	(505)	-	-	(505)	(3,082)	-	-	(3,587)
Total contributions, net	(7,878)	-	-	(7,878)	808	-	-	(7,070)
Change in net position	(8,726)	(244)	-	(8,970)	6,419	26	-	(2,525)
Net position, beginning of period	1,564,792	56,911	-	1,621,703	1,895,147	6,236	-	3,523,086
Net position, end of period	$ 1,556,066	$ 56,667	$ -	$ 1,612,733	$ 1,901,566	$ 6,262	$ -	$ 3,520,561

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Combining Statement of Revenues, Expenses, and Changes in Net Position
(in thousands - unaudited) for the five months ended February 2023

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Eliminations	Total JEA
Operating revenues								
Electric - base	$ 280,854	$ -	$ -	$ 280,854	$ -	$ -	$ (3,540)	$ 277,314
Electric - fuel and purchased power	269,565	8,884	(8,884)	269,565	-	-	(5,780)	263,785
Water and sewer	-	-	-	-	206,126	-	(177)	205,949
District energy system	-	-	-	-	-	4,812	(308)	4,504
Other operating revenues	11,373	-	-	11,373	6,273	-	(2,171)	15,475
Total operating revenues	561,792	8,884	(8,884)	561,792	212,399	4,812	(11,976)	767,027
Operating expenses								
Operations and maintenance:								
Maintenance and other operating expenses	113,026	(794)	-	112,232	87,553	2,153	(11,976)	189,962
Fuel	198,800	-	-	198,800	-	-	-	198,800
Purchased power	108,226	-	(8,884)	99,342	-	-	-	99,342
Depreciation	89,883	170	-	90,053	82,621	1,149	-	173,823
State utility and franchise taxes	29,907	-	-	29,907	4,547	-	-	34,454
Recognition of deferred costs and revenues, net	7,803	6,358	-	14,161	7,739	-	-	21,900
Total operating expenses	547,645	5,734	(8,884)	544,495	182,460	3,302	(11,976)	718,281
Operating income	14,147	3,150	-	17,297	29,939	1,510	-	48,746
Nonoperating revenues (expenses)								
Interest on debt	(23,986)	(1,515)	-	(25,501)	(17,687)	(593)	-	(43,781)
Earnings from The Energy Authority	6,226	-	-	6,226	-	-	-	6,226
Allowance for funds used during construction	2,132	-	-	2,132	6,721	99	-	8,952
Other nonoperating income, net	1,624	94	-	1,718	1,015	-	-	2,733
Investment income	6,518	194	-	6,712	4,192	20	-	10,924
Other interest, net	(1,816)	-	-	(1,816)	(329)	-	-	(2,145)
Total nonoperating expenses, net	(9,302)	(1,227)	-	(10,529)	(6,088)	(474)	-	(17,091)
Income before contributions	4,845	1,923	-	6,768	23,851	1,036	-	31,655
Contributions (to) from								
General Fund, City of Jacksonville, Florida	(39,788)	-	-	(39,788)	(11,222)	-	-	(51,010)
Developers and other	2,483	-	-	2,483	39,986	-	-	42,469
Reduction of plant cost through contributions	(2,483)	-	-	(2,483)	(21,406)	-	-	(23,889)
Total contributions, net	(39,788)	-	-	(39,788)	7,358	-	-	(32,430)
Special item	11,135	-	-	11,135	-	-	-	11,135
Change in net position	(23,808)	1,923	-	(21,885)	31,209	1,036	-	10,360
Net position, beginning of year	1,612,802	8,341	-	1,621,143	1,957,477	6,272	-	3,584,892
Net position, end of period	$ 1,588,994	$ 10,264	$ -	$ 1,599,258	$ 1,988,686	$ 7,308	$ -	$ 3,595,252

JEA

Combining Statement of Revenues, Expenses, and Changes in Net Position
(in thousands - unaudited) for the five months ended February 2022

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Eliminations	Total JEA
Operating revenues								
Electric - base	$ 325,921	$ -	$ -	$ 325,921	$ -	$ -	$ (3,566)	$ 322,355
Electric - fuel and purchased power	216,993	38,617	(38,616)	216,994	-	-	(3,631)	213,363
Water and sewer	-	-	-	-	193,019	-	(77)	192,942
District energy system	-	-	-	-	-	3,259	(128)	3,131
Other operating revenues	8,954	233	-	9,187	7,858	1	(956)	16,090
Total operating revenues	551,868	38,850	(38,616)	552,102	200,877	3,260	(8,358)	747,881
Operating expenses								
Operations and maintenance:								
Maintenance and other operating expenses	93,730	29,053	-	122,783	76,993	1,651	(8,358)	193,069
Fuel	168,294	-	-	168,294	-	-	-	168,294
Purchased power	120,876	-	(38,616)	82,260	-	-	-	82,260
Depreciation	198,648	171	-	198,819	72,002	1,106	-	271,927
State utility and franchise taxes	25,299	-	-	25,299	4,468	-	-	29,767
Recognition of deferred costs and revenues, net	(49,066)	32,762	-	(16,304)	3,566	-	-	(12,738)
Total operating expenses	557,781	61,986	(38,616)	581,151	157,029	2,757	(8,358)	732,579
Operating income	(5,913)	(23,136)	-	(29,049)	43,848	503	-	15,302
Nonoperating revenues (expenses)								
Interest on debt	(26,199)	(4,562)	-	(30,761)	(16,327)	(512)	-	(47,600)
Earnings from The Energy Authority	14,783	-	-	14,783	-	-	-	14,783
Allowance for funds used during construction	1,080	-	-	1,080	3,324	47	-	4,451
Other nonoperating income, net	1,606	108	-	1,714	1,018	-	-	2,732
Investment income	416	28	-	444	541	1	-	986
Other interest, net	10	-	-	10	11	-	-	21
Total nonoperating expenses, net	(8,304)	(4,426)	-	(12,730)	(11,433)	(464)	-	(24,627)
Income before contributions	(14,217)	(27,562)	-	(41,779)	32,415	39	-	(9,325)
Contributions (to) from								
General Fund, City of Jacksonville, Florida	(39,394)	-	-	(39,394)	(11,111)	-	-	(50,505)
Developers and other	1,936	-	-	1,936	34,684	-	-	36,620
Reduction of plant cost through contributions	(1,936)	-	-	(1,936)	(21,747)	-	-	(23,683)
Total contributions, net	(39,394)	-	-	(39,394)	1,826	-	-	(37,568)
Special item	100,000	-	-	100,000	-	-	-	100,000
Change in net position	46,389	(27,562)	-	18,827	34,241	39	-	53,107
Net position, beginning of year	1,509,677	84,229	-	1,593,906	1,867,325	6,223	-	3,467,454
Net position, end of period	$ 1,556,066	$ 56,667	$ -	$ 1,612,733	$ 1,901,566	$ 6,262	$ -	$ 3,520,561

JEA

Combining Statement of Cash Flows

(in thousands - unaudited) for the five months ended February 2023

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Eliminations	Total JEA
Operating activities								
Receipts from customers	$ 674,844	$ 8,884	$ (8,923)	$ 674,805	$ 197,685	$ 4,543	$ (9,805)	$ 867,228
Payments to suppliers	(400,601)	(1,775)	8,923	(393,453)	(76,349)	(1,838)	11,976	(459,664)
Payments for salaries and benefits	(87,066)	-	-	(87,066)	(35,046)	(347)	-	(122,459)
Other operating activities	24,689	(19)	-	24,670	6,782	-	(2,171)	29,281
Net cash provided by operating activities	211,866	7,090	-	218,956	93,072	2,358	-	314,386
Noncapital and related financing activities								
Contribution to General Fund, City of Jacksonville, Florida	(39,709)	-	-	(39,709)	(11,200)	-	-	(50,909)
Net cash used in noncapital and related financing activities	(39,709)	-	-	(39,709)	(11,200)	-	-	(50,909)
Capital and related financing activities								
Acquisition and construction of capital assets	(91,352)	-	-	(91,352)	(169,056)	(7,287)	-	(267,695)
Interest paid on debt	(30,396)	(2,029)	-	(32,425)	(25,489)	(706)	-	(58,620)
Repayment of debt principal	(47,120)	(15,285)	-	(62,405)	(9,850)	(1,815)	-	(74,070)
Capital contributions	-	-	-	-	18,581	-	-	18,581
Revolving credit agreement withdrawals	-	-	-	-	-	4,000	-	4,000
Other capital financing activities	2,147	114	-	2,261	1,236	-	-	3,497
Net cash used in capital and related financing activities	(166,721)	(17,200)	-	(183,921)	(184,578)	(5,808)	-	(374,307)
Investing activities								
Proceeds from sale and maturity of investments	89,066	586	-	89,652	26,022	-	-	115,674
Purchase of investments	(230,586)	(586)	-	(231,172)	(61,158)	-	-	(292,330)
Distributions from The Energy Authority	6,420	-	-	6,420	-	-	-	6,420
Investment income	4,290	70	-	4,360	2,362	20	-	6,742
Net cash provided by (used in) investing activities	(130,810)	70	-	(130,740)	(32,774)	20	-	(163,494)
Net change in cash and cash equivalents	(125,374)	(10,040)	-	(135,414)	(135,480)	(3,430)	-	(274,324)
Cash and cash equivalents at beginning of year	327,733	24,864	-	352,597	163,282	4,811	-	520,690
Cash and cash equivalents at end of period	$ 202,359	$ 14,824	$ -	$ 217,183	$ 27,802	$ 1,381	$ -	$ 246,366
Reconciliation of operating income to net cash provided by operating activities								
Operating income	$ 14,147	$ 3,150	$ -	$ 17,297	$ 29,939	$ 1,510	$ -	$ 48,746
Adjustments:								
Depreciation and amortization	89,883	170	-	90,053	82,621	1,149	-	173,823
Recognition of deferred costs and revenues, net	7,803	6,358	-	14,161	7,739	-	-	21,900
Other nonoperating income, net	9,321	-	-	9,321	(329)	-	-	8,992
Changes in noncash assets and noncash liabilities:								
Accounts receivable	74,423	-	-	74,423	2,061	(269)	-	76,215
Inventories	(3,136)	-	-	(3,136)	(21,290)	-	-	(24,426)
Other assets	26,705	(26)	-	26,679	(4)	(7)	-	26,668
Accounts and accrued expenses payable	(59,759)	(301)	-	(60,060)	(497)	(32)	-	(60,589)
Current liabilities payable from restricted assets	-	(2,261)	-	(2,261)	-	-	-	(2,261)
Other noncurrent liabilities and deferred inflows	52,479	-	-	52,479	(7,168)	7	-	45,318
Net cash provided by operating activities	$ 211,866	$ 7,090	$ -	$ 218,956	$ 93,072	$ 2,358	$ -	$ 314,386
Noncash activity								
Contribution of capital assets from developers	$ 2,483	$ -	$ -	$ 2,483	$ 21,406	$ -	$ -	$ 23,889
Unrealized investment fair market value changes, net	$ 1,564	$ 136	$ -	$ 1,700	$ 1,360	$ -	$ -	$ 3,060

JEA

Combining Statement of Cash Flows

(in thousands - unaudited) for the five months ended February 2022

	Electric System and Bulk Power Supply System	SJRPP System	Elimination of Intercompany transactions	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Eliminations	Total JEA
Operating activities								
Receipts from customers	$ 520,404	$ 38,429	$ (38,621)	$ 520,212	$ 195,493	$ 3,396	$ (7,402)	$ 711,699
Payments to suppliers	(339,650)	(1,981)	38,621	(303,010)	(54,326)	(1,444)	8,358	(350,422)
Payments for salaries and benefits	(83,294)	-	-	(83,294)	(32,992)	(307)	-	(116,593)
Other operating activities	110,365	206	-	110,571	5,959	1	(956)	115,575
Net cash provided by operating activities	207,825	36,654	-	244,479	114,134	1,646	-	360,259
Noncapital and related financing activities								
Contribution to General Fund, City of Jacksonville, Florida	(39,316)	-	-	(39,316)	(11,089)	-	-	(50,405)
Net cash used in noncapital and related financing activities	(39,316)	-	-	(39,316)	(11,089)	-	-	(50,405)
Capital and related financing activities								
Acquisition and construction of capital assets	(62,664)	-	-	(62,664)	(87,836)	(2,185)	-	(152,685)
Defeasance of debt	(47,630)	(27,255)	-	(74,885)	-	-	-	(74,885)
Interest paid on debt	(31,966)	(5,273)	-	(37,239)	(22,644)	(629)	-	(60,512)
Repayment of debt principal	(66,220)	(14,175)	-	(80,395)	(9,370)	(1,770)	-	(91,535)
Capital contributions	-	-	-	-	12,938	-	-	12,938
Revolving credit agreement withdrawals	-	-	-	-	-	1,000	-	1,000
Other capital financing activities	2,942	56	-	2,998	1,368	-	-	4,366
Net cash used in capital and related financing activities	(205,538)	(46,647)	-	(252,185)	(105,544)	(3,584)	-	(361,313)
Investing activities								
Proceeds from sale and maturity of investments	74,776	554	-	75,330	20,395	-	-	95,725
Purchase of investments	(179,412)	(554)	-	(179,966)	(52,352)	-	-	(232,318)
Distributions from The Energy Authority	4,448	-	-	4,448	-	-	-	4,448
Investment income	718	42	-	760	621	1	-	1,382
Net cash provided by (used in) investing activities	(99,470)	42	-	(99,428)	(31,336)	1	-	(130,763)
Net change in cash and cash equivalents	(136,499)	(9,951)	-	(146,450)	(33,835)	(1,937)	-	(182,222)
Cash and cash equivalents at beginning of year	386,774	133,953	-	520,727	188,136	4,250	-	713,113
Cash and cash equivalents at end of period	$ 250,275	$ 124,002	$ -	$ 374,277	$ 154,301	$ 2,313	$ -	$ 530,891
Reconciliation of operating income to net cash provided by operating activities								
Operating income	$ (5,913)	$ (23,136)	$ -	$ (29,049)	$ 43,848	$ 503	$ -	$ 15,302
Adjustments:								
Depreciation and amortization	198,648	171	-	198,819	72,277	1,106	-	272,202
Recognition of deferred costs and revenues, net	(49,066)	32,762	-	(16,304)	3,566	-	-	(12,738)
Other nonoperating income (loss), net	100,045	-	-	100,045	11	-	-	100,056
Changes in noncash assets and noncash liabilities:								
Accounts receivable	6,647	(187)	-	6,460	3,275	138	-	9,873
Inventories	(12,889)	-	-	(12,889)	(3,139)	-	-	(16,028)
Other assets	801	65	-	866	(2,593)	(10)	-	(1,737)
Accounts and accrued expenses payable	1,623	27,103	-	28,726	(2,045)	(105)	-	26,576
Current liabilities payable from restricted assets	-	(124)	-	(124)	-	-	-	(124)
Other noncurrent liabilities and deferred inflows	(32,071)	-	-	(32,071)	(1,066)	14	-	(33,123)
Net cash provided by operating activities	$ 207,825	$ 36,654	$ -	$ 244,479	$ 114,134	$ 1,646	$ -	$ 360,259
Noncash activity								
Contribution of capital assets from developers	$ 1,936	$ -	$ -	$ 1,936	$ 21,747	$ -	$ -	$ 23,683
Unrealized investment fair market value changes, net	$ (395)	$ (10)	$ -	$ (405)	$ (380)	$ -	$ -	$ (785)

JEA
Debt Service Coverage
February 2023
(unaudited)

	Month February 2023	Month February 2022	Year-to-Date February 2023	Year-to-Date February 2022
Electric System				
Senior debt service coverage, (annual minimum 1.20x)	13.07 x	5.76 x	8.51 x	11.56 x
Senior and subordinated debt service coverage, (annual minimum 1.15x)	7.39 x	3.13 x	4.78 x	6.28 x
Bulk Power Supply System				
Debt service coverage, (annual minimum 1.15x)	1.71 x	2.11 x	1.90 x	13.68 x
St. Johns River Power Park, Second Resolution				
Debt service coverage, (annual minimum 1.15x)	1.13 x	1.13 x	1.14 x	3.87 x
Water and Sewer System				
Senior debt service coverage, (annual minimum 1.25x)	4.20 x	6.84 x	4.07 x	7.08 x
Senior and subordinated debt service coverage excluding capacity fees [1]	2.96 x	5.24 x	2.95 x	5.55 x
Senior and subordinated debt service coverage including capacity fees [1]	3.50 x	5.93 x	3.40 x	6.15 x
District Energy System				
Debt service coverage	2.23 x	1.32 x	2.13 x	1.28 x

[1] Annual minimum coverage is either 1.00x aggregate debt service and aggregate subordinated debt service (excluding capacity charges) or the sum of 1.00x aggregate debt service and 1.20x aggregate subordinated debt service (including capacity charges).

JEA
Electric System
Operating Statistics
February 2023 and 2022 (unaudited)

	Month 2023	Month 2022	Variance	Year-to-Date 2023	Year-to-Date 2022	Variance
Electric revenues sales (000s omitted):						
Residential	$ 58,993	$ 58,076	1.58%	$ 294,112	$ 262,204	12.17%
Commercial	36,872	30,915	19.27%	189,828	159,269	19.19%
Industrial	21,474	15,815	35.78%	106,148	85,214	24.57%
Public street lighting	1,349	1,233	9.41%	6,587	5,988	10.00%
Electric revenues - territorial	118,688	106,039	11.93%	596,675	512,675	16.38%
Sales for resale - off system	11	34	-67.65%	869	246	253.25%
Electric revenues	118,699	106,073	11.90%	597,544	512,921	16.50%
Regulatory	30	(11,998)	-100.25%	(45,986)	30,035	-253.11%
Allowance for doubtful accounts	(223)	(1)	22200.00%	(1,139)	(42)	2611.90%
Net electric revenues	118,506	94,074	25.97%	550,419	542,914	1.38%
MWh sales						
Residential	371,618	420,778	-11.68%	2,010,405	2,094,264	-4.00%
Commercial	264,560	248,764	6.35%	1,476,845	1,486,173	-0.63%
Industrial	193,855	161,378	20.12%	1,049,665	1,052,616	-0.28%
Public street lighting	4,292	4,299	-0.16%	22,812	22,959	-0.64%
Total MWh sales - territorial	834,325	835,219	-0.11%	4,559,727	4,656,012	-2.07%
Sales for resale - off system	400	750	-46.67%	16,558	3,660	352.40%
Total MWh sales	834,725	835,969	-0.15%	4,576,285	4,659,672	-1.79%
Average number of accounts						
Residential	454,269	443,336	2.47%	452,258	441,971	2.33%
Commercial	55,562	54,764	1.46%	55,414	54,682	1.34%
Industrial	200	198	1.01%	200	197	1.52%
Public street lighting	4,021	3,984	0.93%	4,000	3,981	0.48%
Total average accounts	514,052	502,282	2.34%	511,872	500,831	2.20%
Residential averages						
Revenue per account - $	129.86	131.00	-0.87%	650.32	593.26	9.62%
kWh per account	818	949	-13.81%	4,445	4,738	-6.19%
Revenue per kWh - ¢	15.87	13.80	15.02%	14.63	12.52	16.85%
Degree days						
Heating degree days	82	215	(133)	732	946	(214)
Cooling degree days	104	45	59	432	368	64
Total degree days	186	260	(74)	1,164	1,314	(150)
Degree days - 30 year average	258			1,381		

JEA
Water and Sewer System
Operating Statistics
February 2023 and 2022 (unaudited)

	Month								
	Water			Sewer			Reuse		
	2023	2022	Variance	2023	2022	Variance	2023	2022	Variance
Revenues (000s omitted):									
Residential	$ 8,149	$ 7,702	5.80%	$ 12,156	$ 11,766	3.31%	$ 1,201	$ 1,055	13.84%
Commercial and industrial	3,915	3,867	1.24%	8,986	9,481	-5.22%	441	372	18.55%
Irrigation	2,275	2,126	7.01%	N/A	N/A	N/A	18	17	5.88%
Gross revenues	14,339	13,695	4.70%	21,142	21,247	-0.49%	1,660	1,444	14.96%
Rate stabilization	1,141	(219)	-621.00%	1,681	(340)	-594.41%	132	(23)	-673.91%
Allowance for doubtful accounts	(29)	-		(43)	-		(3)	-	
Net revenues	$ 15,451	$ 13,476	14.66%	$ 22,780	$ 20,907	8.96%	$ 1,789	$ 1,421	25.90%
Kgal sales (000s omitted)									
Residential	1,370,846	1,322,256	3.67%	1,195,272	1,189,757	0.46%	183,684	135,603	35.46%
Commercial and industrial	1,111,180	1,074,242	3.44%	973,136	1,028,929	-5.42%	90,542	74,101	22.19%
Irrigation	334,828	304,314	10.03%	N/A	N/A	N/A	38,491	41,515	-7.28%
Total kgals sales	2,816,854	2,700,812	4.30%	2,168,408	2,218,686	-2.27%	312,717	251,219	24.48%
Average number of accounts:									
Residential	324,979	316,836	2.57%	291,318	282,922	2.97%	24,574	21,326	15.23%
Commercial and industrial	27,178	26,865	1.17%	19,332	19,101	1.21%	879	804	9.33%
Irrigation	38,399	38,145	0.67%	N/A	N/A	N/A	43	43	0.00%
Total average accounts	390,556	381,846	2.28%	310,650	302,023	2.86%	25,496	22,173	14.99%
Residential averages:									
Revenue per account - $	25.08	24.31	3.17%	41.73	41.59	0.34%	48.87	49.47	-1.21%
Kgals per account	4.22	4.17	1.20%	4.10	4.21	-2.61%	7.47	6.36	17.45%
Revenue per kgals - $	5.94	5.82	2.06%	10.17	9.89	2.83%	6.54	7.78	-15.94%

	Year-to-Date								
	Water			Sewer			Reuse		
	2023	2022	Variance	2023	2022	Variance	2023	2022	Variance
Revenues (000s omitted):									
Residential	$ 43,291	$ 41,031	5.51%	$ 65,160	$ 62,118	4.90%	$ 6,995	$ 6,419	8.97%
Commercial and industrial	20,416	19,886	2.67%	47,476	47,078	0.85%	2,710	2,623	3.32%
Irrigation	12,737	12,819	-0.64%	N/A	N/A	N/A	91	114	-20.18%
Gross revenues	76,444	73,736	3.67%	112,636	109,196	3.15%	9,796	9,156	6.99%
Rate stabilization	1,793	1,696	5.72%	5,416	(721)	-851.18%	445	(44)	-1111.36%
Allowance for doubtful accounts	(154)	-		(231)	-		(19)	-	
Net revenues	$ 78,083	$ 75,432	3.51%	$ 117,821	$ 108,475	8.62%	$ 10,222	$ 9,112	12.18%
Kgal sales (000s omitted)									
Residential	7,685,702	7,390,978	3.99%	6,801,037	6,514,181	4.40%	1,062,009	990,337	7.24%
Commercial and industrial	5,816,294	5,748,128	1.19%	5,148,091	5,133,656	0.28%	565,375	551,018	2.61%
Irrigation	1,984,481	2,038,288	-2.64%	N/A	N/A	N/A	226,062	388,592	-41.83%
Total kgals sales	15,486,477	15,177,394	2.04%	11,949,128	11,647,837	2.59%	1,853,446	1,929,947	-3.96%
Average number of accounts:									
Residential	324,079	315,330	2.77%	290,383	281,486	3.16%	24,029	20,859	15.20%
Commercial and industrial	27,168	26,796	1.39%	19,326	19,054	1.43%	872	791	10.24%
Irrigation	38,388	38,162	0.59%	N/A	N/A	N/A	43	43	0.00%
Total average accounts	389,635	380,288	2.46%	309,709	300,540	3.05%	24,944	21,693	14.99%
Residential averages:									
Revenue per account - $	133.58	130.12	2.66%	224.39	220.68	1.68%	291.11	307.73	-5.40%
Kgals per account	23.72	23.44	1.19%	23.42	23.14	1.21%	44.20	47.48	-6.91%
Revenue per kgals - $	5.63	5.55	1.44%	9.58	9.54	0.42%	6.59	6.48	1.70%

	Month				Year-to-Date			
Rain statistics	2023	2022	Variance	30 Year Avg	2023	2022	Variance	30 Year Avg
Rainfall	1.42	2.09	(0.67)	2.86	8.47	12.22	(3.75)	14.95
Rain Days	5	7	(2)	8	23	29	(6)	38

Appendix

JEA
Schedule of Cash and Investments
(in thousands - unaudited) February 2023

	Electric System and Bulk Power Supply System	SJRPP System	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Total JEA
Unrestricted cash and investments						
Operations	$ 16,973	$ 2,872	$ 19,845	$ 16,690	$ 1,566	$ 38,101
Rate stabilization:						
Environmental	20,164	-	20,164	18,441	-	38,605
Purchased Power	100,577	-	100,577	-	-	100,577
DSM/Conservation	9,796	-	9,796	-	-	9,796
Total rate stabilization funds	130,537	-	130,537	18,441	-	148,978
Customer deposits	45,688	-	45,688	14,119	-	59,807
General reserve	-	965	965	-	-	965
Self insurance reserve funds:						
Self funded health plan	15,780	-	15,780	-	-	15,780
Property insurance reserve	10,000	-	10,000	-	-	10,000
Total self insurance reserve funds	25,780	-	25,780	-	-	25,780
Environmental liability reserve	15,552	-	15,552	-	-	15,552
Total unrestricted cash and investments	$ 234,530	$ 3,837	$ 238,367	$ 49,250	$ 1,566	$ 289,183
Restricted assets						
Renewal and replacement funds	$ 230,697	$ 3,222	$ 233,919	$ 25,387	$ (1,451)	$ 257,855
Debt service reserve account	53,352	3,314	56,666	57,587	-	114,253
Debt service funds	26,904	8,080	34,984	40,785	1,266	77,035
Construction funds	110	-	110	207	-	317
Environmental funds	-	-	-	1,410	-	1,410
Subtotal	311,063	14,616	325,679	125,376	(185)	450,870
Unrealized holding gain (loss) on investments	(6,497)	116	(6,381)	(1,143)	-	(7,524)
Other funds	-	480	480	-	-	480
Total restricted cash and investments	$ 304,566	$ 15,212	$ 319,778	$ 124,233	$ (185)	$ 443,826
Total cash and investments	$ 539,096	$ 19,049	$ 558,145	$ 173,483	$ 1,381	$ 733,009

JEA
Schedule of Cash and Investments
(in thousands) September 2022

	Electric System and Bulk Power Supply System	SJRPP System	Total Electric Enterprise Fund	Water and Sewer Enterprise Fund	District Energy System Fund	Total JEA
Unrestricted cash and investments						
Operations	$ 3,539	$ 2,971	$ 6,510	$ 27,084	$ 1,341	$ 34,935
Rate stabilization:						
Environmental	20,728	-	20,728	26,094	-	46,822
Purchased Power	55,000	-	55,000	-	-	55,000
DSM/Conservation	8,824	-	8,824	-	-	8,824
Total rate stabilization funds	84,552	-	84,552	26,094	-	110,646
Customer deposits	45,043	-	45,043	14,711	-	59,754
General reserve	-	338	338	-	-	338
Self insurance reserve funds:						
Self funded health plan	14,145	-	14,145	-	-	14,145
Property insurance reserve	10,000	-	10,000	-	-	10,000
Total self insurance reserve funds	24,145	-	24,145	-	-	24,145
Environmental liability reserve	15,797	-	15,797	-	-	15,797
Total unrestricted cash and investments	$ 173,076	$ 3,309	$ 176,385	$ 67,889	$ 1,341	$ 245,615
Restricted assets						
Renewal and replacement funds	$ 233,018	$ 4,252	$ 237,270	$ 112,930	$ 1,049	$ 351,249
Debt service reserve account	53,352	3,839	57,191	56,606	-	113,797
Debt service funds	69,890	17,350	87,240	32,499	2,421	122,160
Construction funds	111	-	111	646	-	757
Environmental funds	-	-	-	4,400	-	4,400
Subtotal	356,371	25,441	381,812	207,081	3,470	592,363
Unrealized holding gain (loss) on investments	(8,061)	13	(8,048)	(2,502)	-	(10,550)
Other funds	-	190	190	-	-	190
Total restricted cash and investments	$ 348,310	$ 25,644	$ 373,954	$ 204,579	$ 3,470	$ 582,003
Total cash and investments	$ 521,386	$ 28,953	$ 550,339	$ 272,468	$ 4,811	$ 827,618

JEA
INVESTMENT PORTFOLIO REPORT
FEBRUARY 2023
(unaudited)

	INVESTMENT	BOOK VALUE	YIELD	% OF TOTAL
*	Treasuries	$ 38,889,844	2.67%	5.27%
	Agencies			
	Federal Farm Credit Bank	53,631,929	4.68%	7.27%
	Federal Home Loan Bank	206,537,054	3.02%	27.99%
	Total	260,168,983	3.36%	35.25%
	Municipal Bonds	97,777,201	3.55%	13.25%
	Commercial Paper	134,493,583	4.79%	18.22%
	U.S. Treasury Money Market Funds (1)	31,050,006	4.42%	4.21%
	Agency Money Market Funds (2)	1,000,000	4.36%	0.14%
	PALM Money Market Fund	30,500,000	4.72%	4.13%
	Florida Prime Fund	93,500,000	4.77%	12.67%
	Wells Fargo Bank Accounts (3)			
	Electric, Scherer	30,924,561	2.98%	4.19%
	SJRPP	13,248,561	2.98%	1.80%
	Water & Sewer, DES	6,429,382	2.98%	0.87%
	Total Portfolio	$ 737,982,122.00	3.87%	100.00%

Backed by Full Faith and Credit of U. S. Government

Weighted Avg. Annual Yield Excluding Bank & Money Market Funds: 3.53%

Weighted Avg. Annual Yield Including Bank & Money Market Funds: 3.87%

Some investments listed above may be classified as Cash Equivalents on the Statements of Net Position in accordance with generally accepted accounting principles.

(1) Treasury Funds: Fidelity, Goldman Sachs, State Street

(2) Government Funds: State Street, Wells Fargo Allspring

(3) Month-end bank balances

JEA

Schedule of Outstanding Indebtedness
February 2023
(unaudited)

	Interest Rates	Principal Payment Dates	Par Amount Principal Outstanding	Current Portion of Long-Term Debt
Electric Enterprise				
Electric System				
Fixed Rate Senior	3.000-6.056%	2026-2044	423,430,000	-
Fixed Rate Subordinated	3.375-6.406%	2023-2039	418,700,000	4,685,000
Variable Rate Senior	2.639-3.640%	2023-2040	430,910,000	7,950,000
Variable Rate Subordinated	3.220-3.260%	2023-2038	51,485,000	4,145,000
Total Electric System	3.758% (wtd avg)	2023-2044	1,324,525,000	16,780,000
Bulk Power Supply System				
Fixed Rate Senior	5.300-5.920%	2023-2030	24,765,000	2,495,000
St. Johns River Power Park				
Fixed Rate Senior	2.750-5.450%	2023-2028	92,715,000	15,865,000
Total Electric Enterprise	3.737% (wtd avg)	2023-2044	1,442,005,000	35,140,000
Water and Sewer System				
Fixed Rate Senior	3.000-6.310%	2023-2044	865,290,000	38,485,000
Fixed Rate Subordinated	2.750-5.000%	2023-2040	88,845,000	8,170,000
Variable Rate Senior[(1)]	3.275-3.300%	2023-2042	137,110,000	4,035,000
Variable Rate Subordinated	3.216-3.325%	2023-2038	95,810,000	1,675,000
Total Water and Sewer System	3.701% (wtd avg)	2023-2044	1,187,055,000	52,365,000
District Energy System				
Fixed Rate Senior	3.244-4.538%	2023-2034	27,825,000	1,870,000
Other Obligations	5.639%	2024	7,000,000	-
Total District Energy System	4.606% (wtd avg)	2023-2034	34,825,000	1,870,000
Total JEA	3.732% (wtd avg)	2023-2044	2,663,885,000	89,375,000

JEA

Debt Ratio
(unaudited)

	Current YTD
Electric Enterprise	50.0%
Water and Sewer System	36.2%

JEA
Interest Rate Swap Position Report
February 2023
(unaudited)

JEA Debt Management Swaps Variable to Fixed

ID	Dealer	Effective Date	Termination Date	Allocation	Fixed Rate	Floating Rate (1)	Spread	Rate Cap	Index
Electric System									
1	Goldman Sachs	9/18/2003	9/16/2033	$ 84,800,000	3.717	3.105	0.612	n/a	68% 1 mth Libor
3	Morgan Stanley	1/27/2005	10/1/2039	82,575,000	4.351	3.190	1.161	n/a	SIFMA
4	JPMorgan	1/27/2005	10/1/2035	74,925,000	3.661	3.105	0.556	n/a	68% 1 mth Libor
6	JPMorgan	1/27/2005	10/1/2037	39,175,000	3.716	3.105	0.611	n/a	68% 1 mth Libor
8	Morgan Stanley	1/31/2007	10/1/2031	62,980,000	3.907	3.190	0.717	n/a	SIFMA
10	Goldman Sachs	1/31/2008	10/1/2036	51,680,000	3.836	3.190	0.646	n/a	SIFMA
			Total	396,135,000					
Water/Sewer System									
9	Merrill Lynch	3/8/2007	10/1/2041	85,290,000	3.895	3.190	0.705	n/a	SIFMA
			Total	85,290,000					
			Grand Total	$ 481,425,000	Wtd Avg Spread		0.732		

Note: (1) The "Floating Rate" column is the average of the floating rate for each instrument for this month.

JEA
Electric System
Production Statistics
February 2023 and 2022 (unaudited)

	Month			Year-to-Date		
	2023	**2022**	**Variance**	**2023**	**2022**	**Variance**
Generated power:						
Steam:						
Fuel oil #6						
Fuel expense	$ 1,052,739	$ -		$ 4,619,669	$ 1,389,112	232.56%
Barrels consumed	9,436	-		39,106	13,100	198.52%
$/ per barrel consumed	$ 111.57	$ -		$ 118.13	$ 106.04	11.40%
kWh generated (1)	5,404,952	614	880185.34%	21,259,248	7,289,009	191.66%
Cost per MWh	$ 194.77	$ -		$ 217.30	$ 190.58	14.02%
Natural gas units #1-3						
Fuel expense - variable	$ 4,984,095	$ 8,114,217	-38.58%	$ 35,888,109	$ 31,965,128	12.27%
MMBTUs consumed	1,100,629	1,399,886	-21.38%	6,005,337	5,798,700	3.56%
$/ per MMBTU consumed	$ 4.53	$ 5.80	-21.87%	$ 5.98	$ 5.51	8.41%
kWh generated (1)	96,672,878	118,528,746	-18.44%	521,476,819	500,785,095	4.13%
Cost per MWh	$ 51.56	$ 68.46	-24.69%	$ 68.82	$ 63.83	7.82%
Biomass units #1-2						
Fuel expense	$ 17,632.00	$ 91,337.00	-80.70%	$ 436,135.00	$ 412,892.00	5.63%
kWh generated	2,697,705	-		15,345,093	-	
Cost per MWh	$ 6.54	$ -		$ 28.42	$ -	
Coal						
Fuel expense	$ 3,649,784	$ 2,308,042	58.13%	$ 18,384,396	$ 16,132,463	13.96%
kWh generated	40,018,717	31,360,281	27.61%	229,439,340	224,211,749	2.33%
Cost per MWh	$ 91.20	$ 73.60	23.92%	$ 80.13	$ 71.95	11.36%
Pet coke and limestone						
Fuel expense	$ 10,295,938	$ 5,873,796	75.29%	$ 36,930,886	$ 21,686,937	70.29%
kWh generated	134,689,605	77,690,144	73.37%	476,950,852	311,305,792	53.21%
Cost per MWh	$ 76.44	$ 75.61	1.11%	$ 77.43	$ 69.66	11.15%
Combustion turbine:						
Fuel oil #2						
Fuel expense	$ 60,008	$ 67,940	-11.68%	$ 1,103,601	$ 452,119	144.10%
Barrels consumed	180	393	-54.20%	9,043	2,953	206.23%
$/ per barrel consumed	$ 333.38	$ 172.88	92.84%	$ 122.04	$ 153.10	-20.29%
kWh generated	131,869	137,888	-4.37%	3,618,884	756,962	378.08%
Cost per MWh	$ 455.06	$ 492.72	-7.64%	$ 304.96	$ 597.28	-48.94%
Natural gas (includes landfill)						
Fuel expense Kennedy & landfill - variable	$ 802,498	$ 949,730	-15.50%	$ 2,791,291	$ 6,483,912	-56.95%
MMBTUs consumed	176,984	163,820	8.04%	491,298	1,166,558	-57.88%
$/ per MMBTU consumed	$ 4.53	$ 5.80	-21.79%	$ 5.68	$ 5.56	2.22%
kWh generated (1)	15,013,836	15,092,828	-0.52%	40,365,797	102,115,023	-60.47%
Cost per MWh	$ 53.45	$ 62.93	-15.06%	$ 69.15	$ 63.50	8.90%
Fuel expense BB simple - variable	$ 962,313	$ 169,658	467.21%	$ 3,640,537	$ 1,410,891	158.03%
MMBTUs consumed	$ 207,696	29,663	600.19%	622,131	260,052	139.23%
$/ per MMBTU consumed	$ 4.63	$ 5.72	-18.99%	$ 5.85	$ 5.43	7.86%
kWh generated (1)	20,162,662	2,637,702	664.40%	57,446,619	23,126,093	148.41%
Cost per MWh	$ 47.73	$ 64.32	-25.80%	$ 63.37	$ 61.01	3.87%
Fuel expense BB combined - variable	$ 9,177,323	$ 12,821,256	-28.42%	$ 84,734,250	$ 74,892,561	13.14%
MMBTUs consumed	1,946,272	2,223,105	-12.45%	13,581,481	13,813,226	-1.68%
$/ per MMBTU consumed	$ 4.72	$ 5.77	-18.24%	$ 6.24	$ 5.42	15.07%
kWh generated (1)	290,189,327	331,530,983	-12.47%	1,984,740,508	2,034,437,064	-2.44%
Cost per MWh	$ 31.63	$ 38.67	-18.22%	$ 42.69	$ 36.81	15.97%
Fuel expense GEC simple - variable	$ 1,441,368	$ 1,163,667	23.86%	$ 11,541,673	$ 10,461,300	10.33%
MMBTUs consumed	279,449	180,616	54.72%	1,720,021	1,704,395	0.92%
$/ per MMBTU consumed	$ 5.16	$ 6.44	-19.94%	$ 6.71	$ 6.14	9.33%
kWh generated	23,837,246	15,909,748	49.83%	150,454,836	150,979,848	-0.35%
Cost per MWh	$ 60.47	$ 73.14	-17.33%	$ 76.71	$ 69.29	10.71%
Natural gas expense - fixed	$ 2,994,924	$ 3,215,811	-6.87%	$ 15,374,978	$ 16,820,327	-8.59%
Total generated power:						
Fuel expense	$ 35,438,622	$ 34,775,454	1.91%	$ 215,445,525	$ 182,107,642	18.31%
kWh generated	628,818,797	592,888,934	6.06%	3,501,097,996	3,355,006,635	4.35%
Cost per MWh	$ 56.36	$ 58.65	-3.92%	$ 61.54	$ 54.28	13.37%

(1) Allocation of kWh generated is based upon a ratio of gas MBTU's (adjusted to oil equivalent - 95.5%) and oil MBTU's.

JEA
Electric System
Production Statistics (Continued)
February 2023 and 2022 (unaudited)

	Month			Year-to-Date		
	2023	2022	Variance	2023	2022	Variance
Cost of fuels						
Natural gas	$ 20,362,521	$ 26,434,339	-22.97%	$ 153,970,838	$ 142,034,119	8.40%
Petcoke	10,295,938	5,873,796	75.29%	36,930,886	21,686,937	70.29%
Coal	3,649,784	2,308,042	58.13%	18,384,396	16,132,463	13.96%
Fuel oil #2	60,008	67,940	-11.68%	1,103,601	452,119	144.10%
Fuel oil #6	1,052,739	-		4,619,669	1,389,112	232.56%
Biomass	17,632	91,337	-80.70%	436,135	412,892	5.63%
Total	$ 35,438,622	$ 34,775,454	1.91%	$ 215,445,525	$ 182,107,642	18.31%
Purchased power:						
TEA & other						
Purchases	$ 9,757,938	$ 13,033,364	-25.13%	$ 66,186,314	$ 68,771,883	-3.76%
kWh purchased	99,110,840	160,210,137	-38.14%	570,808,752	888,334,248	-35.74%
Cost per MWh	$ 98.45	$ 81.35	21.02%	$ 115.95	$ 77.42	49.78%
FPL						
Purchases	$ 3,983,401	$ 6,817,680	-41.57%	$ 33,155,168	$ 13,487,909	145.81%
kWh purchased	117,294,000	133,911,000	-12.41%	669,993,000	278,082,000	140.93%
Cost per MWh	$ 33.96	$ 50.91	-33.30%	$ 49.49	$ 48.50	2.03%
Plant Scherer						
Purchases	$ 1,366,158	$ 299,558	356.06%	$ 5,798,030	$ 16,264,045	-64.35%
kWh purchased	-	-		-	284,609,000	-100.00%
Cost per MWh					$ 57.15	
SJRPP						
Purchases	$ 1,776,812	$ 2,182,586	-18.59%	$ 8,884,061	$ 38,616,466	-76.99%
Total purchased power:						
Purchases	$ 16,884,309	$ 22,333,188	-24.40%	$ 114,023,573	$ 137,140,303	-16.86%
kWh purchased	216,404,840	294,121,137	-26.42%	1,240,801,752	1,451,025,248	-14.49%
Cost per MWh	$ 78.02	$ 75.93	2.75%	$ 91.90	$ 94.51	-2.77%
Subtotal - generated and purchased power:	$ 52,322,931	$ 57,108,642	-8.38%	$ 329,469,098	$ 319,247,945	3.20%
Fuel interchange sales	(9,850)	(34,094)	-71.11%	(868,636)	(164,788)	427.12%
Earnings of The Energy Authority	149,155	(1,103,950)	-113.51%	(5,970,614)	(14,698,392)	-59.38%
Realized and Unrealized (Gains) Losses	1,558,454	(5,072,759)	-130.72%	(24,827,018)	(28,996,062)	-14.38%
Fuel procurement and handling	1,505,849	845,846	78.03%	5,368,503	4,558,905	17.76%
Byproduct reuse	811,324	218,366	271.54%	2,813,048	1,914,968	46.90%
Total generated and net purchased power:						
Cost, net	56,337,863	51,962,051	8.42%	305,984,381	281,862,576	8.56%
kWh generated and purchased	845,223,637	887,010,071	-4.71%	4,741,899,748	4,806,031,883	-1.33%
Cost per MWh	$ 66.65	$ 58.58	13.78%	$ 64.53	$ 58.65	10.03%
Reconciliation:						
Generated and purchased power per above	$ 56,337,863	$ 66.65		$ 305,984,381	$ 64.53	
SJRPP operating expenses:						
SJRPP debt service	$ (1,578,092)	(1.87)		(7,890,461)	(1.66)	
SJRPP R & R	$ (198,720)	(0.24)		(993,599)	(0.21)	
Scherer operating expenses:						
Scherer power production	$ (1,291,775)	(1.53)		(4,221,728)	(0.89)	
Scherer R & R	$ (197,097)	(0.23)		(1,255,097)	(0.26)	
Scherer taxes	$ 122,714	0.15		(321,205)	(0.07)	
MEAG	$ (2,467,601)	(2.92)		(12,409,756)	(2.62)	
FPL capacity	$ (1,400,000)	(1.66)		(7,095,760)	(1.50)	
TEA and other capacity	$ (1,513,814)	(1.79)		(6,790,044)	(1.43)	
Rounding	$ -	-		(1)	(0.00)	
Energy expense per budget page	$ 47,813,478	$ 56.57		$ 265,006,730	$ 55.89	

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Electric System **Budget vs. Actual** **February 2023 and 2022 (unaudited)**	**ANNUAL BUDGET 2022-23**	**Month: BUDGET 2022-23**	**Month: ACTUAL 2022-23**	**Month: Variance %**	**Prior Year Month: ACTUAL 2021-22**	**Prior Year Month: Variance %**
Fuel Related Revenues & Expenses						
Fuel Rate Revenues	$ 671,607,062	$ 54,376,799	$ 57,342,506	5.45%	$ 44,316,008	29.39%
Fuel Expense and Purchased Power:						
Fuel Expense - Electric System	517,390,725	40,623,952	39,314,249		30,766,907	
Other Purchased Power	153,143,481	13,665,983	8,499,229		12,817,863	
Subtotal Energy Expense	670,534,206	54,289,935	47,813,478	11.93%	43,584,770	-9.70%
Transfer to (from) Rate Stabilization, Net	-	-	-		8	
Transfer to (from) Other Regulatory Funds, Net	-	-	9,415,373		730,412	
Fuel Related Uncollectibles	1,072,856	86,864	113,655		818	
Total	671,607,062	54,376,799	57,342,506	-5.45%	44,316,008	-29.39%
Fuel Balance	-	-	-		-	
Nonfuel Related Revenues						
Base Rate Revenues	791,048,000	54,852,302	55,167,260		55,620,634	
Conservation Charge Revenue	732,000	50,758	25,522		78,739	
Environmental Charge Revenue	7,442,000	516,038	505,021		513,370	
Investment Income	5,793,688	499,444	1,384,621		167,987	
Natural Gas Revenue Pass Through	1,498,857	124,905	61,746		113,338	
Other Revenues	37,660,665	3,138,389	3,493,536		2,201,097	
Total	844,175,210	59,181,836	60,637,706	2.46%	58,695,165	3.31%
Nonfuel Related Expenses						
Non-Fuel O&M	269,166,868	18,972,161	18,296,787		23,214,843	
DSM / Conservation O&M	7,111,667	583,585	382,207		137,098	
Environmental O&M	16,998,000	1,416,500	139,499		36,312	
Rate Stabilization - DSM	(279,667)	(23,306)	60,477		795,772	
Rate Stabilization - Environmental	(1,933,468)	(161,122)	(90,112)		(25,234)	
Natural Gas Expense Pass Through	1,595,137	131,993	82,318		136,276	
Debt Principal - Electric System	16,780,000	1,398,333	1,398,333		3,725,833	
Debt Interest - Electric System	60,018,079	5,001,507	4,994,823		4,961,277	
R&R - Electric System	83,341,200	6,945,100	6,945,100		5,527,433	
Operating Capital Outlay	43,621,075	-	-		-	
Operating Capital Outlay - Environmental	472,000	39,333	476,657		502,292	
City Contribution Expense	95,491,107	7,957,592	7,957,592		7,878,804	
Taxes & Uncollectibles	1,515,596	126,300	156,451		19,726	
Emergency Reserve	5,000,000	-	-		-	
Nonfuel Purchased Power:						
* SJRPP D/S Principal	15,865,000	1,322,083	1,322,083		1,273,750	
* SJRPP D/S Interest	3,212,107	267,676	267,676		672,694	
** Other Non-Fuel Purchased Power	226,200,509	8,516,709	7,221,966		17,215,215	
Total Nonfuel Expenses	844,175,210	52,494,444	49,611,857	5.49%	66,072,091	24.91%
Non-Fuel Balance	-	6,687,392	11,025,849		(7,376,926)	
Total Balance	-	6,687,392	11,025,849		(7,376,926)	
Total Revenues	**1,515,782,272**	**113,558,635**	**117,980,212**	3.89%	**103,011,173**	14.53%
Total Expenses	**1,515,782,272**	**106,871,243**	**106,954,363**	-0.08%	**110,388,099**	3.11%
KWH Sold - Territorial	**12,200,000,000**	**845,963,948**	**834,325,122**	-1.38%	**835,219,189**	-0.11%
KWH Sold - Off System	**-**	**-**	**400,000**		**750,000**	
	12,200,000,000	**845,963,948**	**834,725,122**	-1.33%	**835,969,189**	-0.15%

* Gross debt service
** Includes transmission capacity, SJRPP and Scherer R & R, O & M and Investment Income.

JEA
Electric System
Budget vs. Actual
February 2023 and 2022 (unaudited)

		ANNUAL BUDGET 2022-23	Year-to-Date BUDGET 2022-23	Year-to-Date ACTUAL 2022-23	Year-to-Date Variance %	Prior Year-to-Date ACTUAL 2021-22	Prior Year-to-Date Variance %
	Fuel Related Revenues & Expenses						
	Fuel Rate Revenues	$ 671,607,062	$ 289,963,770	$ 269,212,253	-7.16%	$ 183,647,041	46.59%
	Fuel Expense and Purchased Power:						
	Fuel Expense - Electric System	517,390,725	223,476,218	198,800,058		159,585,453	
	Other Purchased Power	153,143,481	66,024,351	66,206,672		57,243,648	
	Subtotal Energy Expense	670,534,206	289,500,569	265,006,730	8.46%	216,829,101	-22.22%
	Transfer to (from) Rate Stabilization, Net	-	-	-		(41,766,988)	
	Transfer to (from) Other Regulatory Funds, Net	-	-	3,689,772		8,543,599	
	Fuel Related Uncollectibles	1,072,856	463,201	515,751		41,329	
	Total	671,607,062	289,963,770	269,212,253	7.16%	183,647,041	-46.59%
	Fuel Balance	-	-	-		-	
	Nonfuel Related Revenues						
	Base Rate Revenues	791,048,000	304,470,954	294,723,832		300,789,983	
	Conservation Charge Revenue	732,000	281,744	189,452		250,530	
	Environmental Charge Revenue	7,442,000	2,864,394	2,761,452		2,861,562	
	Investment Income	5,793,688	2,294,735	4,952,396		811,198	
	Natural Gas Revenue Pass Through	1,498,857	624,524	492,425		484,652	
	Other Revenues	37,660,665	15,691,944	85,039,343		110,424,463	
	Total	844,175,210	326,228,295	388,158,900	18.98%	415,622,388	-6.61%
	Nonfuel Related Expenses						
	Non-Fuel O&M	269,166,868	110,135,225	108,744,045		85,896,470	
	DSM / Conservation O&M	7,111,667	2,917,923	1,497,323		1,280,463	
	Environmental O&M	16,998,000	7,082,500	439,222		237,788	
	Rate Stabilization - DSM	(279,667)	(116,528)	971,992		1,715,682	
	Rate Stabilization - Environmental	(1,933,468)	(805,612)	(563,209)		(122,919)	
	Natural Gas Expense Pass Through	1,595,137	659,967	533,653		589,231	
	Debt Principal - Electric System	16,780,000	6,991,667	6,991,667		18,629,167	
	Debt Interest - Electric System	60,018,079	25,007,533	25,490,668		25,629,054	
	R&R - Electric System	83,341,200	34,725,500	34,725,500		27,637,167	
	Operating Capital Outlay	43,621,075	26,000,000	42,495,697		76,000,000	
	Operating Capital Outlay - Environmental	472,000	196,667	3,130,599		2,746,693	
	City Contribution Expense	95,491,107	39,787,961	39,787,961		39,394,021	
	Taxes & Uncollectibles	1,515,596	631,499	(3,514,198)		178,920	
	Emergency Reserve	5,000,000	-	-		-	
	Nonfuel Purchased Power:						
*	SJRPP D/S Principal	15,865,000	6,610,417	6,610,417		6,368,750	
*	SJRPP D/S Interest	3,212,107	1,338,378	1,338,378		3,689,811	
**	Other Non-Fuel Purchased Power	226,200,509	42,583,545	80,043,071		103,849,857	
	Total Nonfuel Expenses	844,175,210	303,746,642	348,722,786	-14.81%	393,720,155	11.43%
	Non-Fuel Balance	-	22,481,653	39,436,114		21,902,233	
	Total Balance	-	22,481,653	39,436,114		21,902,233	
	Total Revenues	**1,515,782,272**	**616,192,065**	**657,371,153**	6.68%	**599,269,429**	9.70%
	Total Expenses	**1,515,782,272**	**593,710,412**	**617,935,039**	-4.08%	**577,367,196**	-7.03%
	KWH Sold - Territorial	**12,200,000,000**	**4,695,727,243**	**4,559,727,253**	-2.90%	**4,656,011,734**	-2.07%
	KWH Sold - Off System	**-**	**-**	**16,558,000**		**3,660,000**	
		12,200,000,000	**4,695,727,243**	**4,576,285,253**	-2.54%	**4,659,671,734**	-1.79%

* Gross debt service
** Includes transmission capacity, SJRPP and Scherer R & R, O & M and Investment Income.

Water and Sewer System

Budget vs. Actual February 2023 and 2022 (unaudited)	ANNUAL BUDGET 2022-23	Month BUDGET 2022-23	Month ACTUAL 2022-23	Month Variance %	Prior Year Month ACTUAL 2021-22	Prior Year Month Variance %
REVENUES						
Water & Sewer Revenues	$ 477,665,241	$ 34,965,172	$ 36,293,142		$ 35,561,149	
Capacity & Extension Fees	102,742,334	6,977,681	4,535,101		3,030,886	
Investment Income	3,242,935	276,861	467,553		184,296	
Other Income	19,887,497	1,657,291	1,675,543		2,958,685	
Total	603,538,007	43,877,005	42,971,339	-2.06%	41,735,016	2.96%
EXPENSES						
O & M Expenses	204,939,349	15,922,878	15,530,532		14,387,820	
Debt Principal - Water & Sewer	52,365,000	4,363,750	4,363,750		820,833	
Debt Interest - Water & Sewer	50,773,134	4,231,095	4,338,920		4,019,740	
Rate Stabilization - Environmental	-	-	(2,107,969)		579,394	
R&R - Water & Sewer	30,059,700	2,504,975	2,504,975		2,363,167	
Operating Capital Outlay	115,627,627	2,267,369	2,267,369		14,886,918	
Operating Capital Outlay - Capacity/Extension	102,742,334	6,977,681	4,535,101		3,030,886	
Operating Capital Outlay - Environmental	12,121,243	1,010,104	1,593,325		515,538	
City Contribution Expense	26,933,389	2,244,449	2,244,449		2,222,227	
Uncollectibles & Fees	573,198	47,767	98,051		19,303	
Interlocal Agreements	6,403,033	-	-		(1,133,615)	
Emergency Reserve	1,000,000	-	-		-	
Total Expenses	603,538,007	39,570,068	35,368,503	10.62%	41,712,211	15.21%
Total Balance	$ -	$ 4,306,937	$ 7,602,836		$ 22,805	
Sales kgals						
Water	39,504,198	2,607,261	2,816,854	8.04%	2,700,812	4.30%
Sewer	35,052,670	2,338,877	2,481,125	6.08%	2,469,905	0.45%
Total	74,556,868	4,946,138	5,297,979	7.11%	5,170,717	2.46%

Budget vs. Actual February 2023 and 2022 (unaudited)	ANNUAL BUDGET 2022-23	Year-To-Date BUDGET 2022-23	Year-To-Date ACTUAL 2022-23	Year-To-Date Variance %	Prior Year to Date ACTUAL 2021-22	Prior Year to Date Variance %
REVENUES						
Water & Sewer Revenues	$ 477,665,241	$ 188,516,675	$ 194,329,337		$ 187,620,179	
Capacity & Extension Fees	102,742,334	39,147,875	18,580,627		12,937,725	
Investment Income	3,242,935	1,306,042	2,831,369		919,761	
Other Income	19,887,497	8,286,457	7,283,968		9,693,631	
Total	603,538,007	237,257,049	223,025,301	-6.00%	211,171,296	5.61%
EXPENSES						
O & M Expenses	204,939,349	84,802,247	84,785,795		69,694,339	
Debt Principal - Water & Sewer	52,365,000	21,818,750	21,818,748		4,104,165	
Debt Interest - Water & Sewer	50,773,134	21,155,473	21,823,795		20,460,265	
Rate Stabilization - Environmental	-	-	(7,999,234)		(1,040,294)	
R&R - Water & Sewer	30,059,700	12,524,875	12,524,875		11,815,833	
Operating Capital Outlay	115,627,627	38,782,077	38,782,077		72,737,324	
Operating Capital Outlay - Capacity/Extension	102,742,334	39,147,875	18,580,627		12,937,725	
Operating Capital Outlay - Environmental	12,121,243	5,050,518	8,084,424		3,675,333	
City Contribution Expense	26,933,389	11,222,246	11,222,246		11,111,134	
Uncollectibles & Fees	573,198	238,833	503,552		86,060	
Interlocal Agreements	6,403,033	3,686,654	3,338,268		4,722,619	
Emergency Reserve	1,000,000	-	-		-	
Total Expenses	603,538,007	238,429,548	213,465,173	10.47%	210,304,503	-1.50%
Total Balance	$ -	$ (1,172,499)	$ 9,560,128		$ 866,793	
Sales kgals						
Water	39,504,198	14,912,255	15,486,477	3.85%	15,177,394	2.04%
Sewer	35,052,670	13,386,563	13,802,574	3.11%	13,577,784	1.66%
Total	74,556,868	28,298,818	29,289,051	3.50%	28,755,178	1.86%

JEA		Month			Prior Year Month	Page 29
District Energy System						
Budget vs. Actual February 2023 and 2022 (unaudited)	**ANNUAL BUDGET 2022-23**	**BUDGET 2022-23**	**ACTUAL 2022-23**	**Variance %**	**ACTUAL 2021-22**	**Variance %**
REVENUES						
Revenues	$ 12,851,763	$ 888,724	$ 920,082		$ 617,696	
Investment Income	$ -	$ -	$ -		$ 146	
Total	12,851,763	888,724	920,082	3.53%	617,842	48.92%
EXPENSES						
O & M Expenses	6,449,156	393,802	354,542		300,114	
Debt Principal - District Energy System	1,870,000	155,833	155,833		151,250	
Debt Interest - District Energy System	1,371,758	114,313	126,683		101,465	
R&R - District Energy System	450,600	37,550	37,550		33,517	
Operating Capital Outlay	2,710,249	-	-		-	
Total Expenses	12,851,763	701,498	674,608	3.83%	586,346	-15.05%
Total Balance	$ -	$ 187,226	$ 245,474		$ 31,496	

		Year-To-Date			Prior-Year-to-Date	
Budget vs. Actual February 2023 and 2022 (unaudited)	**ANNUAL BUDGET 2022-23**	**BUDGET 2022-23**	**ACTUAL 2022-23**	**Variance %**	**ACTUAL 2021-22**	**Variance %**
REVENUES						
Revenues	$ 12,851,763	$ 5,012,047	$ 4,811,660		$ 3,259,242	
Investment Income	$ -	$ -	$ 20,106		$ 589	
Total	12,851,763	5,012,047	4,831,766	-3.60%	3,259,831	48.22%
EXPENSES						
O & M Expenses	6,449,156	2,506,863	2,149,175		1,650,558	
Debt Principal - District Energy System	1,870,000	779,167	779,167		756,250	
Debt Interest - District Energy System	1,371,758	571,566	586,146		505,146	
R&R - District Energy System	450,600	187,750	187,750		167,583	
Operating Capital Outlay	2,710,249	600,000	600,000		-	
Total Expenses	12,851,763	4,645,346	4,302,238	7.39%	3,079,537	-39.70%
Total Balance	$ -	$ 366,701	$ 529,528		$ 180,294	

2023 Electric Generation Integrated Resource Plan

Message from the CEO

Message here

Executive Summary

Under development

2023 Electric Generation Integrated Resource Plan

VOLUME 1

VOLUME 1

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List of Acronyms

AC	Alternating Current
ACC	Air-Cooled Condenser
Bcf/d	Billion Cubic Feet of Natural Gas per day
BESS	Battery Energy Storage System
BFB	Bubbling Fluidized Bed
CCCT	Combined Cycle Combustion Turbine
CTG	Combustion Turbine Generator
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resources
DSM	Demand Side Management
EIA	Energy Information Administration
GEC	Greenland Energy Center
GHG	Green House Gas
GIS	Graphical Information System
GPCM	Gas Pipeline Competition Model
HHV	Higher Heating Value
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITC	Investment Tax Credit
LDC	Local Distribution Company
LCOE	Levelized Cost of Energy
LNG	Liquified Natural Gas
LT	Long Term
LWR	Light Water Reactor
MT	Middle Term
MW	Megawatts
NGS	Northside Generating Station
NRC	Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
PASA	Projected Assessment of System Adequacy
PEV	Plug-in Electric Vehicle
PLEXOS	Power system modeling software tool from Energy Exemplar
PPA	Power Purchase Agreement
PSS/E	Power System Study/Electric
PTC	Production Tax Credit
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SJRPP	St. Johns River Power Park
SMR	Small Modular Reactor
SOCC	System Operations Control Center
SPRINT	SPRay INTercooling
ST	Short Term
TARA	Transmission Adequacy & Reliability Assessment
UAMPS	Utah Association of Municipal Power Systems

1 Introduction

1.1 Overview of JEA

JEA serves an estimated 478,000 electric, 357,000 water, 279,000 wastewater customers and 15,000 reclaimed water customers.

JEA was created by the City of Jacksonville to serve those who live in Jacksonville and in the surrounding communities. The sole purpose of JEA's business is to ensure the electric, water and sewer demands of JEA's customers are met, both today and for generations to come. JEA's goal is to provide reliable services at the best value to JEA's customers while ensuring the areas' precious natural resources are protected.

JEA owns and operates an Electric System with five generating plants, and all transmission and distribution facilities, including over 745 circuit miles of transmission lines and more than 6,760 miles of distribution lines. JEA also currently purchases energy from several solar sites located across the service territory, including Jacksonville Solar, a 100-acre site on the City's westside, utilizing 200,000 solar panels. In addition, JEA has contractual arrangements to purchase power from two landfill gas facilities and from Vogtle nuclear Units 3 and 4 when the units begin operating.

JEA's existing and future committed generating resources, including owned and contractual purchase resources, are summarized in Table 1-1 at the end of this section.[1]

1.2 IRP Process

This Integrated Resource Plan (IRP) is a figurative compass that will help guide JEA's energy future. The IRP considers energy generation and supply by balancing affordability, reliability, resilience and sustainability for decades to come. JEA currently relies on a diverse fuel mix of petroleum coke, coal, biomass, natural gas, nuclear and solar energy. JEA's aspiration for the future, that will be evaluated through the IRP process, includes reduced carbon emissions, increased utilization of renewable energy, and planning to meet the growing needs of JEA's future population and service territory.

Integrated resource planning is performed throughout the electric utility industry. The primary goals and key steps in developing an IRP include the following:

- Comparing future electric system demand with existing generating resources.
- Evaluating new resource options.
- Analyzing solutions.
- Gathering Stakeholder feedback.
- Determining preferred portfolio.
- Developing action plan(s).

An IRP must evaluate both quantitative factors (variables) and qualitative factors (considerations). Variables evaluated in this IRP include the following:

JEA Load Growth (Customer Demand for Energy)

- Forecast of net energy – how much energy do JEA's customers require aggregated over each year?
- Forecast of net firm peak demand – what is the maximum demand required by JEA's customers in each year?
- Demand-Side Management and Energy Efficiency – what are JEA's customers doing in their homes/business to reduce energy and demand requirements?

[1] For purposes of this IRP, "committed" refers to generating resources for which JEA currently has a contract in place.

- Plug-In Electric Vehicles (PEVs) – how will future adoption of PEVs affect JEA's energy and firm peak demand?
- Electrification – how will future adoption of electric equipment affect JEA's energy and firm peak demand?

Fuel Costs

- Future prices for natural gas.
- Future prices for solid fuel.

Environmental Regulations

- How will costs for emissions of carbon dioxide (CO_2) affect JEA's generating portfolio?
- How will achieving specific percent of energy from resources that do not emit CO_2 affect JEA's generating portfolio?

Emerging Generating Technologies

- What types of new generating technologies should be considered?

Customer-Site Generating (Distributed Energy Resources)

- Customer sited renewables, or distributed energy resources – how will JEA's energy and firm peak demand be affected by JEA customers installing solar or other energy resources on their homes/businesses?

Others

- Cost to build new generating resources.
- How long will JEA's existing generating units continue to operate?
- What does it cost to finance construction of new generating resources?

Considerations evaluated in an IRP include the following:

- Affordability.
- Reliability.
- Environmental.
- Economic development.
- CO_2 emissions reductions.

The IRP utilizes both scenario and sensitivity analysis methodology to evaluate how these variables and considerations impact the future energy needs of JEA and its customers. Scenario analysis considers a set of changes to multiple variables simultaneously to analyze a potential future. Sensitivity analysis considers changes to one of these variables at a time within a given potential future.

Scenarios have been developed that represent potential futures for JEA over the IRP timeframe (30 years). A scenario must be different enough to illustrate how future outcomes may vary in meaningful ways when compared to other scenarios. Similarly, sensitivities are intended to evaluate how a resource portfolio responds to a change in a single variable (e.g., changes to the load forecast or fuel prices). The combination of scenario and sensitivity evaluation provides for a robust analysis of future resource decisions.

1.3 Outline of IRP

The remainder of this IRP Volume 1 is organized as follows:

- Chapter 2 presents an overview of the Stakeholder Engagement process that was an integral part of developing the IRP.
- Chapter 3 discusses the load forecast (peak demands and annual energy requirements) and various components thereof and illustrates JEA's projected need for additional capacity evaluated in this IRP.
- Chapter 4 discusses the methodology used to develop fuel price projections reflected in the IRP, and also addresses fuel transportation considerations.

- Chapter 5 provides an overview of the new generating resources considered in this IRP, including cost and operating characteristics.
- Chapter 6 presents a levelized cost analysis of the economics of the new generating resources outlined in Chapter 5.
- Chapter 7 discusses the scenarios and sensitivities evaluated in this IRP.
- Chapter 8 discusses the optimal generation expansion and production cost modeling methodology and presents the results of the analyses.
- Chapter 9 presents conclusions based on the analyses performed in this IRP.

Table 1-1 Existing and Future Committed Generating Resources

Unit Name	Primary Fuel	Net Dependable Summer MW	Net Dependable Winter MW	Owned/PPA	Commercial Operation Date / PPA Term
Kennedy GT7	Natural Gas	179	191	Owned	2000
Kennedy GT8	Natural Gas	179	191	Owned	2000
Northside ST1	Pet Coke	293	293	Owned	2003
Northside ST2	Pet Coke	293	293	Owned	2003
Northside ST3	Natural Gas	524	524	Owned	1977
Northside GT33-36	Diesel	200	246	Owned	1975
Brandy Branch GT1	Natural Gas	179	191	Owned	2001
Brandy Branch CC4	Natural Gas	596	640	Owned	2005
Greenland Energy Center GT1	Natural Gas	179	191	Owned	2011
Greenland Energy Center GT2	Natural Gas	179	191	Owned	2011
NextEra PPA	System PPA	200	200	PPA	2022 - 2042
Sarasota LFG	LFG	6	6	PPA	2008 - 2026
Trail Ridge LFG	LFG	9	9	PPA	2014 - 2026
Vogtle 3	Nuclear	100	100	PPA	2024 - 2043
Vogtle 4	Nuclear	100	100	PPA	2025 - 2044
Blair Solar	Solar (4 MW AC)	0.7	0	PPA (	2018 - 2038
Jax Solar	Solar (12.6 MW AC)	2.0	0	PPA	2010 - 2040
NW Jax Solar	Solar (7 MW AC)	1.1	0	PPA	2017 - 2042
Old Kings Solar	Solar (1 MW AC)	0.2	0	PPA	2018 - 2038
Old Plank Solar	Solar (3 MW AC)	0.5	0	PPA	2017 - 2037
Simmons Solar	Solar (2 MW AC)	0.4	0	PPA	2018 - 2038
Starratt Solar	Solar (5 MW AC)	0.9	0	PPA	2017 - 2037
SunPort Solar	Solar (5 MW AC)	1.0	0	PPA	2014 - 2039

Notes:

GT: Gas Turbine LFG: Landfill Gas

ST: Steam Turbine PPA: Power Purchase Agreement

CC: Combined Cycle PC: Petroleum Coke

MW AC: Megawatts Alternating-Current Basis Solar Nameplate Rating

PPA term for Vogtle 3 and 4 is a planning assumption indicative of expected online dates of those units when IRP analysis was initiated.

150 MW solar PV PPA not included as it was entered into as IRP was being completed.

2 Stakeholder Engagement

2.1 Overview of the Process

JEA established a Stakeholder engagement process to inform the 2023 IRP. Engaging with a diverse cross-section of community leaders was a critical step in development of the IRP. Stakeholders included residential and commercial customers, community partners, environmental group members, neighborhood associations, municipal representatives and other individuals.

2.1.1 Objectives

The objectives at the outset for the process included the following:

- Improving the transparency of the JEA resource planning and decision making processes.
- Educating Stakeholders on the resource planning process.
- Creating opportunities for Stakeholders to provide feedback on the process.
- Encouraging Stakeholders to share what they learn with colleagues and other community members to garner their additional feedback.
- Promoting dynamic and informed dialogue around planning results and subsequent resource decisions.
- Building understanding and support for JEA's resource decisions.

JEA's intent for the Stakeholder engagement process was that it be open, transparent and data driven. We asked that Stakeholders approach the process with the same intention and encouraged Stakeholders to ask questions, make suggestions and provide data and information.

To facilitate engagement, JEA contracted with Black & Veatch. Black & Veatch retained a local Stakeholder engagement firm, Acuity Design Group, Inc., to support Stakeholder engagement planning, facilitation, and to ensure consideration of lessons learned and best practices from similar efforts across the industry.

2.1.2 Stakeholder Group Formation

As a first step in the process, a comprehensive list of potential Stakeholder organizations was developed and vetted, and a subset of those were then invited to join the process via a letter from Jay Stowe, JEA's Managing Director and CEO. The Stakeholder organizations that were invited to participate included the following:

- Baptist Medical Center
- Bethel Baptist Institutional Church
- City of Jacksonville
- Commercial Metals Company
- Downtown Vision, Inc.
- Duval County School Board
- ElderSource
- First Coast Manufacturers Association
- Jacksonville Aviation Authority
- Jacksonville Civic Council
- Jacksonville Transportation Authority
- Jacksonville University
- JAX Chamber
- Jessie Ball duPont Fund
- Local Initiatives Support Corporation
- Northeast Florida Builders Association
- Northeast Florida Community Action Agency
- North Florida Green Chamber of Commerce
- St. Johns Riverkeeper, Inc.
- Sierra Club Northeast Florida Group
- United Way of Northeast Florida
- University of North Florida

The invitation letter described the purpose, timing and objectives of the process and listed what was being requested of the Stakeholders. A copy of one of the Stakeholder invitation letters is shown in Appendix E – Stakeholder Engagement Details.

2.1.3 Stakeholder Resources

Several documents and other resources were developed and provided to Stakeholders during the process to support communications and document progress through the process. Key documents and resources include the following:

- Communications Plan.
- IRP specific website page.[2]
- IRP email address for Stakeholders to provide comments.
- IRP Brochure.[3]
- IRP Video.[4]
- Stakeholder Presentations (specific to each meeting).[5]
- Mid-May Report (a report providing a recap of the first series of meetings).[6]

The IRP website page identified several key factors that were to be considered in IRP development. These are shown in Figure 2-1.

2.2 Stakeholder Meetings

Stakeholder engagement occurred primarily through a series of formal meetings that occurred during the term of the IRP preparation. The topics and dates for the meetings were synchronized with planned key milestones of the IRP development so that feedback from the Stakeholders could be incorporated immediately into the IRP rather than after the fact. The milestones included development of the Scenarios, development of the key forecasts and supply side options that were foundational to the IRP modeling, the preliminary results of the modeling, the final results of the modeling, and identification of the most common near-term resources for possible implementation by JEA. A list of the meeting dates and topics is provided in Table 2-1.

Table 2-1 Stakeholder Engagement Meetings and Topics

Meeting #	Topic
1. January 2022	Introduction to JEA and the IRP Process
2. February 2022	Planned Scenarios
3. March 2022	Key Forecasts
4. June 2022	New Resource Options
5. September 2022	Preliminary PLEXOS Modeling Results
6. November 2022	Updated PLEXOS Modeling Results
7. February 2023	Final PLEXOS Modeling Results and Implementation Plan
8. May 2023	Final IRP and Implementation Plan

Further detail on the Stakeholder meetings is provided in Appendix E – Stakeholder Engagement Details, including locations, JEA participants, topics presented and feedback received from Stakeholders.

In addition to Stakeholder engagement, JEA Board and Board Committee engagement occurred primarily through a series of meetings that occurred during the term of the IRP preparation. A list of the meeting dates and topics is provided in Table 2-2.

[2] http://www.jea.com/IRP
[3] https://www.jea.com/About/Introducing_the_Integrated_Resource_Planning_Process/
[4] https://youtu.be/PVuRqhggU3c
[5] Under the Electric IRP documents tab at https://www.jea.com/IRP.
[6] Under the Electric IRP documents tab at https://www.jea.com/IRP

Table 2-2 Board and Board Committee Meetings and Topics

Meeting #	Topic and Presenters
January 2022 Board Meeting	Electric Integrated Resource Plan, Laura Schepis, Chief External Affairs Officer
February 2022 Board Meeting	Electric Integrated Resource Plan Update, Raynetta Curry Marshall, Chief Operating Officer and Laura Schepis, Chief External Affairs Officer
July 2022 External Affairs Committee Meeting	Electric Integrated Resource Plan Update, Laura Schepis, Chief External Affairs Officer and Raynetta Curry Marshall, Chief Operating Officer
September 2022 Finance and Operations Committee Meeting	Electric Integrated Resource Plan Update, Raynetta Curry Marshall, Chief Operating Officer
December 2022 Joint Meeting of the Finance & Operations and External Affairs Committees	Electric Integrated Resource Plan (IRP) Scenarios, IRP Project Team
March 2023 Finance and Operations Committee Meeting	Electric Integrated Resource Plan Update, Pedro Melendez, Vice President, Engineering & Construction

Chapter 2: Stakeholder Engagement

Figure 2-1 Key Factors Considered in IRP Development

3 Supplying the Generation Needs of the Community

3.1 Load Forecast

Table 3-1 summarizes the seasonal (winter and summer) peak demand and annual energy forecast that has been developed for the Current Outlook scenario evaluated in this IRP. A discussion of the various scenarios and sensitivities evaluated in this IRP is included in Chapter 7.

Table 3-1 Peak Demand and Energy Forecast (Base)

Year	Summer Peak (MW)	Winter Peak (MW)	Net Energy (GWh)
2022	2,693	2,830	12,827
2023	2,710	2,848	12,948
2024	2,726	2,865	13,057
2025	2,740	2,879	13,160
2026	2,751	2,893	13,250
2027	2,759	2,904	13,327
2028	2,767	2,913	13,399
2029	2,774	2,924	13,470
2030	2,783	2,933	13,534
2031	2,792	2,941	13,595
2032	2,797	2,949	13,654
2033	2,804	2,958	13,712
2034	2,809	2,966	13,764
2035	2,815	2,974	13,814
2036	2,824	2,982	13,862
2037	2,829	2,991	13,905
2038	2,832	3,000	13,949
2039	2,838	3,007	13,987
2040	2,841	3,016	14,024
2041	2,849	3,083	14,057
2042	2,868	3,086	14,085
2043	2,878	3,100	14,111
2044	2,889	3,116	14,137
2045	2,897	3,130	14,160
2046	2,914	3,165	14,183
2047	2,937	3,195	14,201
2048	2,954	3,232	14,212
2049	2,963	3,264	14,225
2050	2,987	3,302	14,242
2051	3,024	3,358	14,237

The base forecast and the alternative forecasts used for the scenarios and sensitivities, which are discussed later in this chapter, were developed by JEA load forecasting specialists.

For the base forecast, JEA began with its most recent load forecast prepared for purposes of its 2022 10 Year Site Plan. That forecast was then updated for the IRP to reflect the most recent and best available information concerning economic growth in the service territory, newly identified commercial and industrial loads, newly identified commercial and industrial loads, and a base level of customer energy efficiency and conservation implementation.

The Black & Veatch Team then developed forecasts of key load components to be applied to the base forecast to modify the forecast to reflect the desired conditions for each scenario. The modifiers included forecast levels of demand side management (DSM), energy efficiency (EE) and load reduction (Conservation), which were prepared using cost estimating and econometric modeling of specific current and future technologies and programs. The modifiers also included forecasts of Plug-In Electric Vehicles (PEVs) market penetration and associated load growth, which were prepared using industry accepted methods to forecast electric vehicle adoption in areas similar to Jacksonville, and levels of other Electrification which were prepared in a similar fashion to PEVs. Finally, a forecast of Customer-Sited Renewables (Distributed Energy Resources) was prepared using a comprehensive DER market simulation model factoring in levels of utility incentives, state/federal subsidies, electric rates and technology costs.

JEA then modified the base forecast with different combinations of load growth and the load modifiers as necessary to reflect the desired conditions for each scenario and sensitivity.

The resulting winter peak demand forecasts that were utilized for each scenario and sensitivity are summarized in Table 3-2 and illustrated on Figure 3-1. Similarly, the resulting annual energy forecasts that were utilized for each scenario and sensitivity are summarized in Table 3-3 and illustrated on Figure 3-2.

The base forecast is used for both the Current Outlook scenario and most of the sensitivities, with the exception of the high load sensitivity discussed below.

The Supplemental scenario used a forecast based off the Current Outlook scenario but modified by increasing the customer-sited solar and batteries to be equivalent 5 percent of residential load. By 2030

A relatively low load forecast was developed for the Economic Downturn scenario. This forecast assumes significantly reduced economic activity in the JEA service area. It is patterned after the 2008 recession during which JEA experienced very low energy sales for an extended period of time.

Another load forecast was developed and is used for both the Efficiency + DER and the Future Net Zero scenarios. This forecast assumes relatively high levels of DSM/EE/Conservation, PEV load growth, electrification of non-vehicle loads and Customer Sited Renewables (5 percent Residential and 3% Commercial by 2030). The net effect is forecast higher than the base forecast.

Another forecast was developed and used for the Increased Electrification scenario. This forecast is based on these same assumptions, except for DSM/EE/Conservation, which is assumed to not increase but rather remain the same as in the base forecast. The net result is a forecast that is highest among all the forecasts used in the scenarios.

Two final forecasts were developed to be used for the sensitivity analysis. A new forecast was developed for the High Load sensitivity based on the load forecast utilized for the Efficiency + DER and Future Net Zero scenarios with the addition of a potential large customer of approximately 200 MW beginning in 2024. The last forecast that was developed for the No Load Growth sensitivity, in which first year of the base forecast is repeated for every year of the study horizon.

Table 3-2 Scenario and Sensitivity Peak Winter Demand Forecasts (MW)

Year	Current Outlook Scenario	Supplemental Scenario	Economic Downturn Scenario / Low Load Sensitivity	Efficiency + DER Scenario / Future NetZero Scenario	Increased Electrification Scenario	High Load Sensitivity	No Load Growth Sensitivity
2022	2,830	2,830	2,827	2,830	2,830	2,830	2,830
2023	2,848	2,847	2,808	2,837	2,849	2,837	2,830
2024	2,865	2,864	2,801	2,850	2,866	2,850	2,830
2025	2,879	2,878	2,769	2,859	2,881	2,994	2,830
2026	2,893	2,891	2,703	2,867	2,896	3,075	2,830
2027	2,904	2,902	2,694	2,875	2,908	3,082	2,830
2028	2,913	2,910	2,729	2,882	2,921	3,089	2,830
2029	2,924	2,920	2,747	2,894	2,939	3,101	2,830
2030	2,933	2,928	2,765	2,908	2,958	3,115	2,830
2031	2,941	2,935	2,743	2,921	2,977	3,129	2,830
2032	2,949	2,942	2,760	2,935	2,996	3,142	2,830
2033	2,958	2,950	2,772	2,979	3,024	3,187	2,830
2034	2,966	2,956	2,785	3,016	3,073	3,224	2,830
2035	2,974	2,963	2,797	3,079	3,136	3,287	2,830
2036	2,982	2,970	2,809	3,132	3,194	3,340	2,830
2037	2,991	2,978	2,821	3,183	3,251	3,391	2,830

Year	Current Outlook Scenario	Supplemental Scenario	Economic Downturn Scenario / Low Load Sensitivity	Efficiency + DER Scenario / Future NetZero Scenario	Increased Electrification Scenario	High Load Sensitivity	No Load Growth Sensitivity
2038	3,000	2,986	2,834	3,251	3,315	3,458	2,830
2039	3,007	2,993	2,845	3,319	3,381	3,527	2,830
2040	3,016	3,001	2,857	3,348	3,428	3,555	2,830
2041	3,083	3,067	2,929	3,381	3,476	3,588	2,830
2042	3,086	3,070	2,936	3,443	3,539	3,650	2,830
2043	3,100	3,082	2,952	3,487	3,593	3,695	2,830
2044	3,116	3,097	2,971	3,548	3,656	3,756	2,830
2045	3,130	3,110	2,988	3,590	3,707	3,797	2,830
2046	3,165	3,144	3,025	3,650	3,769	3,858	2,830
2047	3,195	3,174	3,059	3,700	3,824	3,907	2,830
2048	3,232	3,210	3,101	3,760	3,884	3,967	2,830
2049	3,264	3,241	3,135	3,807	3,937	4,014	2,830
2050	3,302	3,278	3,178	3,866	3,996	4,073	2,830
2051	3,358	3,333	3,238	3,938	4,064	4,145	2,830

Table 3-3 Scenario and Sensitivity Forecast Net Energy (GWh)

Year	Current Outlook Scenario	Supplemental Scenario	Economic Downturn Scenario / Low Load Sensitivity	Efficiency + DER Scenario / Future NetZero Scenario	Increased Electrification Scenario	High Load Sensitivity	No Load Growth Sensitivity
2022	12,827	12,827	12,827	12,827	12,827	12,827	12,827
2023	12,948	12,926	12,229	12,852	12,924	12,852	12,827
2024	13,057	12,996	12,228	12,890	12,998	13,188	12,827
2025	13,160	13,054	12,121	12,925	13,069	14,368	12,827
2026	13,250	13,096	11,864	12,955	13,134	14,534	12,827
2027	13,327	13,122	11,851	12,979	13,195	14,558	12,827
2028	13,399	13,138	12,026	13,015	13,267	14,599	12,827
2029	13,470	13,150	12,128	13,085	13,373	14,664	12,827
2030	13,534	13,148	12,225	13,171	13,495	14,750	12,827
2031	13,595	13,147	12,151	13,271	13,631	14,850	12,827
2032	13,654	13,148	12,247	13,382	13,779	14,966	12,827
2033	13,712	13,158	12,290	13,506	13,937	15,085	12,827
2034	13,764	13,166	12,269	13,633	14,100	15,211	12,827
2035	13,814	13,181	12,467	13,768	14,271	15,347	12,827
2036	13,862	13,197	12,531	13,907	14,447	15,491	12,827
2037	13,905	13,221	12,593	14,044	14,619	15,623	12,827
2038	13,949	13,254	12,652	14,191	14,802	15,770	12,827
2039	13,987	13,292	12,708	14,341	14,988	15,920	12,827
2040	14,024	13,338	12,763	14,500	15,185	16,084	12,827
2041	14,057	13,373	12,813	14,637	15,356	16,216	12,827
2042	14,085	13,392	12,859	14,758	15,513	16,337	12,827
2043	14,111	13,408	12,902	14,870	15,661	16,449	12,827
2044	14,137	13,420	12,944	14,978	15,806	16,562	12,827
2045	14,160	13,434	12,983	15,070	15,933	16,649	12,827
2046	14,183	13,446	13,023	15,160	16,058	16,739	12,827
2047	14,201	13,452	13,059	15,237	16,172	16,816	12,827
2048	14,212	13,448	13,090	15,303	16,275	16,887	12,827
2049	14,225	13,452	13,122	15,360	16,366	16,939	12,827
2050	14,242	13,461	13,157	15,422	16,464	17,001	12,827
2051	14,237	13,472	13,193	15,485	16,562	17,064	12,827

Figure 3-1 Winter Peak Load Forecasts

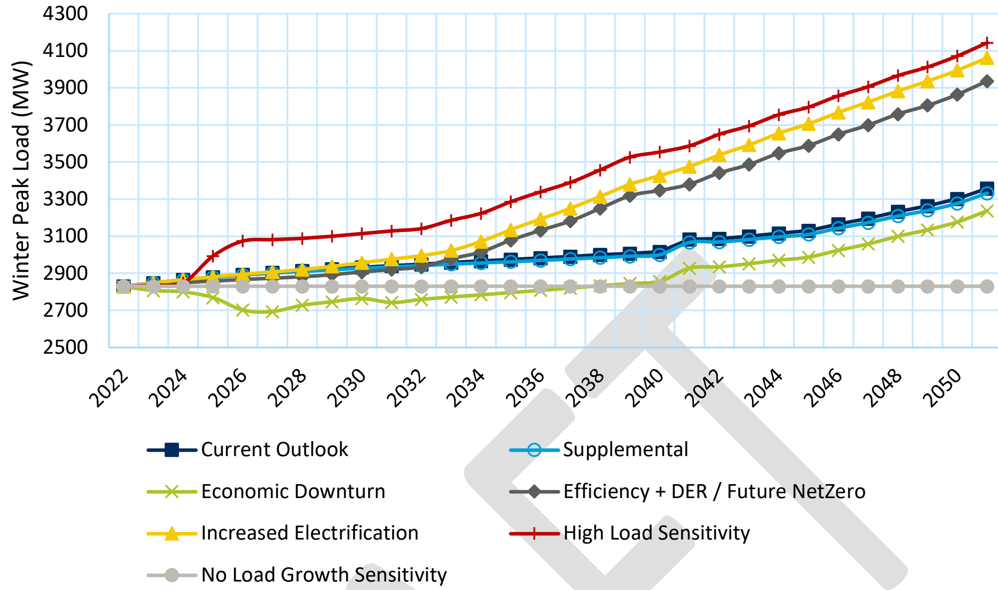
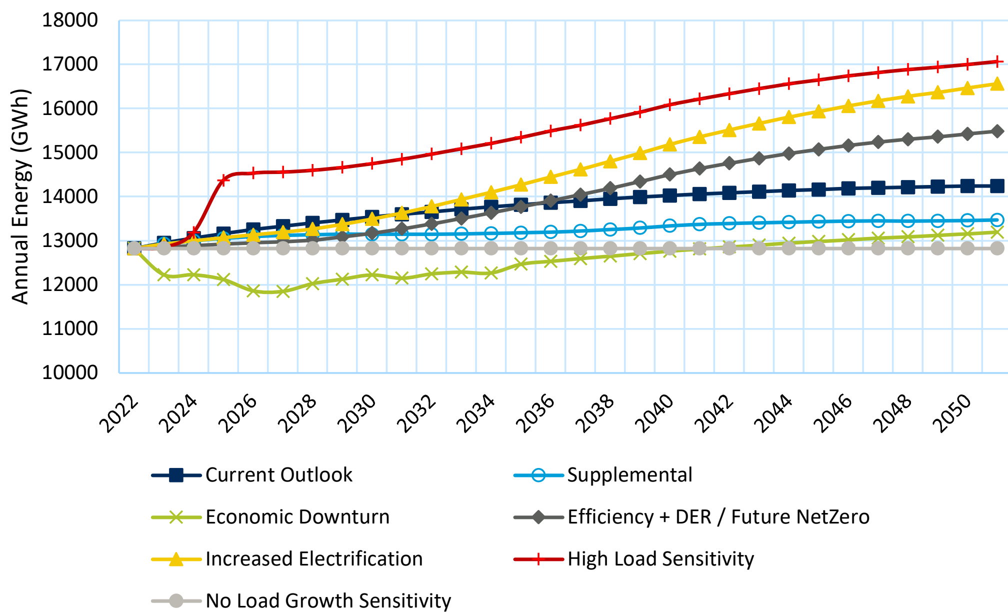


Figure 3-2 Annual Energy Forecasts



3.2 Transportation Electrification Forecasts

Transportation Electrification has the potential for growth and therefore was a key component of the overall load forecasts.

Black & Veatch investigated the potential load impacts from electrical vehicle adoption from both passenger vehicles ("Passenger PEV Forecast") and commercial vehicles ("Commercial On-Road Electrification"). Two separate forecasts were developed for use in the scenarios investigated: one base and one high adoption.

3.2.1 Base Forecast

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

JEA forecasted the number of vehicles in Duval County using multiple regression analysis of historical and forecasted Duval population, median household income and number of households from Moody's Analytics. In turn, the number of PEVs was then forecasted 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.

3.2.2 High Adoption Forecasts

The high adoption forecasts were developed by Black & Veatch and included a forecast for passenger vehicles (High Adoption Passenger PEV Forecast) and one for commercial vehicles (High Adoption Commercial On-Road Electrification Forecast). Both utilized a bottom-up, stock rollover methodology to forecast the adoption rate of electric vehicles in JEA's service territory. The methods and assumptions are outlined in the following sections.

3.2.2.1 High Adoption Passenger PEV Forecast

The passenger PEV forecast estimates the adoption over the study period for light-duty vehicles only. The methodology employed by Black & Veatch is outlined on Figure 3-3. An estimate of vehicle growth in JEA's service territory is forecasted first. Next, the adoption rate of both Battery Electric Vehicles (BEVs) and Plug-In Hybrid Vehicles (PHEVs) are forecasted by assuming an s-curve adoption of electric vehicles to replace existing vehicles at the point of replacement. For the purposes of this analysis, adoption was assumed to follow the Florida Department of Transportation's 2021 EV Infrastructure Master Plan Aggressive Scenario, where the study had projected that 35 percent of new sales would be electric by 2040[7]. The forecasted adoption of passenger PEVs is depicted on Figure 3-4, representing a 22 percent compound annual growth rate of electric vehicles through the study period, or 60 percent of all passenger vehicles by 2050.

The corresponding impact to load is calculated based on the adoption forecast. The annual vehicle miles travelled per capita was assumed at 10,330 miles over the study period[8] and the charging load profiles were estimated by JEA leveraging prototypical charging profiles for residential charging applications. The resulting load impact is depicted on Figure 3-5.

[7] Florida Department of Transportation EV Infrastructure Master Plan 2021 https://fdotwww.blob.core.windows.net/sitefinity/docs/default-source/planning/fto/fdotevmp.pdf

[8] Jacksonville, FL data from U.S. Department of Transportation Federal Highway Administration https://www.fhwa.dot.gov/ohim/onh00/onh2p11.htm

Figure 3-3 High Adoption Passenger PEV Forecast Methodology

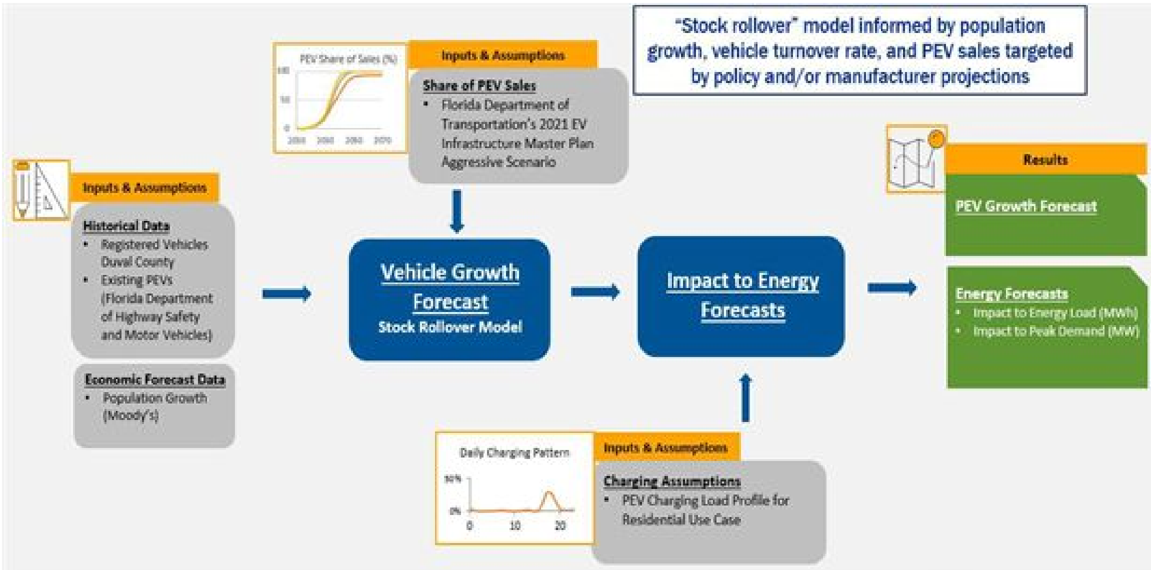


Figure 3-4 High Adoption PEV Forecast by Count

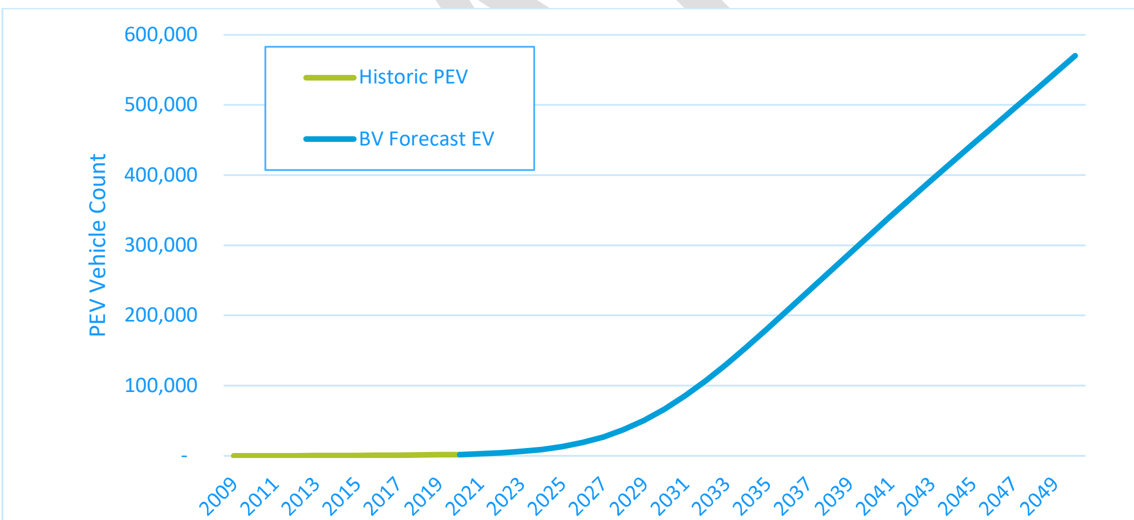
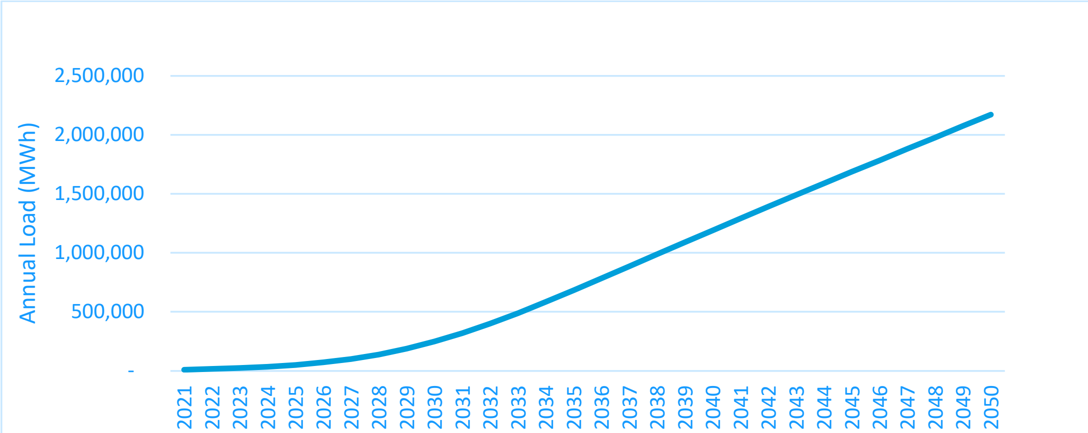


Figure 3-5 High Adoption Passenger PEV Load Impact (MWh)



3.2.2.2 High Adoption Commercial On-Road Electrification Forecast

The Commercial On-Road Electrification forecast estimates the adoption of Class 2 to Class 8 commercial vehicles over the study period, including, but not limited to, vehicles such as the following vehicles:

- Light Commercial Trucks.
- Other Buses.
- Single Unit Short-Haul Trucks.
- Single Unit Long-Haul Trucks.
- School Buses.
- Refuse Trucks.
- Combination Long-Haul Trucks.
- Combination Short-Haul Trucks.

The methodology employed by Black & Veatch is outlined on Figure 3-6 and, similar to the passenger PEV forecast, employs a stock rollover methodology.

An estimate of vehicle changes in JEA's service territory is forecasted first leveraging Department of Transportation registration data across the classes of vehicles and forecasted according to economic forecast indicators. The vehicle turnover and rate of adoption of electric vehicles to replace conventional vehicles are identified by vehicle economics and vehicle availability of electric models for each vehicle class. Vehicle economics are determined by Black & Veatch's proprietary Total Cost of Ownership model, where the cost of ownership over the life of an electric vehicle, charging equipment, operating and maintenance costs are evaluated and compared to a conventional diesel or gasoline-fueled truck of corresponding capabilities. An s-curve adoption is employed with electric share of sales reaching measure saturation at the point in which the electric configuration reaches price parity or better than the conventional configuration and varies by vehicle class and site operation.

The forecasted adoption of commercial on-road electric vehicles is depicted on Figure 3-7, representing a 35 percent compound annual growth rate of electric vehicles through the study period, or 62 percent of all commercial trucks by 2050.

The corresponding impact to load is calculated based on the adoption forecast. Annual energy consumption by vehicle application was estimated by JEA by vehicle class and type as described above. Charging load profiles were estimated by JEA leveraging prototypical use and charging profiles according to application, such as direct current fast charging (DCFC), school bus, transit bus, small fleet, medium fleet and large fleets. The resulting load impact is depicted on Figure 3-8.

Figure 3-6 High Adoption Commercial On-Road Electrification Forecast Methodology

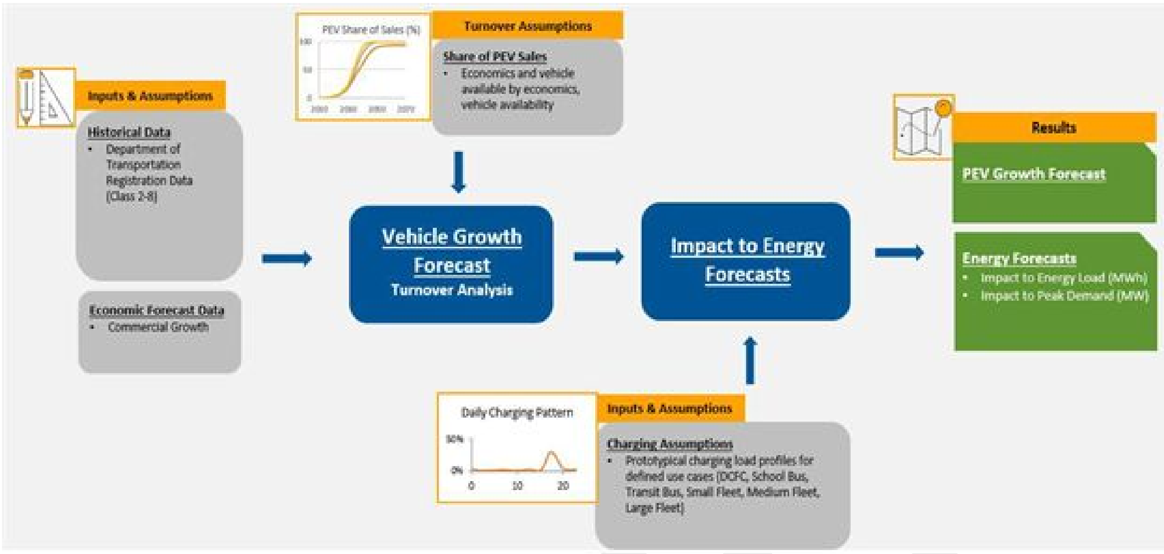


Figure 3-7 High Adoption Commercial On-Road Electrification Forecast by Count

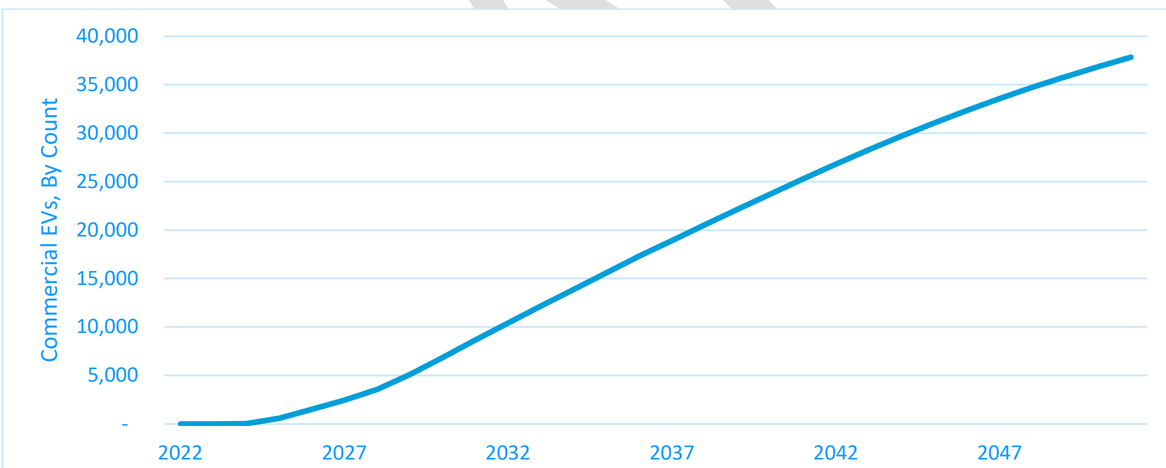
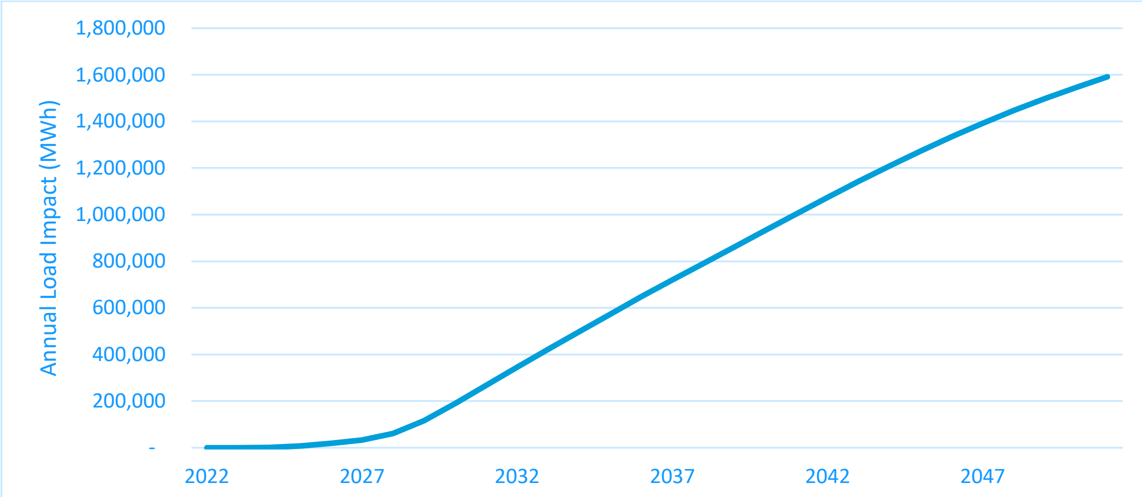


Figure 3-8 High Adoption Commercial On-Road Electrification Load Impact (MWh)



3.3 New Demand-Side Management/Energy Efficiency/Customer-Sited Renewables

Demand-side management (DSM) opportunities provide a reliable, cost-effective resource that contributes to meeting the peak demand and energy requirements of JEA customers.

The Black & Veatch team has developed estimates of DSM opportunities in JEA customers' homes and business, including the installation of energy efficiency technologies as well as customer-sited renewables. These DSM resources reduce total consumption and peak demands in JEA's load forecast.

Two scenarios for DSM opportunities were developed, including a Current Outlook forecast that aligns with current and planned JEA programs and initiatives, and a high forecast that assumes more aggressive DSM program offerings.

3.3.1 Energy Efficiency

For the energy efficiency Current Outlook forecast, the Black & Veatch team incorporated JEA's portfolio of 11 cost-effective residential and commercial EE programs and the project annual incremental energy savings to estimate future load impacts.

For the energy efficiency High forecast, JEA's programs were assumed to be expanded, with additional funding for more aggressive marketing, outreach, and customer education, as well as customer incentives. The resulting energy impacts are forecasted to double from the Current Outlook on an annual incremental basis. Figure 3-9 summarizes the cumulative impacts over the IRP planning horizon for the EE Current Outlook and High Forecast scenarios.

3.3.2 Customer-Sited Renewables

The focus of the customer-sited renewables analysis was on rooftop solar photovoltaic (PV) and battery storage installations.

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

With respect to battery storage, the 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. Figure 3-10 depicts an hourly solar and storage dispatch profile for an illustrative business without net metering.

Similar to the EE analysis, the customer-sited renewables analysis evaluated two cases as follows:

- The base case was modeled based on current JEA system parameters, available tax credits at the time of the analysis, and current JEA battery storage incentives.
- The high PV case was modeled assuming JEA targets a goal of 5 percent of JEA's residential load to be met by rooftop PV by 2030. The analysis adjusted estimated program incentives to align customer adoption rates with this targeted output and incorporated the recently approved extension of the 30 percent Federal Incentive Tax Credit (ITC). The commercial sector PV forecast was then analyzed using similar program incentive assumptions.

Results for each of these cases are shown on Figure 3-11. The forecast load reduction from customer sited renewables under the high PV case is significantly higher than that for the base case.

Figure 3-9 Cumulative Energy Impacts – Energy Efficiency Current Outlook and High Forecast Scenarios

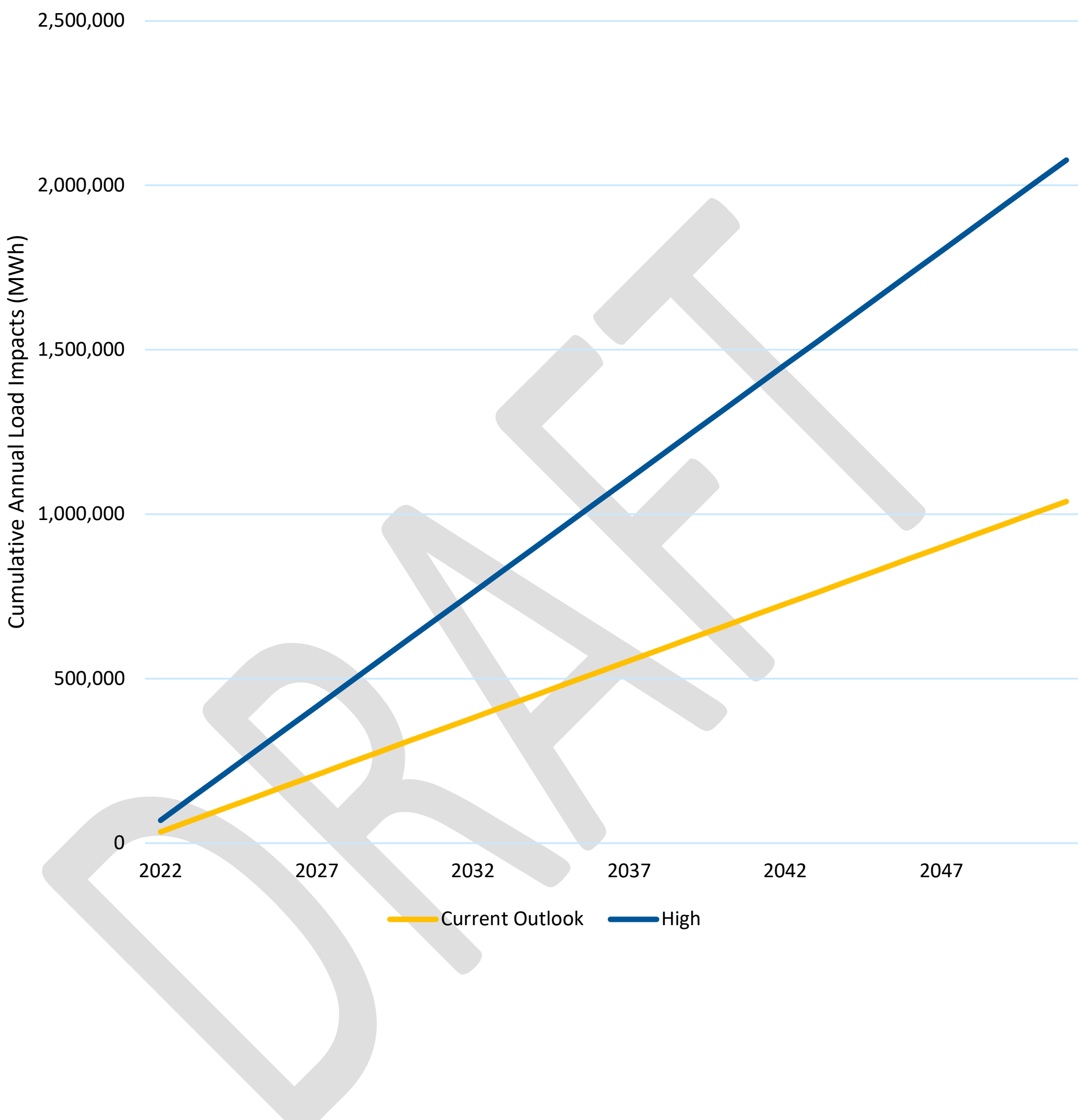


Figure 3-10 Illustrative Optimal Hourly Storage Dispatch

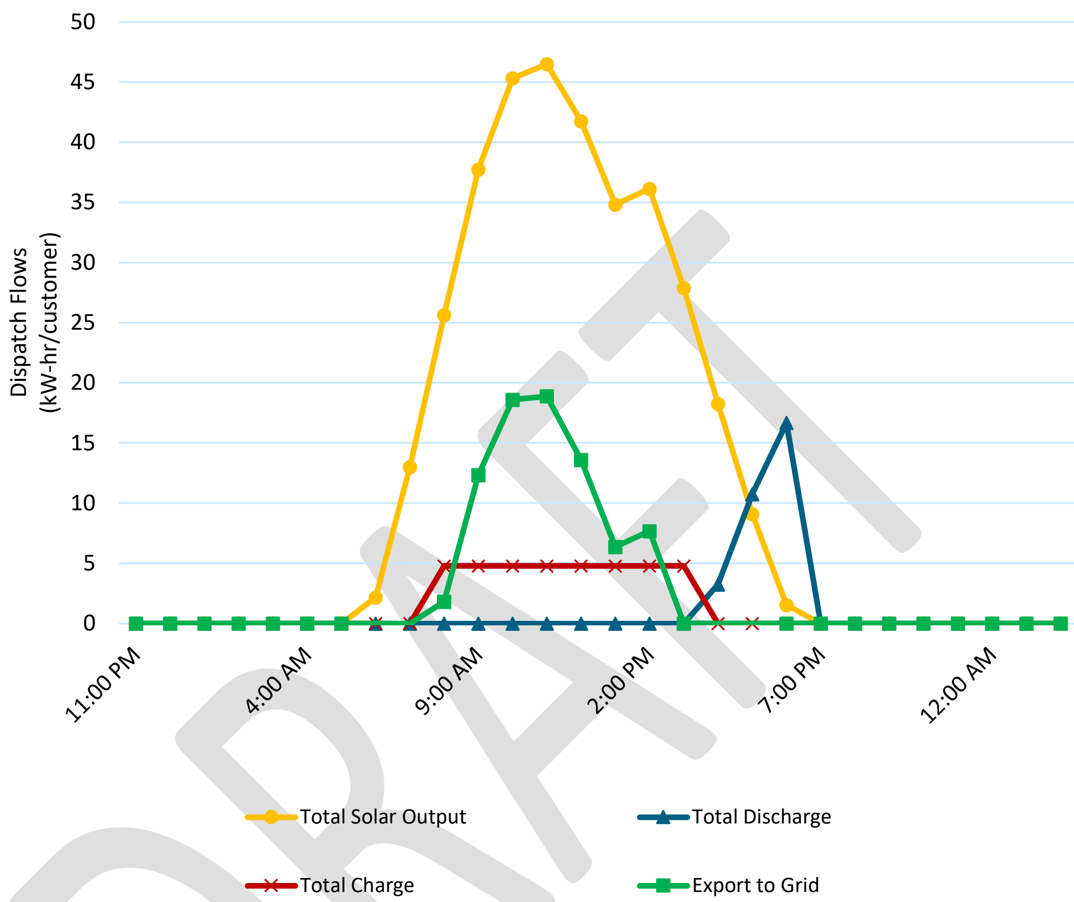
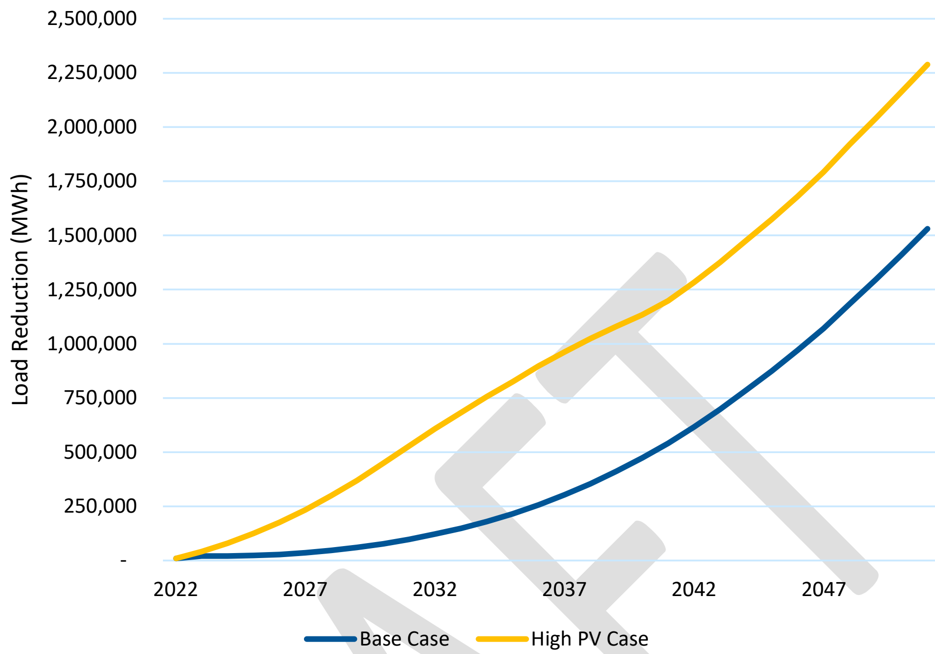


Figure 3-11 Cumulative MWh Load *Reduction* from Solar and Battery Storage



3.4 Capacity Resources

JEA's existing and planned future generating resources, including owned resources and contractual power purchases, total approximately 3,020 MW in the summer and 3,167 MW in the winter. These winter and summer capacity ratings vary over the IRP planning period, as new PPAs (specifically, Vogtle nuclear Units 3 and 4 PPAs) begin and existing PPAs expire, and as Northside 3 is assumed to no longer be operational beginning in the spring of 2029. JEA's projected available summer and winter capacity based on existing and planned generating resources for each year of the IRP planning period is illustrated on Figure 3-12.

3.5 Need for Capacity

JEA's resource planning criteria include having sufficient capacity available to meet forecast peak demand plus a 15 percent generation reserve level (referred to as the reserve margin) for forecasted wholesale and retail firm customer coincident 1-hour peak demand, for both winter and summer seasons. This reserve margin has been determined to be adequate to meet and exceed the industry standard loss of load probability of 0.1 days per year. Additionally, the reserve margin has been used by the Florida Public Service Commission for municipalities in the consideration of the need for additional generation additions

When considering the differential in forecast peak demand between winter and summer, and considering the differential in capacity ratings between winter and summer seasons, JEA's capacity requirements to meet projected peak demand plus reserve margins occur during the winter season[9]. As such, JEA's projected annual winter capacity requirements for each year of the IRP planning period for the Current Outlook scenario are illustrated on Figure 3-13.

Figure 3-13 includes details related to winter capacity provided by JEA's existing and future planned generating resources (including owned resources as well as PPAs) and also accounts for JEA's existing interruptible load program as contributing to meeting projected peak demands. As shown on Figure 3-13, JEA is projected to require 430 MW of new capacity to meet peak demand plus reserve margin requirements in the winter of 2030, with this need increasing to 525 MW by the winter of 2040 and more than 1,300 MW by 2051 (the end of the IRP planning period). The magnitudes of JEA's projected capacity requirements vary based on the forecast of peak demand and continued operation of existing generating resources reflected in each scenario and sensitivity evaluated in this IRP.

[9] As illustrated in Table 1-1, winter capacity ratings are higher than summer capacity ratings for combustion turbines and combined cycles, but not for steam turbines (including natural gas, solid fuel, and nuclear generating resources) and solar PV resources do not provide firm capacity during the time of winter peak demand.

Figure 3-12 Summary and Winter Capacity

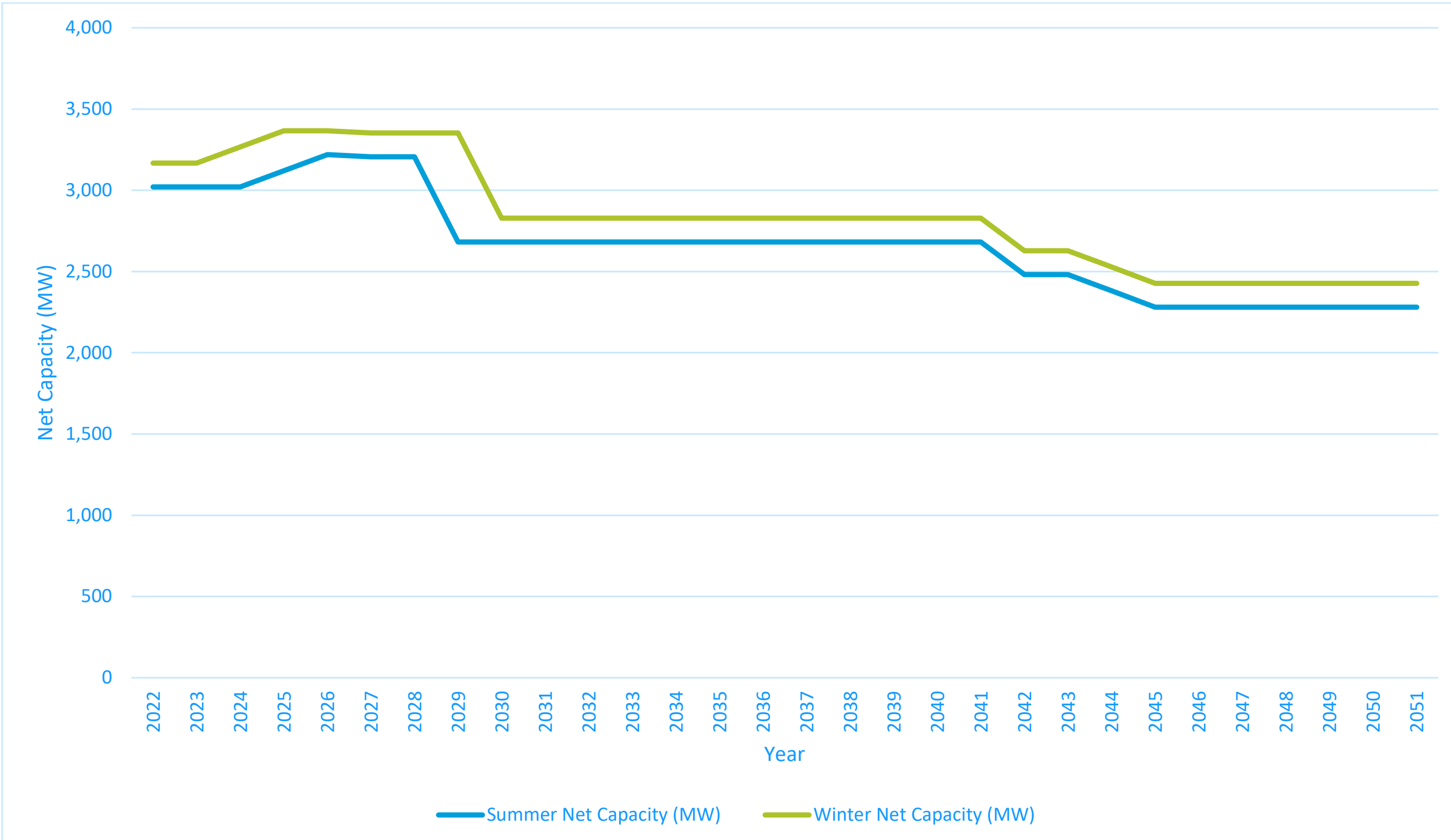
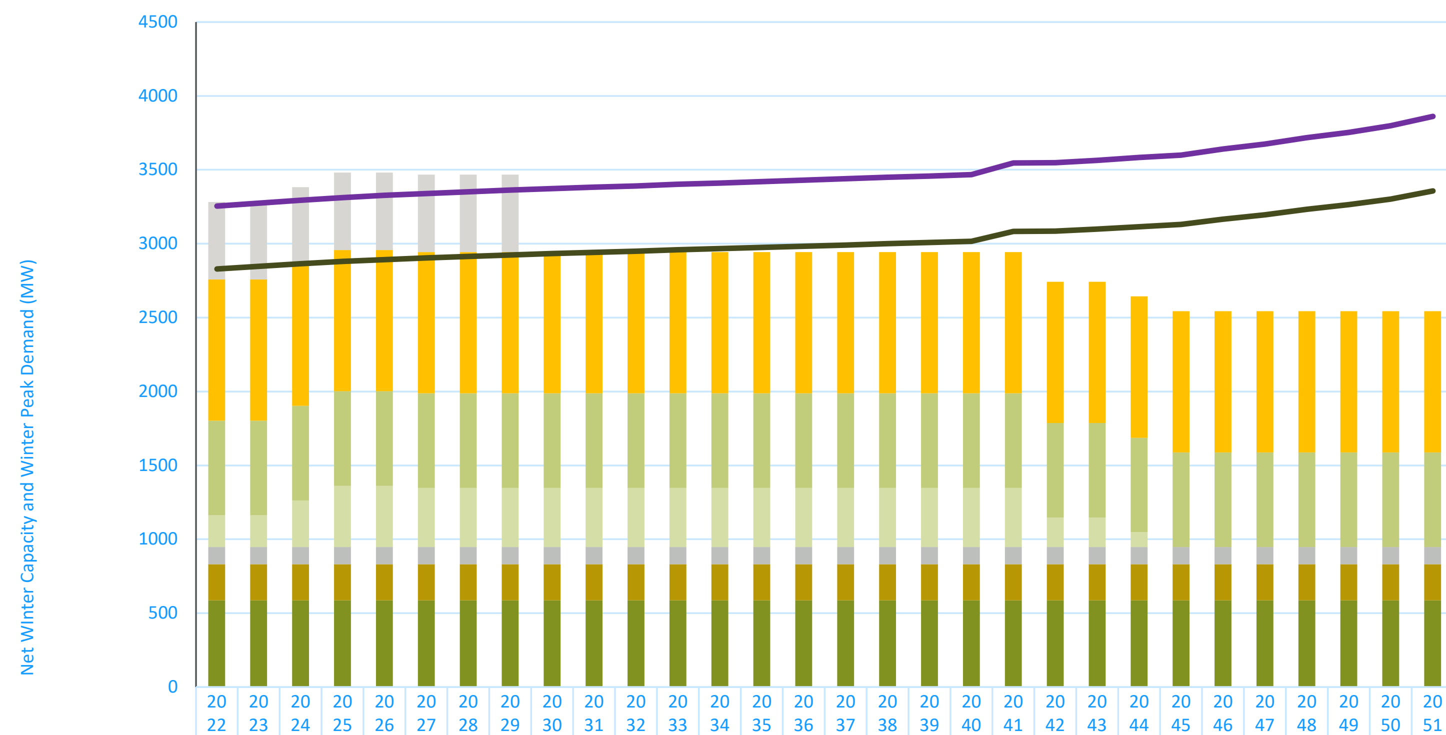


Figure 3-13 Projected Capacity Requirements - Current Outlook Scenario



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
Brandy Branch CC4	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Contracted PPAs	215	215	315	415	415	400	400	400	400	400	400	400	400	400	400
Interruptible Load	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Northside ST 1 and ST 2	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Peak Demand	2830	2848	2865	2879	2893	2904	2913	2924	2933	2941	2949	2958	2966	2974	2982
Peak Demand + 15% Reserve Margin	3255	3275	3295	3311	3327	3340	3350	3362	3373	3382	3391	3402	3411	3420	3429

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
Brandy Branch CC4	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Contracted PPAs	400	400	400	400	400	200	200	100	0	0	0	0	0	0	0
Interruptible Load	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Northside ST 1 and ST 2	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Peak Demand	2991	3000	3007	3016	3083	3086	3100	3116	3130	3165	3195	3232	3264	3302	3358
Peak Demand + 15% Reserve Margin	3440	3450	3458	3468	3546	3549	3564	3583	3599	3640	3675	3717	3754	3798	3862

4 Fuel Price Projections

4.1 Natural Gas Fuel Price Forecasts

Figure 4-1 illustrates the natural gas price forecasts that were developed for the IRP.

These forecasts are used by PLEXOS to determine the future operating costs of both the existing JEA gas-fired resources and the potential new gas-fired resource options. The base forecast is used for the Current Outlook and the Supplemental scenarios. The high forecast is used for the Economic Downturn, Efficiency + DER, Increased Electrification and Future Net Zero scenarios.

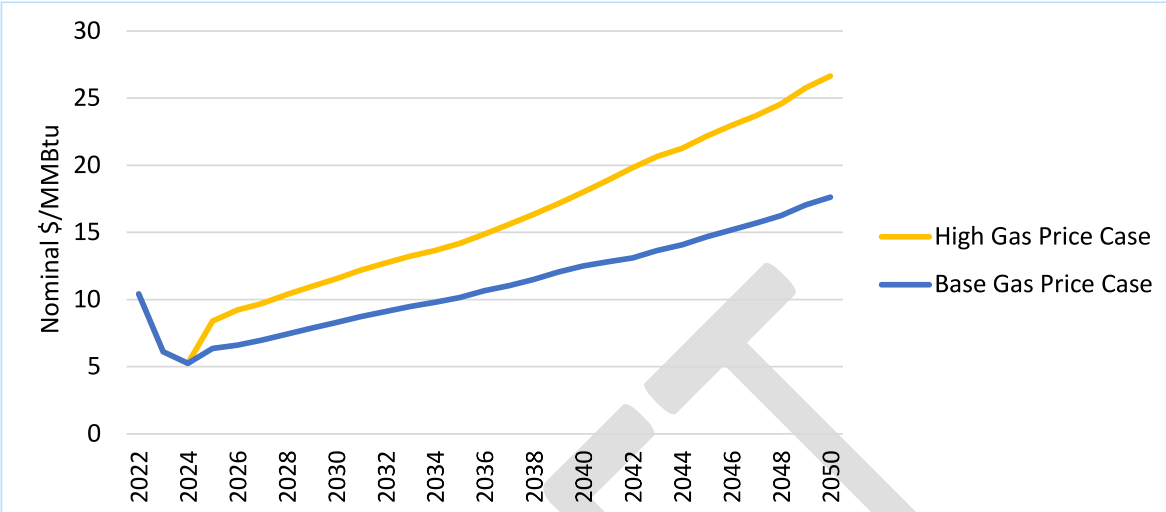
These forecasts are based on prices for natural gas bought and sold at the Henry Hub. Henry Hub is a natural gas pipeline in Louisiana that has access to many of the major gas markets in the United States, including four intrastate and nine interstate pipelines. Because of this access and the large volumes of gas bought and sold, Henry Hub has become the most important natural gas market clearing price point in the U.S. Natural gas contracts across the country are often indexed to the price of gas at Henry Hub. Therefore, it is also the price that is most useful to forecast for purposes of long-term gas planning and procurement.

Each of the forecasts shown consists of a short-term and a long-term component. The first 3 years are taken from the then-current prices for natural gas bought and sold at Henry Hub as published on the New York Mercantile Exchange, or NYMEX. On the NYMEX, parties can contract for gas delivered at Henry Hub for up to 3 years in the future and therefore these actual prices represent a very strong indicator of prices for the first 3 years of the forecast. Prices for the subsequent years are developed using a complex software model that simulates the supply, consumption and import/export of natural gas across North America for several years into the future. The model is named the Gas Pipeline Competition Model, or GPCM, and is the industry standard for long-term gas price forecasting. The model was customized to reflect current gas market conditions, including relatively high levels of liquefied natural gas (LNG) exports caused by the Russia-Ukraine conflict, a continued limitation of pipeline take-away capacity from the Permian and Marcellus/Utica gas production basins, and higher labor, capital and E&P (Exploration and Production) costs associated with the current inflationary price environment.

The base forecast assumes Lower 48 LNG export levels will reach 28.8 Bcf/d by 2030 and 37 Bcf/d by 2040. The high gas price forecast increases this by an additional 3.0 Bcf/d of LNG exports by 2027 and 6 Bcf/d by 2030 assuming continuation of the Ukraine/Russia conflict which has led to higher Western European energy imports. The high gas price forecast also assumes a reduction of 4.0 Bcf/d of pipeline take-away capacity from the Marcellus/Utica basins, which restricts low-cost gas supplies from reaching the Gulf Coast. Higher oil and gas exploration and production were assumed in the high price forecast to reflect the current inflated labor and material costs.

On top of these Henry Hub forecasts, the cost of transportation to the JEA gas-fired resource sites was added. This includes high-pressure interstate transportation from Henry Hub to Florida and also low-pressure intra-state transportation across the local gas distribution system of Peoples Gas. These forecast costs of interstate and intra-state transportation were developed in close coordination with the JEA fuels group and Peoples Gas, particularly with respect to JEA's existing natural gas transportation arrangements and incremental requirements for firm and interruptible gas delivery.

Figure 4-1 Natural Gas Fuel Forecast Prices at Henry Hub

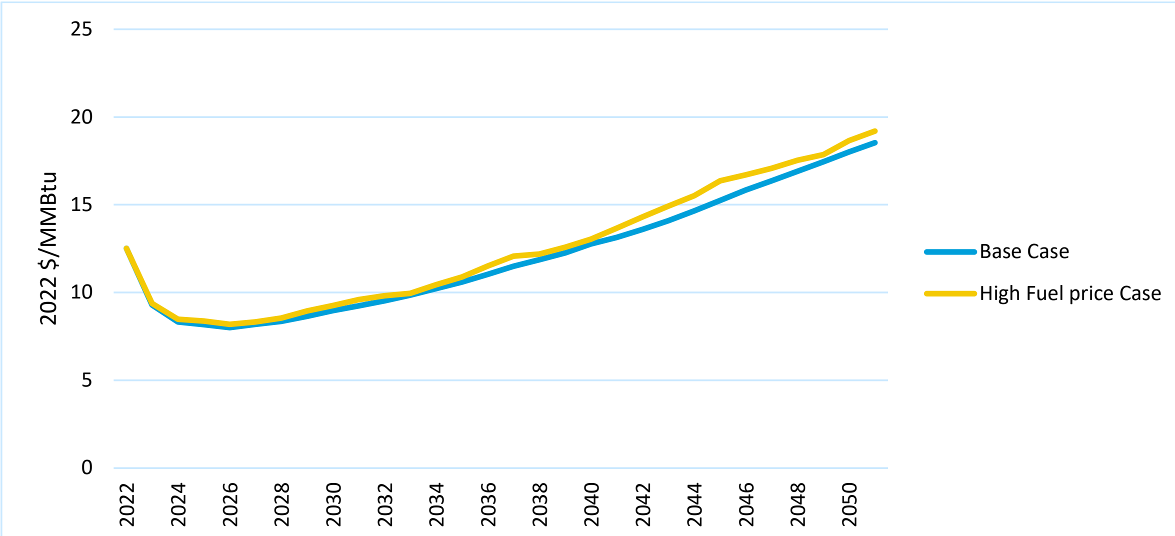


4.2 Northside 1 and 2 Fuel Price Forecasts

Figure 4-2 illustrates the fuel price forecasts for Northside Units 1 and 2 that were developed for the IRP, both a base and high case forecast. The base forecast is used in both the Current Outlook and the Supplemental scenarios, whereas the high forecast is used in the Economic Downturn, Efficiency + DER, Increased Electrification and Future Net Zero scenarios.

Fuel for Northside 1 and 2 is referred to as solid fuel because it is composed primarily of petroleum coke (petcoke) and coal with lesser components of natural gas and biomass. Black & Veatch developed this forecast as a blend of individual forecasts of these fuel components. The coal component is based on the coal price forecast provided by the federal Energy Information Agency (EIA) as part of their 2022 Annual Energy Outlook report. The EIA forecast was then modified to reflect current market conditions, including the impact that the Russia-Ukraine conflict has had on near-term coal demand and its potential impact on Lower 48 coal prices. The petcoke component is based projected delivered coal price adjusted by the historical delivered price relationship between petcoke and coal. The natural gas component was based on the gas price forecast described in Section 4.1. The biomass component was based on a forecast provided by JEA which in turn is based on JEA's experience procuring biomass and knowledge of the local biomass market. The resulting forecasts show a significant decline in prices between 2022 and 2026 as the current fuel supply chain disruptions and extreme market conditions are expected to relax. This is followed by a consistent increasing price trend thereafter driven primarily by increasing coal mining and delivery costs.

Figure 4-2 Solid Fuel Forecast Prices for Northside Units 1 and 2



4.3 Natural Gas Delivery

Assessment of the expected future gas delivery requirements to support addition of new generation at the Northside, SJRPP and GEC sites was performed by JEA in collaboration with the local natural gas distribution company (LDC) that serves JEA. The assessment found that physical upgrades of existing gas delivery systems by pipeline looping or compression and/or installation of new gas delivery systems will be required if JEA implements new incremental gas-fired resources at these sites. Order-of-magnitude estimates of capital and operating and maintenance (O&M) costs for the respective natural gas-based solutions were developed. These estimates along with other information were then utilized within the subsequent PLEXOS modeling to reflect the cost of natural gas delivery to these sites. These estimates are for planning purposes only and do not reflect further analysis that JEA and the LDC may perform for implementation purposes.

For deliveries to Northside and/or SJRPP, JEA and the LDC assessed the feasibility of upgrading an existing PGS-owned low-pressure line and adding compression at the end of the line as-needed to reach operating pressures and flows for each new resource considered.

For deliveries to GEC, the LDC assessed whether or not modifications to the current system would be sufficient to support combined cycle conversion of the existing simple cycle resources at GEC without any upgrades, as well as the potential upgrades required for new gas fired resources. The LDC performed gas system modeling to forecast the expected scope, cost and timing of the necessary upgrades.

5 New Generating Resource Options

5.1 Overview

There were numerous new generating resource options considered for the IRP, including renewable, conventional gas-fired and nuclear technologies. The range of options was developed through discussions between JEA and the Black & Veatch Team and are focused on those that are most relevant and most likely to be viable for JEA. New generating resource options are vital for the IRP process. They are the "building blocks" that the PLEXOS modeling must select to build out of the future JEA generating portfolio to serve future load and compensate for retirements while achieving reliability standards and environmental goals.

5.2 Renewable and Storage Resource Options

There were numerous renewable and storage resource generating options considered for the IRP. These included solar, solar plus integrated storage, standalone storage and biomass resources. Several renewable and storage generating resources were not considered because the general lack of resource potential in Florida and the broader southeastern grid, including on-shore wind, off-shore wind, geothermal, pumped hydro storage and compressed air storage. Detailed descriptions of the options considered is provided in Appendix C – New Generating Resource Options Characterization.

Renewable resources have historically benefited from certain tax benefits under federal law, including ITCs and production tax credits (PTCs). During development of the IRP the U.S. Congress passed the IRA which, among other provisions, introduced a new ITC for storage resources of the kind being studied for the IRP. Prior to this change, storage resources were not eligible for an ITC unless they were integrated into a solar or other renewable resource and would charge and discharge only energy generated by that renewable resource. Introduction of the new storage ITC effectively eliminated the requirement to integrate storage with solar and therefore the solar plus storage options (Options 2 and 3) were not considered in the detailed PLEXOS modeling described elsewhere in this report.

A summary of the renewable and storage options considered is shown in Table 5-1.

Table 5-1 Renewable and Storage Options Considered for the IRP

ID	Resource Option	Solar PV Rating (MW)	Battery Rating (MW)	Battery Capacity (MWh)
1	75 MW Photovoltaic Solar Array	75	NA	NA
2	75 MW Photovoltaic Solar Array with 0.5 hour integrated storage	75	37.5	37.5
3	75 MW Photovoltaic Solar Array with 4 hour integrated storage	75	75	300
4	37.5 MW Lithium Ion 1 hour Battery Storage[10]	NA	37.5	37.5
5	75 MW Lithium Ion 4 hour Battery Storage[11]	NA	75	300
6	50 MW Biomass BFB, with SCR, Baghouse, sorbent injection	47	NA	NA

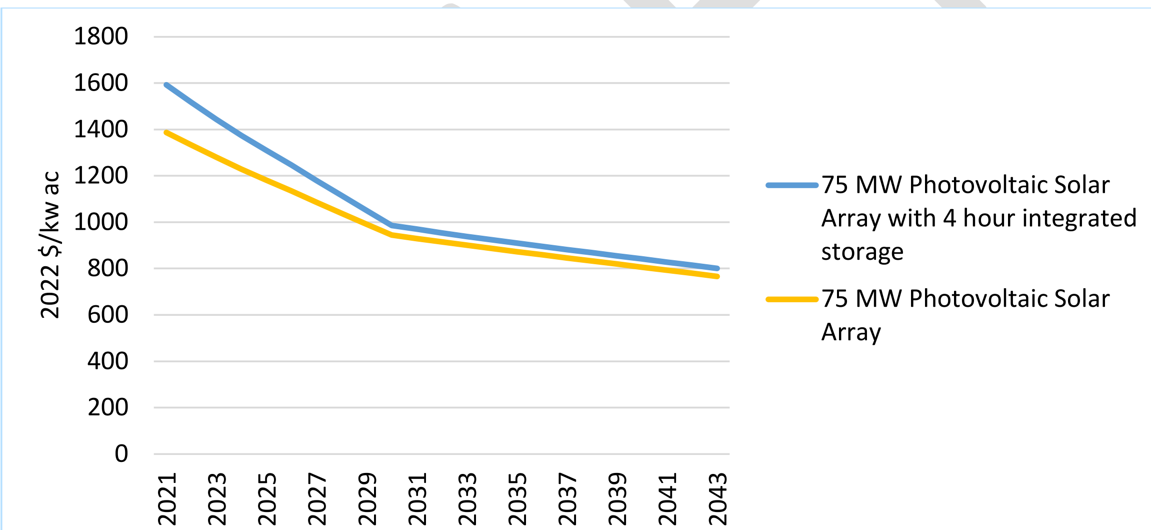
[10] 25 MW 1-hour Battery Storage was also considered.
[11] 50 MW 4-hour Battery Storage was also considered.

Chapter 5: New Generating Resource Options

The capital, O&M cost assumptions for these renewable and storage resources were developed by Black & Veatch engineers that are experienced with design, construction and operation of solar and storage plants. Capital and operating costs were developed from a conceptual design of the resource. To forecast solar annual energy and degradation for the resource, the engineers simulated its operation at varying operating conditions using the PVSyst suite of solar photovoltaic simulation software that is licensed by Black & Veatch. To estimate capital and operating costs the engineers use an estimating module within the PVSyst software, the results of which are then checked for consistency and completeness against estimates that the engineers have developed or seen elsewhere for similar plant configurations.

The capital cost estimates were developed assuming construction of a solar resource in 2022 based on 2022 costs for solar resource technology, including panels, inverters and other solar equipment. We expect that these capital costs will continue to decline for resources constructed in later years due to advancements in technology and manufacturing and construction methods. Black & Veatch therefore reduced these estimated costs for solar resources reaching commercial operation in later years. Figure 5-1 illustrates this forecast.

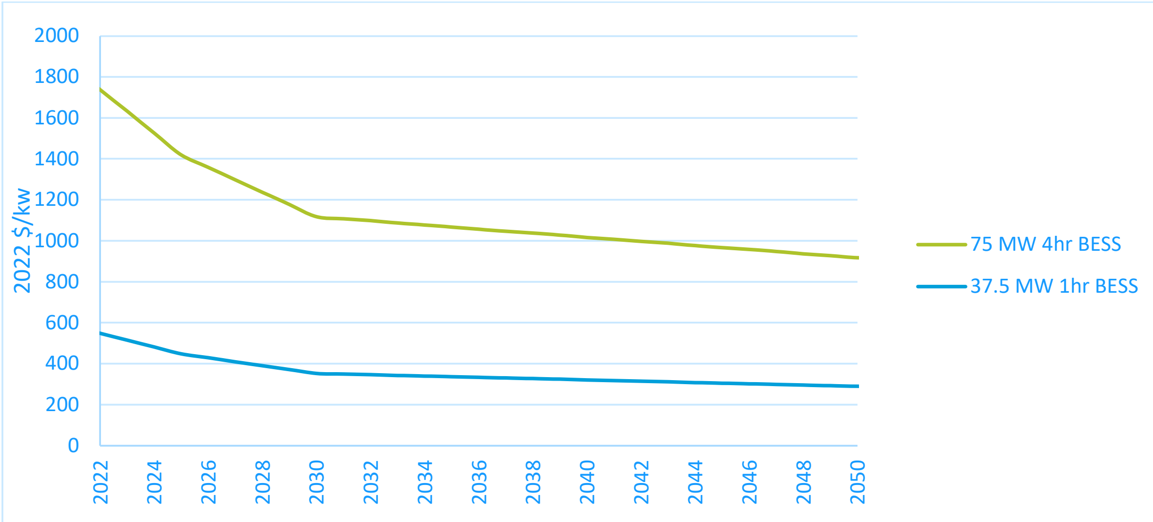
Figure 5-1 Solar Resources - Forecast Capital Costs



5.2.1 Battery Energy Storage Cost Estimating

Similar to the solar resources, capital cost estimates for storage resources were developed assuming construction of the resource in 2022 based on 2022 costs for battery technology, including metals, modules, inverters and other battery equipment. We expect that these capital costs will continue to decline for resources constructed in later years due to advancements in technology and manufacturing and construction methods. Black & Veatch therefore reduced these estimated costs for battery storage resources reaching commercial operation in later years. Figure 5-2 illustrates this forecast.

Figure 5-2 Battery Storage Resources - Forecast Capital Costs



Forecasts are shown for both the 75 MW 4-hour duration and 37.5 MW 1 hour duration battery resources. The forecast was developed by Black & Veatch engineers that are experienced with actual design, construction and operation of battery storage resources.

As can be seen, capital costs are forecast to decline significantly from current levels. This is due to the expected continued decline in capital costs and increasing performance of battery storage resource components (modules, inverters, chilling, etc.). Costs are expected to decline rapidly until 2030 and then less rapidly thereafter as the advancements in technology and reductions in manufacturing costs begin to fade as is typical over the life of new technologies and products.

5.2.2 Federal Tax Credit Considerations

As mentioned previously, under the new tax provisions of the IRA the solar and storage resources (Options 1 through 5) are each eligible for an ITC. The ITC rate is 30 percent and is applicable to the capital cost of the solar components and the storage components of a new solar and new storage resources, respectively. The biomass resource (Option 6) is eligible for a PTC. The PTC rate is $0.026/kWh and is applicable to the energy production from the resource, with the rate escalated for inflation in subsequent years.

Historically, municipal utilities such as JEA have utilized power purchase agreements to obtain solar energy rather than direct ownership of the solar resource. This is primarily because JEA is not a taxpayer and therefore has no taxable income to shelter through use of a tax credit. The value of the ITC is significant and it has been typical in the industry to have a private taxpaying entity own the solar resource and enter a power purchase agreement (PPA) with the municipal entity and indirectly pass the ITC benefit to the municipal entity in the form of a PPA price that is lower than the cost of energy that the municipal entity would have experienced if it owned the solar resource directly.

In contrast to this typical approach, the recently passed IRA provides, among other things, that municipal entities may now receive the value of the ITC in the form of a cash payment from the federal government rather than an ITC (known as "Direct Pay"). Direct Pay would allow JEA to access the ITC and perhaps eliminate the need for a PPA. However, Direct Pay has an additional eligibility requirement for minimum domestic content where the minimum increases in future years. Failure to achieve the domestic content requirement results in a reduced ITC. At this time there is a great level of uncertainty as to if and when adequate domestic content would become available and at what cost. Therefore, for purposes of the IRP, Black & Veatch assumed that JEA would not be eligible for the ITC because of the domestic content requirement, and that the typical PPA arrangement would apply. All solar energy would come through PPAs with private entities. Direct Pay will continue to be evaluated in future IRPs.

In addition to Direct Pay and domestic content, the IRA introduced a new ITC eligibility requirement to pay prevailing wage to labor used for construction and operation of a new resource. We assumed that the private entity owning the solar resource would choose to meet this requirement. Therefore Black & Veatch's PPA price forecasting described in Subsection 5.2.5 reflects both the ITC and a higher resource capital cost (prevailing wage was not assumed in development of the resource option cost estimate).

The IRA also introduced a new extended timeline for reduction of the ITC and PTC available to new resources. Prior to the IRA, the ITC and PTC were scheduled to reduce to 10 percent no later than the year 2026. Under the IRA, they now begin to phase out to 75 percent, then 50 percent and then 0 percent of their original values in the years following the year in which certain annual greenhouse gas (GHG) emissions reductions are achieved by the U.S. The IRS has not provided guidance as to what year this percent reduction might be achieved and it is currently very difficult to forecast in what year it might be achieved. Therefore, for purposes of the IRP, Black & Veatch assumed that the reduction will be achieved in 2041 and the ITC and PTC will step down to 75 percent, 50 percent and 0 percent of their original values in 2042, 2043 and 2044, respectively.

5.2.3 Solar Resource Siting Considerations

In addition to development of the solar resource option cost and performance estimates, a siting analysis was performed to determine the potential location of the new solar resources. A detailed description of the siting analysis is provided in Appendix D, Solar Siting Analysis.

Location of solar resources is important because solar resources are land intensive. About 6-8 acres of land is required for just 1 MW of solar using a common industry assumption. Therefore, for a Scenario that calls for addition of 1,000 MW of new solar would require about 6,000 acres or more of suitable land to be secured for hosting the resources. Securing this amount of land would be a significant effort and would likely require land beyond the JEA service territory due to the sheer magnitude required.

As a first step in the analysis, we did a systematic search for land parcels that could be developed to support up to 4,000 MW of the new solar resources. This amount of new resources was targeted because we expected that the Scenarios that include strong environmental policy goals such as Net Zero could require up to this amount of new solar resources to deliver the energy required.

The land search was done using land data available in a graphical information system (GIS) database for central and northern Florida. These areas were chosen for study because they are expected to have better access to transmission capacity now and in the future than areas north of Florida and areas in southern Florida. Black & Veatch looked for parcels that have factors that would be beneficial for new solar plant development, including size, proximity to high voltage electric lines, the absence of forests and wetlands, and relatively flat terrain. There were 22 factors in total. Then Black & Veatch developed scoring criteria for each factor, a scale from 0 to 9 of representing how well each parcel satisfies the factor. For example, parcels less than 450 acres received a land factor score of 0 since a minimum of 450 acres would be required for a 75 MW plant based on the 6 acres per MW assumption. Parcels that have a high voltage transmission line immediately nearby received a score of 9, whereas those with transmission more than a mile away received a score of 0, and so on for the other factors. Finally, the scores were summed for each parcel and then the parcels were ranked by score.

Results from the land portion of the study reveal that over 100 parcels would be required to host 4,000 MW of the new 75 MW solar resources. Thirty two (32) of these parcels are located in Duval county with the other 68 spread across 23 other counties in northern Florida and the Panhandle. Each of these parcels is large enough to support a 450 acre site for a 75 MW plant. These parcels sum to more than 51,000 acres of land. Acquisition of this much land, either by JEA as direct owner of the plant, or by a third-party plant developer and owner with power sold to JEA, would take many years to accomplish.

With respect to land costs for the new solar resources, it is important to note that new solar resources are in demand by nearly all utilities today. This may result in competition between JEA and other utilities in Florida for the identified solar sites, particularly for those not located in the JEA service territory. This could result in increasing costs for the new solar resources and perhaps limit the total amount of new solar resources that JEA could acquire.

The land cost assumptions that were utilized for the IRP are described in Subsection 5.2.4.

5.2.4 Solar Transmission Considerations

Location of new solar on lands outside the JEA service territory also raises the challenge of electric transmission. JEA would need to secure or construct new remote transmission capacity sufficient to reliably deliver the energy from the remote new solar resources to the JEA service territory. Construction of new transmission is also land intensive and would be a significant effort. We cannot simply assume that large amounts of new solar can be delivered at no cost. The IRP must consider the time and cost required to acquire or build the necessary transmission to interconnect and deliver energy from these new solar sites to the JEA service territory.

The transmission analysis began with review of results from the Solar Siting Analysis. We determined that the scope of the transmission analysis should consider approximately 2,000 MW of the 4,000 MW of sites identified. At that time we expected that the PLEXOS modeling (then yet to be performed) would likely identify that around 2,000 MW of new solar resource capacity must be added to the generation portfolio particularly for the scenarios that require large amounts of carbon reduction. We also determined that the scope should consider sites outside of Duval County as well as inside given the large amount of land required (approximately 6 to 8 acres per MW). We therefore identified a subset of the sites in Duval County that were relatively highly ranked, in proximity to one another and could collectively support approximately 1,000 MW of solar resources (Tier 1 Solar). We did the same for a subset of sites in the Panhandle area that could collectively support another 1,000 MW of solar resources (Tier 2 Solar). We then

determined that the transmission analysis scope should also include four of the solar sites that JEA controls in Duval County that could collectively support another 300 MW of solar resources (Tier 0 Solar). The transmission analysis scope would therefore include a total of 2,600 MW of potential solar resources. The general location of the Tier 0, Tier 1 and Tier 2 sites are identified on the map on Figure 5-3.

Figure 5-3 Map of Sites Utilized in Transmission Analysis

The transmission analysis was performed by Black & Veatch engineers that are experienced with planning, design, construction and operation of transmission facilities. It was performed on the high voltage transmission system of JEA and surrounding areas assuming interconnection of these specific potential new resources using PSS/E and TARA transmission modeling software that Black & Veatch licenses. Load flow and voltage simulations were performed assuming FRCC's standard set of P1 to P7 contingencies. Results of the simulations identified overloads and voltage violations, and the necessary transmission system improvements and voltage support required to mitigate them. Capital costs for the improvements along with a general schedule for their completion were then estimated. The work was performed in consultation with JEA's Transmission Planning Group.

Results of the transmission analysis showed that new high voltage transmission facilities must be constructed in a step-wise fashion to deliver the solar energy, beginning with interconnection facilities for the Tier 0 resources, then interconnection and transmission facilities for the Tier 1 resources, and then interconnection and transmission facilities for the Tier 2 resources. The time to construct these facilities was also estimated based on experience of both the Black & Veatch engineers and JEA's Transmission Planning Group. The Tier 0, Tier 1 and Tier 2 solar resources are not expected to be available until 2026, 2030 and 2032, respectively, when the associated interconnection and transmission facilities are necessary. The first year of solar energy delivery from resources in each tier was constrained to be no earlier than the year of expected completion of the facilities.

5.2.5 Solar PPA Price Forecasting

Black & Veatch utilized the solar resource performance and cost estimates along with the aforementioned assumptions on prevailing wage and ITC to forecast prices for a series of 20-year solar PPAs beginning in each year of the Study Period (the "PPA Price Forecasts"). These forecasts were used in the PLEXOS modeling.

Black & Veatch used a pro-forma financial model that mimics the actual financial modeling that a private party solar developer would perform for a new 75 MW solar project to determine the PPA prices that it must charge to recover costs and earn a profit (the "PPA

Model"). This model has been developed and is maintained and used by Black & Veatch on behalf of potential investors in new solar projects to assess future financial results claimed by the private party project developer. The financial assumptions were developed by Black & Veatch consultants that are experienced with financing of solar projects, including the levels of debt and equity required, interest rates, debt service coverage, required return on equity, taxes and tax credits. This includes the aforementioned ITC eligibility and phase out assumptions under the IRA.

PPA prices were forecast for new solar resources at each of three general siting areas that were identified from the Solar Siting Analysis; Tier 0, Tier 1 and Tier 2. Prices were assumed to be in the form of a first year price in $/MWh escalating thereafter at 3 percent annually. Private party solar developers typically propose escalating price streams to keep the first-year price as low as possible to be competitive. The prices were assumed to be inclusive of all energy, capacity and environmental attributes associated with the project (all output and attributes purchased by JEA).

Following the expiration of the PPA, each project was assumed to earn revenue for the remainder of its 30-year useful life through continued energy sales to JEA or others (years 21-30). Continued energy sales were estimated based on a long-term energy market price forecast performed by Black & Veatch.

Using the methodology and assumptions described above, Black & Veatch forecasted PPA prices for the generic renewable resources. Figure 5-4 illustrates these forecasts. Please note that for ease of price comparison between tiers and years, Figure 5-4 shows the first year PPA price only. Figure 5-5 shows the first year price and each subsequent year price for a Tier 0 PPA starting in each year of the forecast period.

Figure 5-4 Solar PPA Resources Forecast First Year Prices

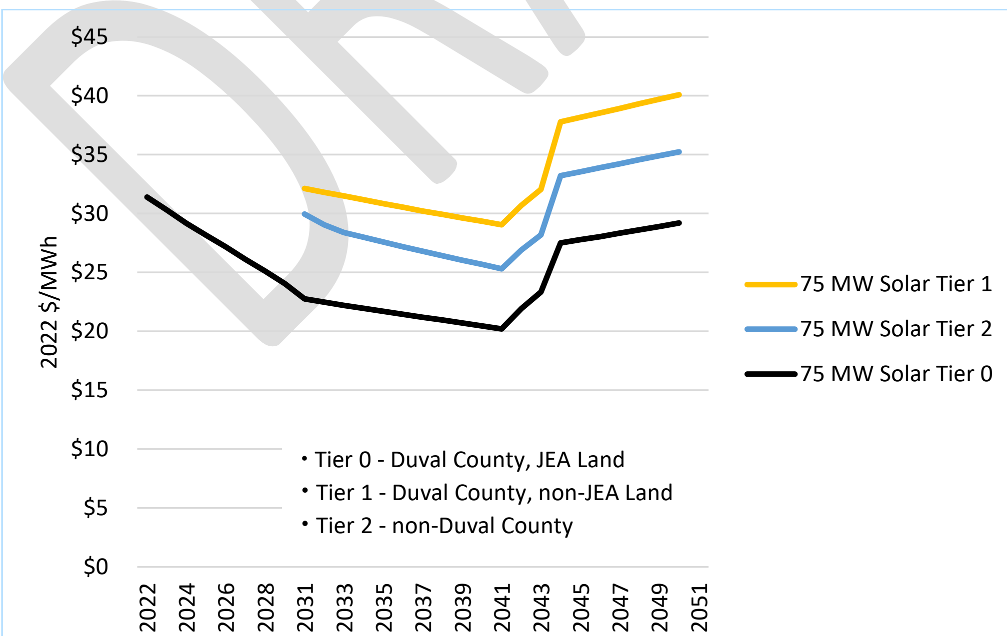
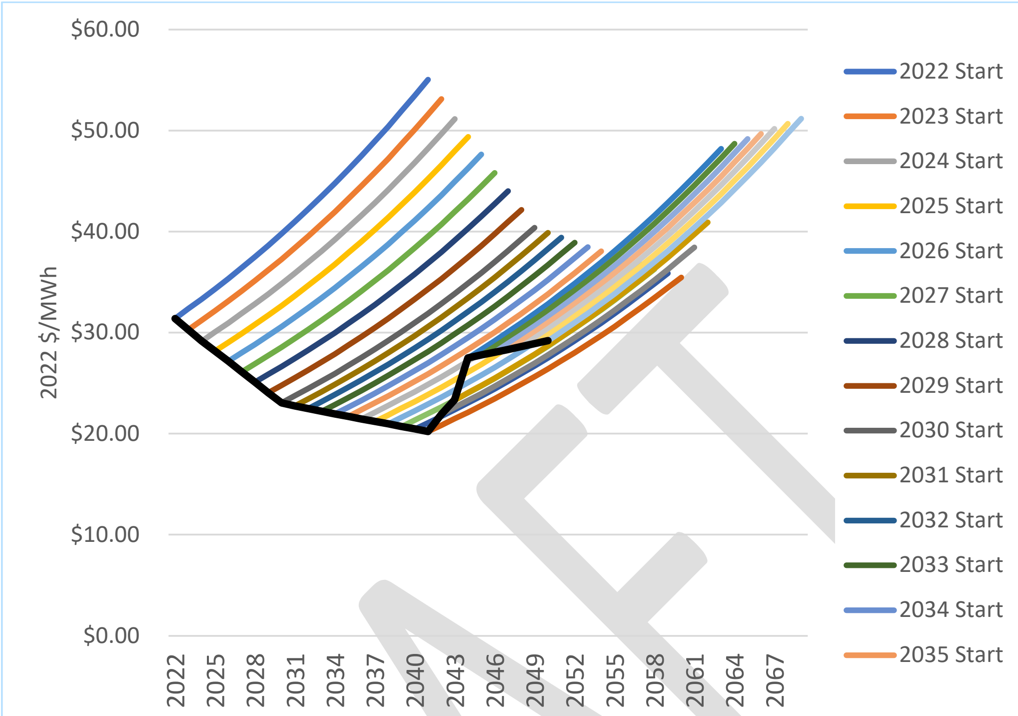


Figure 5-5 Tier 0 Solar Resources PPA Price Streams by Start Year



Also for clarity the prices are shown in 2022 dollars, which means without inflation. Including inflation in the figure would make it difficult to see the real impact of different cost assumptions between tiers and years. If and when PLEXOS chooses to add a Tier 0 solar resource to the capacity expansion, it includes the specific PPA price stream for that start year in its cost calculation in inflated dollars.

As can be sees, the prices differ by location. The lowest prices would be from the Tier 0 sites that JEA would lease to the developers, namely the Deep Creek, Forest Trail, Miller and Peterson sites. The highest prices would be from the Tier 1 sites that the developers would lease from other landowners. The prices in the middle would be from the Tier 2 sites the developers would lease from other landowners. The differences in price are driven directly by differences in land value that underly the lease rates. Lease rates for the Tier 0 sites are assumed to be 0 since JEA would likely charge low or no lease rates to the developers to avoid giving the lease revenue back in the form of a higher PPA price. Lease rates for the Tier 1 sites are based on a survey of prices for open agricultural land in Duval County, which average around $50,000 per acre. Lease rates for the Tier 2 sites are based on a similar survey of the Panhandle area, which reveals an average of around $7,000 per acre.

It is also important to note that the first year PPA prices are also significantly different from year to year. They decline consistently from the 2020s through 2041 (the Initial Period), when they begin to rise to relatively high levels until 2045 (the Middle Period), and then rise even further through 2051 (the Final Period). The Initial Period decline is driven by an expected continued decline in capital costs and increasing performance of solar PV components (panels, inverters, etc.), which in combination effectively reduces capital costs. The Middle Period increase is due to the expected reduction of the ITC, which effectively raises capital costs. The Final Period increase is due to increasing capital costs for solar PV components as the prior downward trend in costs is expected to reverse and future costs begin to rise.

These PPA prices are for energy delivered at the solar plant boundary, which is typical for PPAs. To reflect the true cost of the solar energy to JEA, we took the capital costs of the interconnection and transmission facilities for each tier identified in the aforementioned transmission study, converted them into fixed charge rates and added them to the respective PPA prices for purposes of the PLEXOS modeling.

Unlike the solar PV resources presented earlier, these capital costs are those that JEA would incur to build and own the resource. JEA would not utilize a PPA arrangement to access the battery resource. We assume that JEA will directly own and operate future battery resources because they provide capacity and can be used for a multitude of system reliability purposes such as operating reserves, load following and solar resource balancing, similar to existing and future new gas-fired resources. These benefits would be more difficult to access under a PPA structure where the private party owner would likely place limits on battery use to preserve the battery for other uses or future users. Also, there is sufficient space at the SJRPP, Northside and GEC sites to accommodate these battery storage resources and therefore JEA does not need to rely on a third party to mitigate the risk of site acquisition.

5.2.6 Biomass Cost Estimating

Similar to the solar and battery storage resources, cost and performance estimates for a new biomass resource was developed.

Biomass generating resource estimates in general are highly dependent on the assumed type and quality of biomass fuel to be burned. Black & Veatch, working closely with JEA fuel specialists, determined that woody biomass from forest residues would likely be the most available fuel over the future study period. The composition and moisture content of the woody biomass was based on a fuel composition analysis provided by JEA for biomass fuel burned at Northside Units 1 and 2.

The woody biomass would be chipped and then burned in a bubbling fluidized bed (BFB) technology boiler. Based on the fuel analysis and likely supply available, the biomass resource assumes a single nominal 50 MW unit with standard emissions control technology to meet U.S.-based requirements. The performance estimates are based on high level heat balances and combustion calculations, and the installed cost estimates are based on rough order of magnitude pricing from vendors.

Unlike the solar PV resources presented earlier, the biomass capital and operating costs are those that JEA would incur to build and own the resource. JEA would not utilize a PPA arrangement to access biomass energy. We assume that JEA will directly own and operate a future biomass resource based on its expertise in development and operation of the repowered Northside Units 1 and 2, which consume biomass as a component of the solid fuel stream.

We do not consider the benefit of the PTC for the biomass resource. This is because the PTC has the same Direct Pay eligibility requirement as the ITC, including use of minimum domestic content and as stated for the solar and battery resources there is too much uncertainty as to if and when domestic content will be available and at what prices.

5.3 Gas-Fired Resource Options

There were numerous gas-fired resource generating options considered for the IRP. These included reciprocating engine, standalone combustion turbine, combined cycle combustion turbine and combustion turbine conversion technologies. Detailed information on these resource options is provided in Appendix C – New Generating Resource Options Characterization. A summary of the options is shown in Table 5-2.

Table 5-2 Summary of Gas-Fired Resource Options

ID	Resource Option	Plant Configuration	Average Ambient Net Output[1] (MW)	Heat Rate (Btu/kWh, HHV)
7	2x0 GE LM6000 PF SPRINT	Combustion Turbine	91	9,379
8	1x0 GE LMS100PA+	Combustion Turbine	111	8,818
9	1x0 GE 7FA.05	Combustion Turbine	226	10,080
10	1x0 GE 7HA.02	Combustion Turbine	329	9,256
11	5x0 Wartsila 18V50DF	Reciprocating Engine	89	8,380
12	1x1 GE 7FA.05	Combustion Turbine Combined Cycle	373	6,743
13	2x1 GE 7FA.05	Two Combustion Turbine Combined Cycle	749	6,715
14	1x1 GE 7HA.02	One Combustion Turbine Combined Cycle	558	6,419
15	2x1 GE 7HA.02	Two Combustion Turbine Combined Cycle	1,119	6,397
16	3x1 GE 7HA.02	Three Combustion Turbine Combined Cycle	1,684	6,378
17	1x1 GE 7HA.02	Same as #14 but Air-Cooled Condenser	552	6,484
18	Conversion of existing GEC CTGs	One Combustion Turbine Combined Cycle	318	6,832
19	Conversion of existing GEC CTGs	Two Combustion Turbine Combined Cycle	638	6,830

These estimates were developed by Black & Veatch engineers that are experienced with actual design, construction and operation of gas-fired power plants. The capacity and heat rate estimates are based on technical information provided by General Electric for their combustion turbine based power plants, except for the 18V50DF resource, which is based on technical information provided by Wartsila for their reciprocating engine based power plants. To estimate capacity and heat rate, the engineers develop a conceptual design of each resource and then simulate its operation at varying operating conditions using the Thermoflow suite of thermodynamic simulation software that is licensed by Black & Veatch. To estimate capital and operating costs, the engineers use an estimating module of the Thermoflow software, the results of which are then checked for consistency and completeness against estimates that the engineers have developed or seen elsewhere for similar plant configurations.

Similar to the battery resources presented earlier, these capital and O&M costs are those that JEA would incur to build, own and operate the resource. The resource would not be built and owned by a third-party developer with long-term sales to JEA. We assume that JEA will directly own and operate future gas-fired resources because they provide capacity and can be used for a multitude of system reliability purposes such as operating reserves, load following and solar resource balancing. These benefits would be more difficult to access under a PPA structure where the private party owner would likely place limits on resource use to preserve the resource for other uses or future users. Also, there is sufficient space at the Power Park and GEC sites to accommodate most of these gas-fired resources and therefore JEA does not need to rely on a third party to mitigate the risk of site acquisition.

5.4 Nuclear Resource Options

For purposes of the IRP, Black & Veatch studied seven different nuclear technologies, including Small Modular Light Water Reactor (SMR LWR) and Advanced non-Light Water Reactor (Advanced Reactor) technologies. Detailed information on these resource options is provided in Appendix C – New Generating Resource Options Characterization. A summary of the options is shown in Table 5-3. Each of these technologies is different that the Large Light Water Reactor technology employed at the Vogtle nuclear plant for which JEA will soon be purchasing 200 MW under a 20 year PPA.

Table 5-3 Summary of Nuclear Resource Options

ID	Technology Type	Resource Option	Plant Configuration	Reactor Rating (MWth)	Plant Output (MWE)
20	Small Modular Light Water Reactor (SMR LWR)	NuScale Power Module™	Four, six, or 12 individual power modules.	160 or 250 per module	50 or 77 per module
21	Small Modular Light Water Reactor (SMR LWR)	General Electric-Hitachi (GEH) BWRX-300	Water-cooled, natural circulation Small Modular Reactor (SMR) with passive safety systems.	870	300+
22	Small Modular Light Water Reactor (SMR LWR)	Holtec SMR-160	SMR designed to produce 160 megawatts of electricity using low enriched uranium fuel.	480	160
23	Advanced Reactor	Kairos Power FHR	Salt-cooled high temperature reactor; higher process temperature allows for industrial heating in addition to power production.	311.1	140
24	Advanced Reactor	TerraPower Natrium Reactor	Sodium fast reactor combined with a molten salt energy storage system.	767 est.	345
25	Advanced Reactor	X-energy Xe-100	Modular and scalable with up to 4 modules per group.	200 per module, 800 per 4 module plant	80 per module, 320 per 4 module plant
26	Advanced Reactor	Terrestrial Energy Integral Molten Salt Reactor (IMSR®)	Molten salt as coolant and fuel that permits lower pressure and high temperature operation.	443	195

Of the seven nuclear technologies studied, the option considered for the IRP is the SMR LWR or SMR technology under development by NuScale. The NuScale SMR resource consists of 12 individual 77 MW reactor modules with a combined power rating of 924 MW gross. This option was chosen because it is in an advanced state of development relative to the other nuclear options. The NRC has issued several approvals and rules advancing the technology, including Standard Design Approval of the NuScale module and certification that NuScale's small modular reactor design meets the NRC safety requirements. In December 2022, NuScale applied to the NRC for standard design approval of its multi-module plant design, which if accepted will allow the company to pursue its first reactor deployment in the mid-2020s. NuScale is planning its first deployment of its SMR technology at a site in Utah in the 2030 timeframe for the Utah Associated Municipal Power Systems (UAMPS).

5.5 Assessment of JEA Existing Sites to Host Resource Options

In addition to development of cost and performance estimates for all of the resource options, we assessed the available site space at the Greenland Energy Center (GEC), Northside Generating Station (Northside) and St. Johns River Power Park (SJRPP) JEA generating plant sites to determine which options could be hosted at those sites. This assessment was important because locating new resources at the existing sites would avoid the need to secure new sites and the associated acquisition time, permitting time and cost. GEC, Northside and SJRPP were selected because of the general availability of space relative to other JEA generating sites and the general electrical benefit of having new generation on the eastern side of the JEA system rather than the western side. Figure 5-6 below is a map that illustrates the location of these sites.

Figure 5-6 Locations of Existing Generating Sites

As a first step in the assessment, aerial imagery was used to identify areas at each site that are either currently vacant or could become vacant if existing resources and supporting infrastructure were to be removed in favor of new resources. The areas were then refined based on discussions with JEA engineering and operations staff and other subject matter experts concerning current uses of the areas, dependencies and durations for equipment removal and other factors.

Chapter 5: New Generating Resource Options

The available areas identified at SJRPP are shown on Figure 5-7.

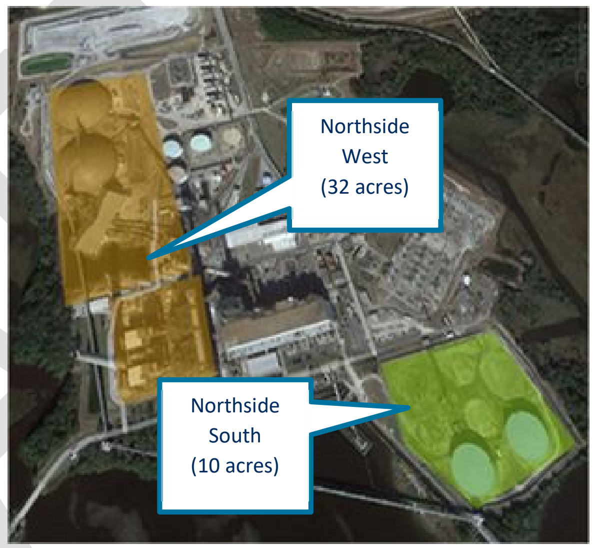
Figure 5-7 SJRPP Available Space

The largest available area is SJRPP South, which is currently vacant and located south of the former St. Johns River Power Park, a 1,252 megawatt coal-fired electric generating plant that was retired in early 2018. This area is generally expected to have fewer buried utilities than the former plant site to the north making it less costly for construction of new resources.

The available areas identified at Northside are shown on Figure 5-8.

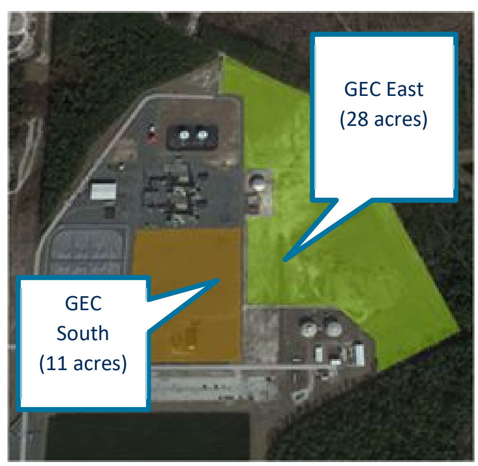
The largest area identified is Northside West, which is the site of the existing Northside Units 1 and 2. This area would only be available if and when Northside Units 1 and 2 are retired and demolished. Demolition is estimated to cost approximately $10 million and take about a year to perform. Therefore, modeling the deployment any of the new resource options at this area would need to factor in the lead time and costs. The Northside South area is currently partially occupied by two fuel oil storage tanks that serve Northside Unit 3. This area would only be available if and when Northside Unit 3 is retired and the fuel oil tanks removed. Therefore, modeling the deployment any of the new resource options at this area would need to factor in the lead time and the costs for tank removal.

Figure 5-8 Northside Available Space



The available areas identified at GEC are shown on Figure 5-9.

Figure 5-9 GEC Available Space



Chapter 5: New Generating Resource Options

The GEC South area is immediately south of the existing GEC dual unit combustion turbine plant. The area is currently vacant and to date has been reserved for future deployment of steam generators and steam turbines that would be part of a conversion of the existing combustion turbine plant to a combustion turbine combined cycle plant. These conversions are considered in the IRP as new resource Options 17 and 18. Use of this area for any other new resource options would generally preclude the deployment of Options 17 and 18. Therefore, modeling the deployment any new resource options other than 17 and 18 at this area would need to remove Options 17 and 18 from consideration. The GEC East Area is currently vacant and to date has generally been reserved for addition of new gas-fired resources at GEC.

With these areas defined, the acreage typically required to host each option versus the acreage available within each area was compared. It is important to note that the nuclear SMR option was excluded from this assessment. This is because at this time the technology is new and therefore the acreage typically required and associated nuclear siting laws and restrictions are unknown.

Results of the comparison show the following:

- The SJRPP, NGS West and GEC West areas are very similar in ability to host potential new resources.
- None of the solar options could be hosted within any of the areas. This is because the acreage required for each (450) exceeds the acreage available (11-145). The solar options must be hosted on new areas elsewhere.
- Any of the battery options could be hosted within any of the areas due to the relatively small acreage required.
- The biomass option could be hosted within SJRPP South only.
- Only the relatively small combustion turbine and reciprocating engine-based options could be hosted within NGS South. The larger combustion turbine based combined cycle options must be hosted within NGS West or SJRPP South.

6 Levelized Cost of Energy Comparisons

A key step in the IRP process is to review the forecast capital and operating costs of each new generating resource option and determine whether any should be eliminated from further consideration due to relatively high forecast capital and operating costs. The purpose of this filtering is to reduce the number of resource options to be considered in the subsequent very detailed and time intensive PLEXOS capacity expansion and production cost simulation modeling process.

The resource options have a wide range of capital and operating costs. To compare and filter them on a common basis, a levelized cost of energy (LCOE) screening analysis was performed. LCOE for a resource is defined as the present value of its costs over its life divided by the present value of its electric generation output over its life. Figure 6-1 summarizes the LCOE formula and the key variables.

Cost variables include assumed installation and ongoing capital costs, fixed O&M costs and variable O&M costs such as fuel. Performance variables include assumed energy production, capacity factor and expected resource life. For renewable resources, assumptions must also be made for degradation rates and component overhaul/replacement costs. Economic variables include assumed ownership, escalation and inflation rates and the discount rate, which is based on the owner's debt and equity capitalization and interest rates.

Economic assumptions utilized for the LCOE analysis are summarized in Table 6-1. These assumptions were based on discussions with JEA economic and financial staff. It is important to note that JEA ownership was assumed for the LCOE analysis. This is in contrast to the PLEXOS modeling where third-party ownership of solar resources under long-term energy sales to JEA was assumed (Solar PPAs). JEA ownership of solar was assumed in the LCOE analysis for consistency and comparability of results across the resource types.

It is important to note that these forecasts do not include the effect of the solar and storage ITC or biomass PTC available under the IRA. For JEA to benefit from the ITC/PTC, it would have to satisfy the Direct Pay requirements, which requires use of domestic content in the resource. Currently, the IRS has not issued guidance on what constitutes domestic content. It is also very difficult to estimate if and when domestic production capacity will be sufficient to provide the amounts of domestic content required for solar, battery storage, and biomass resources and at what prices. Due to this uncertainty, we are taking a conservative approach for purposes of this LCOE analysis by assuming that JEA would not benefit from the ITC. Direct Pay will be further assessed in future IRPs. The assumption of no Direct Pay is for this IRP only and does not reflect additional analysis that JEA may subsequently perform.

Chapter 6: Levelized Cost of Energy Comparisons

Figure 6-1 Levelized Cost of Energy (LCOE) Formula

$$\frac{\sum_{t=1}^{n} \frac{I_t+M_t+F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

LCOE = ***<u>Present Value of Costs over Lifetime</u>***
Present Value of Electric Generation over Lifetime

Where:
I_t : investment expenditures in year t;
M_t : operations and maintenance expenditures in year t;
F_t : fuel expenditures in year t;
E_t : electrical energy generated in year t;
r : discount rate;
n : expected lifetime of system.

Table 6-1 Economic Assumptions for the LCOE Analysis

Parameter	Assumption
Resource ownership	JEA
General inflation rate	3.00%
Construction cost escalation rate	3.00%
Fixed O&M cost escalation rate	3.00%
Non-fuel variable O&M cost escalation rate	3.00%
Interest rate	4.00%
Discount rate (equal to bond interest rate)	4.00%

Cost and performance assumptions utilized for the LCOE analysis of the gas-fired resource options are summarized in Table 6-2. These assumptions are based on the resource characteristics described in Appendix C – New Generating Resource Options Characterization.

Results of the LCOE analysis for the gas-fired new resource options are shown on Figure 6-2. Results are shown for each resource option at a different capacity factor assumption to illustrate the impact of the capacity factor assumption on LCOE.

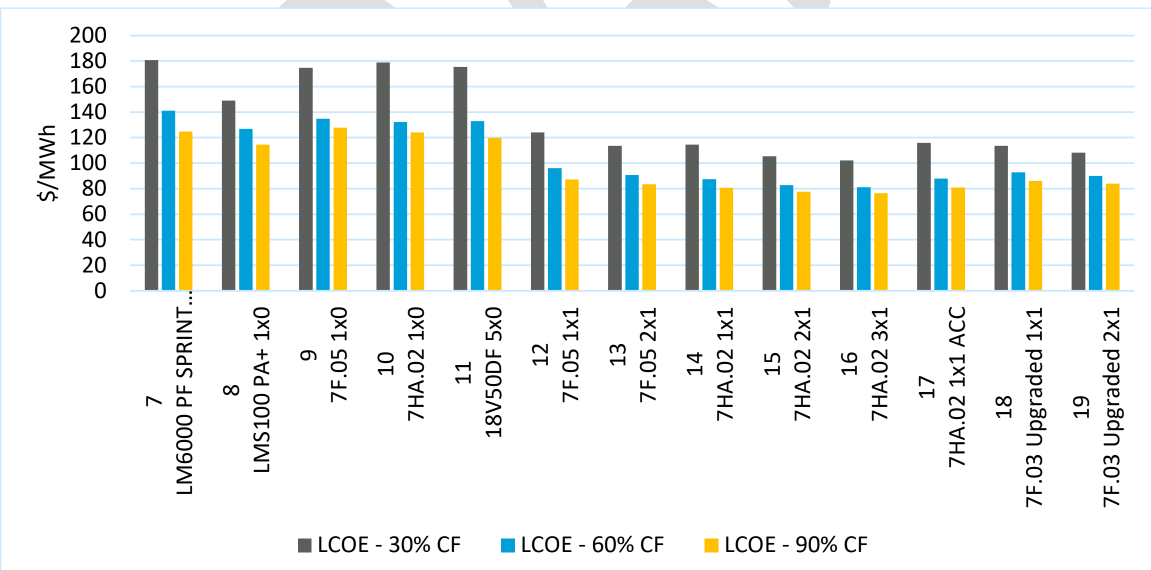
Results for the simple cycle combustion turbine and reciprocating engine resource options (Options 7 through 11) show they have very similar LCOEs across the different capacity factor levels except for Option 8 the LMS100 PA+ 1x0, which has significantly lower costs. Since there is no one option with relatively high costs, none can be eliminated from further modeling.

Results for the combined-cycle combustion turbine resource options (Options 12 through 19) show they also have very similar LCOEs and therefore none can be eliminated from further modeling.

Table 6-2 Gas-Fired New Resource Options - LCOE Assumptions

Option	Resource Configuration	Type	Economic Life (years)	Maximum Capacity - Winter (MW)	Maximum Capacity - Summer (MW)	Capital Cost ($/kw at Winter Capacity)	Capacity Factor (%)	Fixed O&M ($/year)	Variable O&M ($/MWh)
7	LM6000 PF SPRINT 2x0	SCCT	20	99.5	76.1	$1,048	30	1,443,087	7.07
8	LMS100 PA+ 1x0	SCCT	20	115.2	91.2	$1,078	30	1,466,707	4.55
9	7F.05 1x0	SCCT	20	235.7	208.7	$464	30	1,931,240	10.25
10	7HA.02 1x0	SCCT	20	346.2	300.1	$503	30	2,039,503	13.69
11	18V50DF 5x0	SCCT	20	89.4	83.8	$1,445	30	2,029,721	9.08
12	7F.05 1x1	CCCT	25	379.5	342.2	$1,175	60	3,804,971	2.43
13	7F.05 2x1	CCCT	25	761.8	687.5	$974	60	4,946,786	2.34
14	7HA.02 1x1	CCCT	25	571.3	518	$919	60	4,126,527	2.48
15	7HA.02 2x1	CCCT	25	1,146.5	1,039.8	$762	60	5,592,219	2.41
16	7HA.02 3x1	CCCT	25	1,724.6	1,563.6	$646	60	7,387,710	2.39
17	7HA.02 1x1 ACC	CCCT	25	566.6	511.2	$973	60	4,133,777	1.8
18	7F.03 Upgraded 1x1	CCCT	25	328.8	297.3	$924	60	3,686,567	2.75
19	7F.03 Upgraded 2x1	CCCT	25	660.3	597.2	$839	60	4,703,331	2.67

Figure 6-2 LCOE Results for Gas-Fired Resource Options



Chapter 6: Levelized Cost of Energy Comparisons

Cost and performance assumptions utilized for the LCOE analysis of the renewable, storage and nuclear resource options are summarized on Table 6-3. These assumptions are based on the resource characteristics described in Appendix C – New Generating Resource Options Characterization, with the exception of capacity factors for the solar plus storage and storage options which are not stated in the Appendix. Capacity factors for the solar plus storage options were calculated based on the hourly energy production profile for the 75 MW solar resource and common assumptions for hours of discharge per day and round-trip efficiency. Capacity factors for the storage options were calculated using common assumptions for hours of discharge per day and round-trip efficiency.

Results of the LCOE analysis for the renewable, storage and nuclear options are shown on Figure 6-3.

Comparing the options that provide energy only (Options 1, 6 and 20), its apparent that the nuclear Option 20 is significantly more costly and therefore was eliminated from further modeling.

With respect to the options that provide shaped energy (Options 2 and 3), Option 3 is significantly more costly and therefore was eliminated from further modeling. Option 3 has a higher LCOE because it has a higher capital cost (due to its larger battery) and a lower capacity factor. The lower capacity factor indicates that for the given solar profile a 4-hour co-located battery is excessive and a smaller battery size is sufficient.

Although Option 2 was selected for further modeling, it was ultimately removed from further consideration due to passage of the IRA. As described in section 5.2, the IRA allows for a storage ITC which effectively eliminates the need for solar plus integrated storage resources. Therefore Option 2 was excluded since this resource type is no longer required and because exclusion simplifies the PLEXOS modeling.

With respect to the storage options (4 and 5), Option 4 (1 hour capacity) is more costly. Although this LCOE analysis shows that the 1-hour BESS is more costly, the subsequent PLEXOS modeling may show it to be less costly particularly if there is a strong need for short-term storage to provide rapid load following and solar intermittency. Therefore the 1-hour BESS was not eliminated from further modeling.

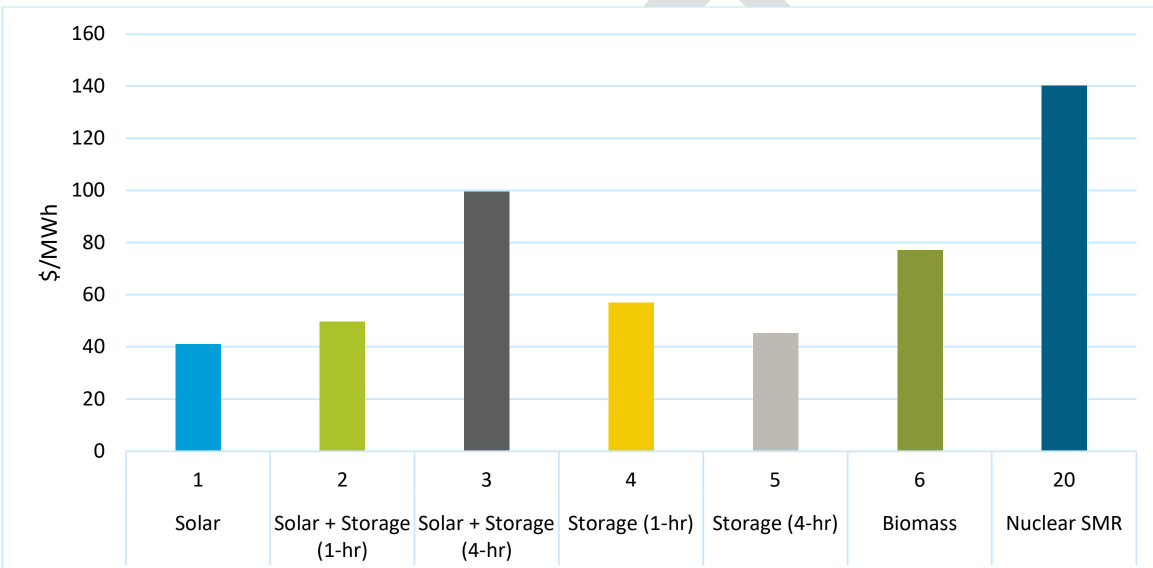
Table 6-3 Renewable, Storage and Nuclear LCOE Assumptions

Option	Resource Configuration	Economic Life (years)	Maximum Capacity (MW-AC)	Capacity Factor (%)	Capital Cost ($/kw at Winter Capacity)	Fixed O&M ($/kWac-year)	Variable O&M ($/MWh)	Degradation Rate (%)
1	Solar	25	74.9	29.9	$1388	7	-	0.5
2	Solar + Storage (1-hr duration)	25	74.9	29.4	$1663	8.22	-	0.5
3	Solar + Storage (4-hr duration)	25	74.9	26	$3134	8.22	-	0.5
4	Storage (1-hr duration)	20	37.5	8.33	$552	2.44	-	-

Chapter 6: Levelized Cost of Energy Comparisons

Option	Resource Configuration	Economic Life (years)	Maximum Capacity (MW-AC)	Capacity Factor (%)	Capital Cost ($/kw at Winter Capacity)	Fixed O&M ($/kWac-year)	Variable O&M ($/MWh)	Degradation Rate (%)
5	Storage (4-hr duration)	20	74.9	33.33	$1747	8.2	-	-
6	Wood Biomass	25	50	80	$3,562	147.5	8.08	-
20	Small Modular Nuclear Reactor	40	854	95	$2,850	7.05	16.4	-
		*Note: For stand-alone storage units, the capacity factor represents 86 percent round trip efficiency.						

Figure 6-3 LCOE Results for Renewable, Storage and Nuclear Resource Options



7 Development of Scenarios and Sensitivities

As discussed throughout the IRP Stakeholders Meetings and elsewhere in this IRP, the IRP utilizes both scenario and sensitivity analysis methodology. Scenario analysis considers a set of changes to multiple variables simultaneously to analyze a potential future. Sensitivity analysis considers changes to one of these variables at a time within a given potential future. The scenarios and sensitivities evaluated throughout the IRP are intended to address uncertainties related to the following:

- Projected load growth (both peak demand and annual energy requirements).
- Penetration of plug-in electric vehicles and electrification in general.
- Demand-side management, energy efficiency, conservation, and customer-sited generation (DERs).
- Future environmental regulation and clean energy standards.
- Projected natural gas and solid fuel prices.

Several key considerations will be critical to holistic evaluation of scenario results. These include affordability, reliability, environmental justice, economic development and CO_2 emission reductions. Affordability will be considered by examining the potential cost and rate increases under each scenario to ensure that they are moderate and would not cause undue hardship on customers. Reliability will be considered by examining the amount of generating capacity at the time of peak customer demand to ensure that it exceeds the peak by the required reserve margin. Environmental justice and economic development will be considered by examining the location of new resources to help ensure that disadvantaged communities will not bear the brunt of potential increased noise and visual impact and that land use would be consistent with future economic development. CO_2 emission reductions will be considered by examining the potential reduction of these emissions relative to the other scenarios.

The following provides a conceptual-level summary of the six scenarios that have been developed for evaluation in the IRP with figures that illustrate the changes to the variables within each scenario as compared to the Current Outlook scenario. Within each figure, the magnitude of variables within the Current Outlook scenario are indicated as “Base” or “None” while “High” and “Low” represent the magnitude of the variable as compared to the corresponding variable within the Current Outlook scenario. Following discussion of the six scenarios, an overview of the six sensitivities is presented.

7.1 Current Outlook Scenario

The Current Outlook scenario reflects the following:

- Inflation and escalation rates increase as compared to recent rates.
- Load forecast based on:
    - Historical customer usage trends and population projections.
    - Historical customer participation in demand-side management/energy efficiency/conservation/DER.
    - Projections of increased plug-in electric vehicle adoption and electrification based on recent historical observations and projected population growth.

- Natural gas and solid fuel prices in-line with recent historical prices following a period of volatility given current international disruptions to fuel markets.
- No cost for emissions of carbon dioxide (CO_2).
- No specific target for renewable energy/clean energy generation.
- Costs for construction of new generating resource options in-line with current costs.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

7.2 Economic Downturn Scenario

The Economic Downturn scenario represents a future with a sustained economic slowdown, driven in part by higher inflation and fuel and commodity costs, and reflects the following:

- Inflation and escalation rates increase as compared to the Current Outlook.
- Load forecast lower than in the Current Outlook, influenced by a combination of the following:
  - Lower customer usage and population projections than the Current Outlook.
  - No changes to demand-side management, energy efficiency, conservation, DER, or electrification as compared to the Current Outlook.
  - Lower plug-in electric vehicle adoption than the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- No cost for emissions of CO_2.
- No specific target for renewable energy/clean energy generation.
- Costs for construction of new generating resource options increase as compared to the Current Outlook.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

A tabular summary of the differences between the Economic Downturn scenario and the Current Outlook scenario is provided in Table 7-1.

Table 7-1 Differences between the Current Outlook and Economic Downturn Scenarios

Area	Variable	Current Outlook	Economic Downtown
Financial	Interest During Construction and Discount Rate	Base	High
	General Inflation Rate	Base	High
	Capital Cost Escalation Rate	Base	High
Demand	Total Net Energy Requirements Forecast	Base	Low
	Net Firm Peak Demand Forecast	Base	Low
	DSM/EE/Conservation	Base	Base
	PEVs	Base	Low
	Electrification	Base	Base
	Customer-Sited Renewables (DERs)	Base	Base

Area	Variable	Current Outlook	Economic Downtown
Environmental Regulations	Carbon Regulations/Cost	None	None
	Clean Energy Standards (CES)	None	None
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	High
	Unit Retirements	Base	Base
"Base" represents variables in Current Outlook Scenario "High" or "Low" represents the magnitude of variables relative to "Base" or "None"			

7.3 Efficiency + DER Scenario

The Efficiency + DER scenario represents a future with increasing levels of interest and participation in demand-side management, conservation, energy efficiency, and DER, driven in part by higher fuel costs, and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast higher than in the Current Outlook, influenced by a combination of the following:
  - Higher customer usage than the Current Outlook, as increases to PEV adoption and electrification are not offset by increased customer participation in demand-side management, energy efficiency, conservation, and DER as compared to the Current Outlook, all as discussed below.
  - Increased customer participation in demand-side management, energy efficiency, conservation, and DER as compared to the Current Outlook.
  - Increased PEV adoption and electrification as compared to the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- No cost for emissions of CO_2.
- No specific target for renewable energy/clean energy generation.
- Lower costs for construction of new generating resource options as compared to the Current Outlook.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

A tabular summary of the differences between the Efficiency + DER scenario and the Current Outlook scenario is provided in Table 7-2.

Table 7-2 Differences between the Current Outlook and Efficiency + DER Scenarios

Area	Variable	Current Outlook	Efficiency + DER
Financial	Interest During Construction and Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	High
	Net Firm Peak Demand Forecast	Base	High
	DSM/EE/Conservation	Base	High
	PEVs	Base	High
	Electrification	Base	High
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	None
	Clean Energy Standards (CES)	None	None
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	Low
	Unit Retirements	Base	Base
"Base" represents variables in Current Outlook Scenario "High" or "Low" represents the magnitude of variables relative to "Base" or "None"			

7.4 Increased Electrification Scenario

The Increased Electrification scenario represents a future with increased levels of interest and adoption of DER and electrification, driven in part by higher fuel costs, and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast higher than in the Current Outlook, influenced by a combination of the following:
  - Higher customer usage than the Current Outlook.
  - Increased customer adoption of plug-in electric vehicles, electrification, and DER as compared to the Current Outlook.
  - No changes to demand-side management, energy efficiency, or conservation as compared to the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- No cost for emissions of CO_2.
- No specific target for renewable energy/clean energy generation.
- Increased costs for construction of new generating resource options as compared to the Current Outlook.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

A tabular summary of the differences between the Increased Electrification scenario and the Current Outlook scenario is provided in Table 7-3.

Table 7-3 Differences between the Current Outlook and Increased Electrification Scenarios

Area	Variable	Current Outlook	Increased Electrification
Financial	Interest During Construction & Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	High
	Net Firm Peak Demand Forecast	Base	High
	DSM/EE/Conservation	Base	Base
	PEVs	Base	High
	Electrification	Base	High
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	None
	CES	None	None
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	High
	Unit Retirements	Base	Base
"Base" represents variables in Current Outlook Scenario "High" or "Low" represents the magnitude of variables relative to "Base" or "None"			

7.5 Future Net Zero Scenario

The Future Net Zero scenario represents a future in which JEA achieves net zero carbon emissions from its generating portfolio by the end of the IRP planning period, and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast higher than in the Current Outlook, influenced by a combination of the following:
  - Higher customer usage than the Current Outlook, as increases to PEV adoption and electrification are not offset by increased customer participation in demand-side management, energy efficiency, conservation, and DER as compared to the Current Outlook, all as discussed below.
  - Increased customer adoption of PEVs, electrification, and DER as compared to the Current Outlook.
  - Increased PEV adoption and electrification as compared to the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- Costs for emissions of CO_2.
- Net-zero CO_2 emissions from JEA's generating portfolio by 2050 with interim CO_2 reductions beginning in 2030, achieved through increased utilization of clean energy resources (i.e., 40 percent clean energy by 2030,

increasing to 100 percent clean energy by 2050).

- No change to costs for construction of new generating resource options as compared to the Current Outlook.

A tabular summary of the differences between the Future Net Zero scenario and the Current Outlook scenario is provided in Table 7-4.

Table 7-4 Differences between the Current Outlook and Future Net Zero Scenarios

Area	Variable	Current Outlook	Future Net Zero
Financial	Interest During Construction and Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	High
	Net Firm Peak Demand Forecast	Base	High
	DSM/EE/Conservation	Base	High
	PEVs	Base	High
	Electrification	Base	High
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	High
	CES	None	High
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	Base
	Unit Retirements	Base	Base
"Base" represents variables in Current Outlook Scenario "High" or "Low" represents the magnitude of variables relative to "Base" or "None"			

7.7 Supplemental Scenario

The Supplemental scenario was developed to address specific requests from Stakeholders received as part of the Stakeholder Engagement process (discussed in Chapter 2 of this IRP), and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast lower than in the Current Outlook Due to increased levels of customer adoption of customer-sited renewables.
- No changes to demand-side management, energy efficiency, or conservation as compared to the Current Outlook.
- No changes to natural gas and solid fuel prices increase as compared to the Current Outlook.
- No costs for emissions of CO_2.
- Net-zero CO_2 emissions from JEA's generating portfolio by 2050 with interim CO_2 reductions beginning in 2030, achieved through increased utilization of renewable energy resources (i.e., 30 percent renewable energy by 2030, increasing to 100 percent renewable energy by 2050).
- No change to costs for construction of new generating resource options as compared to the Current Outlook.
- Removal of Northside Generating Station units 1 and 2 by 2030.

A tabular summary of the differences between the Supplemental scenario and the Current Outlook scenario is provided in Table 7-5.

Table 7-5 Differences between the Current Outlook and Supplemental Scenarios

Area	Variable	Current Outlook	Supplemental
Financial	Interest During Construction & Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	Low
	Net Firm Peak Demand Forecast	Base	Low
	DSM/EE/Conservation	Base	Base
	PEVs	Base	Base
	Electrification	Base	Base
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	None
	CES	None	High
Fuel Prices	Natural Gas	Base	Base
	Solid Fuel	Base	Base
Others	Construction Cost	Base	Base
	Unit Retirements	Base	High
"Base" represents variables in Current Outlook Scenario "High" or "Low" represents the magnitude of variables relative to "Base" or "None"			

7.8 Sensitivities

As discussed throughout the IRP, the IRP evaluated several sensitivities as well as the scenarios that were outlined previously in this chapter. The sensitivities were evaluated within the Current Outlook scenario and, except as noted below, reflect variables that are consistent with those evaluated for the Current Outlook scenario:

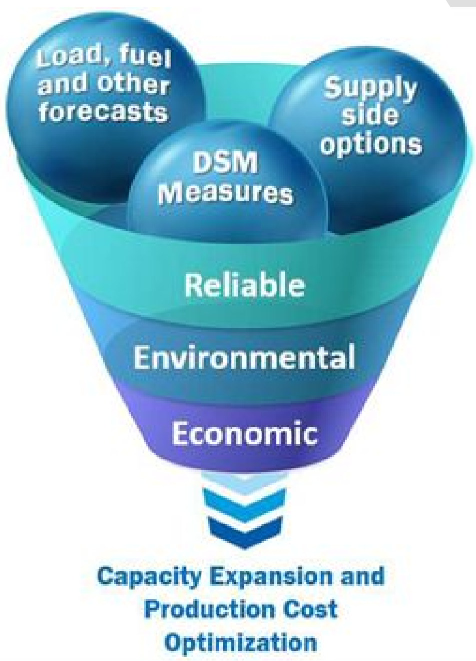
- Low Load Sensitivity: Sensitivity that utilizes the forecast annual peak demand and energy requirements load forecast that is reflected in the Economic Downturn scenario.
- No Load Growth Sensitivity: Sensitivity in which the forecast peak demand and annual energy requirements reflected for 2022 in the Current Outlook scenario are held constant for each year of 2023 through 2051 period.
- High Load Sensitivity: Sensitivity based on the load forecast utilized for the Efficiency + DER and Future Net Zero scenarios with the addition of a potential large customer of approximately 200 MW beginning in 2024.
- High Fuel Sensitivity: Sensitivity in which natural gas and solid fuel prices are higher than those in the Current Outlook scenario, reflecting the high price projections included in Chapter 4 of this IRP.
- Regulated CO_2 Sensitivity: Sensitivity in which all CO_2 emissions are assessed a cost of $30/ton beginning in 2030, increasing by 5 percent annually.
- Net Zero Sensitivity: Sensitivity in which there are zero CO_2 emissions from JEA's generating portfolio by 2050 with interim CO_2 reductions beginning in 2030, achieved through increased utilization of clean energy resources (i.e., 40 percent clean energy by 2030, increasing to 100 percent clean energy by 2050).

8 Modeling Results

8.1 Overview of PLEXOS

Black & Veatch utilized PLEXOS to evaluate the combination of resources available to JEA to meet future demand and energy requirements in the 2022-2051 planning horizon. PLEXOS is an industry standard, capacity expansion and production cost model used by multiple utilities and other utility industry professionals to perform a variety of analysis. PLEXOS was used to evaluate the data discussed in previous sections to produce a least cost resource plan while honoring unit operational constraints and maintaining the ability of the resource plan to serve forecast load requirements in a reliable manner.

Figure 8-1 PLEXOS Constrained Optimization



PLEXOS was used to develop optimal capacity expansion plans and associated production costs for each of the scenarios and sensitivities discussed throughout Chapter 7 of this IRP. While this Chapter presents summary-level information related to the optimal capacity expansion plans, additional details are provided in Appendix A - Detailed PLEXOS Modeling Results. For more details on PLEXOS see Appendix F.

8.2 Results

8.2.1 Resource Additions

Summaries of the resource additions associated with the optimal capacity expansion plan for each scenario and each sensitivity evaluated in this IRP are provided on Figure 8-2 and Figure 8-3, respectively.

The results of the PLEXOS analysis and determination of the optimal capacity expansion plans for each scenario and sensitivity within different timeframes are illustrated on Figure 8-4 and Figure 8-5, respectively. These results indicate that additional solar generation, additional natural gas-fueled generation, and energy storage resources are the near-term (i.e., by the 2030 timeframe) resource additions that will provide benefits to the JEA system, as these new resources consistently comprise the optimal capacity expansion plans across the range of scenarios and sensitivities evaluated as part of this IRP.

Figure 8-2 Forecast Resource Additions for Each Scenario

Figure 8-3 Forecast Resource Additions for Each Sensitivity

Figure 8-4 Summary of Resource Additions for Each Scenario

Incremental Solar PV Additions

	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
Cumulative 2030	300 MW	300 MW	1,275 MW	1,275 MW	1,275 MW	1,275 MW
Additional 2030-2040	0 MW	0 MW	300 MW	450 MW	2,475 MW	2,250 MW
Additional 2040-2050	0 MW	0 MW	75 MW	150 MW	7,125 MW	6,975 MW
Total Solar PV Additions by 2050	**300 MW**	**300 MW**	**1,650 MW**	**1,875 MW**	**10,875 MW**	**10,500 MW**

Incremental Battery Energy Storage System (BESS) Additions

	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
Cumulative 2030	250 MW	0 MW	188 MW	250 MW	824 MW	563 MW
Additional 2030-2040	0 MW	0 MW	225 MW	188 MW	7,575 MW	7,750 MW
Additional 2040-2050	289 MW	612 MW	612 MW	451 MW	10,325 MW	10,438 MW
Total BESS Additions by 2050	**539 MW**	**612 MW**	**1,025 MW**	**889 MW**	**18,724 MW**	**18,751 MW**

Incremental Natural Gas Additions

	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
Cumulative 2030	571 MW	571 MW	571 MW	571 MW	0 MW	461 MW
Additional 2030-2040	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Additional 2040-2050	472 MW	0 MW	582 MW	928 MW	0 MW	0 MW
Total Natural Gas Additions by 2050	**1,043 MW**	**571 MW**	**1,153 MW**	**1,499 MW**	**0 MW**	**461 MW**

Figure 8-5 Summary of Resource Additions for Each Sensitivity

Incremental Solar PV Additions

	Low Load	No Load Growth	High Load	High Fuel	Regulated CO2	Net Zero
Cumulative 2030	225 MW	225 MW	300 MW	1,275 MW	300 MW	1,275 MW
Additional 2030-2040	0 MW	75 MW	0 MW	300 MW	0 MW	2,775 MW
Additional 2040-2050	0 MW	0 MW	0 MW	150 MW	0 MW	7,800 MW
Total Solar PV Additions by 2050	**225 MW**	**300 MW**	**300 MW**	**1,725 MW**	**300 MW**	**11,850 MW**

Incremental Battery Energy Storage System (BESS) Additions

	Low Load	No Load Growth	High Load	High Fuel	Regulated CO2	Net Zero
Cumulative 2030	0 MW	250 MW	400 MW	275 MW	275 MW	450 MW
Additional 2030-2040	0 MW	0 MW	0 MW	0 MW	0 MW	4,075 MW
Additional 2040-2050	388 MW	150 MW	538 MW	289 MW	314 MW	13,414 MW
Total BESS Additions by 2050	**388 MW**	**400 MW**	**938 MW**	**564 MW**	**589 MW**	**17,939 MW**

Incremental Natural Gas Additions

	Low Load	No Load Growth	High Load	High Fuel	Regulated CO2	Net Zero
Cumulative 2030	571 MW	571 MW	571 MW	571 MW	571 MW	0 MW
Additional 2030-2040	0 MW	0 MW	236 MW	0 MW	0 MW	0 MW
Additional 2040-2050	236 MW	0 MW	917 MW	471 MW	471 MW	0 MW
Total Natural Gas Additions by 2050	**807 MW**	**571 MW**	**1,724 MW**	**1,042 MW**	**1,042 MW**	**0 MW**

8.2.2 Energy Generation

Summaries of the amount of energy generated by resource/fuel type associated with the optimal capacity expansion plan for each scenario and each sensitivity evaluated in this IRP are provided on Figure 8-6 and Figure 8-7, respectively.

These results indicate that, consistent with the magnitude of new resource additions by type (i.e., solar PV and natural gas) discussed in Subsection 8.2.1, forecast energy requirements are projected to be met primarily by a combination solar and natural gas resources.

Figure 8-6 Projected Energy Generation for Each Scenario

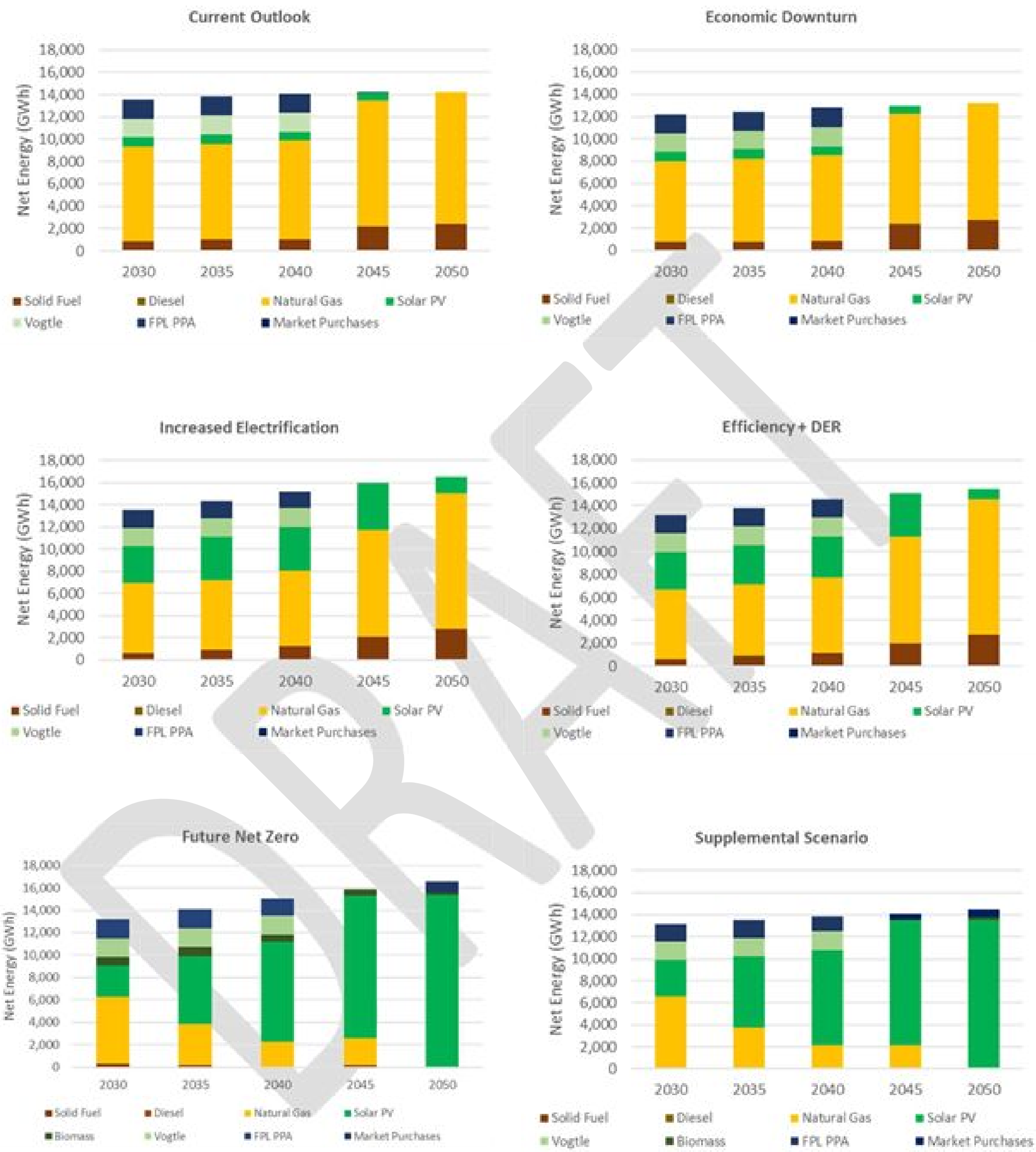
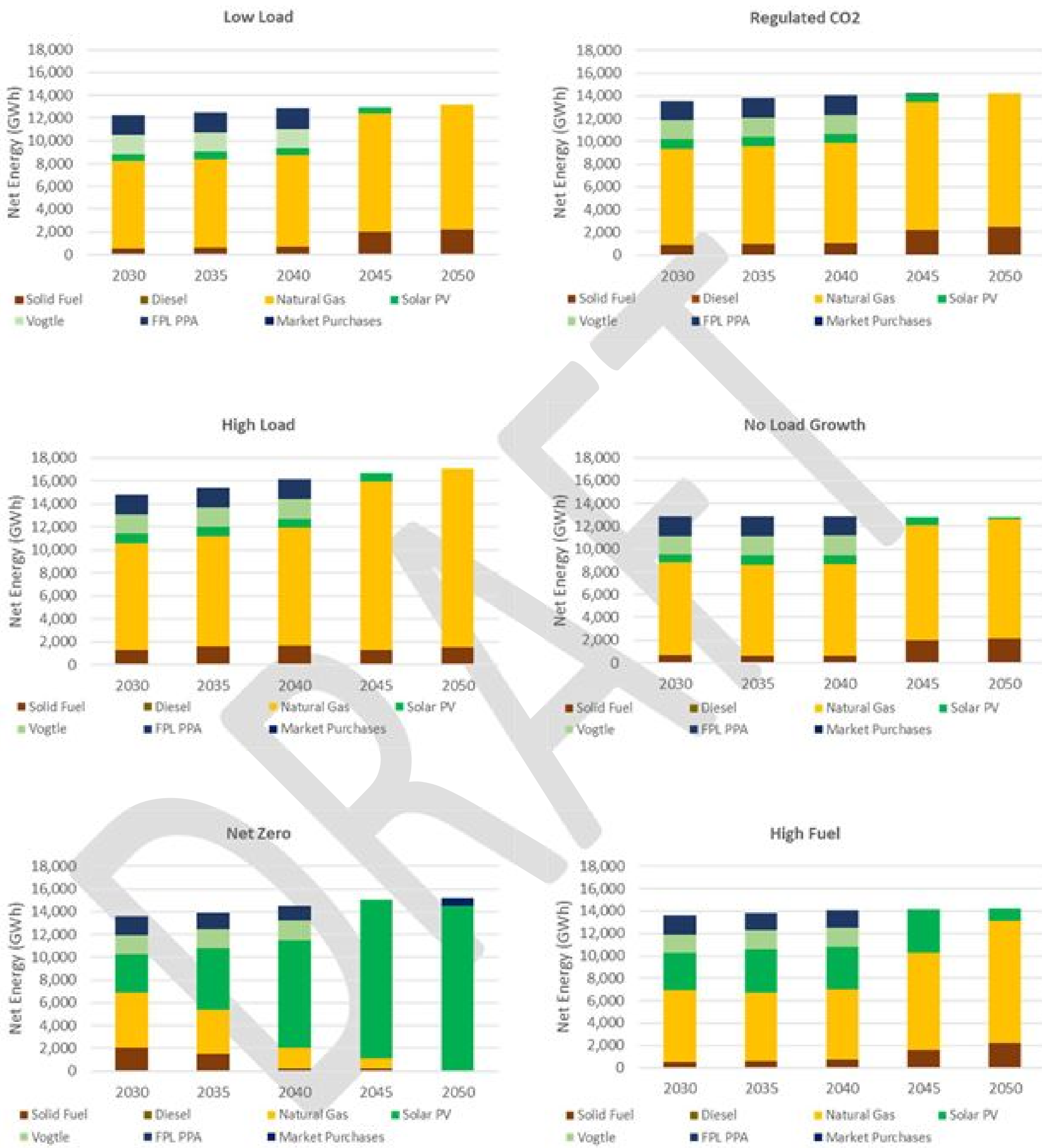


Figure 8-7 Projected Energy Generation for Each Sensitivity



8.2.3 CO_2 Emissions

Summaries of the amount of CO_2 emissions from each generating unit associated with the optimal capacity expansion plan for each scenario and each sensitivity evaluated in this IRP are provided on Figure 8-8 and Figure 8-9, respectively.

These results indicate that, in general, for scenarios and sensitivities that do not include annual targets for percent of generation from renewable and/or clean energy resources (i.e., the Future Net Zero and Supplemental scenarios, and the Net Zero sensitivity), emissions of CO_2 are projected to remain relatively consistent through the 2040 period, followed by an increase when the Vogtle PPAs expire as indicated by the increase in CO_2 emissions in 2045. As a point of reference, CO_2 emissions in the year 2005 were approximately 15,000,000 tons, and the significant decrease in the magnitude of CO_2 emissions shown on Figure 8-8 and Figure 8-9 as compared to 2005 CO_2 emissions illustrates the impact of JEA no longer utilizing various coal-fueled generating units (including Scherer Unit 4 and St. Johns River Power Park Units 1 and 2). Further, the magnitude of the reduction in CO_2 emissions is noteworthy when considering that JEA's system load have grown since 2005, and JEA's is thus projected to serve increased customer energy requirements while simultaneously reducing CO_2 emissions by approximately 66 percent when looking at projected CO_2 emissions for 2030.

Figure 8-8 Forecast CO_2 Emissions for Each Scenario

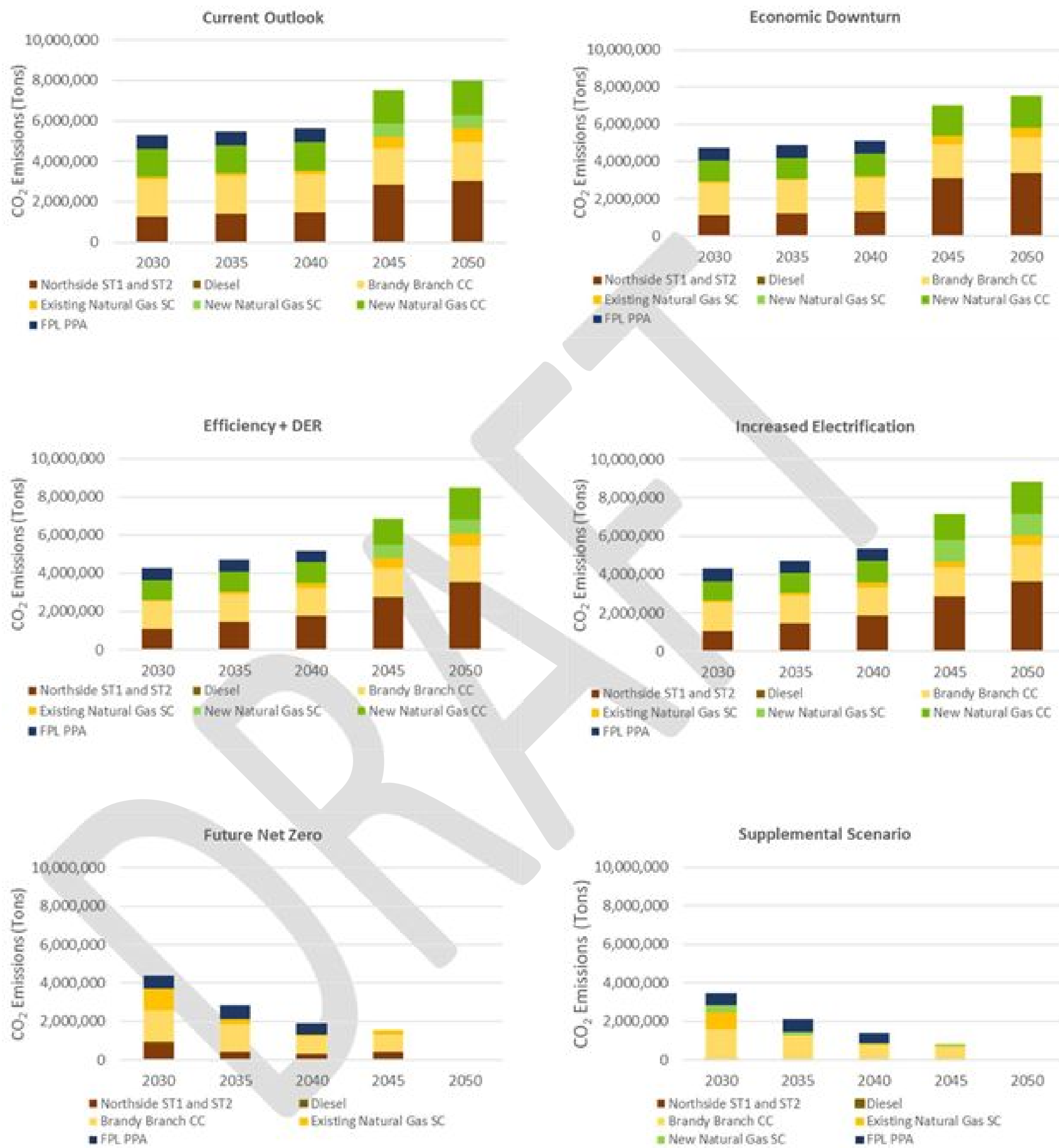


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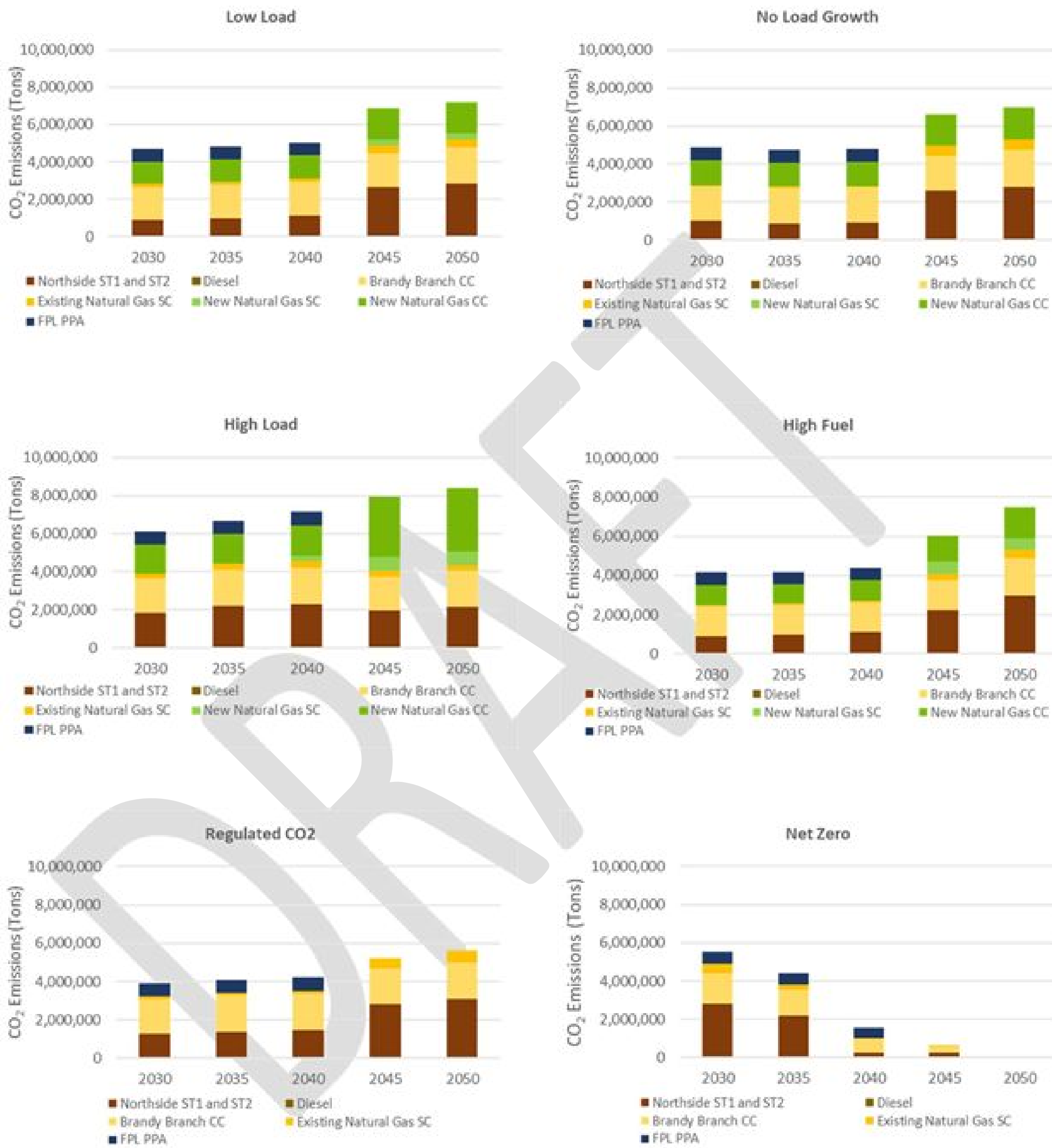
Figure 8-9 Forecast CO_2 Emissions for Each Sensitivity



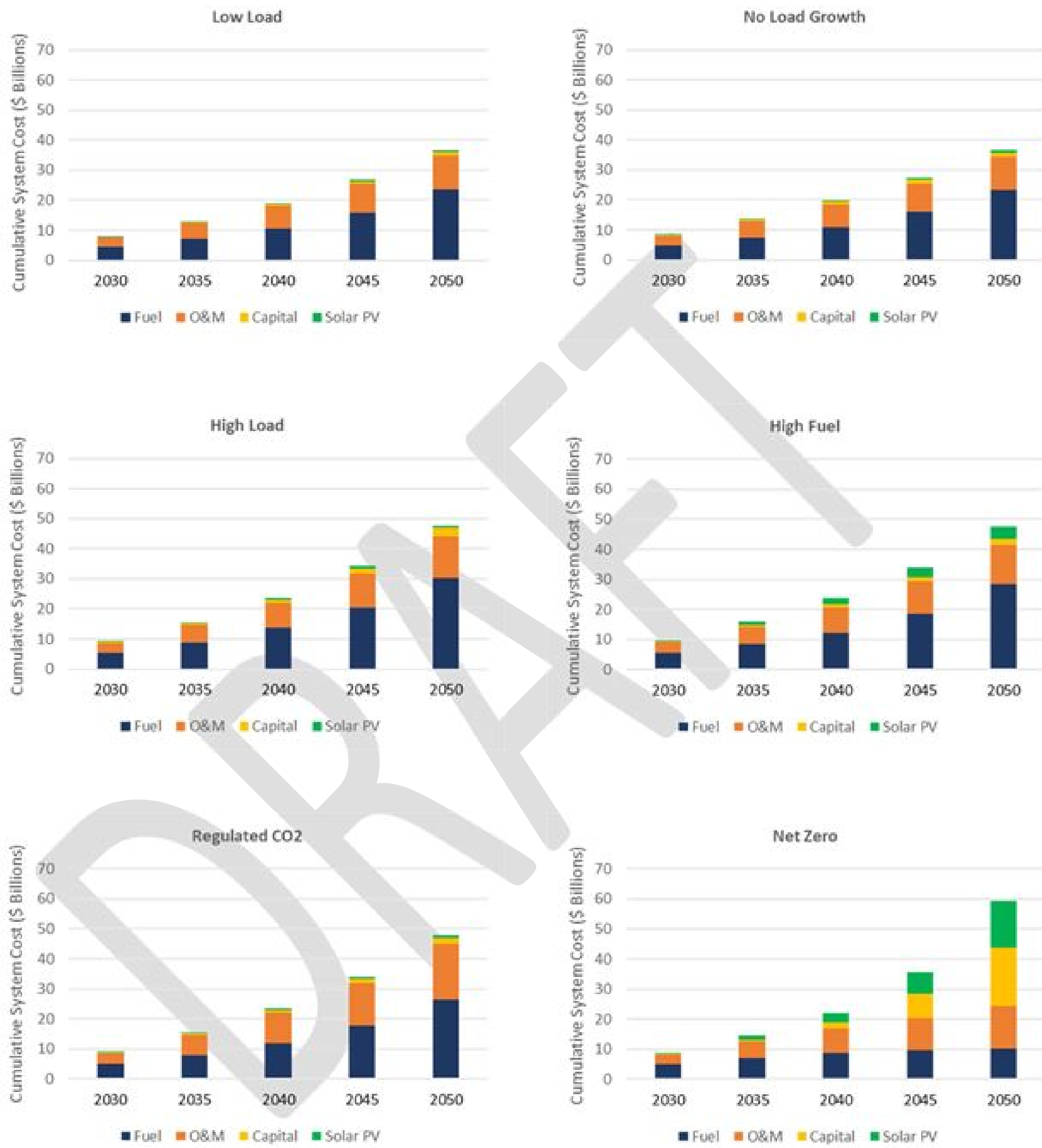
8.2.4 Cumulative System Costs

Summaries of the cumulative system costs associated with the optimal capacity expansion plan for each scenario and sensitivity evaluated in this IRP are provided on Figure 8-10 and Figure 8-11, respectively. The cumulative system costs represent variable production costs as well as fixed O&M costs for existing generating resources and fixed O&M and capital costs for new generating resources, but do not include debt service costs for existing resources as such costs are costs that do not vary by capacity plan.

Important to note is that comparison of cumulative system costs across scenarios or sensitivities may not provide for a meaningful comparison, given differences in variables reflected in the scenarios and sensitivities. However, comparison of the cumulative system costs does provide insight into the costs for JEA to continue to reliably serve its customers energy requirements for certain scenarios or sensitivities being evaluated. For example, the cumulative system cost by 2050 in the Current Outlook scenario is approximately $40 billion, while the cumulative system cost by 2050 for the Net Zero sensitivity (which reflects the same variables as evaluated in the Current Outlook except for a target of no CO_2 emissions by 2050, with a gradual decline in CO_2 emissions between 2030 to 2050) is approximately $60 billion, or approximately 50 percent higher than the cumulative system cost for the Current Outlook scenario by 2050. This differential in cumulative system costs is consistent with the differential between the Supplemental scenario and the Current Outlook scenario, which are similar with respect to most variables but include differences in variables related to increased residential customer-sited renewables and removal of Northside Units 1 and 2 from service in the Supplemental scenario (with the cumulative system cost by 2050 for the Supplemental scenario being approximately 50 percent higher than that of the Current Outlook scenario).

Figure 8-10 Forecast System Costs for Each Scenario

Figure 8-11 Forecast System Costs for Each Sensitivity



9 Conclusions

The modeling results show that under every scenario and sensitivity JEA will need to deploy several hundred MW of new solar PV, energy storage and gas-fired generating resource options over the next 30 years to serve growing customer load and compensate for retirement of Northside Unit 3 and the Vogtle PPAs while maintaining a 15 percent generating reserve margin to ensure continued reliable service.

These results will inform JEA as to the resource options it should implement, particularly those that should be implemented within the next 10 years.

The specific resource options identified by the modeling between 2025 and 2030 under each scenario and sensitivity are summarized in Table 9-1 and Table 9-2, respectively.

Table 9-1 Resources Identified for 2025-2030 by Scenario

	Scenario					
YEAR	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
2025	100 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS		25 MW - 25 MW 1 hr BESS 37.5 MW - 37.5 MW 1 hr BESS 50 MW - 50 MW 1 hr BESS 75 MW - 75 MW 1 hr BESS	50 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS	262 MW - 37.5 MW 1 hr BESS 150 MW - 75 MW 4 hr BESS	225 MW - 75 MW 4 hr BESS
2026	150 MW Solar PV	150 MW Solar PV	300 MW Solar PV	300 MW Solar PV	300 MW Solar PV	300 MW Solar PV
2027						
2028				50 MW - 50 MW 4 hr BESS		
2029	571 MW 1x1 H Class Gas	150 MW Solar PV	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas	95 MW Biomass 150 MW - 75 MW 4 hr BESS	346 MW 1X0 H Class Gas 115 MW 1X0 LMS 100 Gas
2030	150 MW Solar PV	571 MW 1x1 H Class Gas	975 MW Tier1 Solar PV	975 MW Tier1 Solar PV	975 MW Tier 1 Solar PV 262 MW - 37.5 MW 1 hr BESS	975 MW Tier 1 Solar PV 338 MW - 37.5 MW 1 hr BESS

Table 9-2 Resources Identified for 2025-2030 by Sensitivity

	Sensitivity					
YEAR	Low Load	No Growth	High Fuel	Regulated CO2	NetZero	High Load
2025		100 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS	25MW-25MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	25MW-25MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	300 MW - 37.5 MW 1 hr BESS 150 MW - 75 MW 4 hr BESS	150 MW - 37.5 MW 1 hr BESS 100 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS
2026	75 MW Solar PV		300 MW Solar PV	150 MW Solar PV	225 MW Solar PV	300 MW Tier 1 Solar PV
2027					75 MW Solar PV	
2028						
2029	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas		571 MW 1x1 H Class Gas
2030	150 MW Solar PV	225 MW Solar PV	975 MW Tier1 Solar PV	150 MW Solar PV	975 MW Tier 1 Solar PV	

Results show a wide range of resource option types and sizes across the scenarios and sensitivities. Additional filtering is necessary to select a reasonable subset of types and sizes for implementation.

As discussed earlier in this IRP, each scenario represents a possible future that JEA could experience and each sensitivity represents a possible singular event that JEA could experience within the Current Outlook scenario. The future cannot be predicted so it is unreasonable for JEA to select results from one scenario or sensitivity to determine the resource options for near term implementation. It is more reasonable to identify the resource options that appear most frequently across all of the scenarios and sensitivities. In this way, JEA can be confident that the resource options it develops in the near term will become and remain valuable additions to the portfolio regardless of which future occurs.

The resource options that appear most frequently across the scenario and sensitivity results shown above are summarized below ("Near-Term Resources").

- 150 MW BESS (2x75 MW 4 hour)
- 300 MW Solar (4x75 MW Tier 0 Solar PV)
- 571 MW Gas (571 MW 1x1 H Class Gas)
- 975 MW Solar (13x75 MW Tier 1 Solar PV)

It is important to note that this list Near Term Resources is a result of the IRP study only and provides guidance to JEA. It does not reflect further study and determination by JEA of the actual resources that will be implemented.

JEA may need to begin development of these Near-Term Resources as soon as practical. This is particularly true for the 571 MW 1x1 gas-fired resource, which includes a steam turbine component. Any new steam electrical generating facility that generates 75 MW or more requires certification under the Florida

Power Plant Siting Act which would require, among other activities, 1) completion of a site certification process with the Florida Department of Environmental Protection, 2) completion of air quality permitting processes with state and local air quality regulatory agencies and 3) completion of a need determination process with the Florida Public Service Commission.[12] These processes must be completed prior to start of construction and typically take several years to complete. While the ultimate size of the gas-fired resource may change as details are finalized, the process described above are still required for such a combined cycle configuration.

Development of the Tier 1 solar resources should also begin soon given that transmission system upgrades will be required to allow delivery of energy from those resources to load. Transmission system upgrades, particularly new transmission lines and towers, will require successful completion of transmission planning, land acquisition and permitting processes. These processes must be completed prior to start of construction and typically take several years to complete.

The Near-Term Resources also include a significant amount of new BESS in the year 2025. This is because BESS appears in five of the six scenarios and five of the six sensitivities evaluated. It appears in the Future Net Zero and Supplemental scenarios and the High Load and Net Zero Sensitivities due to a potential capacity short fall. In the remainder of the scenarios and sensitivities, it appears due to the benefit of variable cost reduction. These determinations are supported by the fact that the BESS does not appear in Economic Downturn scenario or Low Load sensitivity where both the loads and variable costs are lower. Furthermore, results from additional sensitivity analysis performed on the Current Outlook scenario showed that if PLEXOS is prevented from considering BESS until the early 2030s, total portfolio variable costs actually drop (a savings). The capital cost of these near-term BESS resources is relatively high and therefore further studies on the size and timing of this BESS resource is warranted to determine if and when their benefit becomes more significant.

End of Volume 1

[12] Solar PV facilities that generate 75 MW or more would also require certification under the Florida Power Plant Siting Act; as such, solar PV facilities are typically sized at under 75 MW. For purposes of this IRP, the 75 MW solar PV options serve as a proxy for what may ultimately be sized at just under 75 MW.

2023 Electric Generation Integrated Resource Plan

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List of Acronyms

AACE	Association for the Advancement of Cost Engineering
ABWR	Advanced Boiling Water Reactor
ACC	Air-Cooled Condenser
ACE	Affordable Clean Energy
AFFF	Aqueous Film-Forming Foam
AFS	Axial Fuel Staged
AGP	Advanced Gas Path
ALJ	Administrative Law Judge
AQC	Air Quality Control
ARDP	Advanced Reactor Demonstration Project
ARP	Acid Rain Program
ATI	Array Technologies, Inc.
AWE	Alkaline Water Electrolysis
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BBGS	Brandy Brach Generation Station
BESS	Battery Energy Storage System
BMS	Battery Management System
BOEM	Bureau of Ocean Energy Management
BOP	Balance-of-Plant
BSER	Best System of Emission Reduction
BTA	Best Technology Available
BTU	British Thermal Unit
BWR	Boiling Water Reactor
CAA	Clean Air Act
CBM	Coal Bed Methane
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
CDF	Core Damage Frequency
CEMS	Continuous Emissions Monitoring System
CEQ	Council on Environmental Quality
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFA	Clean Future Act
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CNSC	Canadian Nuclear Safety Commission
CO2	Carbon Dioxide
COD	Chemical Oxygen Demand
COL	Combined Operating License
CPP	Clean Power Plan
CRL	Combustion Residual Leachate
CSAPR	Cross-State Air Pollution Rule
CTG	Combustion Turbine Generator
CWA	Clean Water Act
DLE	Dry Low Emission
DLN	Dry Low Nitrogen Oxide
DOAH	Florida Division of Administrative Hearings
DOD	Depth of Discharge
DOE	Department of Energy
DOI	U.S. Department of Interior
DRR	Data Requirements Rule
DWM	Division of Waste Management
EGU	Electric Generating Unit
ELG	Effluent Limit Guidelines
EON	Energy Options Network
EPA	Environmental Protection Agency
EPC	Engineering Procurement Construction
ERP	Environmental Resource Permitting
ESBWR	Economic Simplified Boiling Water Reactor
ESS	Energy Storage System
FAC	Florida Administrative Code
FCG	Florida Electric Power Coordinating Group

FDEP	Florida Department of Environmental Protection
FDH	Florida Department of Health
FGD	Flue Gas Desulfurization
FMS	Fine-Mesh Screens
FOAK	First of a Kind
FPSC	Florida Public Service Commission
FWC	Florida Fish and Wildlife Conservation Commission
GEC	Greenland Energy Center
GEH	General Electric-Hitachi
GHI	Global Horizontal Irradiance
GMSL	Global mean sea level
HAL	Health Advisory Level
HALEU	High Assay Low-Enriched Uranium
HAP	Hazardous Air Pollutant
HPC	High-Pressure Compressor
HPT	High Pressure Turbine
HRSG	Heat Recovery Steam Generator
HTGR	High Temperature Gas-Cooled Reactor
IGCC	Integrated Gasification Combined Cycle
IMSR	Integral Molten Salt Reactor
IPCC	Intergovernmental Panel on Climate Change
IPT	Intermediate Pressure Turbine
ISO	International Standards Organization
LFA	Lower Floridian Aquifer
LFP	Lithium Iron Phosphate
LHV	Lower Heating Value
LLWR	Large Light Water Reactor
LMO	Lithium Manganese Oxide
LOCA	Loss-of-Coolant Accidents
LPC	Low-Pressure Compressor
LPT	Low-Pressure Turbine
LTO	Lithium Titanate
LTSA	Long-Term Service Agreement
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MDCT	Draft Cooling Tower
MGD	Million Gallons per Day
MMBTU	Metric Million British Thermal Units
MPA	Mitsubishi Power Americas
MSR	Molten Salt Reactor
MVA	Megavolt Amperes
MWE	Megawatt Electric
NAAQS	National Ambient Air Quality Standards
NCA	Lithium Nickel Cobalt Aluminum Oxide
NEF	New Energy Finance
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMC	Lithium Nickel Manganese Cobalt Oxide
NMFS	National Marine Fisheries Service
NOAK	Nth of a Kind
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPM	NuScale Power Module
NRHP	National Register of Historic Places
NSPS	New Source Performance Standards
NSR	New Source Review
NSRDB	National Solar Radiation Database
NWP	Nationwide Permit
OEM	Original Equipment Manufacturer
PCS	Power Conversion System
PEM	Proton Exchange Membrane
PFAS	Per- and Polyfluoroalkyl Substances
PFBS	Perfluorobutane Sulfonic Acid
PFOA	Perfluorooctanoic Acid
PFOS	Perfluorooctane Sulfonic Acid
PM	Particulate Matter
PPSA	Power Plant Siting Act
PSC	Public Service Commission

PSD	Prevention of Significant Deterioration
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RCRA	Resource Conservation and Recovery Act
RGP	Regional General Permit
RICE	Reciprocating Internal Combustion Engine
SAC	Single Annular Combustor
SAT	Single-Axis Trackers
SCADA	Supervisory Control and Data Acquisition
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SHPO	State Historical Preservation Officer
SIP	State Implementation Plan
SMR	Small Modular Reactor
SO2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction
STG	Steam Turbine Generator
THPO	Tribal Historical Preservation Officer
TNC	The Nature Conservancy
TRI	Toxic Release Inventory
TRISO	Tri-Structural Isotropic
TSCA	Toxic Substances Control Act
USACE	U.S. Army Corp of Engineers
USDW	Underground Source of Drinking Water
USEPA	United States Environmental Protection Agency
USFWS	U. S. Fish and Wildlife Service
VDR	Vendor Design Review
VFD	Variable Frequency Drive
WFGD	Wet Flue Gas Desulfurization
WMDCT	Wet Mechanical Draft Cooling Tower
WOTUS	Waters of the United States

A Detailed PLEXOS Modeling Results

Table A-1 - Near Term Capacity Expansion by Scenario

Scenario Analysis - Near Term Build Plans						
Year	**Current Outlook**	**Economic Downturn**	**Efficiency + DER**	**Increased Electrification**	**Future Net Zero**	**Supplemental**
2025	100MW - 50MW 4hr BESS 150MW - 75MW 4hr BESS		25MW - 25MW 1hr BESS 37.5MW - 37.5MW 1hr BESS 50MW - 50MW 1hr BESS 75MW - 75MW 1hr BESS	50MW-50MW 4hr BESS 150MW-75MW 4hr BESS	262MW-37.5MW 1hr BESS 150MW-75MW 4hr BESS	225MW-75MW 4hr BESS
2026	150MW Solar PV	150MW Solar PV	300MW Solar PV	300MW Solar PV	300MW Solar PV	300MW Solar PV
2027						
2028				50MW-50MW 4hr BESS		
2029	571 MW 1x1 H Class Gas	150MW Solar PV	571 MW 1x1 H Class Gas	571MW 1x1 H Class Gas	95MW Biomass 150MW-75MW 4hr BESS	346MW 1X0 H Class Gas 115MW 1X0 LMS 100 Gas
2030	150MW Solar PV	571 MW 1x1 H Class Gas	975MW Tier1 Solar PV	975MW Tier1 Solar PV	975MW Tier1 Solar PV 262MW-37.5MW 1hr BESS	975MW Tier1 Solar PV 338MW-37.5MW 1hr BESS
2031					450MW-75MW 4hr BESS	525MW-75MW 4hr BESS
2032					100MW-50MW 4hr BESS 450MW-75MW 4hr BESS	525MW-75MW 4hr BESS
2033			150MW Tier2 Solar PV	375MW Tier2 Solar PV	300MW Tier2 Solar PV 350MW-50MW 4hr BESS 750MW-75MW 4hr BESS	300MW Tier2 Solar PV 50MW-50MW 4hr BESS 525MW-75MW 4hr BESS

Appendix A – Detailed PLEXOS Modeling Results

Table A-2 - Midterm Capacity Expansion by Scenario

Scenario Analysis – Midterm Build Plans						
Year	**Current Outlook**	**Economic Downturn**	**Efficiency + DER**	**Increased Electrification**	**Future Net Zero**	**Supplemental**
2034					300MW Tier2 Solar PV 550MW-50MW 4hr BESS 600MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2035					675MW Tier2 Solar PV 150MW-50MW 4hr BESS 600MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2036			75MW Tier2 Solar PV	75MW Tier2 Solar PV	75MW Tier2 Solar PV 675MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2037					600MW-75MW 4hr BESS	75MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2038			37.5MW-37.5MW 1hr BESS	75MW-37.5MW 1hr BESS	450MW Tier2 Solar PV 100MW-50MW 4hr BESS 600MW-76MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2039			112MW - 37.5MW 1hr BESS	75MW-37.5MW 1hr BESS	300MW Tier2 Solar PV 50MW-50MW 4hr BESS 600MW-75MW 4hr BESS	75MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2040			75MW Tier2 Solar PV 75MW- 37.5MW 1hr BESS	38MW-37.5MW 1hr BESS	375MW Tier2 Solar PV 350MW-50MW 4hr BESS 600MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2041			75MW Tier2 Solar PV	150MW Tier2 Solar PV 25MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS	300MW Tier2 Solar PV 500MW-50MW 4hr BESS 600MW-75MW 4hr BESS	75MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2042		50MW-25MW 1hr BESS 37.5MW-37.5MW 1hr BESS	236MW 1X0 F Class Gas	346MW 1x0 H Class Gas	400MW-50MW 4hr BESS 675MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS

Appendix A – Detailed PLEXOS Modeling Results

Table A-3 – Long Term Capacity Expansion by Scenario

Scenario Analysis - Long Term Build Plan						
Year	**Current Outlook**	**Economic Downturn**	**Efficiency + DER**	**Increased Electrification**	**Future Net Zero**	**Supplemental**
2043	236 MW 1x0 F Class Gas	25MW - 25MW 1hr BESS	346MW 1X0 H Class Gas	236MW 1x0 F Class Gas	1050MW Tier2 Solar PV 400MW-50MW 4hr BESS 525MW-75MW 4hr BESS	525MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2044	75MW - 37.5MW 1hr BESS	112MW - 37.5MW 1hr BESS			450MW-50MW 4hr BESS 825MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2045	236 MW 1x0 F Class Gas	112MW - 37.5MW 1 hr BESS	50MW - 25MW 1hr BESS 112MW - 37.5MW 1hr BESS 50MW - 50MW 4hr BESS	346MW 1x0 H Class Gas	525MW Tier2 Solar PV 350WM-50MW 4hr BESS 375MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2046		75MW - 75MW 4hr BESS	25MW - 25MW 1hr BESS 50MW - 50MW 4hr BESS		1125MW Tier2 Solar PV 400MW-50MW 4hr BESS 600MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2047	37.5MW - 37.5MW 1hr BESS		75MW-75MW 1hr BESS	25MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS	975MW Tier2 Solar PV 400MW-50MW 4hr BESS 525MW-525MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2048	37.5 MW - 37.5MW 1hr BESS	50MW-50MW 4hr BESS	75MW-25MW 1hr BESS 75MW-75MW 4hr BESS	150MW-75MW 4hr BESS	1050MW Tier2 Solar PV 450MW-50MW 4hr BESS 900MW-75MW 4hr BESS	900MW Tier2 Solar PV 38MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2049	37.5 MW - 37.5MW 1hr BESS	50MW-50MW 4hr BESS		25MW-25MW 1hr BESS	750MW Tier2 Solar PV 125MW-25MW 1hr BESS 225MW-37.5MW 1hr BESS 400MW-50MW 4hr BESS 525MW-75MW 4hr BESS	900MW Tier2 Solar PV 125MW-25MW 1hr BESS 375MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2050	25MW - 25MW1hr BESS	50MW-50MW 4hr BESS	25MW-25MW 1hr BESS	75MW-75MW 4hr BESS	1350MW Tier2 Solar PV 250MW-25MW 1hr BESS 375MW-37.5MW 1hr BESS 650MW-50MW 4hr BESS 600MW-75MW 4hr BESS	95MW Biomass 975MW Tier1 Solar PV 900MW Tier2 Solar PV 250MW-25MW 1hr BESS 375MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2051	25MW - 25MW 1hr BESS 50MW - 50MW 4hr BESS	50MW-50MW 4hr BESS	75MW-75MW 4hr BESS	75MW-75MW 4hr BESS		525MW-75MW 4hr BESS

Appendix A – Detailed PLEXOS Modeling Results

Table A-4 – Near Term Capacity Expansion by Sensitivity

Current Outlook Sensitivities - Near Term Build Plans						
Year	**Low Load**	**No Growth**	**High Fuel**	**Regulated CO_2**	**NetZero**	**High Load**
2025		100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	25MW-25MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	25MW-25MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	300MW-37.5MW 1hr BESS 150MW-75MW 4hr BESS	150MW-37.5MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS
2026	75MW Solar PV		300MW Solar PV	150MW Solar PV	225MW Solar PV	300MW Tier1 Solar PV
2027					75MW Solar PV	
2028						
2029	571MW 1x1 H Class Gas	571MW 1x1 H Class Gas	571MW 1x1 H Class Gas	571MW 1x1 H Class Gas		571MW 1x1 H Class Gas
2030	150MW SolarPV	225MW Solar PV	975MW Tier1 Solar PV	150MW Solar PV	975MW Tier1 Solar PV	
2031					75MW-75MW 4hr BESS	
2032		75MW Solar PV				
2033			300MW Tier2 Solar PV		600MW Tier2 Solar PV 375MW-75MW 4hr BESS	

Appendix A – Detailed PLEXOS Modeling Results

Table A-5 – Midterm Capacity Expansion by Sensitivity

Current Outlook Sensitivities - Midterm Build Plans						
Year	**Low Load**	**No Growth**	**High Fuel**	**Regulated CO_2**	**NetZero**	**High Load**
2034					375MW Tier2 Solar PV	
2035					600MW Tier2 Solar PV	
2036						
2037					75MW Tier2 Solar PV 150MW-75MW 4hr BESS	
2038					75MW Tier2 Solar PV 975MW-75mw 4hr BESS	236MW 1x0 F Class Gas
2039					150MW Tier2 Solar PV 100MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2040					900MW Tier2 Solar PV 450MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2041			150MW Tier2 Solar PV		75MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2042	25MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS				900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	571MW 1x1 H Class Gas

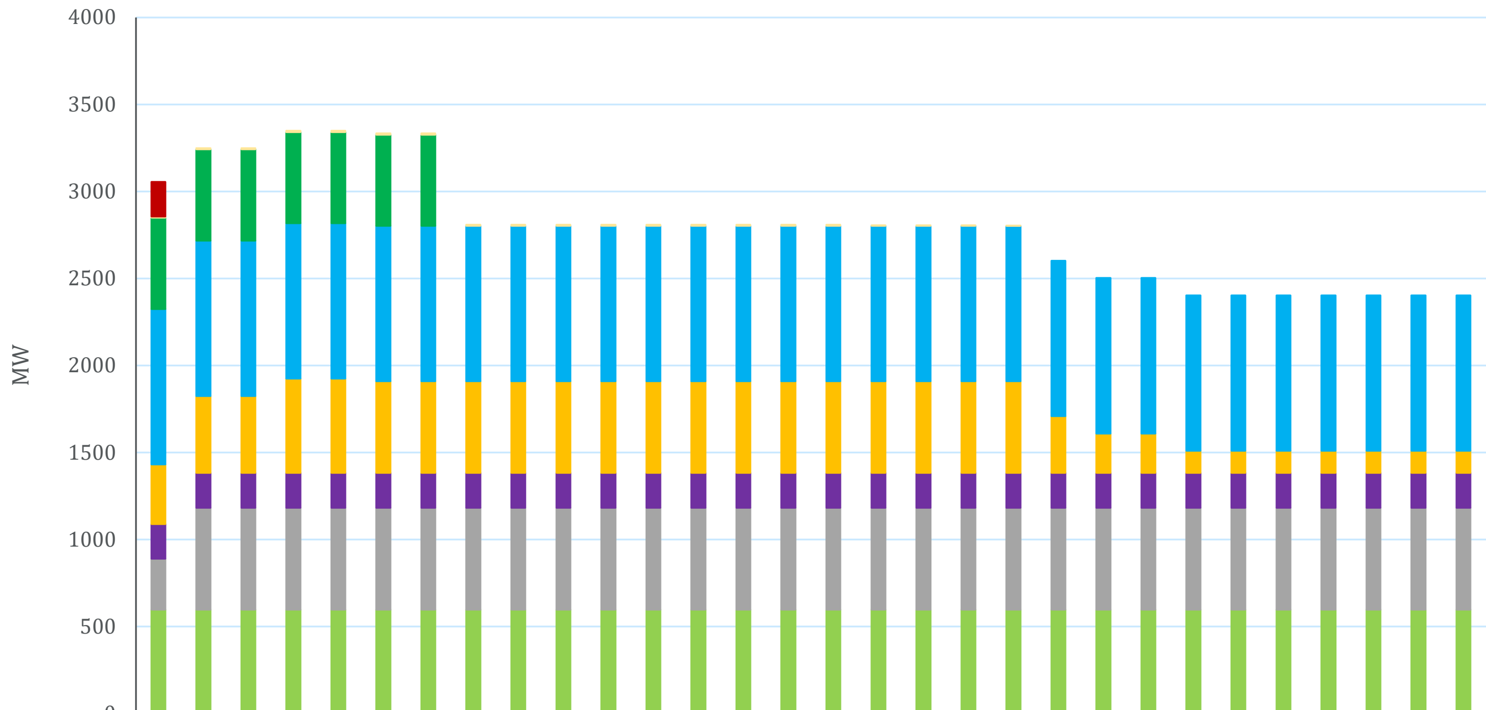
Appendix A – Detailed PLEXOS Modeling Results

Table A-6 – Long Term Capacity Expansion by Sensitivity

Current Outlook Sensitivities - Long Term Build Plans						
Year	**Low Load**	**No Growth**	**High Fuel**	**Regulated CO_2**	**NetZero**	**High Load**
2043	38MW-37.5MW 1hr BESS				900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2044	112MW-37.5MW 1hr BESS		25MW-25MW 1hr BESS 75MW-37.5MW 1hr BESS	25MW-25MW 1hr BESS 75MW-37.5MW 1hr BESS	900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2045	236MW 1X0 F Class Gas	150MW-37.5MW 1hr BESS	471MW 1x0 F Class Gas	471MW 1x0 F Class Gas	900MW Tier2 Solar PV 388MW-37.5MW 1hr BESS 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	346MW 1x0 H Class Gas 75MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS
2046					900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2047					900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	50MW-50MW 4hr BESS
2048	25MW-25MW 1hr BESS		38MW-37.5MW 1hr BESS	38MW-37.5MW 1hr BESS	975MW Tier2 Solar PV 38MW-37.5MW 1hr BESS 200MW-50MW 4hr BESS 150MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2049	50MW-50MW 4hr BESS		38MW-37.5MW 1hr BESS	38MW-37.5MW 1hr BESS	900MW Tier2 Solar PV 375MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 375MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2050	50MW-50MW 4hr BESS		38MW-37.5MW 1hr BESS	50MW-50MW 4hr BESS	95MW Biomass 450MW Tier2 Solar PV 38MW-37.5MW 1hr BESS 700MW-50MW 4hr BESS 450MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2051	50MW-50MW 4hr BESS		75MW-75MW 4hr BESS	38MW-37.5MW 1hr BESS 50MW-50MW 4hr BESS	75MW-75MW 4hr BESS	75MW-75MW 4hr BESS

Appendix A – Detailed PLEXOS Modeling Results

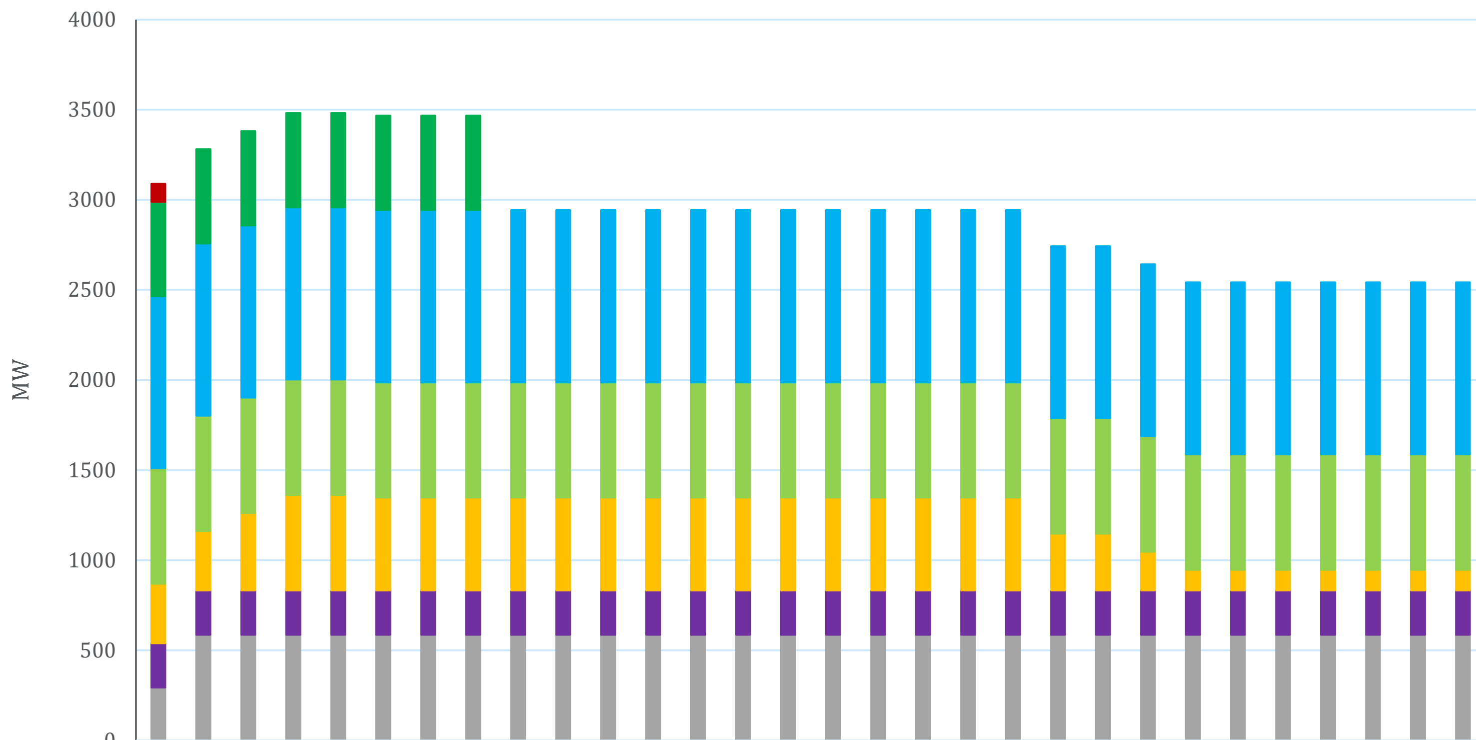
Figure A-1 - Baseline Annual Firm Capacity (August) without Capacity Additions



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
BBCC 2x1	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596

Appendix A – Detailed PLEXOS Modeling Results

Figure A-2 - Baseline Annual Firm Capacity (January) without Capacity Additions

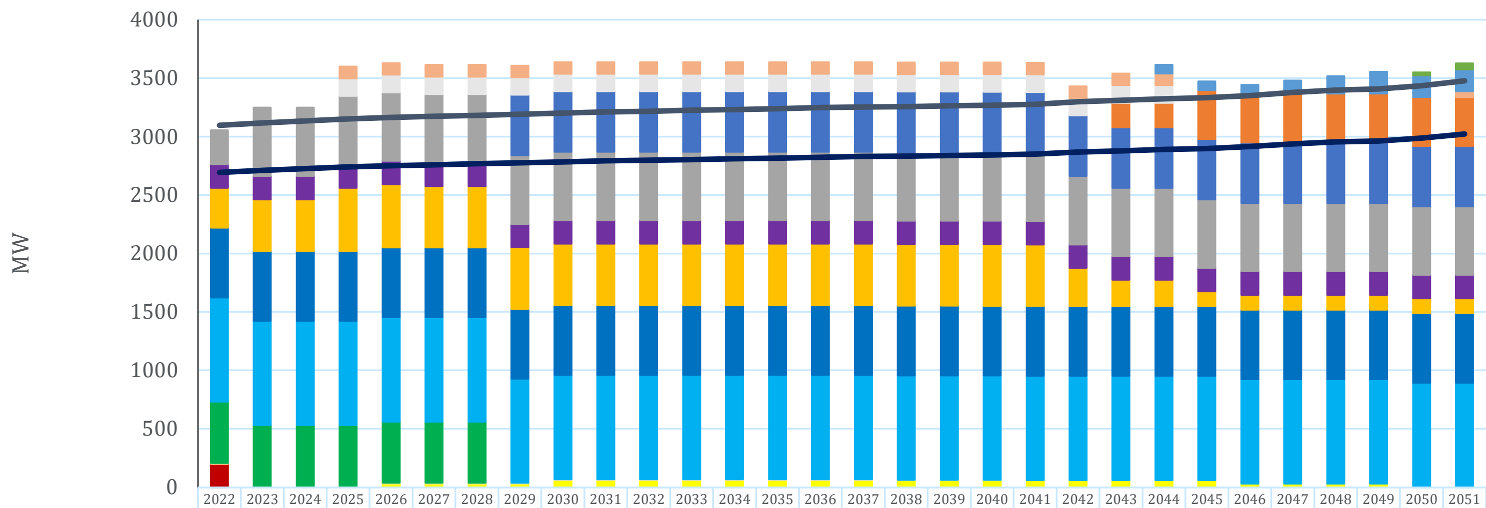


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
BBCC 2x1	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
BBCC 2x1	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586

Appendix A – Detailed PLEXOS Modeling Results

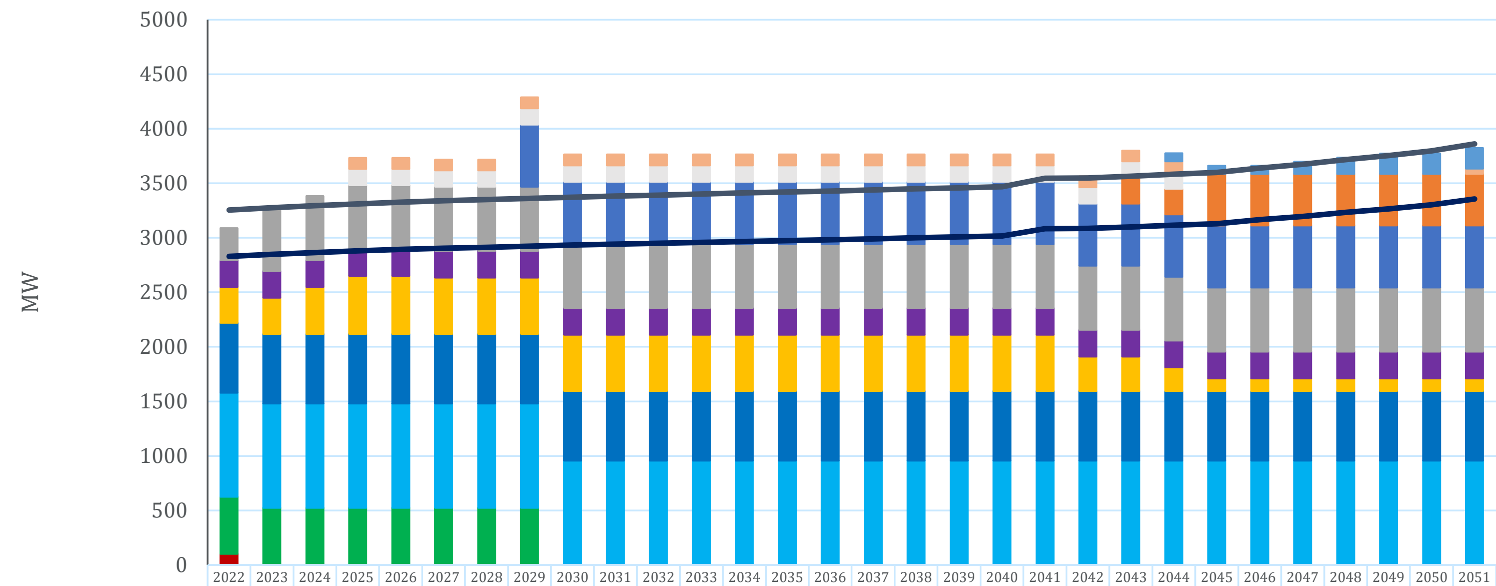
Figure A-3 - Current Outlook Scenario – Annual Firm Capacity (August)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	50
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	113	150	188	188	188
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	50
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	209	209	417	417	417	417	417	417	417
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	0	0	0	0	30	30	30	30	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	30	30	30	30	0	0
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2710	2726	2740	2751	2759	2767	2774	2783	2792	2797	2804	2809	2815	2824	2829	2832	2838	2841	2849	2868	2878	2889	2897	2914	2937	2954	2963	2987	3024
Peak + 15%	3097	3116	3135	3151	3163	3173	3182	3190	3200	3210	3216	3224	3230	3237	3247	3253	3256	3264	3268	3276	3299	3310	3322	3331	3351	3378	3398	3407	3435	3477

Appendix A – Detailed PLEXOS Modeling Results

Figure A-4 - Current Outlook Scenario – Annual Firm Capacity (January)

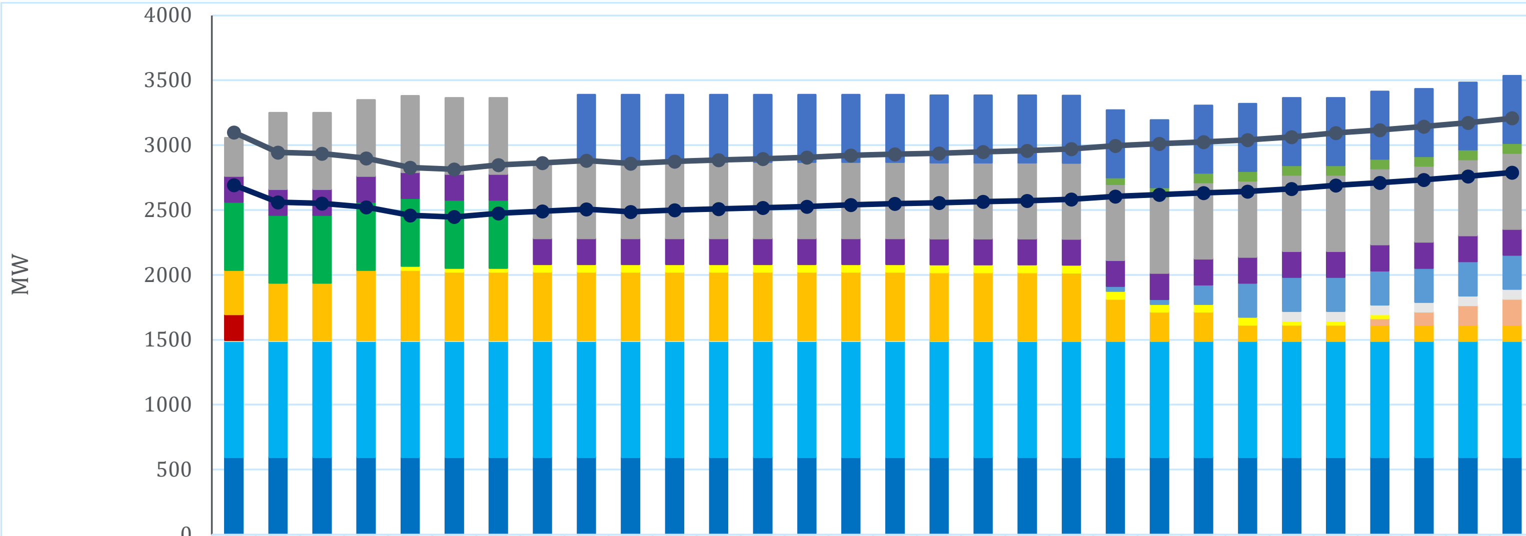


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2848	2865	2879	2893	2904	2913	2924	2933	2941	2949	2958	2966	2974	2982
Peak + 15%	3255	3275	3295	3311	3327	3340	3350	3362	3373	3382	3391	3402	3411	3420	3429

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
37.5 MW 1hr BESS	0	0	0	0	0	0	0	75	75	75	113	150	188	188	188
50 MW 4hr BESS	100	100	100	100	100	100	100	100	0	0	0	0	0	0	50
75 MW 4hr BESS	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
7F.05 1x0_2	0	0	0	0	0	0	236	236	471	471	471	471	471	471	471
7HA.02 1x1	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2991	3000	3007	3016	3083	3086	3100	3116	3130	3165	3195	3232	3264	3302	3358
Peak + 15%	3440	3450	3458	3468	3546	3549	3564	3583	3599	3640	3675	3717	3754	3798	3862

Appendix A – Detailed PLEXOS Modeling Results

Figure A-5 - Economic Downturn Scenario – Annual Firm Capacity (August)

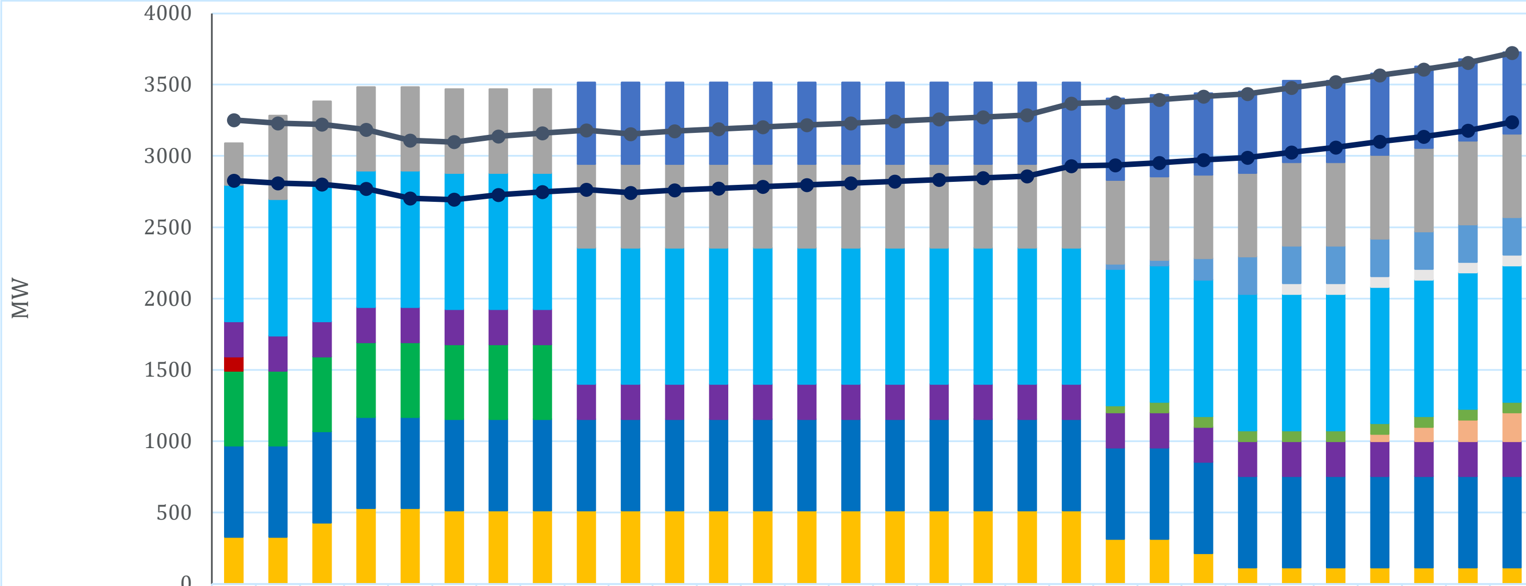


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
7HA.02 1x1	0	0	0	0	0	0	0	0	518	518	518	518	518	518	518
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar SSOs	0	0	0	0	30	30	30	60	60	60	60	60	60	60	60
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Peak	2693	2559	2552	2521	2458	2447	2475	2490	2505	2485	2499	2508	2516	2526	2539
Peak + 15%	3097	2943	2934	2899	2827	2815	2846	2863	2881	2858	2874	2884	2894	2905	2920

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
7HA.02 1x1	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
25 MW 1hr BESS	0	0	0	0	0	50	75	75	75	75	75	75	75	75	75
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
37.5 MW 1hr BESS	0	0	0	0	0	38	38	150	263	263	263	263	263	263	263
75 MW 4hr BESS	0	0	0	0	0	0	0	0	0	75	75	75	75	75	75
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar SSOs	60	60	60	60	60	60	60	60	60	30	30	30	0	0	0
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	50	100	150	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Peak	2549	2555	2564	2571	2582	2605	2619	2631	2643	2663	2690	2710	2734	2759	2789
Peak + 15%	2931	2938	2949	2956	2969	2996	3011	3025	3039	3062	3094	3116	3144	3173	3208

Appendix A – Detailed PLEXOS Modeling Results

Figure A-6 - Economic Downturn Scenario – Annual Firm Capacity (January)

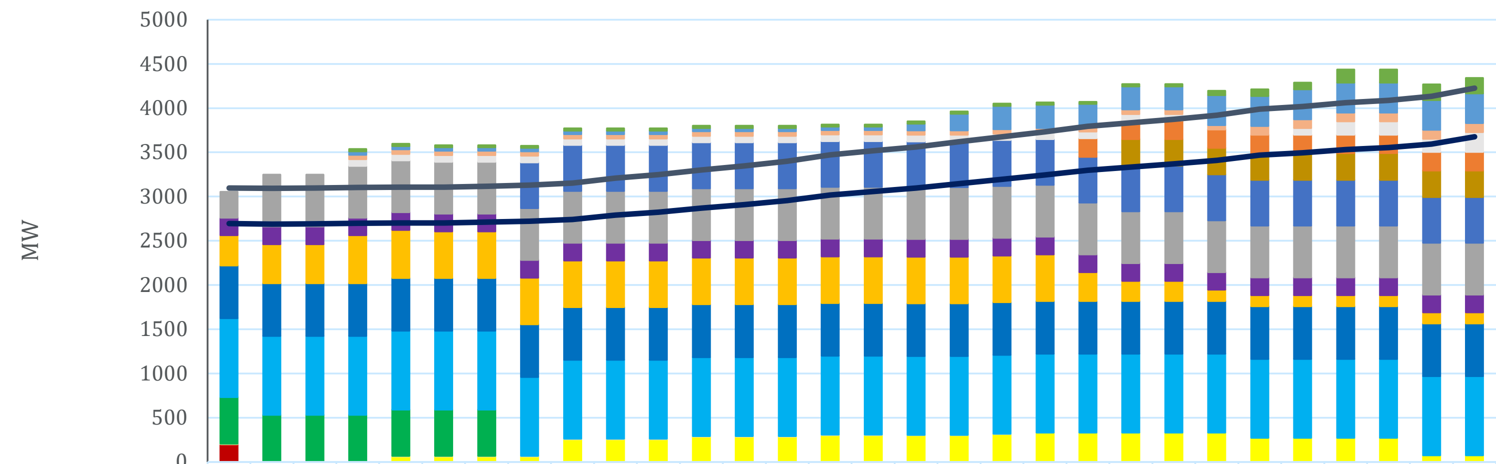


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
7HA.02 1x1	0	0	0	0	0	0	0	0	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Peak	2827	2808	2801	2769	2703	2694	2729	2747	2765	2743	2760	2772	2785	2797	2809
Peak + 15%	3251	3229	3221	3185	3108	3099	3138	3159	3179	3154	3174	3188	3202	3216	3230

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
7HA.02 1x1	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
37.5 MW 1hr BESS	0	0	0	0	0	38	38	150	263	263	263	263	263	263	263
75 MW 4hr BESS	0	0	0	0	0	0	0	0	0	75	75	75	75	75	75
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
25 MW 1hr BESS	0	0	0	0	0	50	75	75	75	75	75	75	75	75	75
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	50	100	150	200
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Peak	2821	2834	2845	2857	2929	2936	2952	2971	2988	3025	3059	3101	3135	3178	3238
Peak + 15%	3244	3259	3272	3286	3368	3376	3395	3417	3436	3479	3518	3566	3606	3654	3724

Appendix A – Detailed PLEXOS Modeling Results

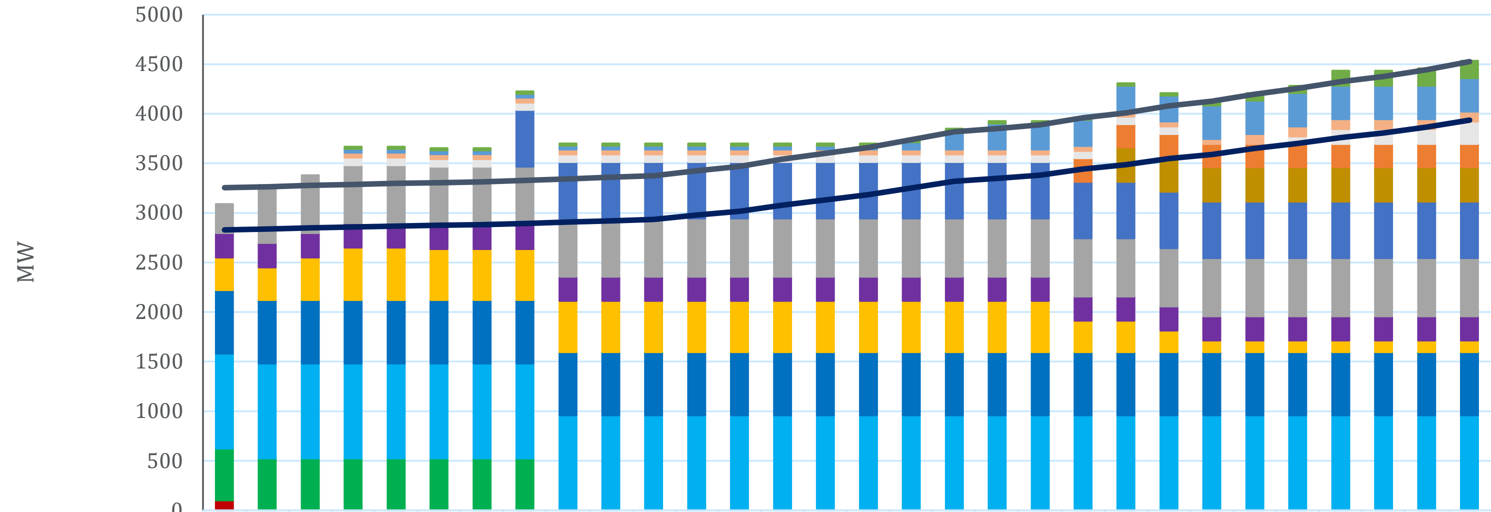
Figure A-7 - Efficiency + DER Scenario – Annual Firm Capacity (August)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	50	75	75	150	150	175	175
37.5 MW 1hr BESS	0	0	0	38	38	38	38	38	38	38	38	38	38	38	38	38	75	188	263	263	263	263	263	338	338	338	338	338	338	338
50 MW 4hr BESS	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	100	100	100	100	100	100
75 MW 4hr BESS	0	0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	0	0	75	150	150	150	225
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	209	209	209	209	209	209	209	209	209	209
7HA.02 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	0	0	0	0	60	60	60	60	255	255	255	285	285	285	300	300	300	300	315	330	330	330	330	330	270	270	270	270	75	75
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2690	2692	2698	2701	2702	2710	2722	2741	2789	2823	2869	2909	2955	3018	3058	3097	3147	3196	3244	3299	3333	3369	3408	3467	3495	3532	3555	3594	3677
Peak + 15%	3097	3093	3096	3103	3107	3108	3116	3130	3153	3207	3247	3299	3345	3399	3471	3517	3562	3619	3675	3731	3793	3833	3874	3919	3987	4020	4062	4089	4133	4229

Appendix A – Detailed PLEXOS Modeling Results

Figure A-8 - Efficiency + DER Scenario – Annual Firm Capacity (January)

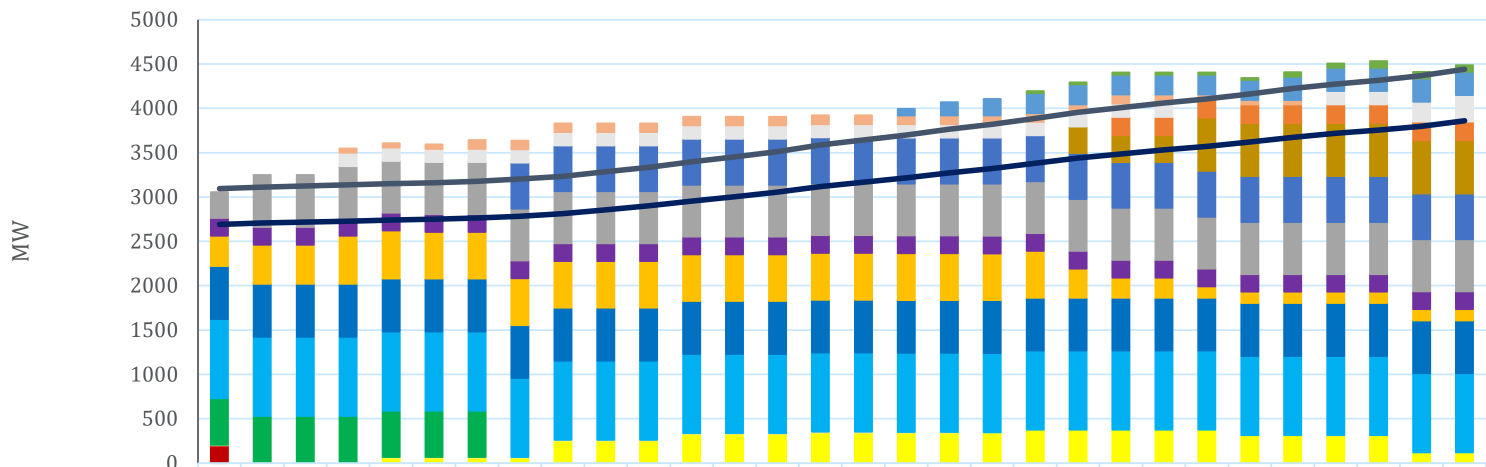


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
25 MW 1hr BESS	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	38	38	38	38	38	38	38	38	38	38	38	38
50 MW 4hr BESS	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50
75 MW 4hr BESS	0	0	0	75	75	75	75	75	75	75	75	75	75	75	75
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2837	2850	2859	2867	2875	2882	2894	2908	2921	2935	2979	3016	3079	3132
Peak + 15%	3255	3263	3277	3288	3298	3306	3314	3328	3344	3359	3375	3426	3468	3541	3602

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	25	25	25	25	25	25	25	25	50	75	75	150	150	175	175
37.5 MW 1hr BESS	38	75	188	263	263	263	263	263	338	338	338	338	338	338	338
50 MW 4hr BESS	50	50	50	50	50	50	50	50	50	100	100	100	100	100	100
75 MW 4hr BESS	75	75	75	75	75	75	75	75	0	0	75	150	150	150	225
7F.05 1x0_2	0	0	0	0	0	236	236	236	236	236	236	236	236	236	236
7HA.02 1x0_2	0	0	0	0	0	0	346	346	346	346	346	346	346	346	346
7HA.02 1x1	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	3183	3251	3319	3348	3381	3443	3487	3548	3590	3650	3700	3760	3807	3866	3938
Peak + 15%	3660	3738	3817	3850	3888	3959	4010	4081	4128	4198	4255	4324	4378	4446	4529

Appendix A – Detailed PLEXOS Modeling Results

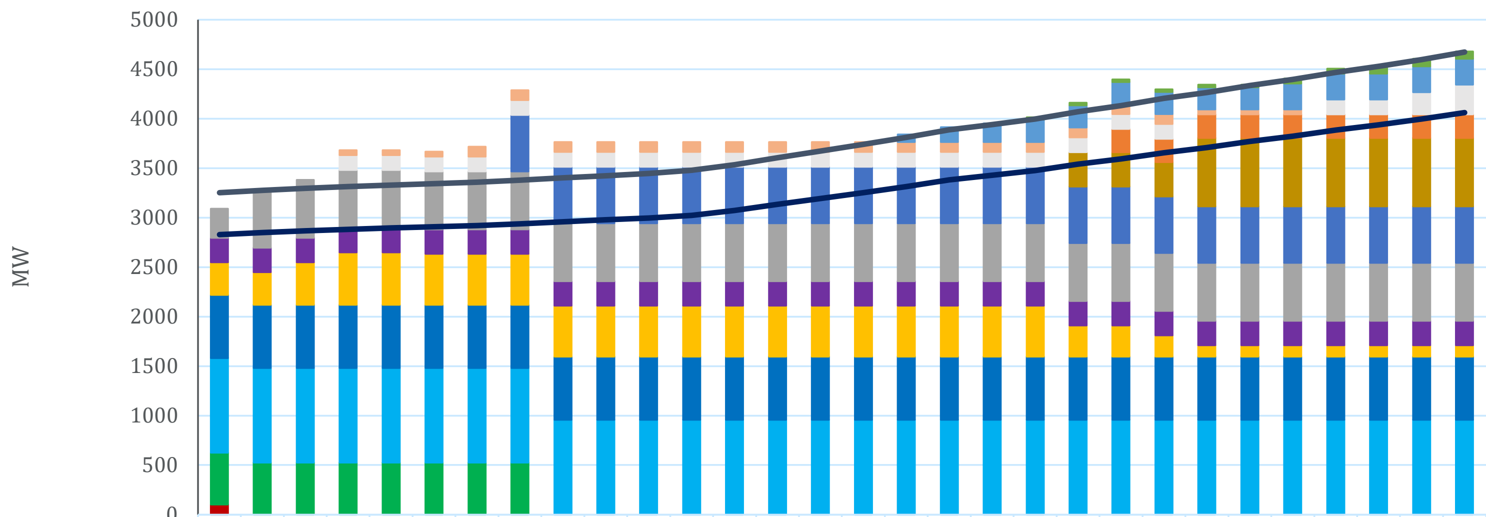
Figure A-9 - Increased Electrification Scenario – Annual Firm Capacity (August)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	50	50	75	75	75
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	150	188	225	225	225	225	225	225	263	263	263	263	263
50 MW 4hr BESS	0	0	0	50	50	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	50	50	50	0	0	0	0
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0	150	150	225	300
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	209	209	209	209	209	209	209	209	209
7HA.02 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300	300	600	600	600	600	600	600	600
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	0	0	0	0	60	60	60	60	255	255	255	330	330	330	345	345	345	345	345	375	375	375	375	375	315	315	315	315	120	120
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2706	2716	2729	2740	2749	2764	2785	2812	2856	2901	2953	3002	3055	3118	3168	3218	3273	3322	3381	3438	3484	3530	3571	3620	3673	3718	3754	3798	3862
Peak + 15%	3097	3112	3123	3138	3151	3161	3178	3202	3234	3284	3336	3396	3452	3513	3586	3643	3700	3764	3821	3888	3954	4007	4060	4107	4163	4224	4275	4317	4368	4441

Appendix A – Detailed PLEXOS Modeling Results

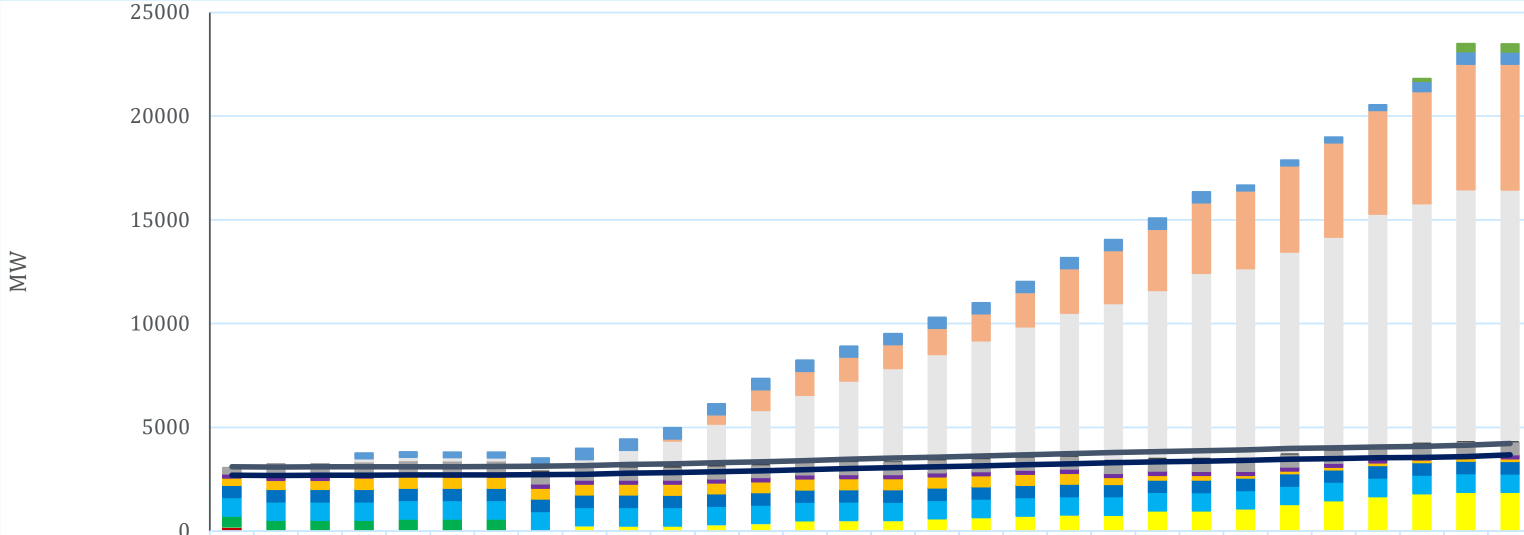
Figure A-10 - Increased Electrification Scenario – Annual Firm Capacity (January)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	50	50	75	75	75
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	150	188	225	225	225	225	225	225	263	263	263	263	263
50 MW 4hr BESS	0	0	0	50	50	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	50	50	50	0	0	0	0
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0	150	150	225	300
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	236	236	236	236	236	236	236	236	236
7HA.02 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	692	692	692	692	692	692	692
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2849	2866	2881	2896	2908	2921	2939	2958	2977	2996	3024	3073	3136	3194	3251	3315	3381	3428	3476	3539	3593	3656	3707	3769	3824	3884	3937	3996	4064
Peak + 15%	3255	3276	3296	3314	3330	3345	3359	3379	3402	3424	3446	3477	3534	3606	3673	3739	3812	3888	3942	3998	4070	4132	4204	4263	4334	4397	4466	4528	4596	4673

Appendix A – Detailed PLEXOS Modeling Results

Figure A-11 - Future Net Zero Scenario – Annual Firm Capacity (August)

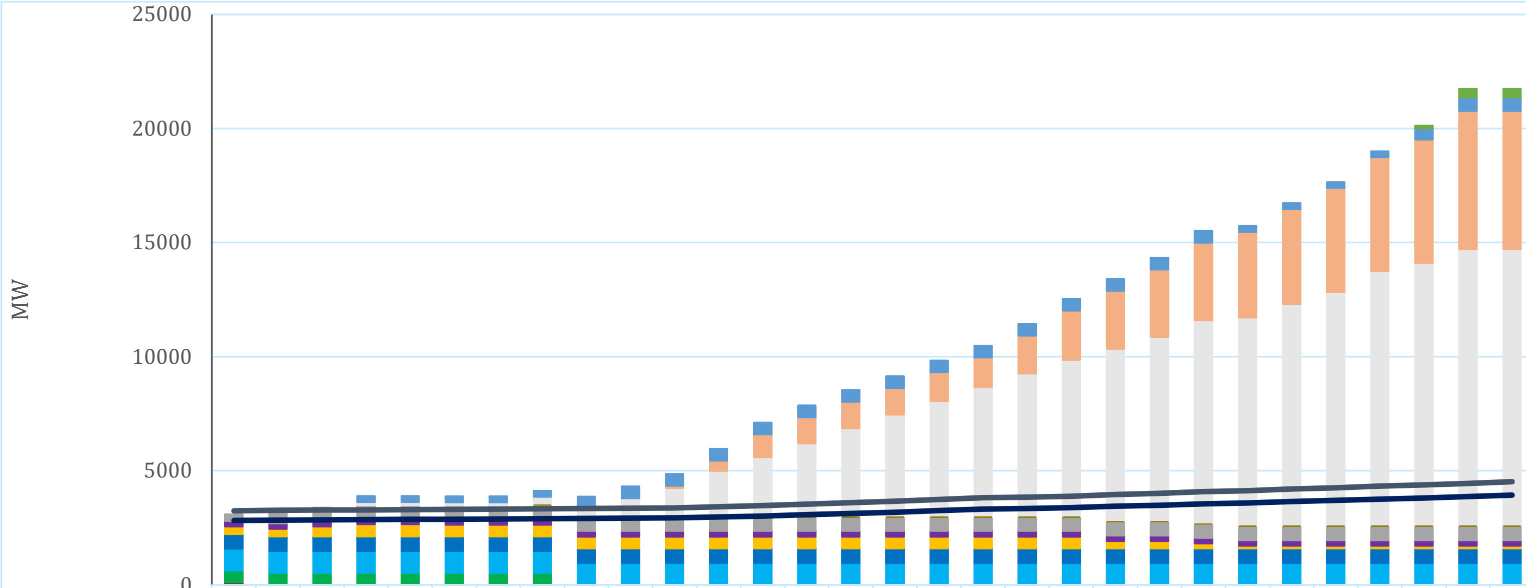


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37.5 MW 1hr BESS	0	0	0	263	263	263	263	263	525	525	525	525	525	525	525
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	100	450	1000	1150	1150
75 MW 4hr BESS	0	0	0	150	150	150	150	300	300	750	1200	1950	2550	3150	3825
BioMass	0	0	0	0	0	0	0	95	95	95	95	95	95	95	95
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Solar SSOs	0	0	0	0	60	60	59	59	253	252	250	309	367	500	512
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2690	2692	2698	2701	2702	2710	2722	2741	2789	2823	2869	2909	2955	3018
Peak + 15%	3097	3093	3096	3103	3107	3108	3116	3130	3153	3207	3247	3299	3345	3399	3471

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	125	375	375
37.5 MW 1hr BESS	525	525	525	525	525	525	525	525	263	263	263	263	488	600	600
50 MW 4hr BESS	1150	1250	1300	1650	2150	2550	2950	3400	3750	4150	4550	5000	5400	6050	6050
75 MW 4hr BESS	4425	5025	5625	6225	6825	7500	8025	8850	9075	9675	10200	11100	11475	12075	12075
BioMass	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	510	597	654	725	781	777	982	977	1077	1286	1474	1676	1817	1887	1877
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	3058	3097	3147	3196	3244	3299	3333	3369	3408	3467	3495	3532	3555	3594	3677
Peak + 15%	3517	3562	3619	3675	3731	3793	3833	3874	3919	3987	4020	4062	4089	4133	4229

Appendix A – Detailed PLEXOS Modeling Results

Figure A-12 - Future Net Zero Scenario – Annual Firm Capacity (August)

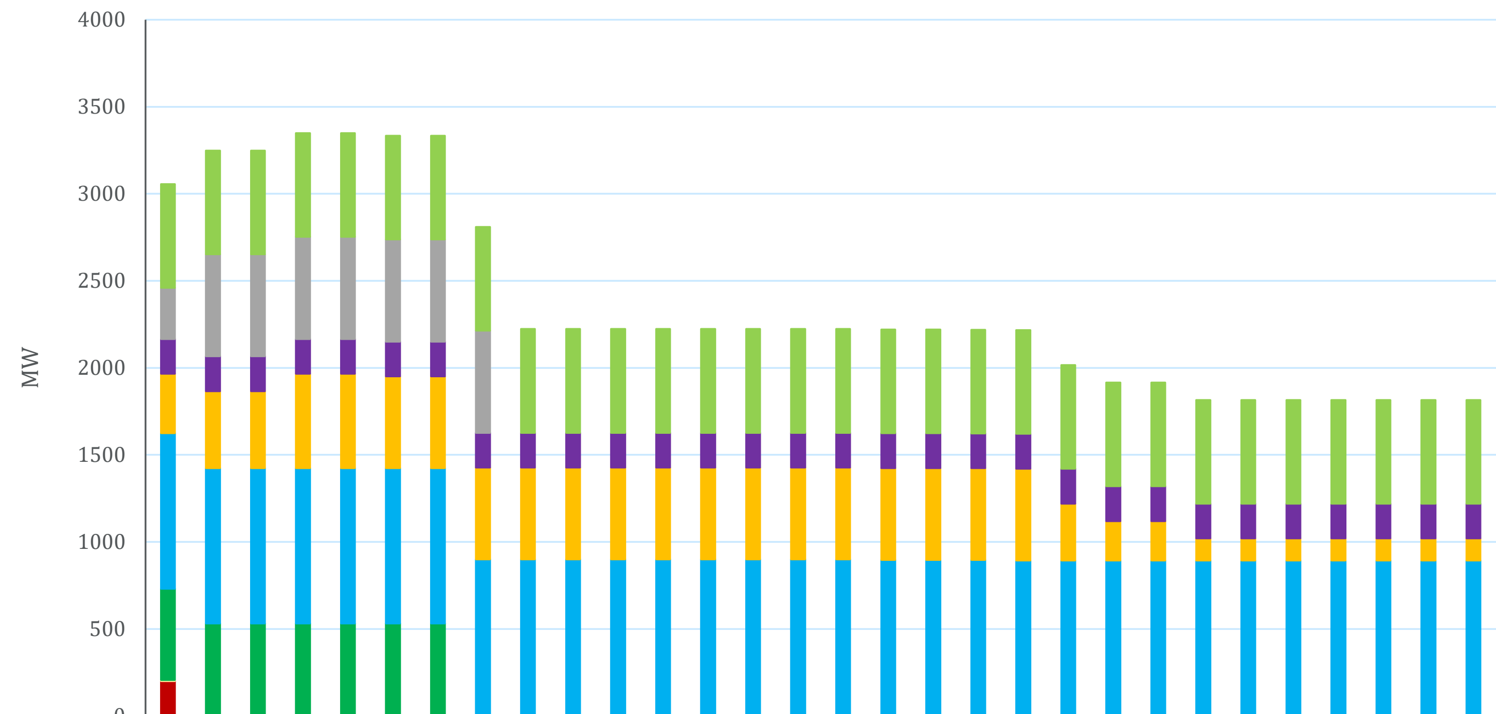


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37.5 MW 1hr BESS	0	0	0	263	263	263	263	263	525	525	525	525	525	525	525
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	100	450	1000	1150	1150
75 MW 4hr BESS	0	0	0	150	150	150	150	300	300	750	1200	1950	2550	3150	3825
BioMass	0	0	0	0	0	0	0	95	95	95	95	95	95	95	95
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2837	2850	2859	2867	2875	2882	2894	2908	2921	2935	2979	3016	3079	3132
Peak + 15%	3255	3263	3277	3288	3298	3306	3314	3328	3344	3359	3375	3426	3468	3541	3602

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	125	375	375
37.5 MW 1hr BESS	525	525	525	525	525	525	525	525	263	263	263	263	488	600	600
50 MW 4hr BESS	1150	1250	1300	1650	2150	2550	2950	3400	3750	4150	4550	5000	5400	6050	6050
75 MW 4hr BESS	4425	5025	5625	6225	6825	7500	8025	8850	9075	9675	10200	11100	11475	12075	12075
BioMass	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	3183	3251	3319	3348	3381	3443	3487	3548	3590	3650	3700	3760	3807	3866	3938
Peak + 15%	3660	3738	3817	3850	3888	3959	4010	4081	4128	4198	4255	4324	4378	4446	4529

Appendix A – Detailed PLEXOS Modeling Results

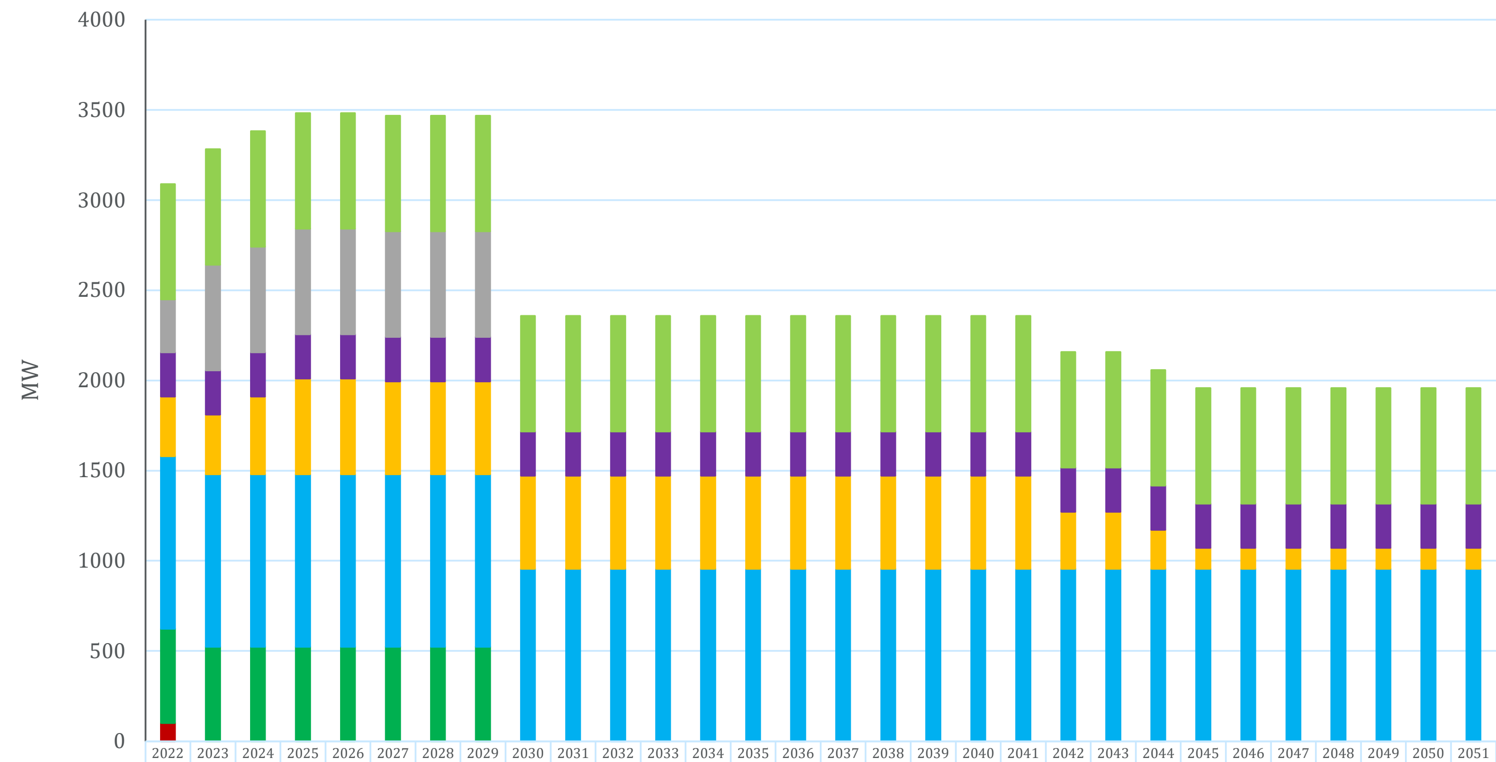
Figure A-13 - Supplemental Scenario – Annual Firm Capacity (August) without Capacity Addition



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
BBCC 2x1	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Coal STs	293	586	586	586	586	586	586	586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix A – Detailed PLEXOS Modeling Results

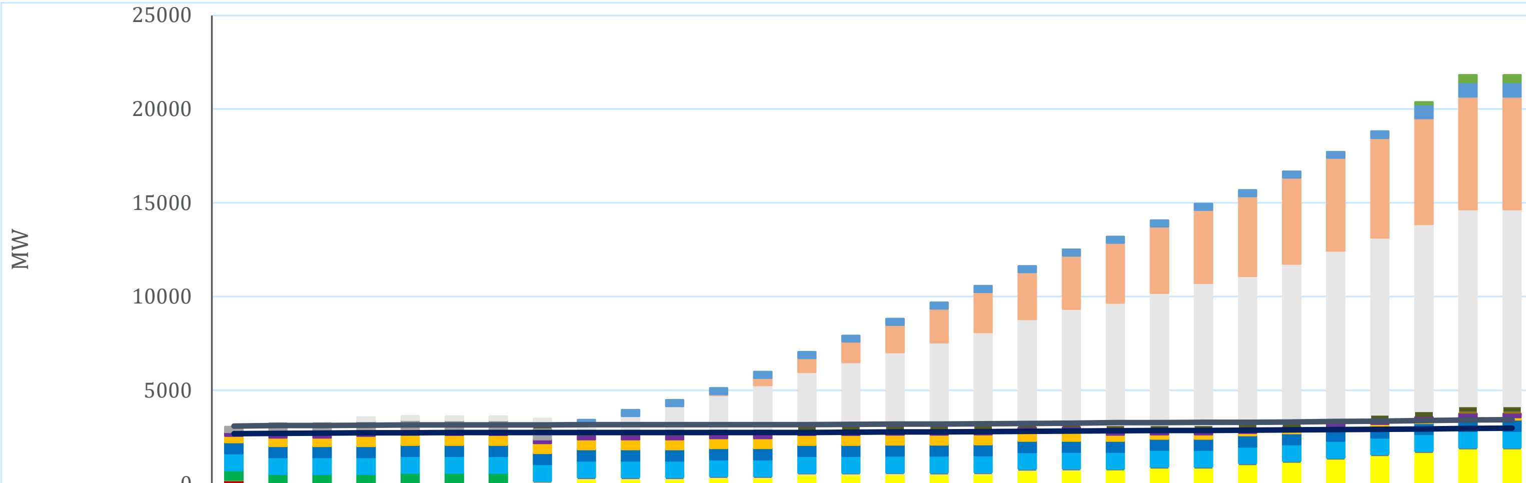
Figure A-14 - Supplemental Scenario – Annual Firm Capacity (January) without Capacity Addition



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
BBCC 2x1	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Coal STs	293	586	586	586	586	586	586	586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix A – Detailed PLEXOS Modeling Results

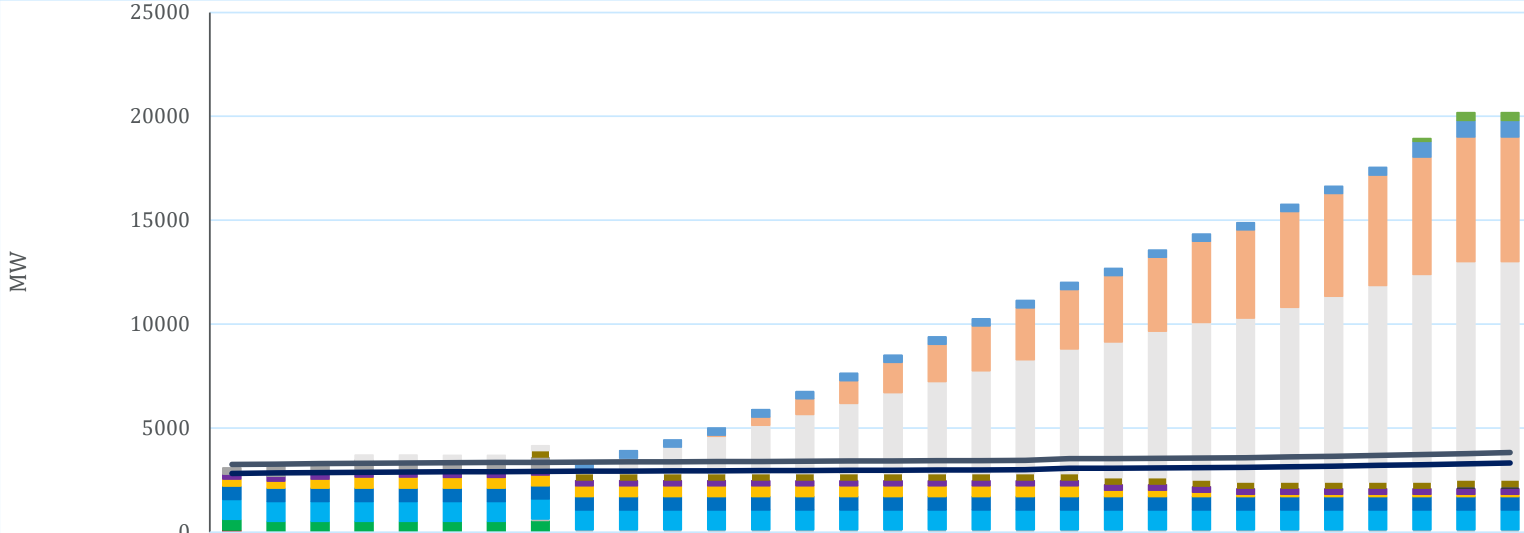
Figure A-15 - Supplemental Scenario – Annual Firm Capacity (August)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	125	375	375
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	375	750	788	788
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	50	400	750	1100	1450	1800	2150	2500	2850	3200	3550	3900	4250	4600	4950	5300	5650	6000	6000
75 MW 4hr BESS	0	0	0	225	225	225	225	225	225	750	1275	1800	2325	2850	3375	3900	4425	4950	5475	6000	6525	7050	7575	7875	8400	8925	9450	9975	10500	10500
7HA.02 1x0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	95	95
Coal STs	293	586	586	586	586	586	586	586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
LMS100 PA+ 1x0	0	0	0	0	0	0	0	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	0	0	0	0	60	60	60	60	255	255	255	315	315	495	495	510	510	525	705	720	720	825	825	1005	1125	1305	1485	1665	1845	1845
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2706	2716	2727	2734	2739	2742	2744	2746	2749	2748	2750	2750	2751	2767	2773	2783	2796	2806	2821	2840	2848	2858	2864	2880	2901	2918	2939	2962	2984
Peak + 15%	3097	3112	3123	3136	3144	3150	3154	3156	3158	3161	3160	3162	3162	3164	3183	3189	3201	3216	3227	3244	3266	3275	3286	3294	3312	3336	3356	3380	3406	3432

Appendix A – Detailed PLEXOS Modeling Results

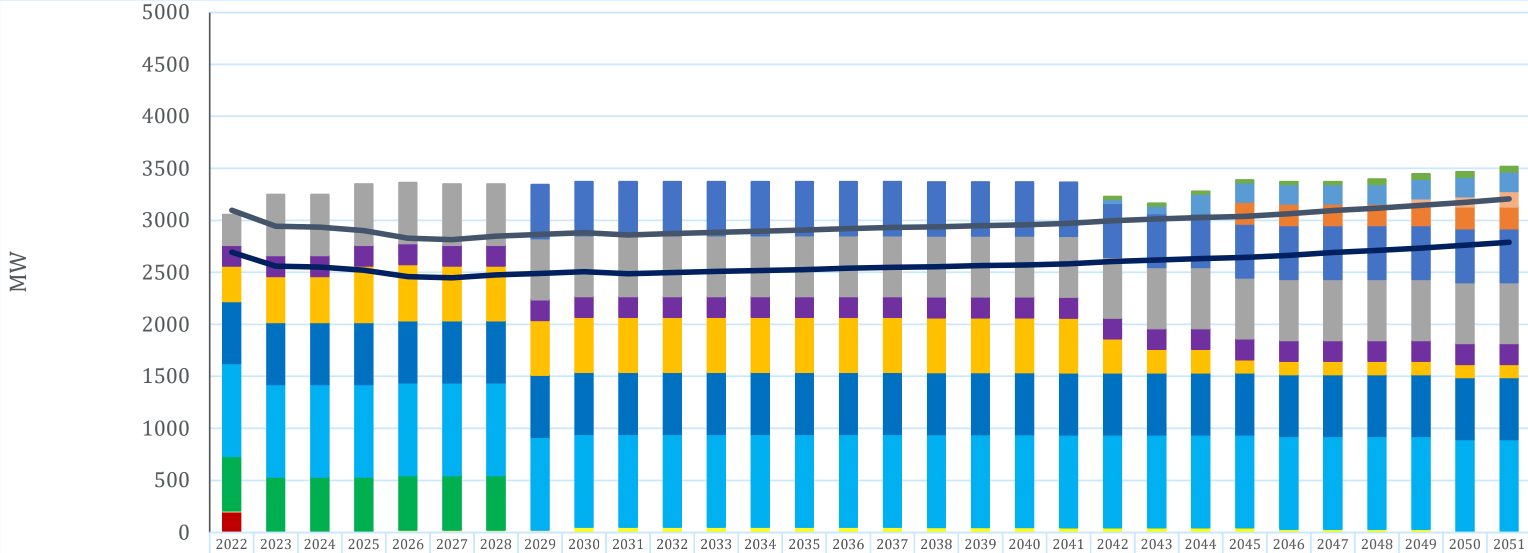
Figure A-16 - Supplemental Scenario – Annual Firm Capacity (January)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	125	375	375
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	338	375	750	788	788
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	50	400	750	1100	1450	1800	2150	2500	2850	3200	3550	3900	4250	4600	4950	5300	5650	6000	6000
75 MW 4hr BESS	0	0	0	225	225	225	225	225	225	750	1275	1800	2325	2850	3375	3900	4425	4950	5475	6000	6525	7050	7575	7875	8400	8925	9450	9975	10500	10500
7HA.02 1x0	0	0	0	0	0	0	0	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346	346
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	95	95
Coal STs	293	586	586	586	586	586	586	586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
LMS100 PA+ 1x0	0	0	0	0	0	0	0	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2847	2864	2878	2891	2902	2910	2920	2928	2935	2942	2950	2956	2963	2970	2978	2986	2993	3001	3067	3070	3082	3097	3110	3144	3174	3210	3241	3278	3333
Peak + 15%	3255	3275	3294	3310	3325	3337	3347	3358	3367	3375	3383	3392	3400	3408	3415	3424	3433	3441	3451	3528	3530	3545	3562	3577	3616	3650	3691	3727	3770	3833

Appendix A – Detailed PLEXOS Modeling Results

Figure A-17 - Low Load Sensitivity – Annual Firm Capacity (August)

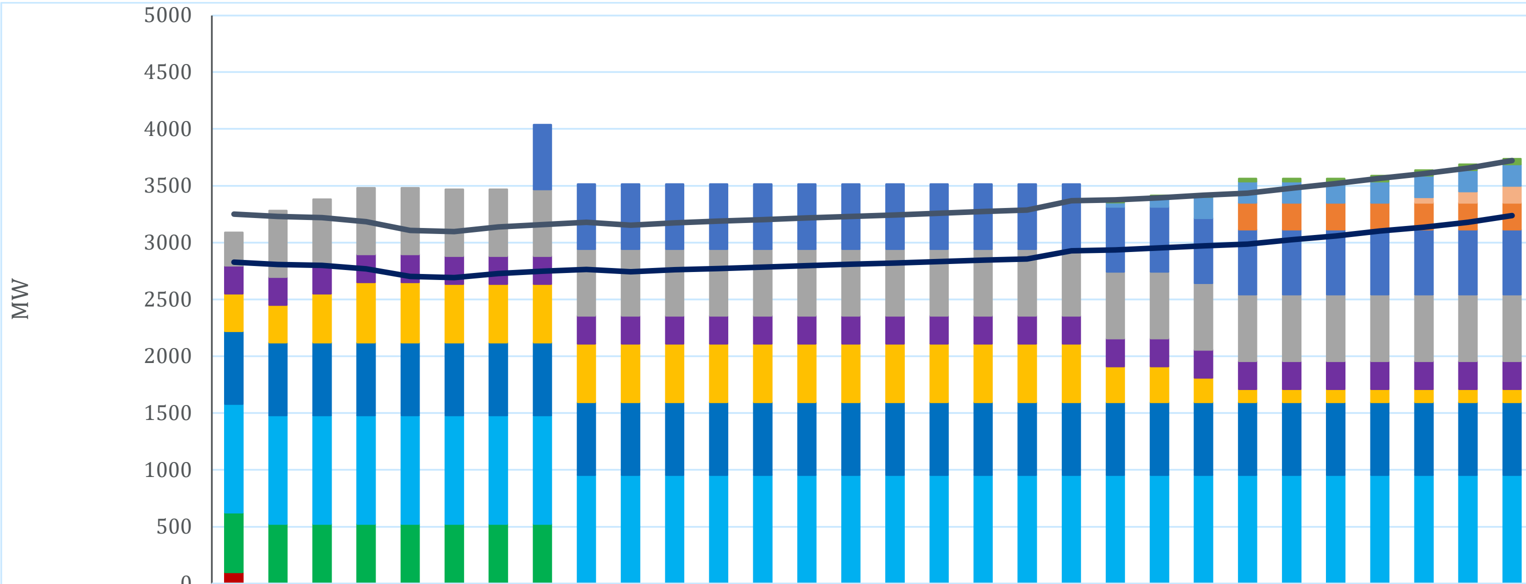


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Solar SSOs	0	0	0	0	15	15	15	15	45	45	45	45	45	45	45
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2559	2552	2521	2458	2447	2475	2490	2505	2485	2499	2508	2516	2526	2539
Peak + 15%	3097	2943	2934	2899	2827	2815	2846	2863	2881	2858	2874	2884	2894	2905	2920

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	25	25	25	25	25	25	50	50	50	50
37.5 MW 1hr BESS	0	0	0	0	0	38	75	188	188	188	188	188	188	188	188
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150
7F.05 1x0_2	0	0	0	0	0	0	0	0	209	209	209	209	209	209	209
7HA.02 1x1	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	45	45	45	45	45	45	45	45	45	30	30	30	30	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2549	2555	2564	2571	2582	2605	2619	2631	2643	2663	2690	2710	2734	2759	2789
Peak + 15%	2931	2938	2949	2956	2969	2996	3011	3025	3039	3062	3094	3116	3144	3173	3208

Appendix A – Detailed PLEXOS Modeling Results

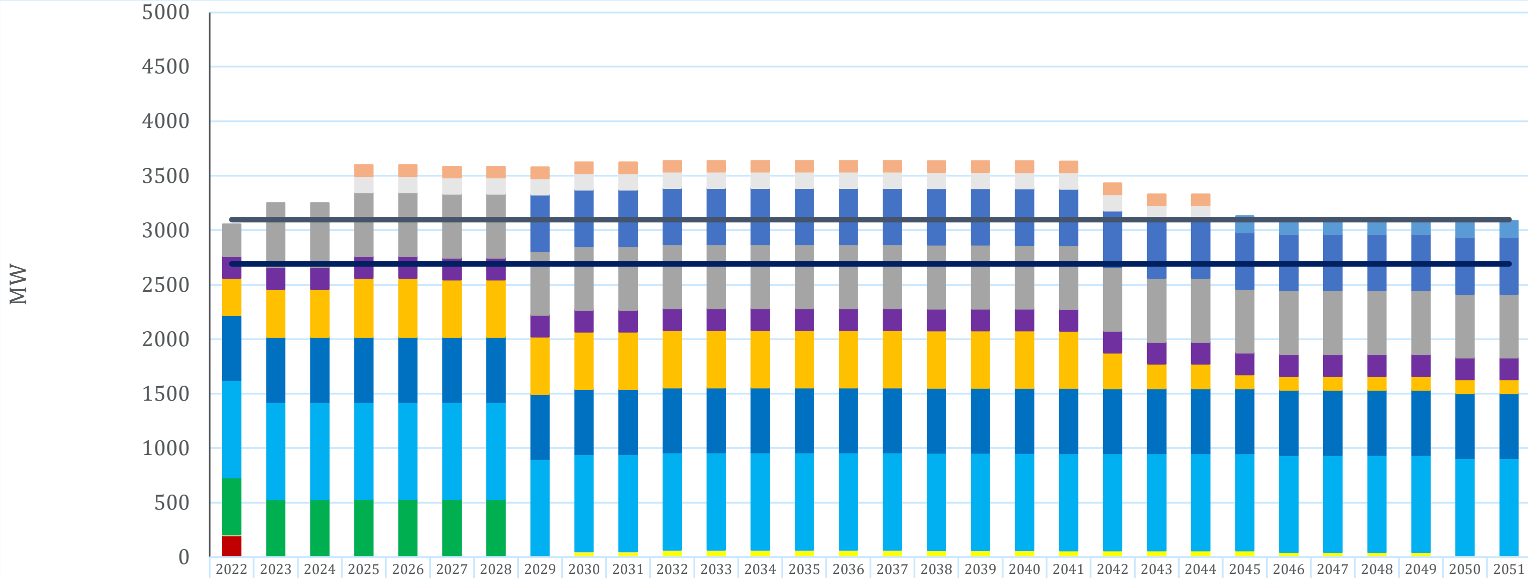
Figure A-18 - Low Load Sensitivity – Annual Firm Capacity (January)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	50	50	50	50
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	38	75	188	188	188	188	188	188	188	188
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	236	236	236	236	236	236	236
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2827	2808	2801	2769	2703	2694	2729	2747	2765	2743	2760	2772	2785	2797	2809	2821	2834	2845	2857	2929	2936	2952	2971	2988	3025	3059	3101	3135	3178	3238
Peak + 15%	3251	3229	3221	3185	3108	3099	3138	3159	3179	3154	3174	3188	3202	3216	3230	3244	3259	3272	3286	3368	3376	3395	3417	3436	3479	3518	3566	3606	3654	3724

Appendix A – Detailed PLEXOS Modeling Results

Figure A-19 - No Load Growth Sensitivity – Annual Firm Capacity (August)

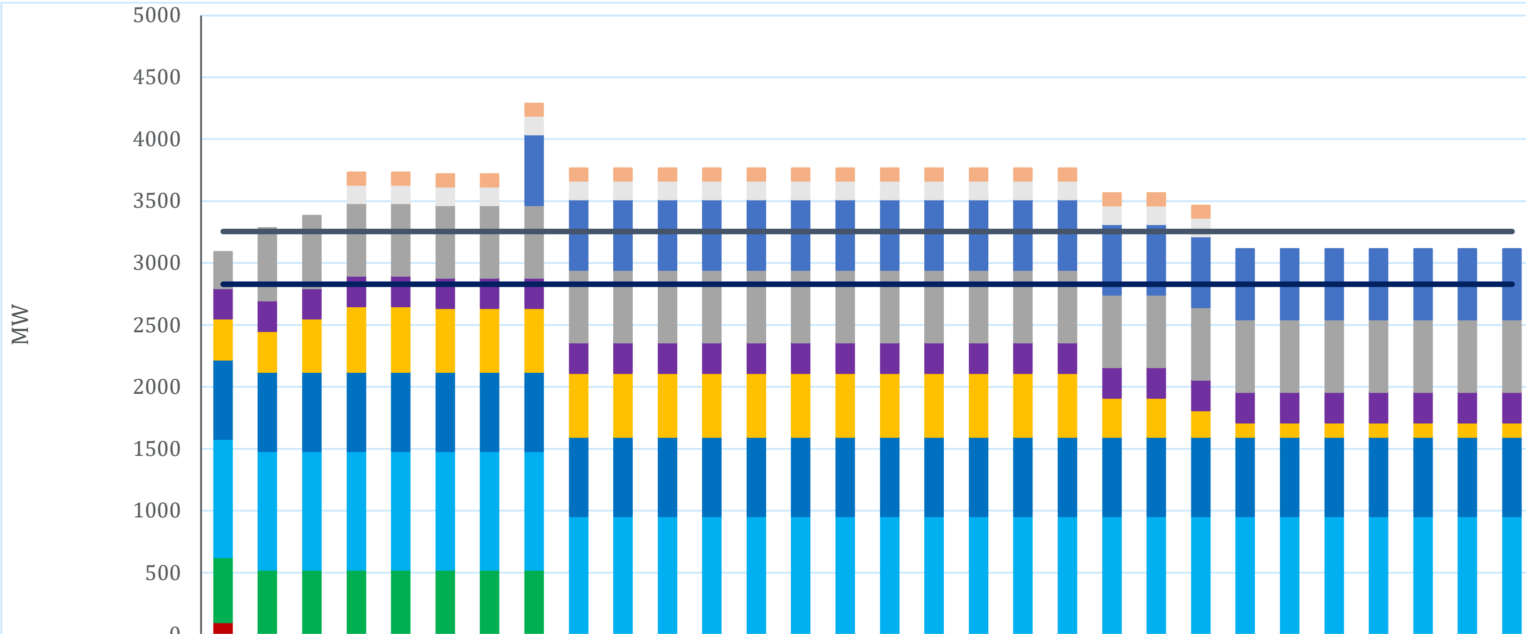


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Solar SSOs	0	0	0	0	0	0	0	0	45	45	60	60	60	60	60
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693
Peak + 15%	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	150	150	150	150	150	150	150
50 MW 4hr BESS	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0
75 MW 4hr BESS	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
7HA.02 1x1	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	60	60	60	60	60	60	60	60	60	45	45	45	45	15	15
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693	2693
Peak + 15%	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097	3097

Appendix A – Detailed PLEXOS Modeling Results

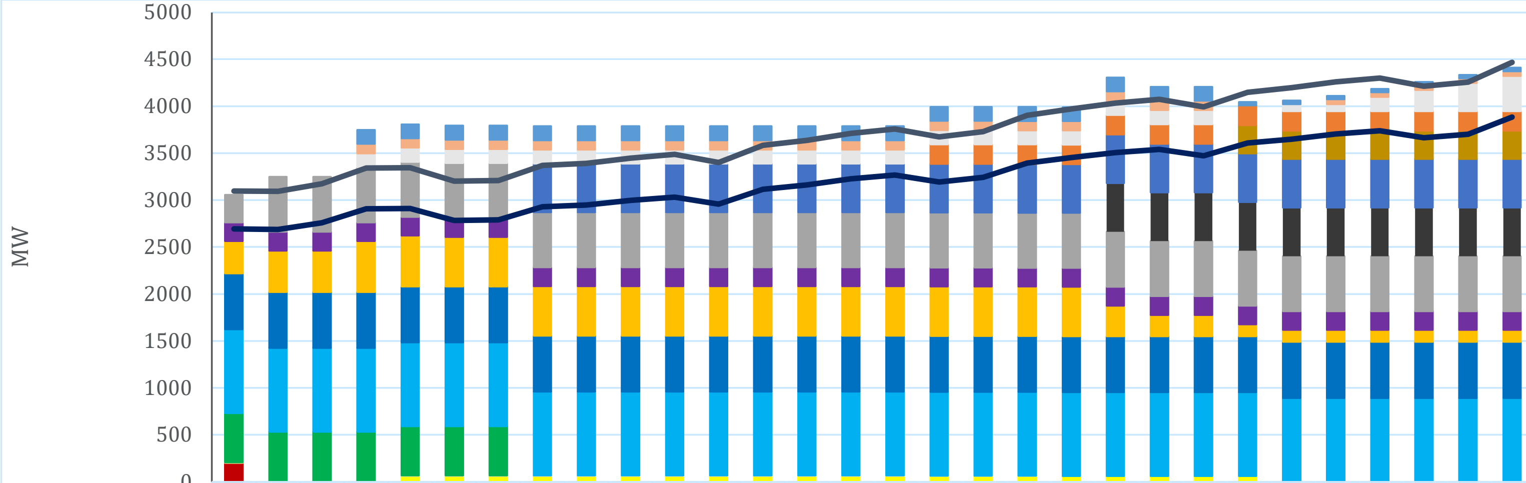
Figure A-20 - No Load Growth Sensitivity – Annual Firm Capacity (January)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830	2830
Peak + 15%	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255	3255

Appendix A – Detailed PLEXOS Modeling Results

Figure A-21 - High Load Sensitivity – Annual Firm Capacity (August)

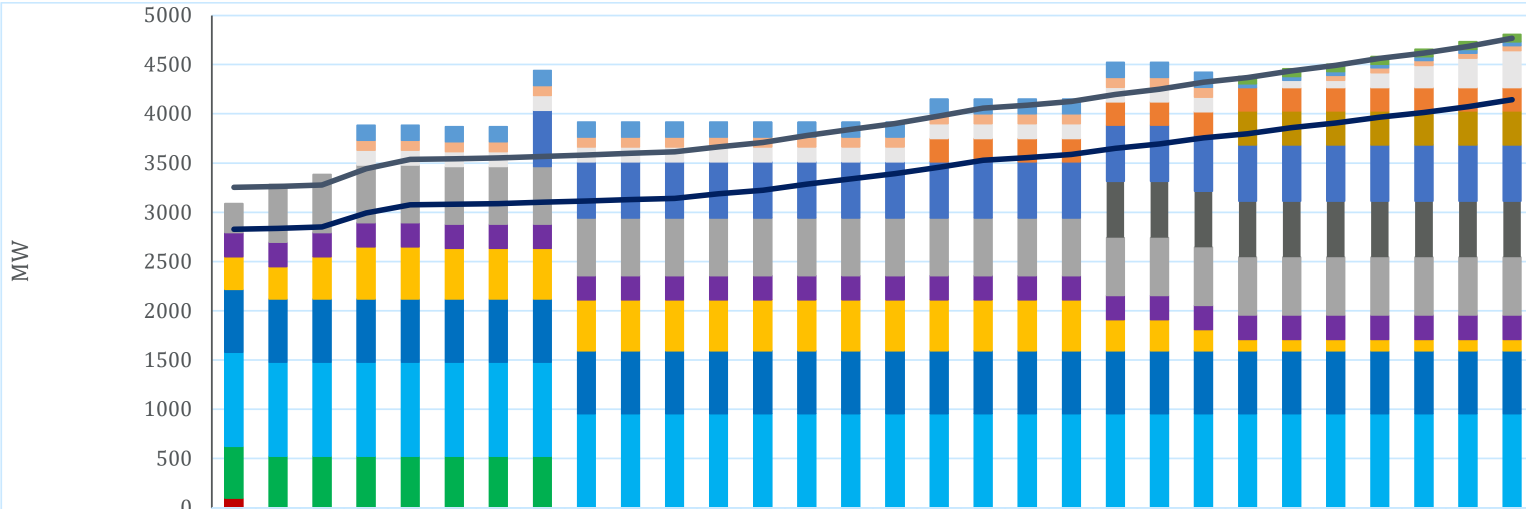


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
37.5 MW 1hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518
7HA.02 1x1_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Solar SSOs	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2690	2760	2906	2909	2783	2791	2929	2949	2997	3031	2956	3116	3163	3226
Peak + 15%	3097	3094	3174	3342	3345	3200	3210	3368	3391	3447	3486	3399	3583	3637	3710

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
37.5 MW 1hr BESS	150	150	150	150	150	150	150	150	38	38	38	38	38	38	38
50 MW 4hr BESS	100	100	100	100	100	100	100	100	0	0	50	50	50	50	50
75 MW 4hr BESS	150	150	150	150	150	150	150	150	0	75	75	150	225	300	375
7F.05 1x0_2	0	209	209	209	209	209	209	209	209	209	209	209	209	209	209
7HA.02 1x0_2	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300
7HA.02 1x1	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
7HA.02 1x1_2	0	0	0	0	0	518	518	518	518	518	518	518	518	518	518
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	60	60	60	60	60	60	60	60	60	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	3266	3193	3243	3394	3452	3506	3541	3471	3607	3649	3703	3739	3663	3702	3885
Peak + 15%	3756	3672	3729	3903	3970	4032	4072	3992	4148	4196	4258	4300	4212	4257	4468

Appendix A – Detailed PLEXOS Modeling Results

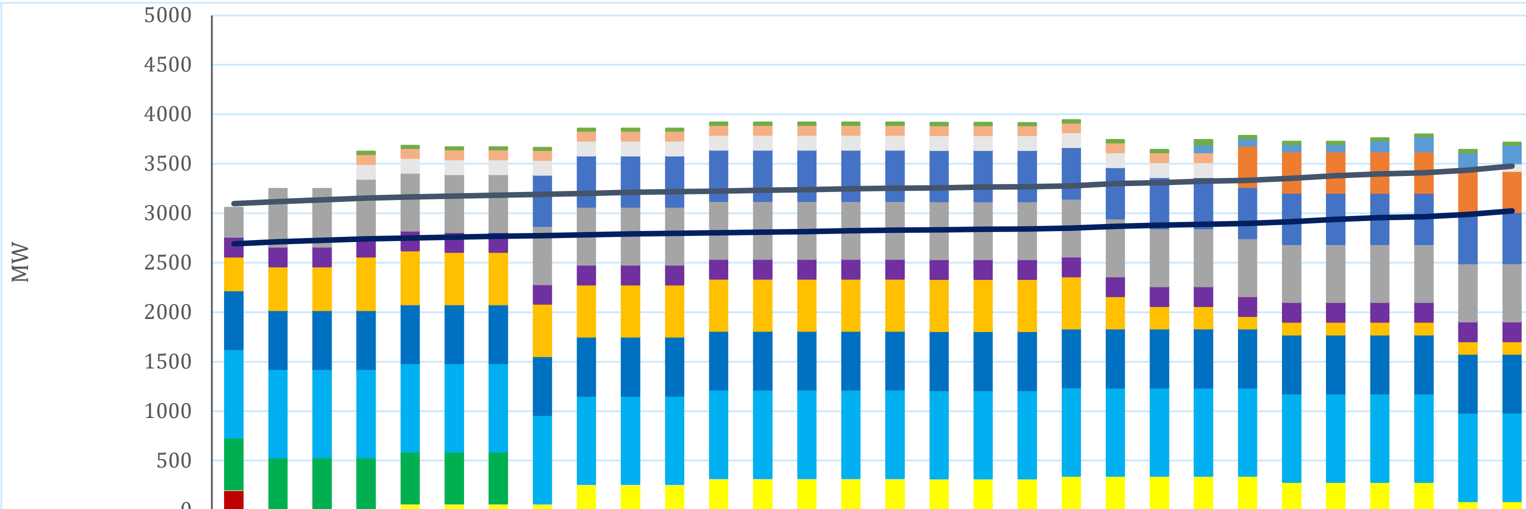
Figure A-22 - High Load Sensitivity – Annual Firm Capacity (January)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	75	75	75
37.5 MW 1hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	38	38	38	38	38	38	38
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	50	50	50	50	50
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	75	75	150	225	300	375
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	236	236	236	236	236	236	236	236	236	236	236	236	236	236
7HA.02 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	346	346	346	346	346	346	346
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
7HA.02 1x1_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2837	2850	2994	3075	3082	3089	3101	3115	3129	3142	3187	3224	3287	3340	3391	3458	3527	3555	3588	3650	3695	3756	3797	3858	3907	3967	4014	4073	4145
Peak + 15%	3255	3263	3278	3443	3536	3544	3552	3566	3582	3598	3613	3665	3708	3780	3841	3900	3977	4056	4088	4126	4198	4249	4319	4367	4437	4493	4562	4616	4684	4767

Appendix A – Detailed PLEXOS Modeling Results

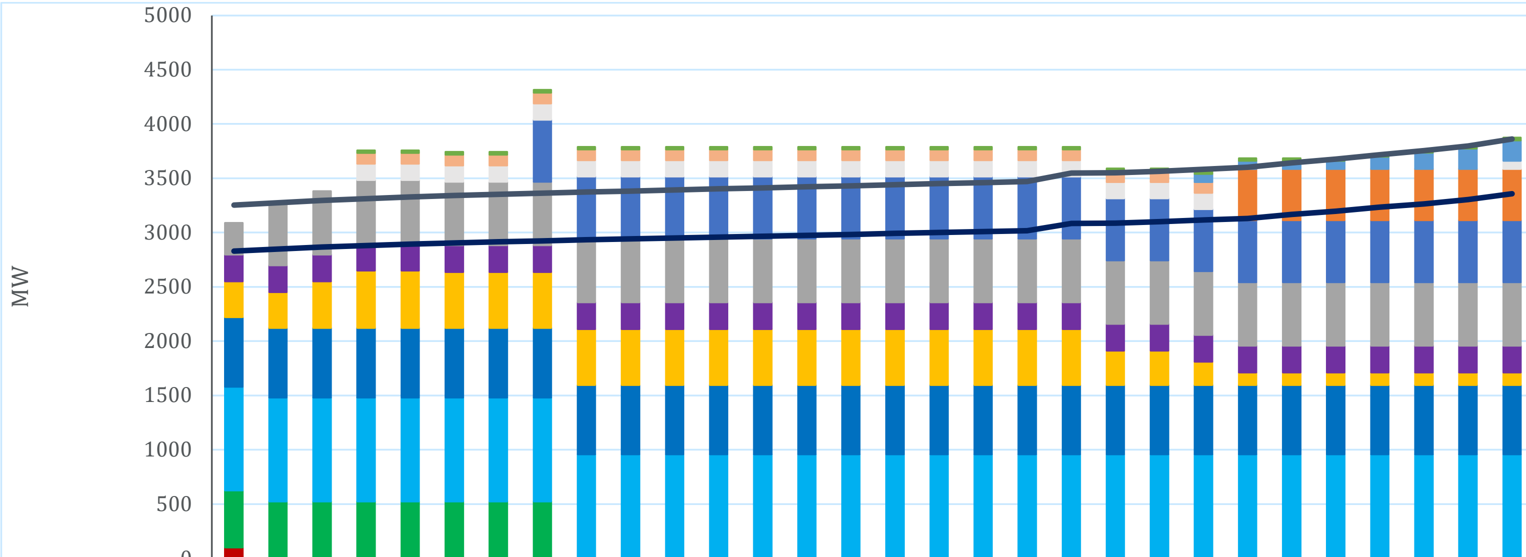
Figure A-23 - High Fuel Sensitivity – Annual Firm Capacity (August)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	50	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	113	150	188	188
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	75
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	417	417	417	417	417	417	417
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	0	0	0	0	60	60	60	60	255	255	255	315	315	315	315	315	315	315	315	345	345	345	345	345	285	285	285	285	90	90
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2710	2726	2740	2751	2759	2767	2774	2783	2792	2797	2804	2809	2815	2824	2829	2832	2838	2841	2849	2868	2878	2889	2897	2914	2937	2954	2963	2987	3024
Peak + 15%	3097	3116	3135	3151	3163	3173	3182	3190	3200	3210	3216	3224	3230	3237	3247	3253	3256	3264	3268	3276	3299	3310	3322	3331	3351	3378	3398	3407	3435	3477

Appendix A – Detailed PLEXOS Modeling Results

Figure A-24 - High Fuel Sensitivity – Annual Firm Capacity (January)

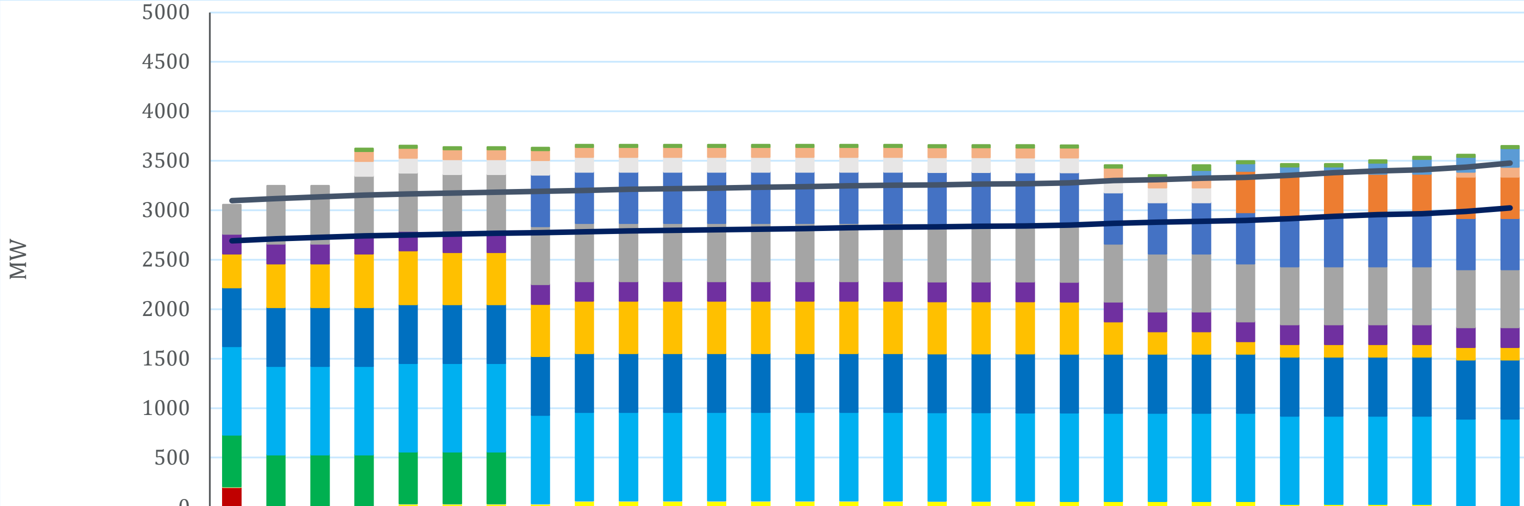


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
25 MW 1hr BESS	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2848	2865	2879	2893	2904	2913	2924	2933	2941	2949	2958	2966	2974	2982
Peak + 15%	3255	3275	3295	3311	3327	3340	3350	3362	3373	3382	3391	3402	3411	3420	3429

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	25	25	25	25	25	25	25	50	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	0	0	0	0	75	75	75	75	113	150	188	188
50 MW 4hr BESS	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0
75 MW 4hr BESS	150	150	150	150	150	150	150	150	0	0	0	0	0	0	75
7F.05 1x0_2	0	0	0	0	0	0	0	0	471	471	471	471	471	471	471
7HA.02 1x1	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2991	3000	3007	3016	3083	3086	3100	3116	3130	3165	3195	3232	3264	3302	3358
Peak + 15%	3440	3450	3458	3468	3546	3549	3564	3583	3599	3640	3675	3717	3754	3798	3862

Appendix A – Detailed PLEXOS Modeling Results

Figure A-25 - Regulated CO_2 Sensitivity – Annual Firm Capacity (August)

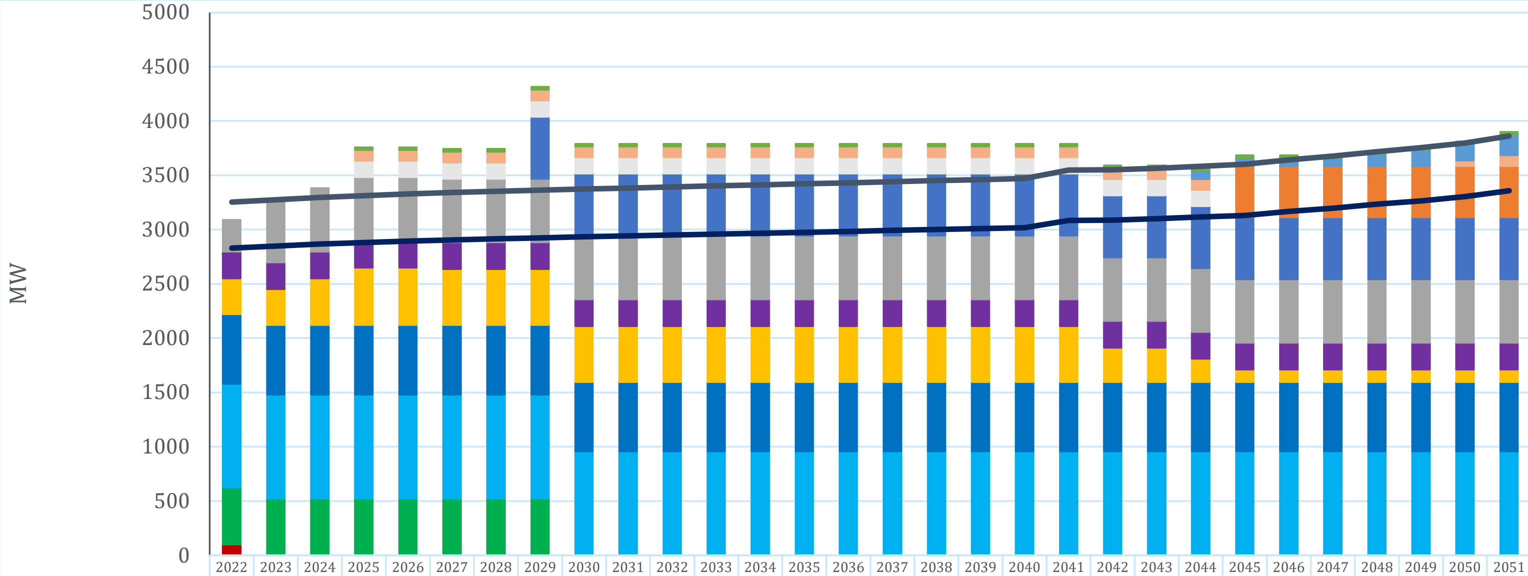


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
25 MW 1hr BESS	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7HA.02 1x1	0	0	0	0	0	0	0	518	518	518	518	518	518	518	518
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Solar SSOs	0	0	0	0	30	30	30	30	60	60	60	60	60	60	60
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2710	2726	2740	2751	2759	2767	2774	2783	2792	2797	2804	2809	2815	2824
Peak + 15%	3097	3116	3135	3151	3163	3173	3182	3190	3200	3210	3216	3224	3230	3237	3247

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	25	25	25	25	25	25	25	50	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	0	0	0	0	75	75	75	75	113	150	150	188
50 MW 4hr BESS	100	100	100	100	100	100	100	100	0	0	0	0	0	50	100
75 MW 4hr BESS	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
7F.05 1x0_2	0	0	0	0	0	0	0	0	417	417	417	417	417	417	417
7HA.02 1x1	518	518	518	518	518	518	518	518	518	518	518	518	518	518	518
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	60	60	60	60	60	60	60	60	60	30	30	30	30	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2829	2832	2838	2841	2849	2868	2878	2889	2897	2914	2937	2954	2963	2987	3024
Peak + 15%	3253	3256	3264	3268	3276	3299	3310	3322	3331	3351	3378	3398	3407	3435	3477

Appendix A – Detailed PLEXOS Modeling Results

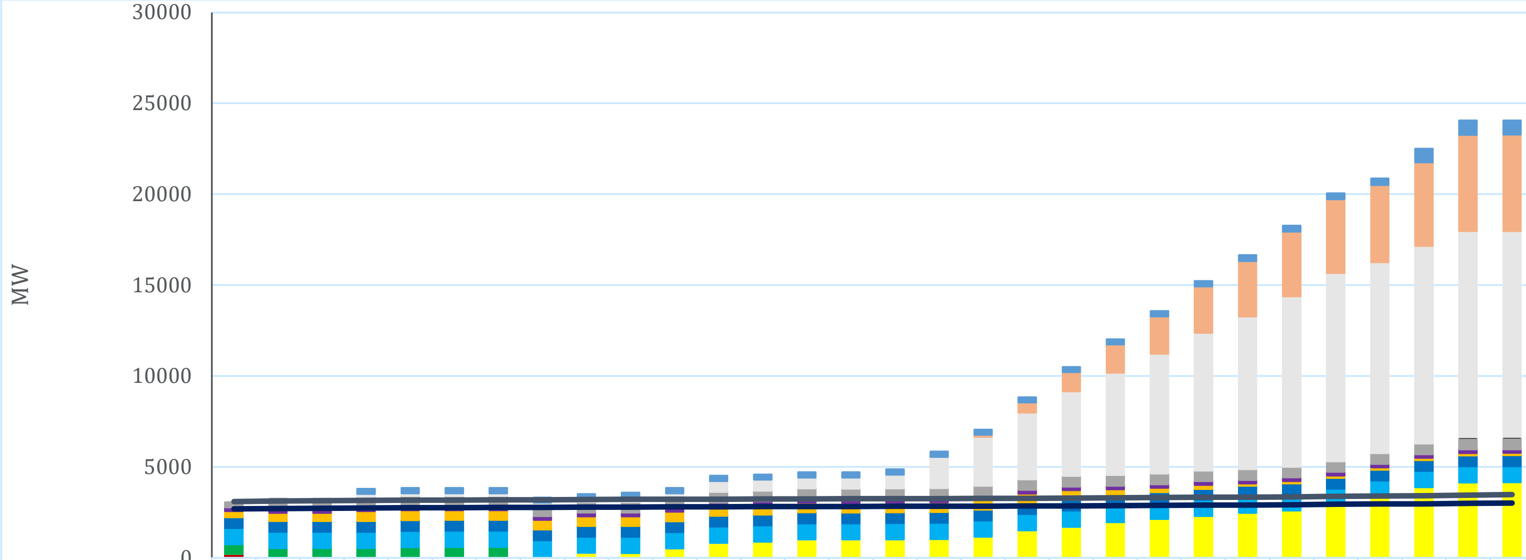
Figure A-26 - Regulated CO_2 Sensitivity – Annual Firm Capacity (January)



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
25 MW 1hr BESS	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	50	25	25	25	25	25	25	25
37.5 MW 1hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75	75	75	75	113	150	150	188
50 MW 4hr BESS	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	50	100
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
7F.05 1x0_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	471	471	471	471	471	471	471
7HA.02 1x1	0	0	0	0	0	0	0	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2848	2865	2879	2893	2904	2913	2924	2933	2941	2949	2958	2966	2974	2982	2991	3000	3007	3016	3083	3086	3100	3116	3130	3165	3195	3232	3264	3302	3358
Peak + 15%	3255	3275	3295	3311	3327	3340	3350	3362	3373	3382	3391	3402	3411	3420	3429	3440	3450	3458	3468	3546	3549	3564	3583	3599	3640	3675	3717	3754	3798	3862

Appendix A – Detailed PLEXOS Modeling Results

Figure A-27 - Net Zero Sensitivity – Annual Firm Capacity (August)

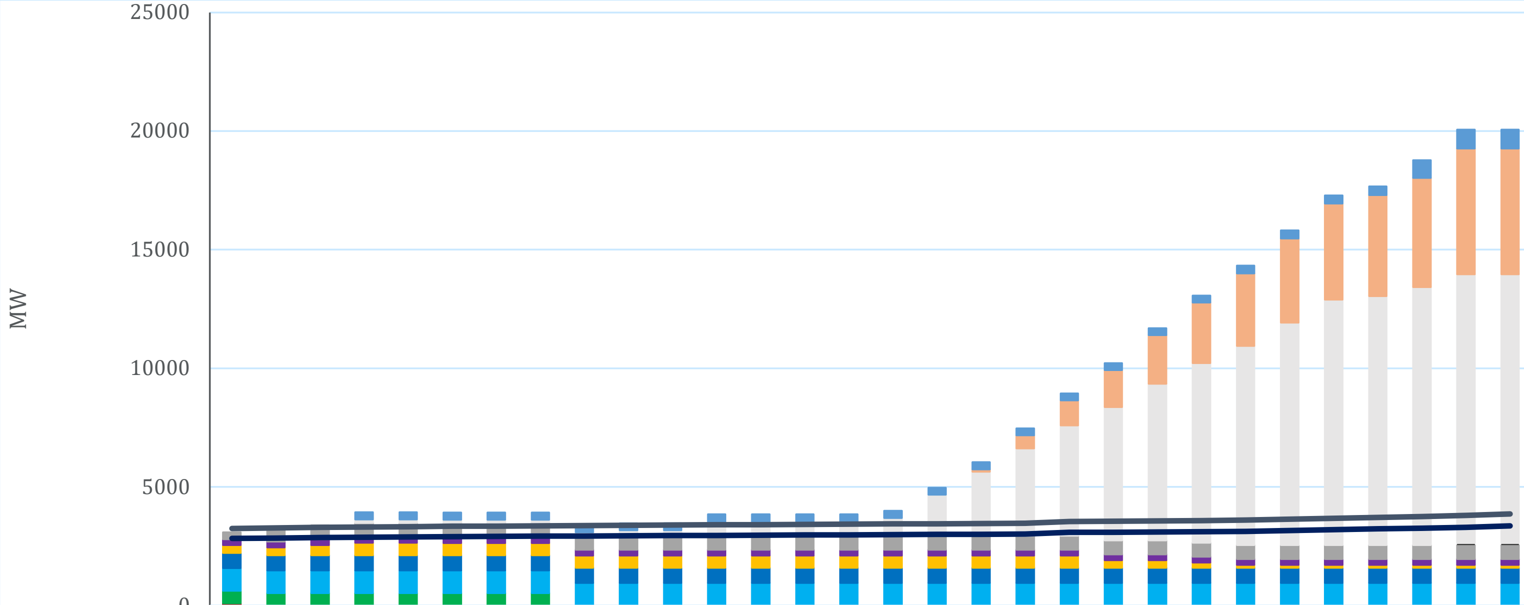


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
37.5 MW 1hr BESS	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	225	225	600	600	600	600
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	342	442	442	542	542	527	527	527	527	527	527	527	527	527	527
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0
Solar	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Solar SSOs	0	0	0	0	45	60	59	59	253	252	506	804	877	994	991
TEA Purchases	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2693	2710	2726	2740	2751	2759	2767	2774	2783	2792	2797	2804	2809	2815	2824
Peak + 15%	3097	3116	3135	3151	3163	3173	3182	3190	3200	3210	3216	3224	3230	3237	3247

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
37.5 MW 1hr BESS	300	300	300	300	300	300	300	300	338	338	338	375	750	788	788
50 MW 4hr BESS	0	0	100	550	1050	1550	2050	2550	3050	3550	4050	4250	4600	5300	5300
75 MW 4hr BESS	750	1725	2700	3675	4650	5625	6600	7575	8400	9375	10350	10500	10875	11325	11325
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	95	95
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Firm Purchases	527	527	527	527	527	327	227	227	127	127	127	127	127	127	127
Gas CCs	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Gas CTs	893	893	893	893	893	893	893	893	893	893	893	893	893	893	893
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	7	4	4	3	1	0	0	0	0	0	0	0	0	0	0
Solar SSOs	1003	1016	1147	1504	1695	1945	2119	2293	2465	2597	2905	3345	3874	4138	4142
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2829	2832	2838	2841	2849	2868	2878	2889	2897	2914	2937	2954	2963	2987	3024
Peak + 15%	3253	3256	3264	3268	3276	3299	3310	3322	3331	3351	3378	3398	3407	3435	3477

Appendix A – Detailed PLEXOS Modeling Results

Figure A-28 - Net Zero Sensitivity – Annual Firm Capacity (January)

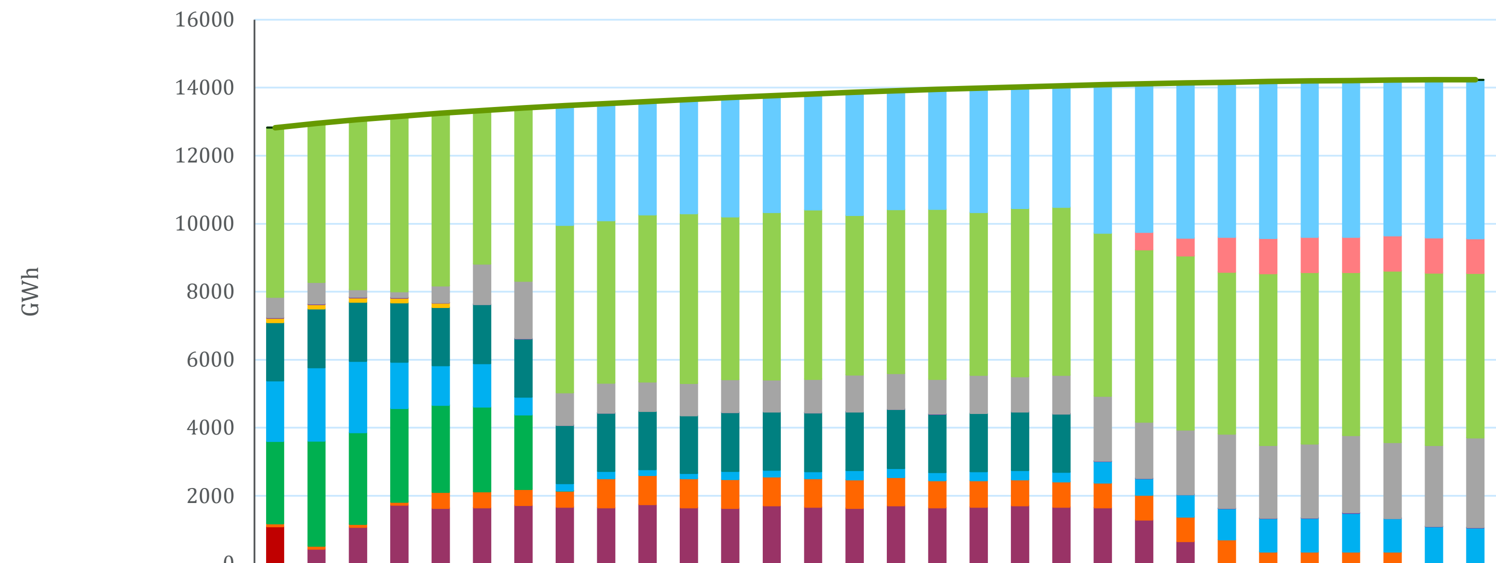


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
37.5 MW 1hr BESS	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300
50 MW 4hr BESS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75 MW 4hr BESS	0	0	0	150	150	150	150	150	150	225	225	600	600	600	600
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal STs	293	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	330	330	430	530	530	515	515	515	515	515	515	515	515	515	515
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0
TEA Purchases	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2830	2848	2865	2879	2893	2904	2913	2924	2933	2941	2949	2958	2966	2974	2982
Peak + 15%	3255	3275	3295	3311	3327	3340	3350	3362	3373	3382	3391	3402	3411	3420	3429

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
37.5 MW 1hr BESS	300	300	300	300	300	300	300	300	337.5	337.5	337.5	375	750	787.5	787.5
50 MW 4hr BESS	0	0	100	550	1050	1550	2050	2550	3050	3550	4050	4250	4600	5300	5300
75 MW 4hr BESS	750	1725	2700	3675	4650	5625	6600	7575	8400	9375	10350	10500	10875	11325	11325
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	95	95
Coal STs	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Firm Purchases	515	515	515	515	515	315	315	215	115	115	115	115	115	115	115
Gas CCs	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak	2991	3000	3007	3016	3083	3086	3100	3116	3130	3165	3195	3232	3264	3302	3358
Peak + 15%	3440	3450	3458	3468	3546	3549	3564	3583	3599	3640	3675	3717	3754	3798	3862

Appendix A – Detailed PLEXOS Modeling Results

Figure A-29 – Current Outlook Scenario – Annual Energy by Resource

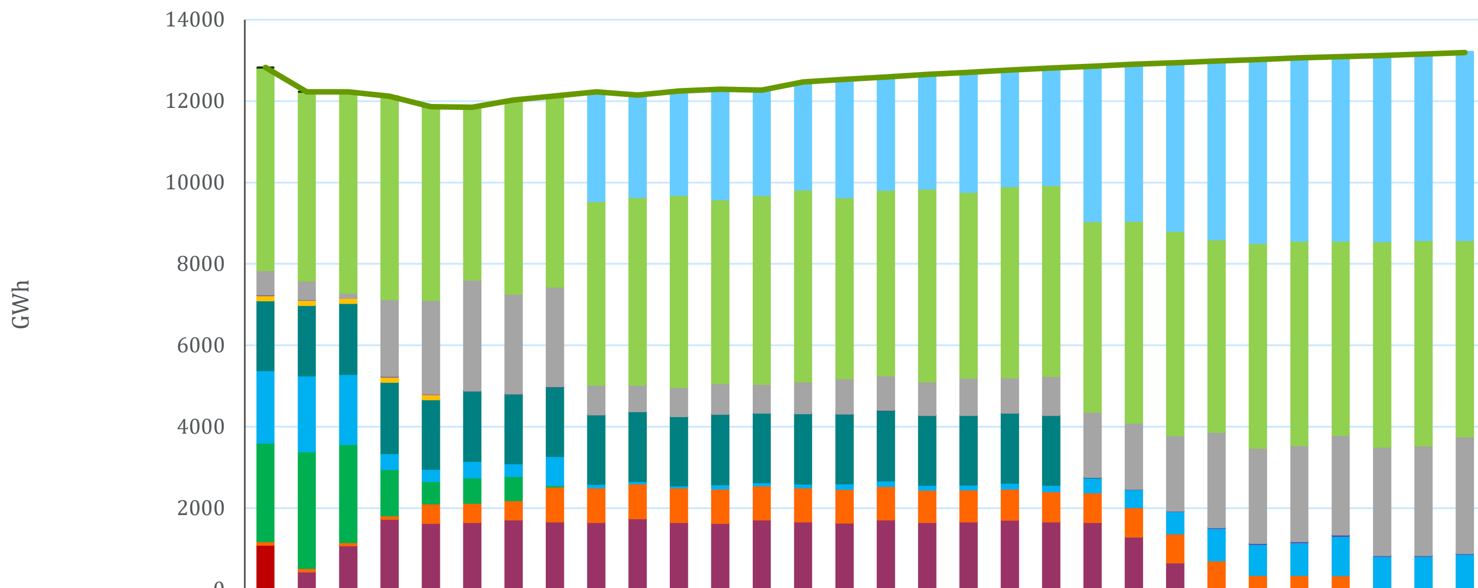


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	5	3	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	3533	3465	3351	3376	3536	3453	3428	3644
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	4971	4656	4982	5157	5086	4519	5103	4928	4774	4921	4996	4783	4926	4980	4690
Coal STs	597	638	229	176	496	1190	1688	957	886	866	949	966	944	988	1084
Diesel CTs	17	14	13	18	8	5	2	0	1	0	0	3	2	1	2
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1748	1714	1733	1718	1713	1713	1713	1699	1732	1713	1732	1718
Gas CTs	1781	2155	2096	1366	1170	1280	523	217	212	167	153	240	196	206	280
NorthSide ST3	2425	3091	2700	2754	2553	2491	2190	11	0	0	0	0	0	0	0
Solar PV	86	85	85	84	476	474	472	469	859	855	852	846	842	837	834
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12948	13057	13160	13250	13327	13399	13470	13534	13595	13654	13712	13764	13814	13862

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	1	0	0	1	0	0	12
Advanced CC	3516	3552	3681	3593	3596	4387	4391	4589	4547	4611	4597	4605	4579	4658	4655
Advanced SC	0	0	0	0	0	0	510	518	1029	1029	1031	1035	1032	1032	1023
BBCC 2x1	4817	4995	4789	4949	4941	4799	5075	5119	4763	5051	5046	4788	5050	5067	4834
Coal STs	1052	1025	1121	1036	1137	1903	1654	1903	2181	2147	2178	2272	2230	2384	2644
Diesel CTs	4	3	0	5	1	12	3	4	13	10	6	14	5	7	7
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1732	1713	1713	1718	1713	5	0	0	0	0	0	0	0	0	0
Gas CTs	269	244	259	274	286	626	491	656	908	978	991	1143	984	1101	1062
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	827	796	785	768	746	734	726	723	718	357	355	354	351	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	13905	13949	13987	14024	14057	14085	14111	14137	14160	14183	14201	14212	14225	14242	14237

Appendix A – Detailed PLEXOS Modeling Results

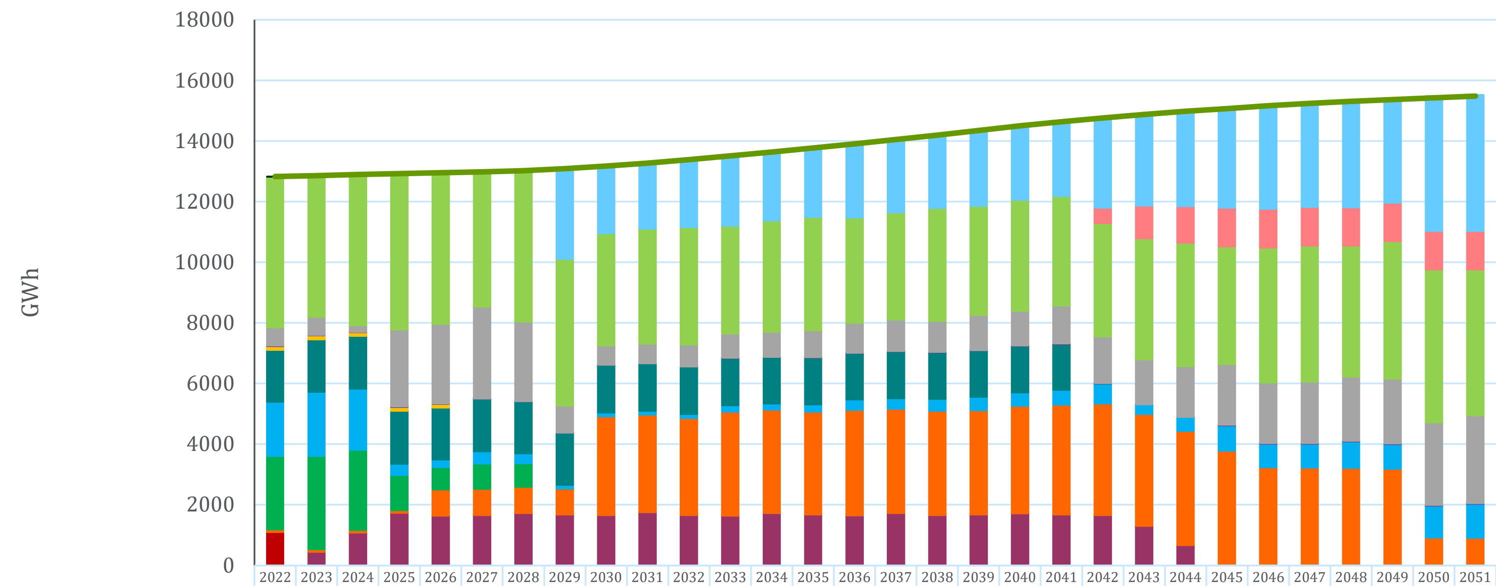
Figure A-30 – Economic Downturn Scenario – Annual Energy by Resource



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	8	3	0	17	5	0	0	3	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	0	2685	2509	2558	2706	2582	2644	2899	2778	2803	2943	2855	2883	3818	3851	4139	4380	4532	4517	4538	4604	4614	4629
BBCC 2x1	4970	4642	4936	4972	4748	4239	4758	4687	4507	4611	4714	4516	4638	4717	4443	4555	4742	4563	4701	4686	4680	4958	5028	4730	5025	5020	4772	5042	5045	4825
Coal STs	600	460	124	1891	2303	2724	2450	2441	729	652	716	750	702	778	866	847	821	916	863	960	1599	1620	1846	2345	2339	2360	2444	2667	2697	2863
Diesel CTs	17	7	4	13	5	3	1	11	0	0	0	1	0	0	1	1	2	0	3	0	7	7	9	19	19	19	28	11	10	17
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1747	1709	1729	1716	1710	1712	1712	1698	1731	1712	1731	1716	1731	1711	1711	1716	1710	5	0	0	0	0	0	0	0	0	0
Gas CTs	1782	1861	1722	396	299	408	318	715	81	63	53	104	76	91	132	137	125	122	148	160	366	448	547	796	768	811	971	830	830	876
NorthSide ST3	2423	2868	2408	1137	553	619	589	29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	86	85	85	84	476	474	472	861	857	853	850	844	840	835	832	825	794	783	766	744	732	724	721	716	356	354	353	0	0	0
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	12827	12229	12228	12121	11864	11851	12026	12128	12225	12151	12247	12290	12269	12467	12531	12593	12652	12708	12763	12813	12859	12902	12944	12983	13023	13059	13090	13122	13157	13193

Appendix A – Detailed PLEXOS Modeling Results

Figure A-31 – Efficiency + DER Scenario – Annual Energy by Resource

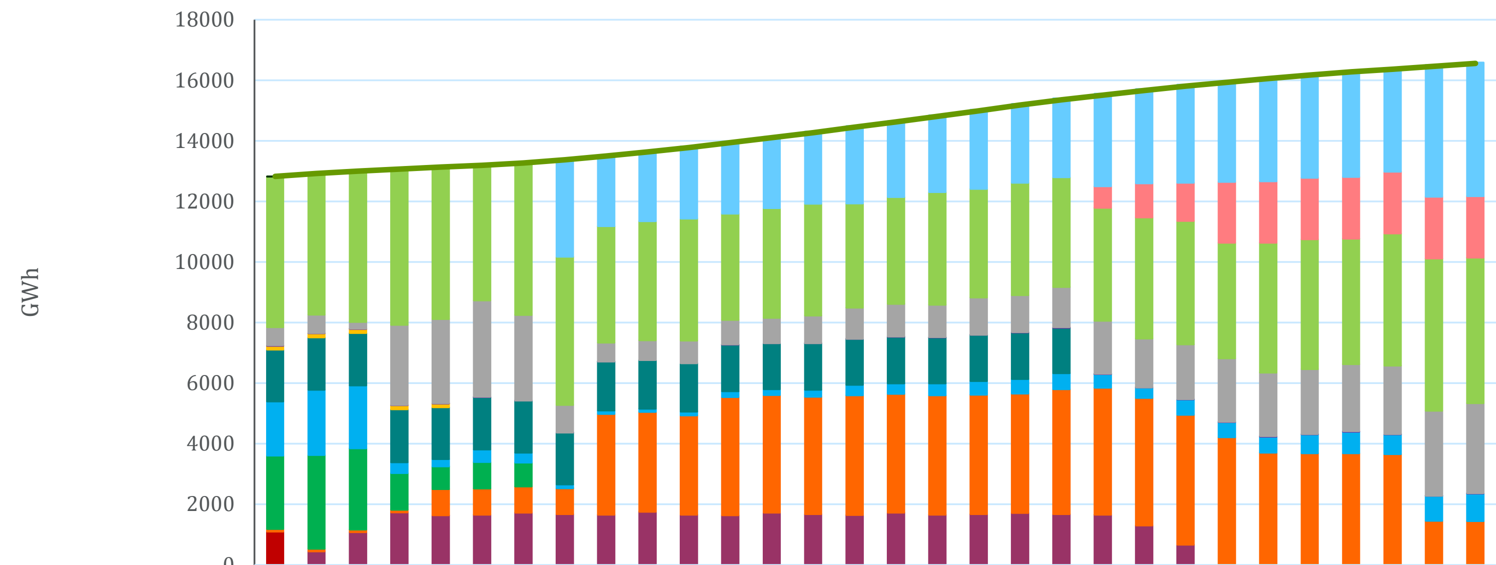


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	4	2	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	2997	2246	2189	2256	2323	2282	2304	2453
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	4970	4656	4974	5145	5007	4470	4992	4835	3695	3794	3870	3557	3670	3732	3477
Coal STs	599	594	209	2540	2625	3028	2628	899	633	645	724	803	828	892	991
Diesel CTs	17	13	11	17	6	4	2	0	1	0	0	4	2	2	2
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1748	1712	1732	1718	1713	1577	1569	1563	1560	1538	1556	1535
Gas CTs	1780	2120	2016	367	249	405	331	123	129	123	133	210	203	236	345
NorthSide ST3	2424	3077	2643	1160	731	841	781	9	0	0	0	0	0	0	0
Solar PV	86	85	85	84	868	864	861	855	3259	3220	3200	3433	3413	3397	3482
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12852	12890	12925	12955	12979	13015	13085	13171	13271	13382	13506	13633	13768	13907

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	2415	2423	2512	2465	2480	2983	3033	3166	3286	3425	3455	3542	3455	4446	4485
Advanced SC	0	0	0	0	0	516	1078	1197	1274	1274	1272	1264	1268	1274	1273
BBCC 2x1	3546	3732	3596	3661	3620	3737	3997	4075	3890	4452	4496	4323	4533	5044	4811
Coal STs	1036	1024	1161	1146	1250	1532	1485	1672	2002	2002	2024	2112	2140	2724	2896
Diesel CTs	6	8	1	15	14	16	4	7	17	25	22	23	13	18	18
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1550	1532	1543	1535	1510	5	0	0	0	0	0	0	0	0	0
Gas CTs	348	397	439	440	496	657	313	458	832	773	789	880	821	1056	1124
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	3443	3444	3447	3550	3624	3683	3695	3772	3782	3232	3219	3208	3182	913	908
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	14044	14191	14341	14500	14637	14758	14870	14978	15070	15160	15237	15303	15360	15422	15485

Appendix A – Detailed PLEXOS Modeling Results

Figure A-32 – Increased Electrification Scenario – Annual Energy by Resource

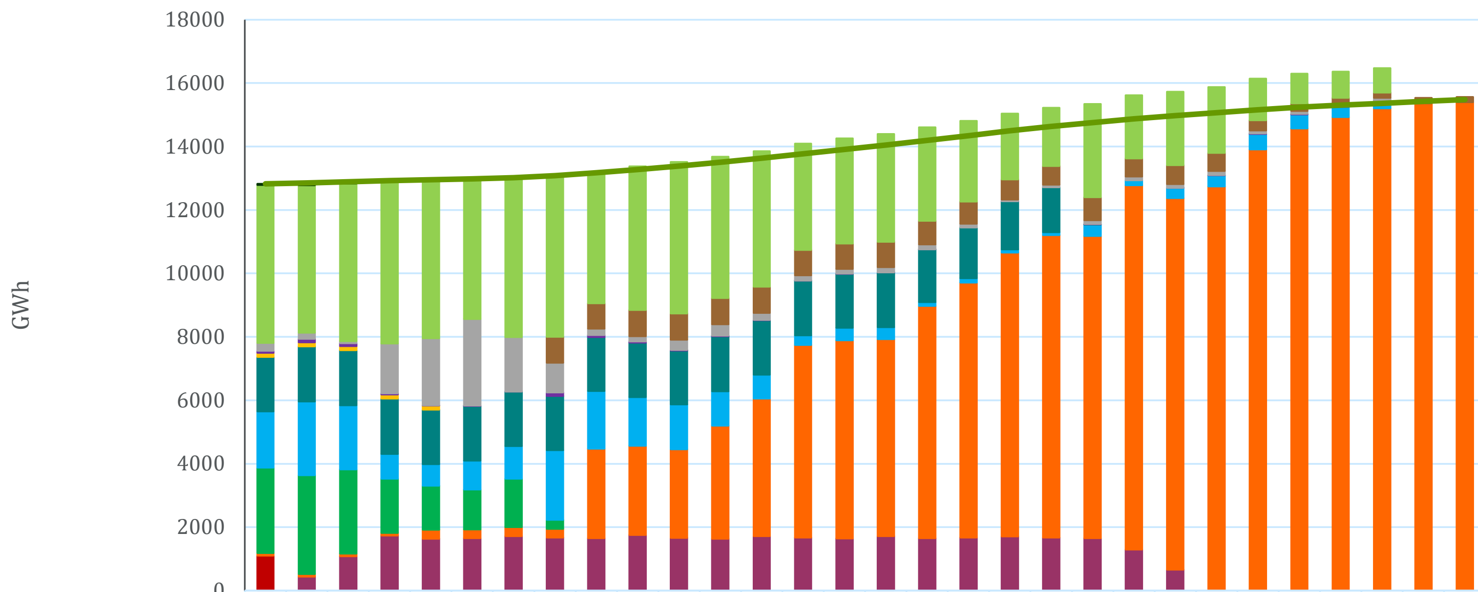


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	5	3	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	3233	2351	2318	2386	2383	2358	2383	2549
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	4970	4657	4977	5150	5036	4492	5045	4892	3843	3934	4023	3504	3626	3696	3443
Coal STs	599	607	219	2639	2778	3181	2829	914	629	653	755	812	833	910	1029
Diesel CTs	17	14	13	17	6	4	2	0	0	0	0	4	2	2	3
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1748	1713	1732	1718	1713	1612	1603	1596	1540	1521	1538	1522
Gas CTs	1780	2154	2075	356	237	413	325	116	114	108	121	190	191	227	340
NorthSide ST3	2424	3099	2676	1213	747	879	795	8	0	0	0	0	0	0	0
Solar PV	86	85	85	84	868	864	861	855	3328	3297	3274	3904	3888	3881	3958
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12924	12998	13069	13134	13195	13267	13373	13495	13631	13779	13937	14100	14271	14447

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	2514	2536	2623	2608	2604	3064	3114	3236	3299	3411	3413	3496	3424	4358	4409
Advanced SC	0	0	0	0	0	709	1126	1258	2010	2021	2024	2035	2032	2032	2030
BBCC 2x1	3521	3719	3583	3714	3627	3729	3998	4075	3815	4290	4291	4147	4369	5030	4807
Coal STs	1081	1069	1227	1217	1325	1744	1611	1813	2098	2102	2141	2215	2255	2805	2972
Diesel CTs	7	8	1	16	15	11	6	9	8	14	14	15	9	7	8
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1540	1521	1531	1538	1504	5	0	0	0	0	0	0	0	0	0
Gas CTs	347	397	455	475	527	453	348	511	506	527	622	716	652	824	913
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	3926	3939	3941	3944	4127	4190	4209	4289	4210	3705	3685	3680	3658	1453	1444
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	14619	14802	14988	15185	15356	15513	15661	15806	15933	16058	16172	16275	16366	16464	16562

Appendix A – Detailed PLEXOS Modeling Results

Figure A-33 – Future Net Zero Scenario – Annual Energy by Resource

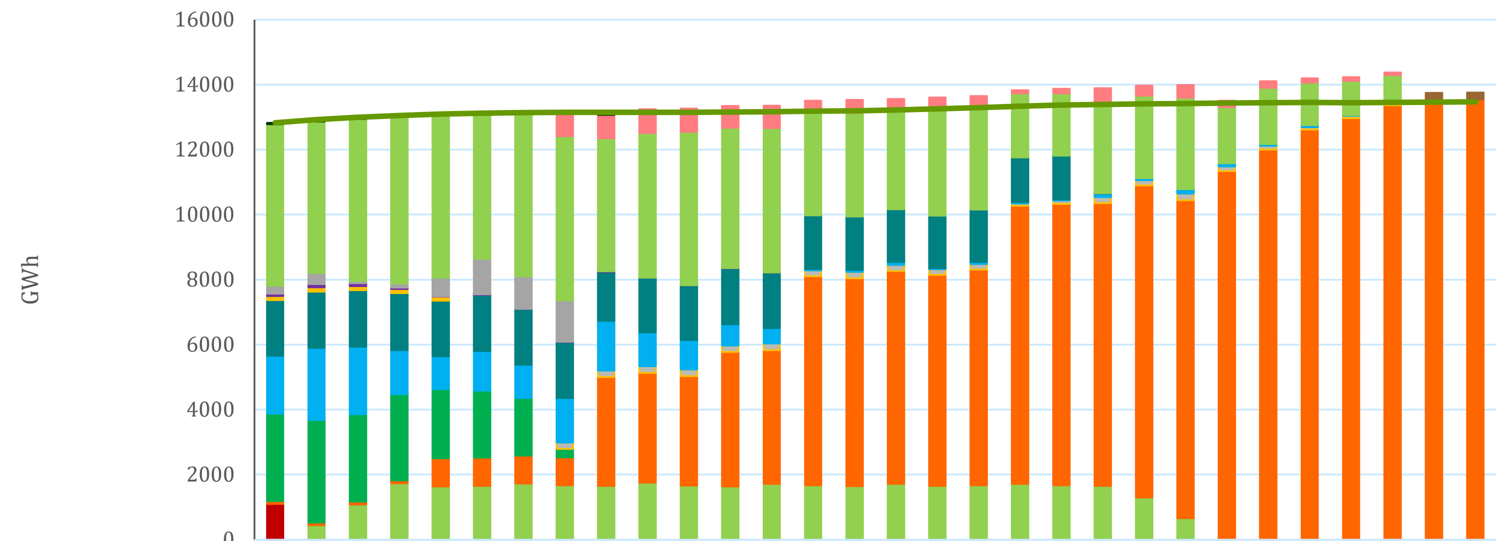


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	41	70	52	7	0	0	0	9	0	0	0	0	0	0	0
BBCC 2x1	4976	4655	4973	5128	5024	4448	5050	5079	4155	4533	4776	4458	4272	3356	3318
BioMass	0	0	0	0	0	0	0	818	801	825	831	830	830	800	796
Coal STs	248	191	71	1575	2115	2722	1716	930	202	162	326	355	221	166	150
Diesel CTs	66	114	88	33	9	9	8	112	64	41	18	24	10	3	3
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1749	1713	1732	1718	1713	1698	1712	1699	1732	1713	1723	1706
Gas CTs	1775	2321	2021	774	677	911	1023	2195	1820	1541	1409	1082	760	302	389
NorthSide ST3	2693	3113	2652	1711	1394	1253	1530	283	0	0	0	0	0	0	0
Solar PV	86	85	85	84	280	279	278	276	2819	2810	2801	3566	4333	6075	6252
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12852	12890	12925	12955	12979	13015	13085	13171	13271	13382	13506	13633	13768	13907

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	3404	2949	2547	2081	1837	2936	1993	2309	2082	1314	934	826	771	0	0
BioMass	798	746	698	630	591	723	573	600	565	328	243	191	171	167	160
Coal STs	160	152	116	58	85	125	114	122	137	89	87	80	77	0	0
Diesel CTs	1	0	0	1	0	6	0	1	5	16	25	15	13	0	0
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1729	1665	1603	1518	1411	5	0	0	0	0	0	0	0	0	0
Gas CTs	379	125	139	98	92	364	160	320	348	491	438	319	242	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	6208	7318	8036	8944	9538	9526	11481	11714	12744	13909	14571	14930	15201	15365	15400
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	14044	14191	14341	14500	14637	14758	14870	14978	15070	15160	15237	15303	15360	15422	15485

Appendix A – Detailed PLEXOS Modeling Results

Figure A-34 – Supplemental Scenario – Annual Energy by Resource

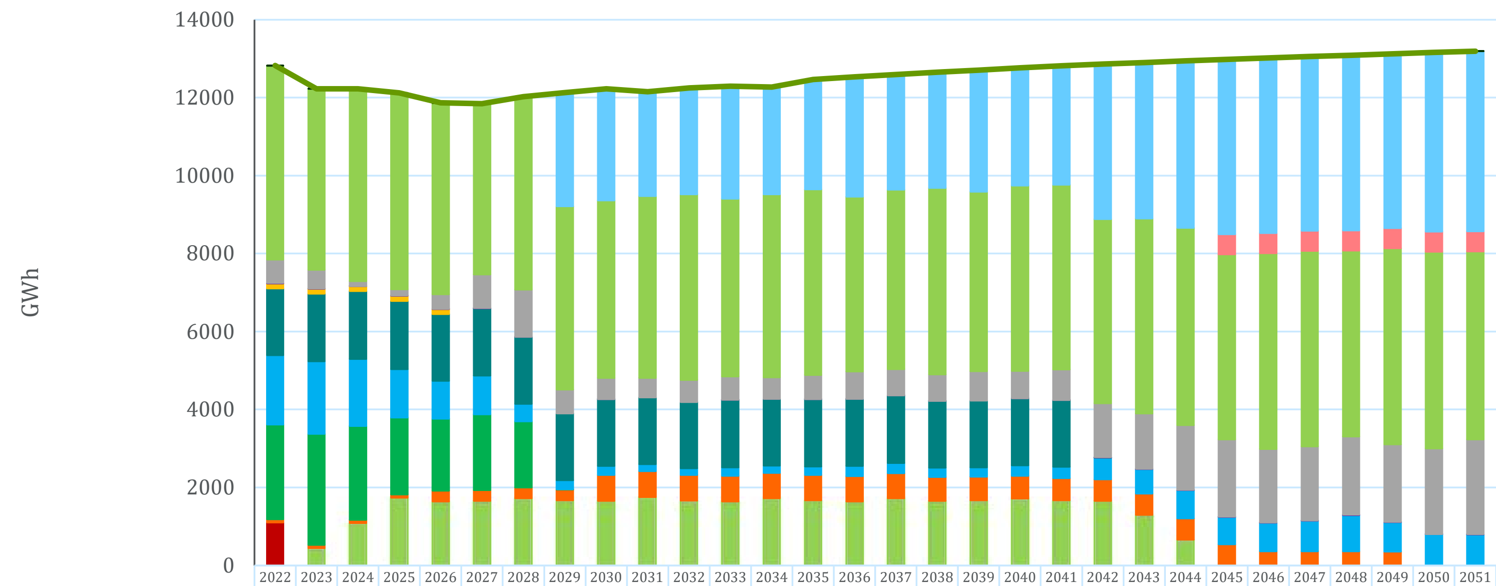


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	41	64	57	16	0	0	0	0	80	0	0	0	0	0	0
Advanced SC	0	0	0	0	0	0	0	758	717	737	725	665	689	323	404
BBCC 2x1	4976	4656	4976	5157	5062	4501	5075	5055	4097	4452	4717	4319	4445	3206	3189
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal STs	247	342	72	124	568	1098	995	1272	0	0	0	0	0	0	0
Diesel CTs	66	106	93	48	9	13	3	12	14	2	0	10	0	0	1
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1737	1749	1713	1733	1718	1713	1503	1686	1689	1724	1713	1649	1635
Gas CTs	1777	2218	2079	1358	1013	1221	1024	1370	1532	1038	904	651	475	50	69
LMS100 PA+ 1x0	0	0	0	0	0	0	0	202	202	202	202	202	202	181	196
NorthSide ST3	2693	3153	2685	2653	2118	2061	1773	264	0	0	0	0	0	0	0
Solar PV	86	85	85	84	868	864	861	855	3349	3379	3372	4134	4113	6430	6398
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12926	12996	13054	13096	13122	13138	13150	13148	13147	13148	13158	13166	13181	13197

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	344	305	299	103	146	396	312	394	198	200	135	111	82	0	0
BBCC 2x1	3049	3327	3198	1969	1912	2840	2533	2817	1734	1734	1302	1056	864	0	0
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	204	213
Coal STs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel CTs	0	0	0	0	0	1	0	0	0	0	1	0	0	0	0
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1629	1612	1610	1371	1344	5	0	0	0	0	0	0	0	0	0
Gas CTs	88	40	65	41	37	105	67	136	99	56	65	19	13	0	0
LMS100 PA+ 1x0	181	167	170	70	105	192	159	202	139	108	75	76	53	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	6551	6498	6639	8564	8660	8697	9602	9785	11339	12006	12616	12969	13362	13543	13541
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	13221	13254	13292	13338	13373	13392	13408	13420	13434	13446	13452	13448	13452	13461	13472

Appendix A – Detailed PLEXOS Modeling Results

Figure A-35 – Low Load Sensitivity – Annual Energy by Resource

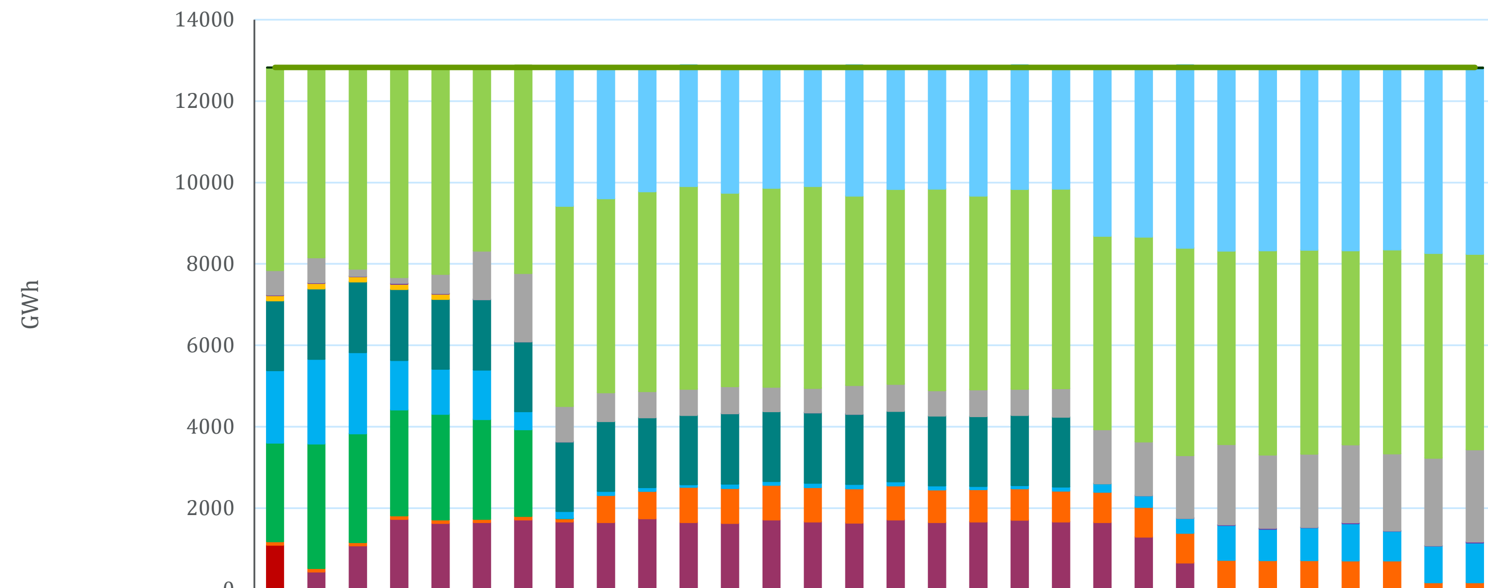


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	3	0	17	5	1	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	2913	2864	2675	2727	2880	2750	2819	3073
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	4971	4642	4936	5021	4901	4389	4950	4708	4553	4665	4765	4565	4692	4764	4489
Coal STs	599	482	125	156	379	859	1212	614	544	505	570	597	554	619	699
Diesel CTs	17	8	4	14	6	3	1	0	0	0	0	1	0	0	1
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1749	1713	1732	1718	1712	1712	1712	1698	1731	1712	1731	1717
Gas CTs	1779	1863	1717	1242	973	992	451	228	230	179	168	223	189	213	264
NorthSide ST3	2426	2844	2411	1975	1841	1942	1695	7	0	0	0	0	0	0	0
Solar PV	86	85	85	84	280	279	278	276	667	663	661	657	653	650	648
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12229	12228	12121	11864	11851	12026	12128	12225	12151	12247	12290	12269	12467	12531

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1
Advanced CC	2951	2967	3119	3016	3048	3975	4006	4293	4495	4506	4480	4501	4486	4613	4621
Advanced SC	0	0	0	0	0	0	0	0	513	513	514	516	516	516	516
BBCC 2x1	4605	4789	4606	4755	4741	4724	5004	5062	4752	5026	5020	4769	5029	5053	4826
Coal STs	677	675	755	705	781	1388	1420	1655	1976	1884	1900	2002	1993	2192	2431
Diesel CTs	1	2	0	3	0	7	7	10	9	9	6	17	5	4	5
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1731	1712	1711	1716	1712	5	0	0	0	0	0	0	0	0	0
Gas CTs	267	240	245	269	296	554	624	724	704	729	788	931	753	800	794
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	642	612	602	585	565	553	546	544	540	361	359	357	355	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	12593	12652	12708	12763	12813	12859	12902	12944	12983	13023	13059	13090	13122	13157	13193

Appendix A – Detailed PLEXOS Modeling Results

Figure A-36 – No Load Growth Sensitivity – Annual Energy by Resource

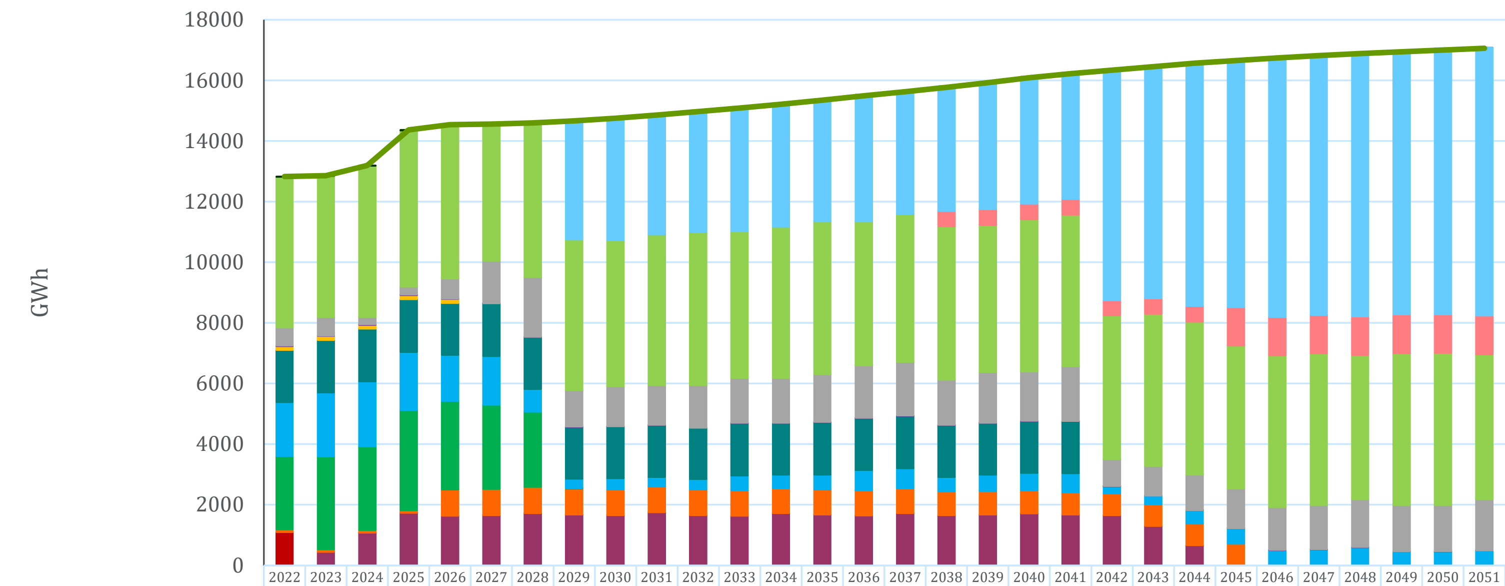


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	10	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	3430	3247	3075	2976	3111	2983	2945	3214
BBCC 2x1	4971	4655	4974	5154	5086	4518	5101	4918	4766	4907	4979	4752	4891	4957	4651
Coal STs	599	619	182	145	477	1193	1677	867	709	645	644	660	599	599	708
Diesel CTs	17	15	3	18	10	2	1	0	0	0	0	2	0	1	0
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1749	1714	1733	1718	1713	1713	1713	1699	1732	1714	1733	1718
Gas CTs	1779	2079	1999	1210	1113	1213	443	166	96	95	67	105	97	103	108
NorthSide ST3	2425	3060	2666	2605	2593	2448	2130	7	0	0	0	0	0	0	0
Solar PV	86	85	85	84	84	83	83	83	671	667	862	856	851	847	844
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	13	0	0	0	0	23
Advanced CC	3013	3006	3178	3043	3006	4166	4187	4492	4506	4480	4480	4521	4478	4559	4557
BBCC 2x1	4789	4955	4762	4911	4902	4756	5032	5093	4752	5016	5016	4765	5013	5035	4802
Coal STs	667	623	658	648	701	1324	1320	1543	1970	1806	1795	1918	1893	2147	2268
Diesel CTs	0	0	0	0	0	0	0	3	14	22	12	20	8	12	16
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1732	1713	1713	1718	1713	5	0	0	0	0	0	0	0	0	0
Gas CTs	98	98	79	76	106	208	285	363	858	766	807	911	728	897	983
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	837	806	795	777	756	744	735	733	728	724	720	717	712	178	177
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827	12827

Appendix A – Detailed PLEXOS Modeling Results

Figure A-37 – High Load Sensitivity – Annual Energy by Resource

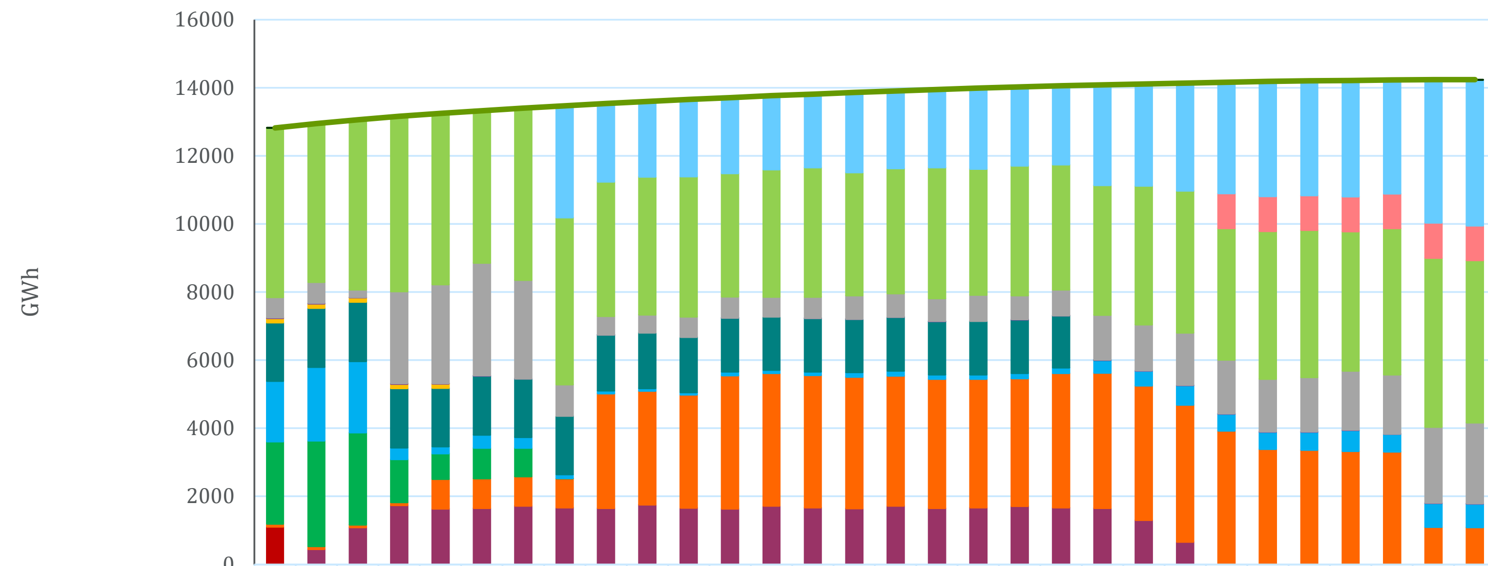


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	4	5	19	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	3952	4051	3971	4005	4105	4080	4037	4185
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	4971	4656	4989	5156	5084	4518	5101	4965	4826	4976	5064	4838	4989	5041	4748
Coal STs	600	616	243	256	662	1405	1974	1208	1318	1311	1398	1475	1474	1580	1731
Diesel CTs	17	13	16	25	13	7	5	3	1	1	0	11	4	7	8
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1713	1733	1738	1749	1714	1733	1718	1712	1713	1713	1698	1732	1712	1732	1717
Gas CTs	1783	2109	2147	1906	1517	1612	749	312	371	318	340	486	437	489	674
NorthSide ST3	2421	3065	2755	3309	2922	2777	2484	22	0	0	0	0	0	0	0
Solar PV	86	85	85	84	868	864	861	855	851	847	844	838	834	829	827
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12852	13188	14368	14534	14558	14599	14664	14750	14850	14966	15085	15211	15347	15491

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced CC	4071	4114	4216	4189	4170	7637	7678	8041	8130	8561	8578	8708	8707	8776	8850
Advanced SC	0	516	516	518	516	486	507	517	1274	1274	1274	1278	1274	1274	1273
BBCC 2x1	4876	5056	4850	5017	5005	4753	5024	5051	4713	4998	4998	4752	5007	5013	4786
Coal STs	1761	1490	1672	1624	1803	884	976	1171	1308	1413	1463	1574	1534	1535	1693
Diesel CTs	13	5	0	11	9	0	2	5	6	5	3	8	1	1	1
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1732	1712	1713	1718	1713	5	0	0	0	0	0	0	0	0	0
Gas CTs	663	474	545	574	630	230	283	439	509	503	524	596	459	457	487
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	819	788	777	760	738	726	718	715	710	0	0	0	0	0	0
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	15623	15770	15920	16084	16216	16337	16449	16562	16649	16739	16816	16887	16939	17001	17064

Appendix A – Detailed PLEXOS Modeling Results

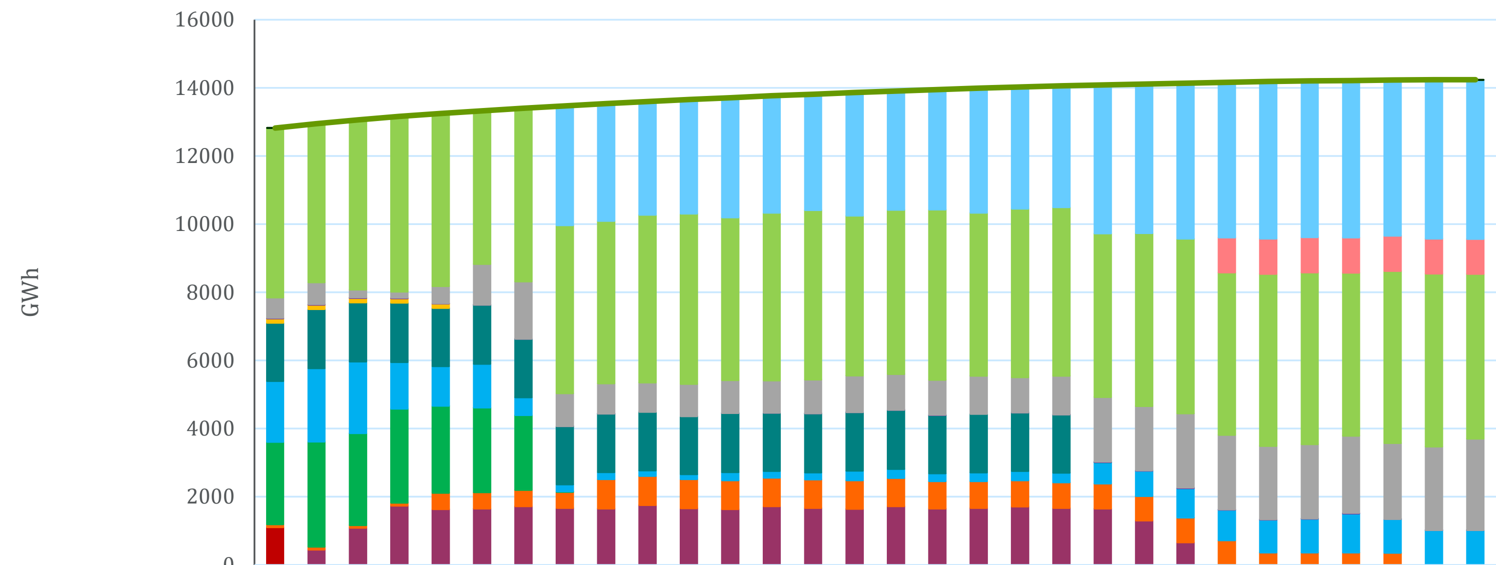
Figure A-38 – High Fuel Sensitivity – Annual Energy by Resource



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	8	5	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8
Advanced CC	0	0	0	0	0	0	0	3310	2331	2247	2294	2264	2207	2194	2392	2314	2326	2414	2353	2349	2984	3031	3202	3266	3376	3367	3407	3344	4214	4280
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1028	1021	1018	1028	1021	1032	1018
BBCC 2x1	4970	4656	4982	5152	5053	4504	5079	4910	3949	4052	4126	3620	3739	3807	3608	3672	3845	3701	3813	3675	3816	4072	4171	3860	4341	4326	4096	4298	4965	4769
Coal STs	600	614	224	2694	2904	3310	2898	923	545	530	595	627	588	617	694	689	674	765	701	765	1314	1350	1543	1577	1548	1593	1730	1737	2234	2378
Diesel CTs	17	14	14	17	6	3	2	0	0	0	0	2	0	0	1	1	3	0	4	1	7	8	9	9	9	8	12	5	6	5
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1748	1713	1733	1718	1713	1641	1632	1623	1578	1559	1573	1566	1585	1566	1570	1573	1528	5	0	0	0	0	0	0	0	0	0
Gas CTs	1783	2165	2097	344	213	390	312	111	86	72	67	107	96	102	137	143	126	133	155	160	372	438	567	494	506	533	616	523	708	694
NorthSide ST3	2421	3105	2704	1262	748	900	839	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	86	85	85	84	868	864	861	855	3365	3346	3326	3914	3896	3888	3861	3820	3794	3772	3752	3947	3970	3954	4026	3927	3382	3359	3325	3304	1091	1085
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	12827	12948	13057	13160	13250	13327	13399	13470	13534	13595	13654	13712	13764	13814	13862	13905	13949	13987	14024	14057	14085	14111	14137	14160	14183	14201	14212	14225	14242	14237

Appendix A – Detailed PLEXOS Modeling Results

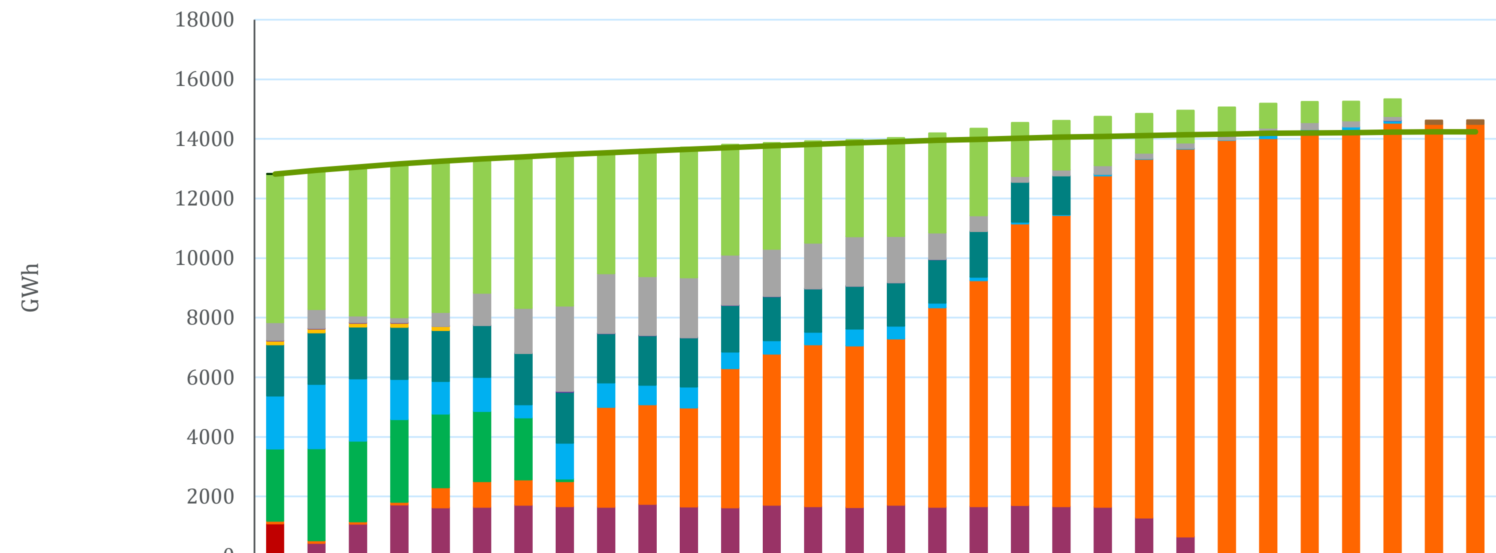
Figure A-39 – Regulated CO_2 Sensitivity – Annual Energy by Resource



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	8	5	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	6
Advanced CC	0	0	0	0	0	0	0	3534	3467	3354	3380	3545	3459	3432	3648	3519	3553	3687	3601	3599	4392	4404	4597	4551	4614	4594	4602	4574	4679	4671
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1029	1029	1031	1035	1032	1032	1022
BBCC 2x1	4971	4656	4982	5155	5088	4519	5101	4931	4777	4924	4996	4781	4927	4979	4692	4819	4998	4789	4948	4945	4799	5080	5128	4765	5051	5044	4788	5048	5072	4837
Coal STs	598	638	229	173	504	1191	1683	964	885	862	950	965	945	989	1074	1052	1032	1119	1033	1135	1899	1887	2185	2191	2153	2173	2265	2231	2451	2681
Diesel CTs	17	14	13	17	8	4	2	0	1	0	0	3	2	1	2	4	3	0	5	1	12	12	15	11	10	7	14	6	6	5
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1748	1713	1733	1718	1713	1713	1713	1699	1732	1713	1732	1718	1732	1713	1713	1718	1713	5	0	0	0	0	0	0	0	0	0
Gas CTs	1781	2155	2096	1367	1163	1283	524	208	209	167	149	235	190	204	283	265	235	255	272	282	624	738	864	895	966	996	1149	986	1014	1014
NorthSide ST3	2424	3090	2700	2759	2550	2487	2196	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	86	85	85	84	476	474	472	469	859	855	852	846	842	837	834	827	796	785	768	746	734	726	723	718	361	359	357	355	0	0
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	12827	12948	13057	13160	13250	13327	13399	13470	13534	13595	13654	13712	13764	13814	13862	13905	13949	13987	14024	14057	14085	14111	14137	14160	14183	14201	14212	14225	14242	14237

Appendix A – Detailed PLEXOS Modeling Results

Figure A-40 – Net Zero Sensitivity – Annual Energy by Resource

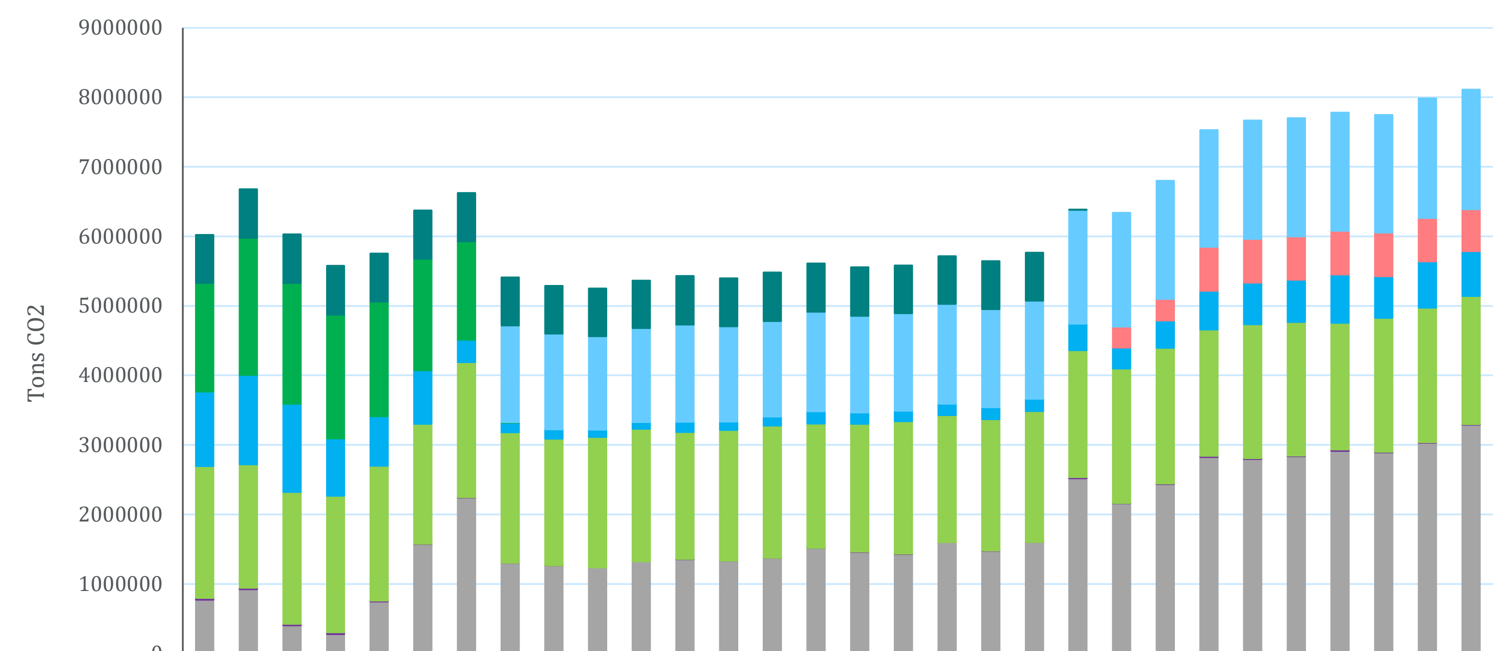


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Market Purchase	8	5	3	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	4971	4656	4978	5155	5081	4514	5094	5080	4081	4256	4351	3696	3560	3410	3235
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal STs	600	637	231	172	464	1081	1512	2861	2005	1973	2013	1677	1583	1532	1662
Diesel CTs	17	14	14	19	7	4	2	24	12	9	6	12	3	3	5
Firm Purchases	129	129	129	129	130	0	0	0	0	0	0	0	0	0	0
FPL PPA	1714	1733	1738	1749	1713	1733	1718	1713	1648	1655	1644	1567	1481	1448	1434
Gas CTs	1779	2155	2096	1352	1094	1148	443	1198	817	656	709	560	445	420	568
NorthSide ST3	2424	3092	2702	2775	2472	2352	2074	90	0	0	0	0	0	0	0
Solar PV	86	85	85	84	671	860	854	844	3354	3343	3324	4662	5077	5437	5420
TEA Purchases	1099	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	0	442	1082	1735	1637	1654	1721	1670	1654	1752	1658	1637	1718	1670	1642
Energy Load (from Loads)	12827	12948	13057	13160	13250	13327	13399	13470	13534	13595	13654	13712	13764	13814	13862

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Market Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BBCC 2x1	3295	3331	2906	1790	1647	1627	1308	1081	911	814	676	632	567	0	0
BioMass	0	0	0	0	0	0	0	0	0	0	0	0	0	122	130
Coal STs	1548	897	530	188	193	293	184	184	169	236	235	207	142	0	0
Diesel CTs	4	5	0	0	0	0	0	0	0	3	0	0	4	0	0
Firm Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL PPA	1457	1460	1533	1345	1302	5	0	0	0	0	0	0	0	0	0
Gas CTs	429	149	113	56	28	50	19	21	14	105	129	90	81	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV	5579	6695	7588	9448	9769	11113	12032	13006	13962	14025	14199	14320	14540	14496	14497
TEA Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle	1718	1654	1670	1712	1670	1654	1296	660	0	0	0	0	0	0	0
Energy Load (from Loads)	13905	13949	13987	14024	14057	14085	14111	14137	14160	14183	14201	14212	14225	14242	14237

Appendix A – Detailed PLEXOS Modeling Results

Figure A-41 – Current Outlook Scenario - CO_2 Emissions by Resource Type

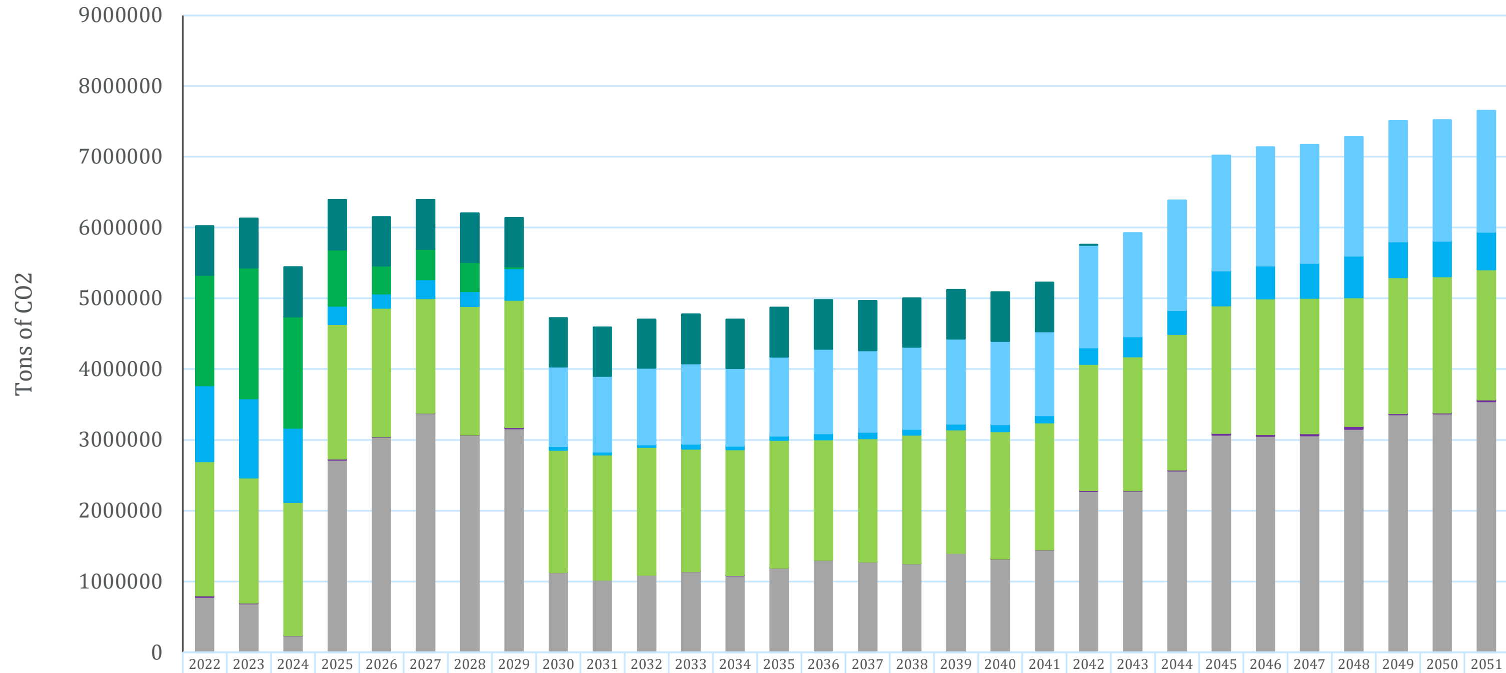


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	7797	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	8E+05	7E+05	8E+05	3E+05	1E+05	1E+05	1E+05	97443	2E+05	1E+05	1E+05	2E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	24520	20756	18800	23177	10592	6455	2655	570.6	1106	0	0	4865	3188	1650	2500
Coal STs	8E+05	9E+05	4E+05	3E+05	8E+05	2E+06	2E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	3E+05	3E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	2E+05	2E+05	2E+05	2E+05	2E+05	4E+05	3E+05	4E+05	6E+05	6E+05	6E+05	7E+05	6E+05	7E+05	6E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	5874	3763	0	7455	2151	15863	4852	6561	18420	14570	9390	20461	8362	10291	11030
Coal STs	1E+06	1E+06	2E+06	1E+06	2E+06	3E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-42 – Economic Downturn Scenario - CO_2 Emissions by Resource Type

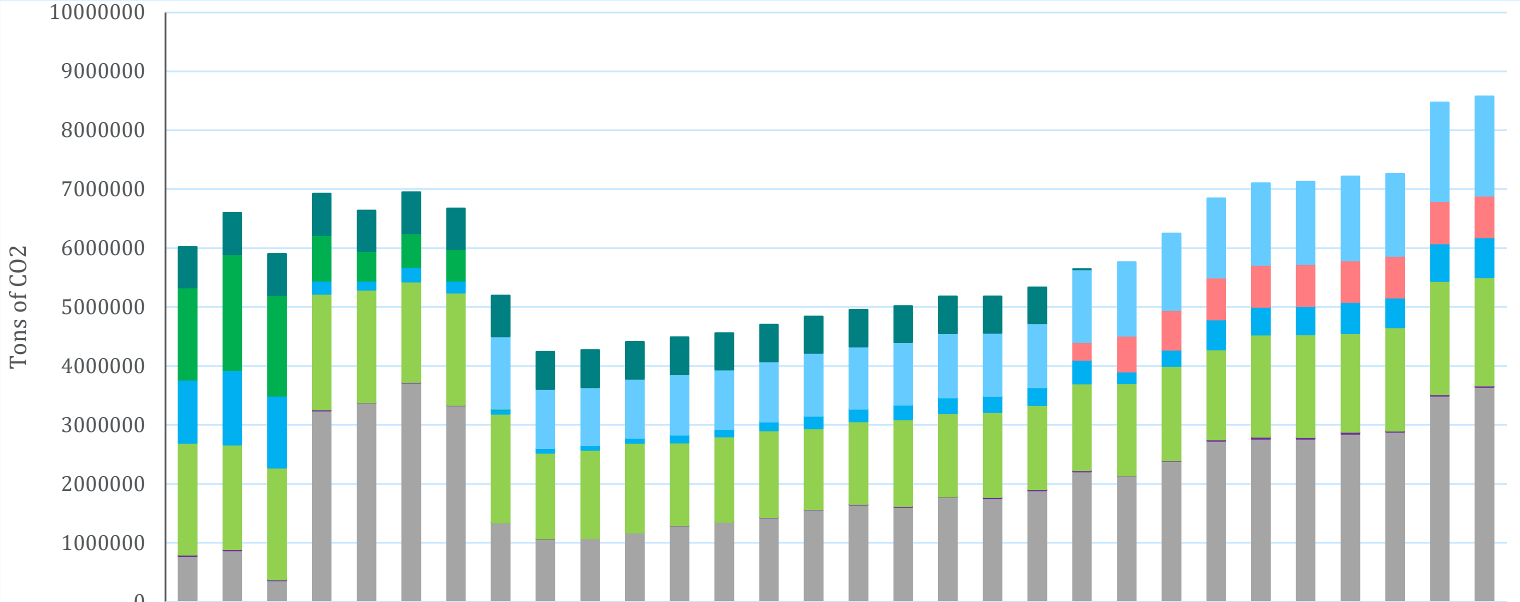


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	8E+05	4E+05	4E+05	4E+05	21260	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	3E+05	2E+05	3E+05	2E+05	5E+05	53380	42419	35926	69278	50698	60814	86896
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	23941	10684	5842	17775	6809	4032	1938	16227	292	0	0	1559	292.7	188.6	1423
Coal STs	8E+05	7E+05	2E+05	3E+06	3E+06	3E+06	3E+06	3E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	88580	82345	81912	97272	1E+05	2E+05	3E+05	3E+05	5E+05	5E+05	5E+05	6E+05	5E+05	5E+05	5E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	1363	2615	0	4037	420.5	9797	9189	13024	26062	27261	28111	39488	16241	14208	23481
Coal STs	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	4E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-43 – Efficiency + DER Scenario - CO_2 Emissions by Resource Type

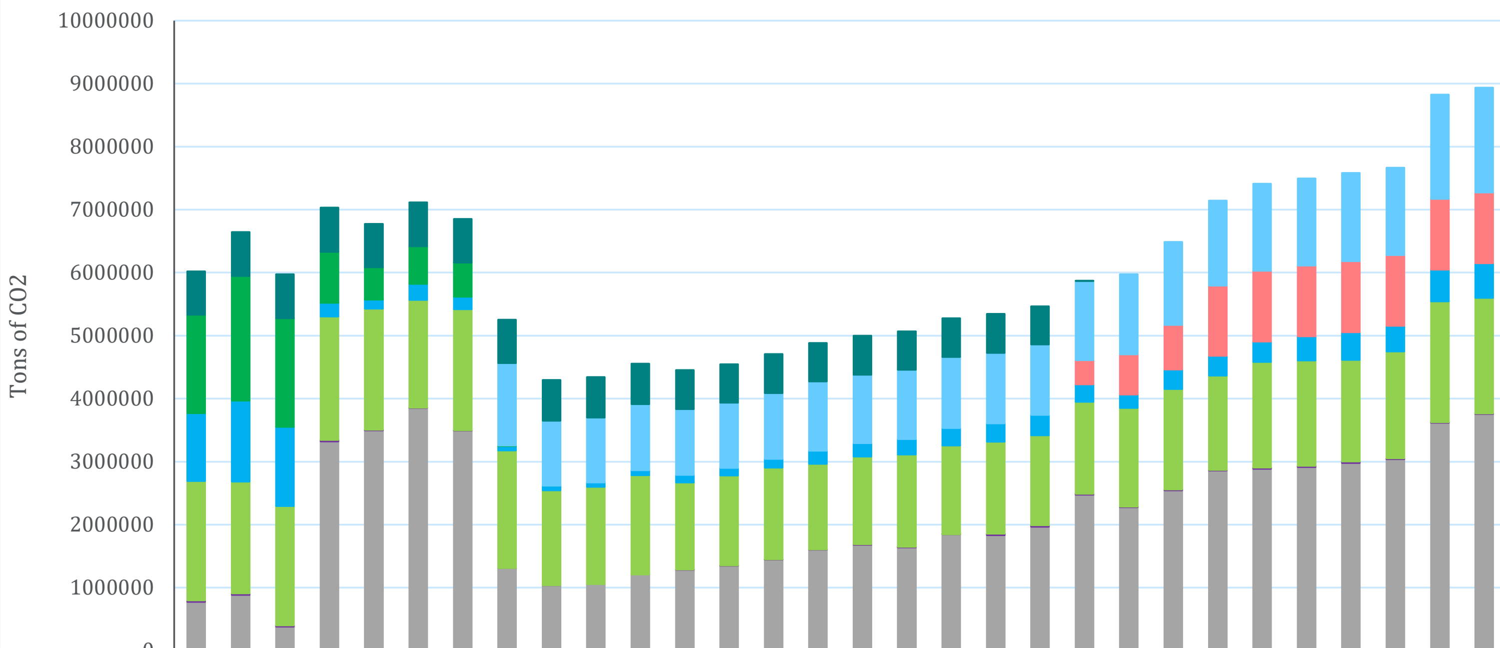


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	8E+05	5E+05	6E+05	5E+05	6520	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	2E+05	2E+05	2E+05	2E+05	77134	80426	78154	84284	1E+05	1E+05	1E+05	2E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06	2E+06	1E+06	1E+06	1E+06	1E+06
Diesel CTs	23972	19341	16167	21996	8791	5123	2902	443.6	1447	0	0	5799	3037	3389	3545
Coal STs	8E+05	9E+05	4E+05	3E+06	3E+06	4E+06	3E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	6E+05	6E+05	6E+05	6E+05	6E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	3E+05	6E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	2E+05	2E+05	3E+05	3E+05	3E+05	4E+05	2E+05	3E+05	5E+05	5E+05	5E+05	5E+05	5E+05	6E+05	7E+05
BBCC 2x1	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	9153	11408	2301	21524	19661	22165	5839	10497	24795	35231	31298	32946	18945	25518	25279
Coal STs	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	4E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-44 – Increased Electrification Scenario - CO_2 Emissions by Resource Type

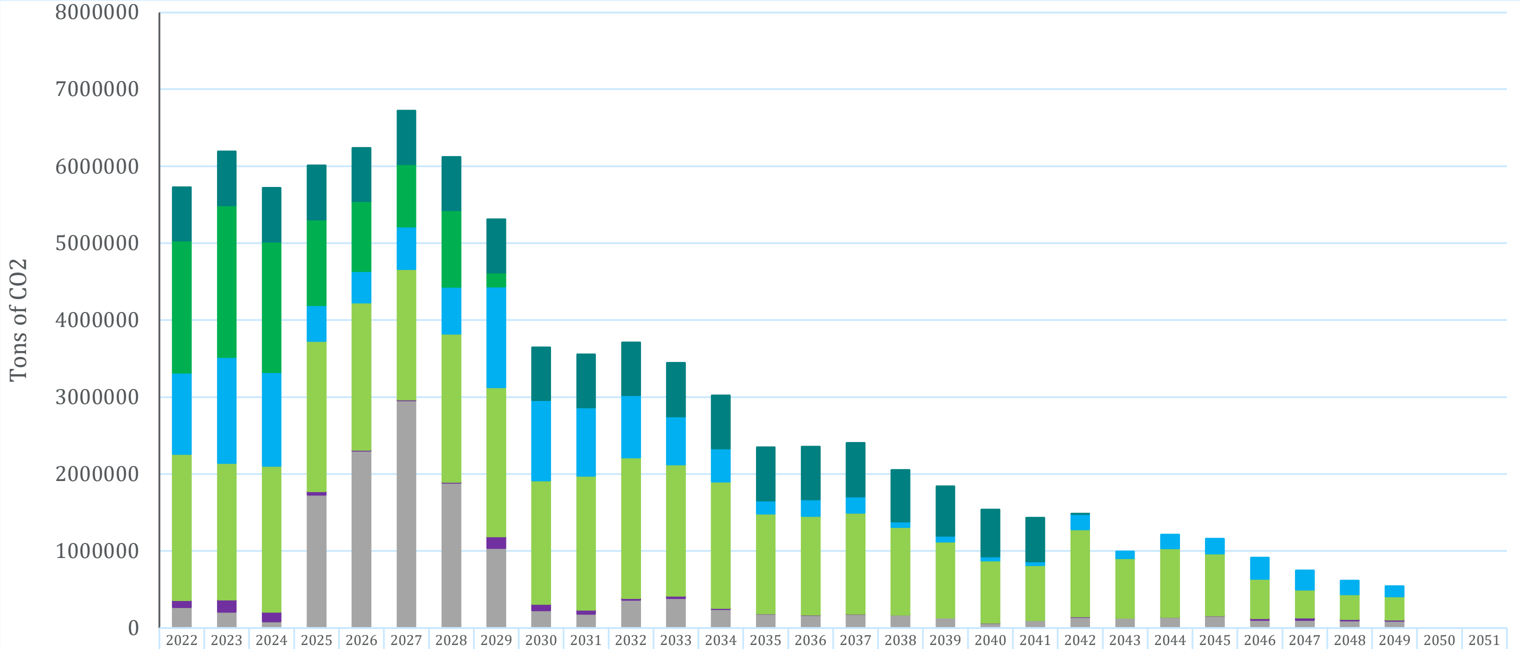


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	8E+05	5E+05	6E+05	5E+05	5611	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	2E+05	1E+05	3E+05	2E+05	72567	71343	68602	76749	1E+05	1E+05	1E+05	2E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06	1E+06	1E+06
Diesel CTs	23972	20125	18951	22597	8952	5065	2303	279.7	719.8	0	0	5318	2415	3551	3779
Coal STs	8E+05	9E+05	4E+05	3E+06	3E+06	4E+06	3E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	6E+05	6E+05	6E+05	6E+05	6E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	4E+05	6E+05	7E+05	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	2E+05	2E+05	3E+05	3E+05	3E+05	3E+05	2E+05	3E+05	3E+05	3E+05	4E+05	4E+05	4E+05	5E+05	6E+05
BBCC 2x1	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	9497	11751	1556	22716	22104	14428	8097	12688	11348	20139	20190	21472	12801	10748	12019
Coal STs	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	4E+06	4E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-45 – Future Net Zero Scenario - CO_2 Emissions by Resource Type

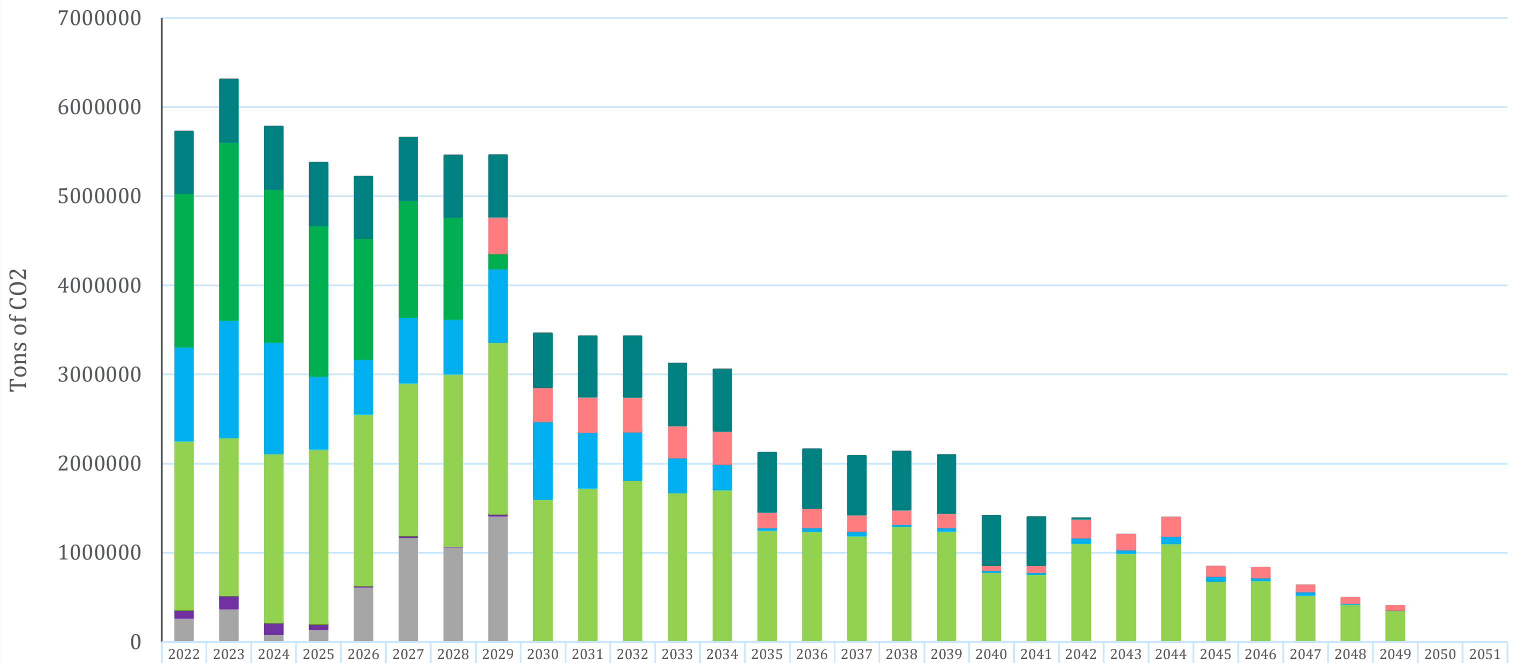


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	1E+06	9E+05	8E+05	1E+06	2E+05	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	5E+05	4E+05	6E+05	6E+05	1E+06	1E+06	9E+05	8E+05	6E+05	4E+05	2E+05	2E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06
Diesel CTs	92233	2E+05	1E+05	42876	12183	12391	11001	2E+05	83847	52561	22667	31219	12905	3457	4317
Coal STs	3E+05	2E+05	86395	2E+06	2E+06	3E+06	2E+06	1E+06	2E+05	2E+05	4E+05	4E+05	2E+05	2E+05	2E+05

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	6E+05	6E+05	6E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	2E+05	70165	75353	54030	50239	2E+05	87641	2E+05	2E+05	3E+05	2E+05	2E+05	1E+05	0	0
BBCC 2x1	1E+06	1E+06	1E+06	8E+05	7E+05	1E+06	8E+05	9E+05	8E+05	5E+05	4E+05	3E+05	3E+05	0	0
Diesel CTs	1630	495.7	0	1633	0	8185	0	757	6397	20537	31885	19861	16319	0	0
Coal STs	2E+05	2E+05	1E+05	64682	1E+05	1E+05	1E+05	1E+05	2E+05	1E+05	1E+05	95976	93391	0	0

Appendix A – Detailed PLEXOS Modeling Results

Figure A-46 – Supplemental Scenario - CO_2 Emissions by Resource Type

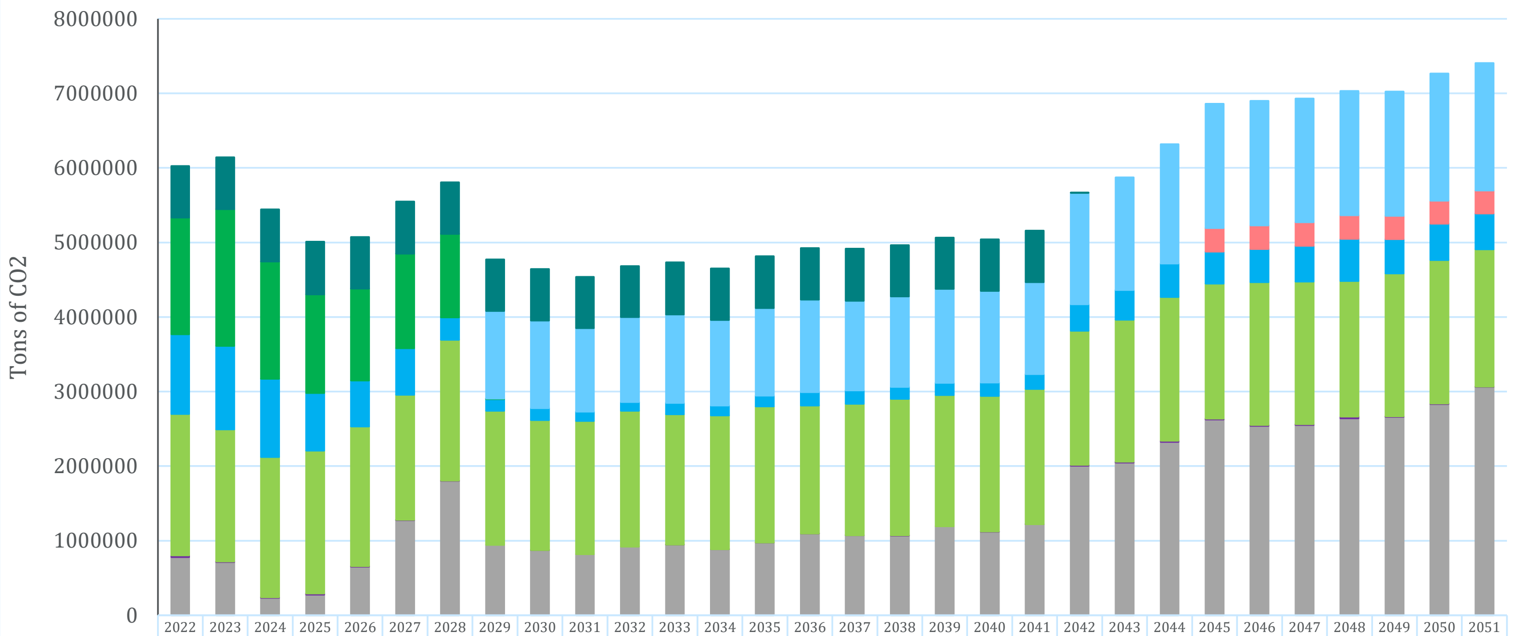


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	6E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	0	0	0	0	0	0	0	4E+05	4E+05	4E+05	4E+05	4E+05	4E+05	2E+05	2E+05
NorthSide ST3	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06	1E+06	2E+05	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	8E+05	6E+05	7E+05	6E+05	8E+05	9E+05	6E+05	5E+05	4E+05	3E+05	29869	40708
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06
Diesel CTs	92573	1E+05	1E+05	63072	11590	18285	3699	16531	17971	1928	533	13181	251.5	0	765.9
Coal STs	3E+05	4E+05	87755	1E+05	6E+05	1E+06	1E+06	1E+06	0	0	0	0	0	0	0

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	6E+05	6E+05	6E+05	5E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	2E+05	2E+05	2E+05	54963	77763	2E+05	2E+05	2E+05	1E+05	1E+05	71771	59102	43349	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	52330	24253	39142	23630	22224	61833	40517	81269	56082	32341	37922	10988	8170	0	0
BBCC 2x1	1E+06	1E+06	1E+06	8E+05	8E+05	1E+06	1E+06	1E+06	7E+05	7E+05	5E+05	4E+05	4E+05	0	0
Diesel CTs	0	0	0	0	0	1803	0	31.39	0	0	1378	0	0	0	0
Coal STs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix A – Detailed PLEXOS Modeling Results

Figure A-47 – Low Load Sensitivity - CO_2 Emissions by Resource Type

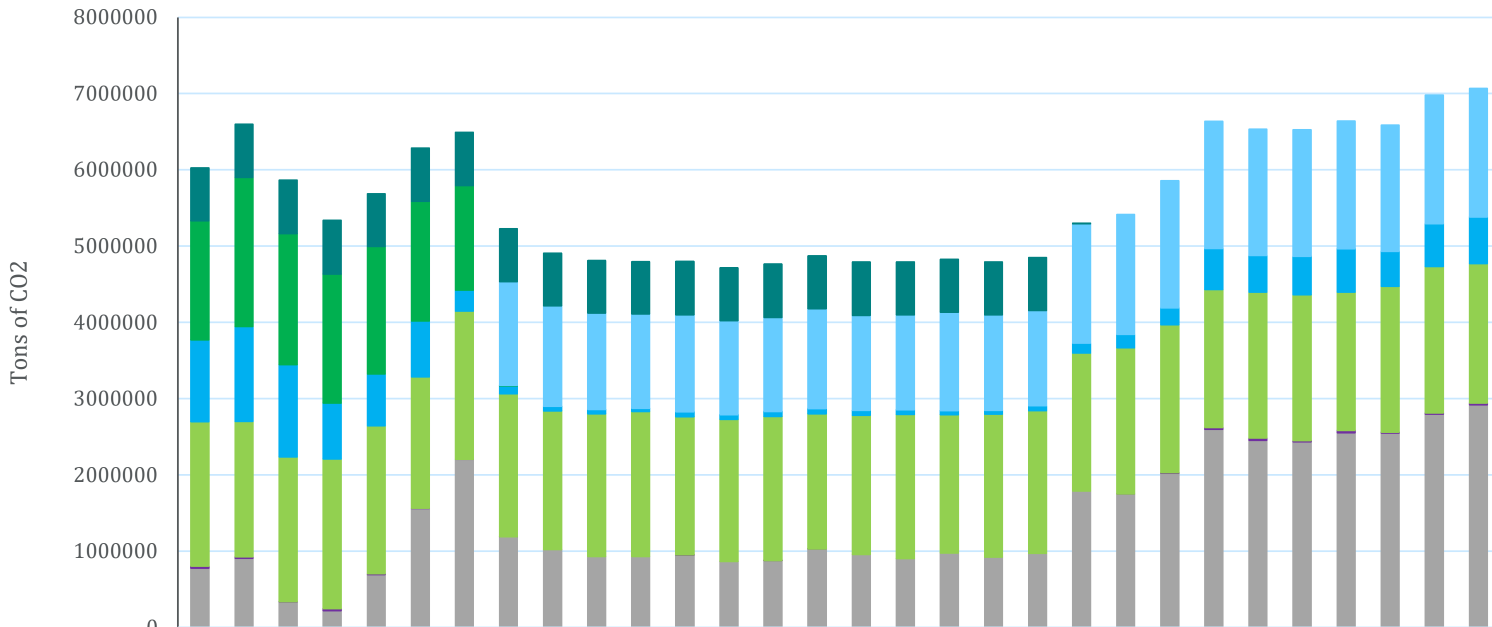


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	1E+06	1E+06	1E+06	1E+06	6274	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	8E+05	6E+05	6E+05	3E+05	2E+05	2E+05	1E+05	1E+05	2E+05	1E+05	1E+05	2E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	24208	10828	5839	18153	7613	4701	2131	0	345.3	0	0	1723	497.2	226.5	1525
Coal STs	8E+05	7E+05	2E+05	3E+05	7E+05	1E+06	2E+06	9E+05	9E+05	8E+05	9E+05	9E+05	9E+05	1E+06	1E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	0	0	3E+05	3E+05	3E+05	3E+05	3E+05	3E+05	3E+05
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	2E+05	2E+05	2E+05	2E+05	2E+05	4E+05	4E+05	5E+05	4E+05	4E+05	5E+05	6E+05	5E+05	5E+05	5E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	1574	2631	0	4279	404.6	10219	9917	14291	12777	13590	9566	24096	7752	6140	7252
Coal STs	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-48 – No Load Growth Sensitivity - CO_2 Emissions by Resource Type

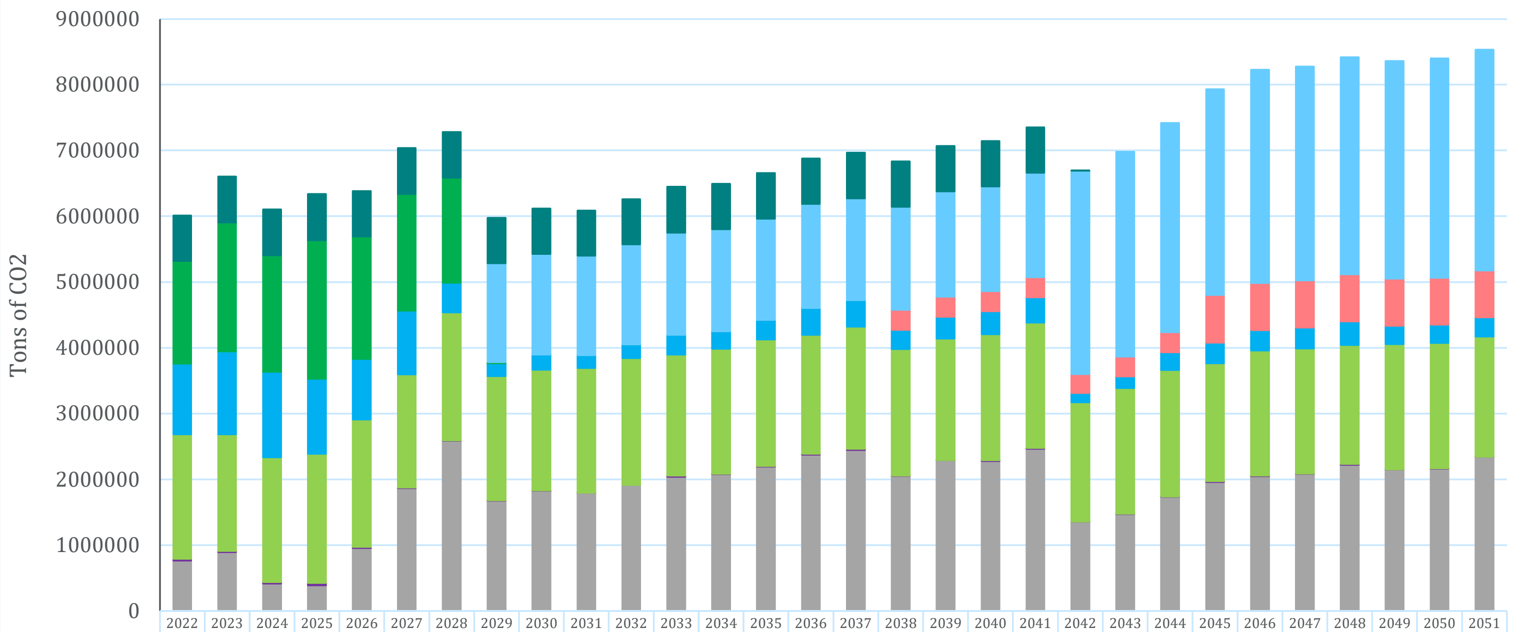


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	6052	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	7E+05	7E+05	7E+05	3E+05	1E+05	60612	60050	43296	65855	61167	64673	67441
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	24362	21949	4545	23403	13059	2186	1551	351.3	0	0	0	2092	0	1482	411.8
Coal STs	8E+05	9E+05	3E+05	2E+05	7E+05	2E+06	2E+06	1E+06	1E+06	9E+05	9E+05	9E+05	9E+05	9E+05	1E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	62194	61179	50940	48577	66418	1E+05	2E+05	2E+05	5E+05	5E+05	5E+05	6E+05	5E+05	6E+05	6E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	0	0	0	0	0	0	676.5	4673	21066	30710	17183	28551	12210	17799	23633
Coal STs	1E+06	9E+05	1E+06	9E+05	1E+06	2E+06	2E+06	2E+06	3E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-49 – High Load Sensitivity - CO_2 Emissions by Resource Type

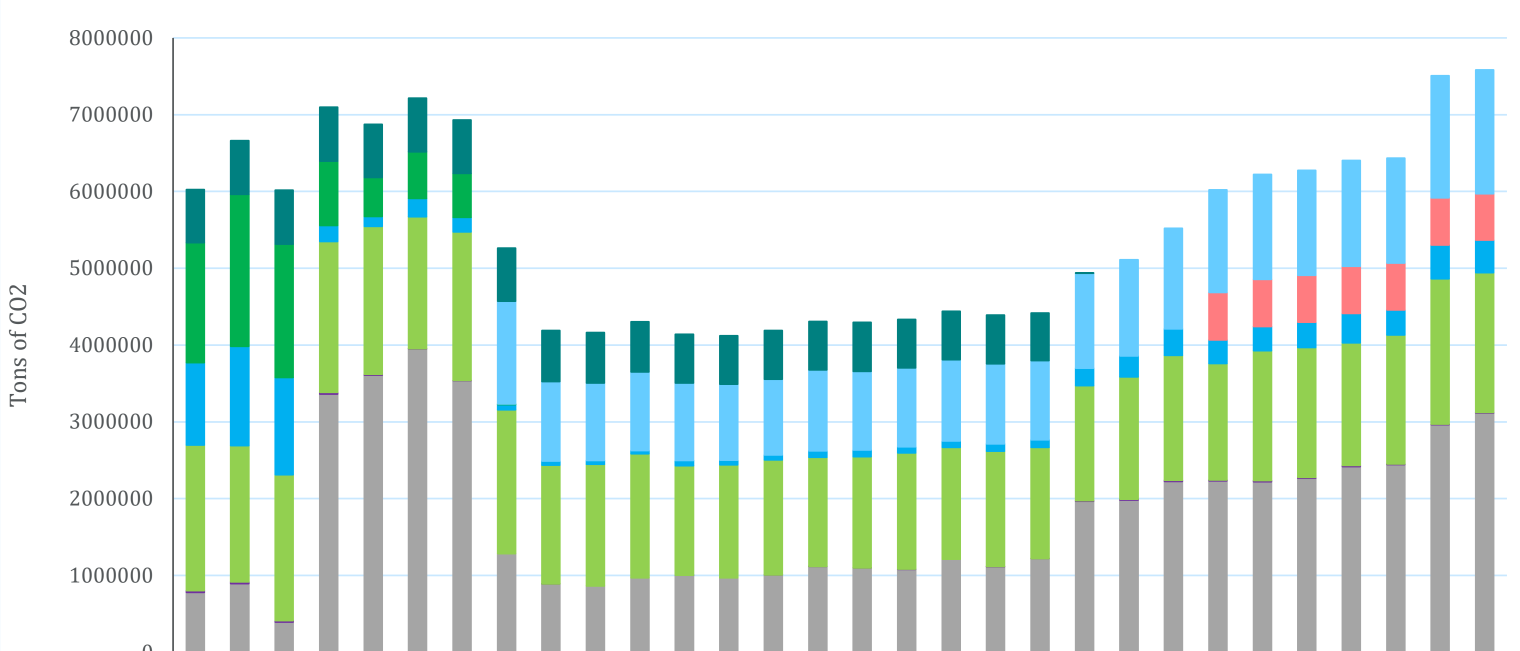


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	16640	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	1E+06	9E+05	1E+06	5E+05	2E+05	2E+05	2E+05	2E+05	3E+05	3E+05	3E+05	4E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	23936	19492	22440	32195	18024	10516	6647	4215	2214	1179	0	14933	5861	9534	10800
Coal STs	8E+05	9E+05	4E+05	4E+05	1E+06	2E+06	3E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	2E+06	2E+06	2E+06	2E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06
Advanced SC	0	3E+05	3E+05	3E+05	3E+05	3E+05	3E+05	3E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	4E+05	3E+05	3E+05	3E+05	4E+05	1E+05	2E+05	3E+05	3E+05	3E+05	3E+05	4E+05	3E+05	3E+05	3E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	17539	6465	527.2	15465	13039	779.3	2187	7290	8994	6690	4699	11584	1786	1909	1337
Coal STs	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-50 – High Fuel Sensitivity - CO_2 Emissions by Resource Type

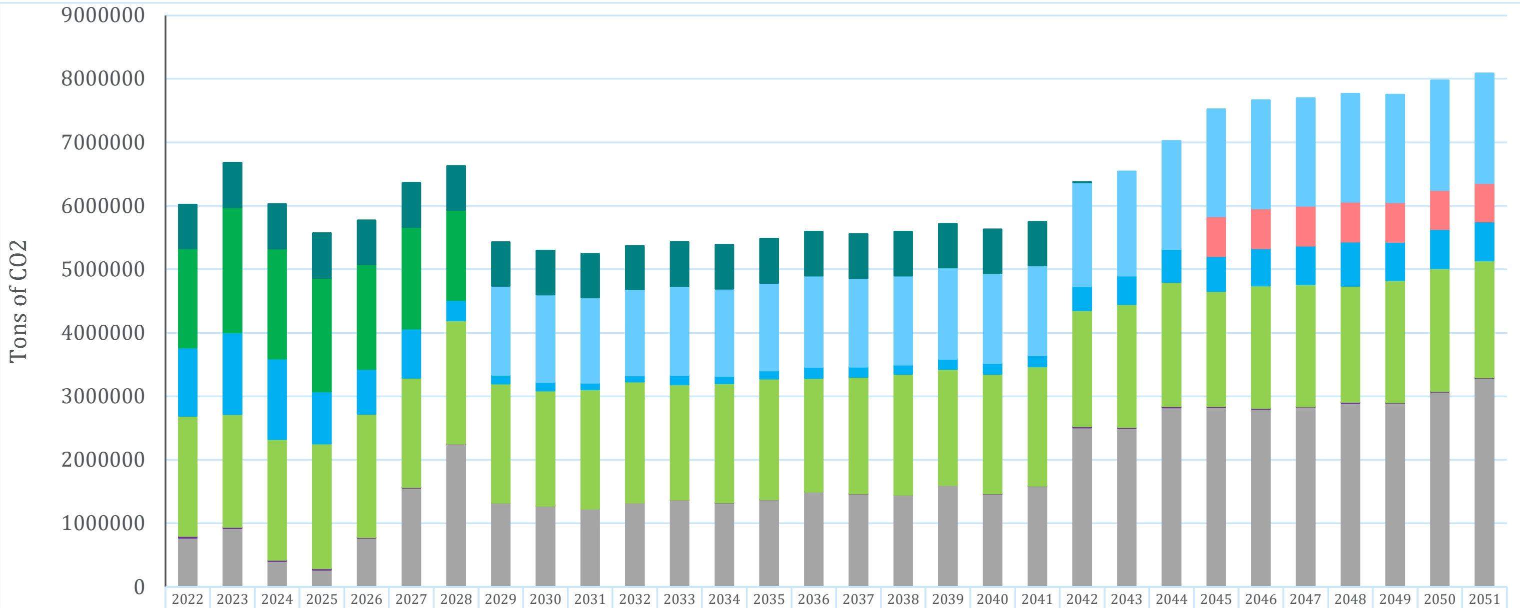


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	6E+05	6E+05	6E+05	6E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	8E+05	5E+05	6E+05	6E+05	6440	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	2E+05	1E+05	2E+05	2E+05	69708	53914	46289	42768	67834	60231	64690	85367
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06	1E+06	1E+06
Diesel CTs	23993	20517	19541	22609	8616	4616	2423	0	251.2	0	0	2211	0	841.2	1150
Coal STs	8E+05	9E+05	4E+05	3E+06	4E+06	4E+06	4E+06	1E+06	9E+05	9E+05	1E+06	1E+06	1E+06	1E+06	1E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	6E+05	6E+05	6E+05	6E+05	6E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	0	0	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	88071	78728	83358	96606	99761	2E+05	3E+05	3E+05	3E+05	3E+05	3E+05	4E+05	3E+05	4E+05	4E+05
BBCC 2x1	1E+06	2E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	1813	3685	0	5652	1420	10436	10719	13650	12470	13699	11500	16949	7371	8625	7736
Coal STs	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	3E+06	3E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-51 – Regulated CO_2 Sensitivity - CO_2 Emissions by Resource Type

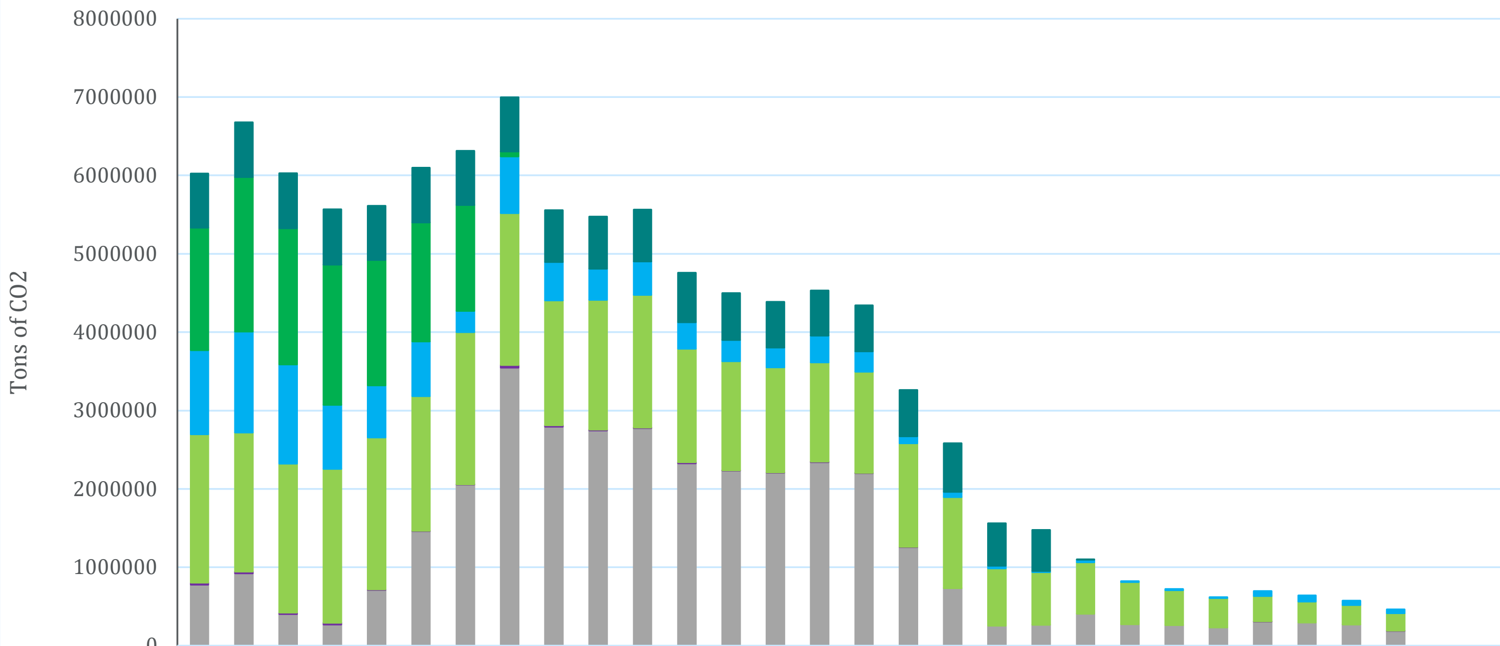


	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05
Advanced CC	0	0	0	0	0	0	0	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	7771	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	8E+05	7E+05	8E+05	3E+05	1E+05	1E+05	1E+05	94853	1E+05	1E+05	1E+05	2E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	24519	20756	18800	22670	10648	6122	2623	405.8	1059	0	0	4766	3141	1602	2525
Coal STs	8E+05	9E+05	4E+05	3E+05	8E+05	2E+06	2E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06	1E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	1E+06	1E+06	1E+06	1E+06	1E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Advanced SC	0	0	0	0	0	0	0	0	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05	6E+05
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	2E+05	1E+05	2E+05	2E+05	2E+05	4E+05	4E+05	5E+05	5E+05	6E+05	6E+05	7E+05	6E+05	6E+05	6E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06
Diesel CTs	5811	3670	0	7365	2068	15796	16532	21620	15599	14319	11858	20892	8736	8972	7604
Coal STs	1E+06	1E+06	2E+06	1E+06	2E+06	3E+06	2E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06	3E+06

Appendix A – Detailed PLEXOS Modeling Results

Figure A-52 – Net Zero Sensitivity - CO_2 Emissions by Resource Type



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
FPL PPA	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	7E+05	6E+05	6E+05	6E+05	6E+05
Advanced CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	63149	0	0	0	0	0	0	0
Gas CTs	1E+06	1E+06	1E+06	8E+05	7E+05	7E+05	3E+05	7E+05	5E+05	4E+05	4E+05	3E+05	3E+05	3E+05	3E+05
BBCC 2x1	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	2E+06	1E+06	1E+06	1E+06	1E+06
Diesel CTs	24280	20683	19200	24045	9506	5199	2494	34208	15855	11563	7415	15061	3982	4311	6652
Coal STs	8E+05	9E+05	4E+05	3E+05	7E+05	1E+06	2E+06	4E+06	3E+06	3E+06	3E+06	2E+06	2E+06	2E+06	2E+06

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
FPL PPA	6E+05	6E+05	6E+05	5E+05	5E+05	1932	0	0	0	0	0	0	0	0	0
Advanced CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advanced SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NorthSide ST3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	3E+05	90326	67316	33675	16714	30486	11390	13294	8905	62032	76818	53409	48423	0	0
BBCC 2x1	1E+06	1E+06	1E+06	7E+05	7E+05	7E+05	5E+05	4E+05	4E+05	3E+05	3E+05	3E+05	2E+05	0	0
Diesel CTs	5142	6506	0	0	0	0	0	0	0	3900	0	0	4527	0	0
Coal STs	2E+06	1E+06	7E+05	3E+05	3E+05	4E+05	3E+05	3E+05	2E+05	3E+05	3E+05	3E+05	2E+05	0	0

Appendix A – Detailed PLEXOS Modeling Results

Table A-7 - Current Outlook Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	Cumulative Present Worth Cost (CPWC)
2022	12,827	-	12,818	8	0	821,483	-	105,662	54,737	41,911	118	969,175	1,023,912	-	-	1,023,912	1,023,911.79
2023	12,948	-	12,943	5	0	550,209	-	188,228	73,618	32,300	145	770,882	844,500	-	-	844,500	1,835,931.29
2024	13,057	-	13,054	3	-	439,883	-	231,266	75,420	27,803	118	699,070	774,490	-	-	774,490	2,551,990.67
2025	13,160	275	13,415	20	-	485,970	-	304,215	79,791	20,169	113	810,467	890,258	31,162	389,378	921,420	3,371,130.03
2026	13,250	266	13,507	9	-	494,093	13,808	260,853	82,356	30,423	118	799,296	881,652	31,162	-	912,814	4,151,407.17
2027	13,327	176	13,502	1	-	547,627	14,151	255,144	177,158	35,009	140	852,071	1,029,228	31,162	-	1,060,390	5,022,970.63
2028	13,399	191	13,590	0	-	566,714	14,503	265,470	86,515	40,451	148	887,286	973,801	31,162	-	1,004,962	5,817,207.08
2029	13,470	278	13,749	-	0	512,813	14,863	252,998	106,436	31,619	49	812,342	918,778	77,854	663,615	996,632	6,574,565.14
2030	13,534	290	13,824	-	0	520,723	28,718	251,522	100,608	37,700	47	838,710	939,319	77,854	-	1,017,172	7,317,803.07
2031	13,595	299	13,894	0	0	544,229	29,432	274,216	102,113	38,843	46	886,766	988,879	77,854	-	1,066,733	8,067,275.31
2032	13,654	290	13,944	-	-	579,983	30,163	262,704	99,807	40,458	49	913,358	1,013,165	77,854	-	1,091,019	8,804,328.33
2033	13,712	309	14,020	1	0	611,299	30,913	275,749	138,991	42,503	50	960,514	1,099,504	77,854	-	1,177,358	9,569,117.59
2034	13,764	305	14,069	-	0	629,364	31,681	300,776	106,900	42,824	49	1,004,695	1,111,595	77,854	-	1,189,449	10,312,043.70
2035	13,814	310	14,124	-	0	660,441	32,468	292,071	104,504	47,435	50	1,032,465	1,136,970	77,854	-	1,214,824	11,041,635.28
2036	13,862	309	14,171	0	0	705,202	33,275	281,269	158,587	51,309	55	1,071,111	1,229,698	77,854	-	1,307,552	11,796,713.90
2037	13,905	321	14,225	1	0	729,045	34,102	294,751	110,586	50,226	53	1,108,177	1,218,763	77,854	-	1,296,617	12,516,679.37
2038	13,949	329	14,278	-	0	768,220	34,949	273,834	137,510	52,106	53	1,129,162	1,266,672	77,854	-	1,344,526	13,234,532.79
2039	13,987	314	14,300	0	0	809,527	35,818	268,285	127,052	59,740	57	1,173,426	1,300,478	77,854	-	1,378,332	13,942,131.72
2040	14,024	328	14,350	1	-	841,703	36,708	283,614	150,102	59,736	54	1,221,816	1,371,918	77,854	-	1,449,772	14,657,779.84
2041	14,057	337	14,394	-	0	874,457	37,620	256,861	141,932	61,801	58	1,230,797	1,372,729	77,854	-	1,450,583	15,346,288.10
2042	14,085	359	14,441	2	0	1,096,340	38,555	274,439	106,619	66,027	88	1,475,449	1,582,069	77,854	-	1,659,923	16,103,855.07
2043	14,111	343	14,454	0	0	1,181,578	39,513	199,216	212,554	63,445	79	1,483,831	1,696,385	94,135	203,434	1,790,520	16,889,595.42
2044	14,137	362	14,498	1	0	1,301,164	40,495	101,308	138,288	67,254	88	1,510,310	1,648,598	97,683	44,342	1,746,282	17,626,448.42
2045	14,160	29	14,185	4	0	1,487,193	41,501	104,295	139,695	102,337	104	1,735,431	1,875,126	83,794	215,823	1,958,920	18,421,233.85
2046	14,183	28	14,209	3	0	1,579,285	19,973	102,097	132,705	105,455	104	1,806,915	1,939,620	83,794	-	2,023,414	19,210,611.02
2047	14,201	43	14,243	0	0	1,632,167	20,469	95,865	138,397	108,819	105	1,857,424	1,995,822	85,676	23,525	2,081,498	19,991,415.89
2048	14,212	58	14,263	6	0	1,711,480	20,978	121,402	151,208	109,941	108	1,963,910	2,115,118	87,592	23,941	2,202,711	20,785,909.88
2049	14,225	67	14,292	0	0	1,773,586	21,499	100,024	170,510	115,237	107	2,010,453	2,180,962	89,546	24,411	2,270,509	21,573,359.86
2050	14,242	79	14,319	2	0	1,891,759	-	109,151	147,647	115,870	112	2,116,892	2,264,539	90,918	17,146	2,355,458	22,358,851.94
2051	14,237	157	14,367	1	0	1,960,155	-	113,347	154,964	110,826	119	2,184,448	2,339,412	101,073	126,883	2,440,485	23,141,396.82

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$14,600.61	$ 378.13	$4,098.67	$2,070.30	$ 930.86	$ 1.59	$20,009.85	$22,080.15	$1,061.25		$23,141.40

Appendix A – Detailed PLEXOS Modeling Results

Table A-8 - Economic Downturn Scenario - Cumulative Present Worth Costs (CPWC)

	Energy					Production Cost		Plant O&M Costs									
YEAR	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	Cumulative Present Worth Cost (CPWC)
2022	12,827	-	12,818	8	0	821,384	-	105,196	54,737	42,095	118	968,792	1,023,529	-	-	1,023,529	1,023,529.19
2023	12,948	-	12,227	3	0	502,750	-	177,925	74,169	31,131	130	711,936	786,105	-	-	786,105	1,772,200.73
2024	13,057	-	12,227	0	-	392,114	-	217,223	76,563	25,707	101	635,144	711,707	-	-	711,707	2,417,740.17
2025	13,160	-	12,104	17	0	548,718	-	295,665	75,251	67,128	131	911,642	986,894	-	-	986,894	3,270,256.00
2026	13,250	-	11,859	5	0	539,552	12,371	254,506	78,467	58,195	119	864,742	943,209	-	-	943,209	4,046,236.47
2027	13,327	-	11,850	0	0	581,028	12,801	243,339	178,553	51,653	131	888,951	1,067,504	-	-	1,067,504	4,882,653.80
2028	13,399	-	12,026	0	0	611,005	13,247	258,998	84,042	50,811	120	934,180	1,018,222	-	-	1,018,222	5,642,466.79
2029	13,470	-	12,125	3	0	631,435	26,024	266,000	87,458	59,316	106	982,882	1,070,340	-	-	1,070,340	6,403,137.67
2030	13,534	-	12,225	-	0	607,987	26,930	248,203	99,630	54,057	41	937,219	1,036,848	58,173	751,875	1,095,021	7,144,290.87
2031	13,595	-	12,151	-	0	626,305	27,867	271,509	101,791	56,862	38	982,582	1,084,372	58,173	-	1,142,545	7,880,785.44
2032	13,654	-	12,247	0	0	670,417	28,837	260,318	99,752	58,221	40	1,017,833	1,117,585	58,173	-	1,175,757	8,602,598.31
2033	13,712	-	12,290	0	0	702,847	29,840	269,857	143,870	62,403	42	1,064,989	1,208,859	58,173	-	1,267,031	9,343,405.25
2034	13,764	-	12,269	0	-	718,032	30,879	295,006	108,762	65,147	40	1,109,105	1,217,867	58,173	-	1,276,040	10,053,951.83
2035	13,814	-	12,467	-	0	768,446	31,953	288,645	106,629	69,927	44	1,159,015	1,265,644	58,173	-	1,323,817	10,756,000.14
2036	13,862	-	12,531	0	0	821,708	33,065	278,700	169,074	72,896	47	1,206,416	1,375,491	58,173	-	1,433,663	11,480,097.40
2037	13,905	-	12,593	-	0	860,836	34,216	287,832	114,775	76,439	46	1,259,369	1,374,144	58,173	-	1,432,317	12,169,066.22
2038	13,949	-	12,652	0	0	917,760	35,407	272,082	146,820	80,385	46	1,305,679	1,452,499	58,173	-	1,510,671	12,861,122.23
2039	13,987	-	12,708	-	0	966,387	36,639	267,961	135,417	88,063	50	1,359,100	1,494,517	58,173	-	1,552,690	13,538,555.55
2040	14,024	-	12,762	1	0	1,020,681	37,914	279,831	163,618	91,582	48	1,430,056	1,593,674	58,173	-	1,651,846	14,224,931.87
2041	14,057	-	12,813	-	0	1,084,615	39,233	255,237	154,918	99,068	52	1,478,205	1,633,123	58,173	-	1,691,296	14,894,235.13
2042	14,085	34	12,891	1	0	1,385,565	40,599	269,532	117,679	112,345	79	1,808,120	1,925,799	63,017	55,840	1,988,815	15,643,798.76
2043	14,111	43	12,943	2	0	1,505,951	42,012	205,851	233,811	115,741	80	1,869,633	2,103,444	64,449	16,510	2,167,893	16,421,947.38
2044	14,137	86	13,028	2	0	1,657,744	43,474	113,872	143,965	123,582	89	1,938,759	2,082,724	70,796	73,163	2,153,520	17,158,127.88
2045	14,160	130	13,103	10	0	1,867,906	44,986	120,004	144,011	123,408	106	2,156,411	2,300,422	77,270	74,631	2,377,692	17,932,236.20
2046	14,183	234	13,249	7	0	1,986,185	22,031	128,359	139,113	121,973	106	2,258,654	2,397,767	91,210	160,692	2,488,977	18,703,988.07
2047	14,201	242	13,299	2	0	2,059,328	22,798	134,783	146,748	125,410	107	2,342,427	2,489,175	91,210	-	2,580,385	19,465,982.84
2048	14,212	281	13,359	12	0	2,162,111	23,591	170,695	165,578	132,279	110	2,488,787	2,654,364	100,949	112,267	2,755,314	20,240,889.26
2049	14,225	353	13,473	2	0	2,291,743	-	120,378	193,378	126,423	115	2,538,659	2,732,037	110,880	114,471	2,842,916	21,002,359.62
2050	14,242	417	13,571	3	0	2,380,686	-	120,849	166,587	125,480	115	2,627,130	2,793,718	120,999	116,646	2,914,716	21,745,885.23
2051	14,237	480	13,641	3	0	2,479,206	-	151,929	176,624	129,060	121	2,760,315	2,936,939	131,421	120,145	3,068,360	22,491,331.98

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 14,796.38	$ 330.80	$ 3,706.49	$ 1,875.52	$ 1,141.98	$ 1.40	$ 19,977.05	$ 21,852.56	$ 638.77		$ 22,491.33

Appendix A – Detailed PLEXOS Modeling Results

Table A-9 - Efficiency + DER Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,364	-	105,232	54,737	41,943	118	968,658	1,023,394	-	-	1,023,394	1,023,394.42
2023	12,948	-	12,848	4	0	544,330	-	186,642	73,618	32,186	143	763,301	836,919	-	-	836,919	1,828,124.52
2024	13,057	-	12,887	2	-	431,976	-	228,487	75,420	26,776	114	687,353	762,773	-	-	762,773	2,533,351.03
2025	13,160	190	13,096	19	-	605,841	-	300,582	77,211	45,613	145	952,181	1,029,391	18,065	225,727	1,047,456	3,464,535.76
2026	13,250	201	13,148	8	0	588,094	27,616	256,340	79,769	52,420	134	924,603	1,004,372	18,065	-	1,022,437	4,338,519.48
2027	13,327	196	13,174	1	-	637,213	28,302	245,258	174,569	50,141	149	961,062	1,135,631	18,065	-	1,153,696	5,286,773.47
2028	13,399	197	13,211	0	0	658,819	29,005	260,400	83,917	56,903	135	1,005,262	1,089,179	18,065	-	1,107,244	6,161,844.18
2029	13,470	171	13,257	0	0	638,225	29,726	250,440	103,844	56,490	49	974,930	1,078,774	64,757	663,615	1,143,531	7,030,833.87
2030	13,534	213	13,384	0	0	513,164	136,412	244,759	98,020	81,920	39	976,293	1,074,313	64,757	-	1,139,070	7,863,141.28
2031	13,595	216	13,487	0	-	543,675	139,802	267,061	99,460	87,440	39	1,038,018	1,137,478	64,757	-	1,202,235	8,707,815.85
2032	13,654	216	13,599	-	0	587,710	143,276	255,650	97,080	90,106	42	1,076,784	1,173,864	64,757	-	1,238,621	9,544,583.97
2033	13,712	216	13,720	1	-	609,403	162,283	269,223	136,206	101,133	46	1,142,089	1,278,295	64,757	-	1,343,052	10,417,004.98
2034	13,764	216	13,848	0	-	637,733	166,316	293,091	104,047	107,850	48	1,205,038	1,309,084	64,757	-	1,373,841	11,275,102.25
2035	13,814	216	13,983	0	-	681,858	170,449	286,650	101,580	114,718	51	1,253,725	1,355,306	64,757	-	1,420,063	12,127,955.07
2036	13,862	216	14,122	1	-	733,390	182,784	274,919	155,586	122,804	55	1,313,952	1,469,538	64,757	-	1,534,295	13,013,971.93
2037	13,905	216	14,257	3	-	782,522	187,326	291,931	107,518	135,015	58	1,396,851	1,504,369	64,757	-	1,569,126	13,885,252.09
2038	13,949	231	14,420	2	-	845,288	191,981	277,061	134,752	140,451	57	1,454,839	1,589,591	66,335	19,725	1,655,926	14,769,364.67
2039	13,987	274	14,615	-	-	897,415	196,752	263,989	125,412	147,809	62	1,506,027	1,631,438	71,169	60,395	1,702,607	15,643,437.59
2040	14,024	303	14,796	7	0	954,562	210,251	296,414	149,231	154,342	62	1,615,632	1,764,863	74,451	41,014	1,839,314	16,551,374.79
2041	14,057	303	14,936	4	0	1,021,019	224,201	275,808	141,043	167,171	67	1,688,266	1,829,310	74,451	-	1,903,761	17,454,980.41
2042	14,085	303	15,056	5	-	1,326,215	229,773	282,484	117,641	174,897	80	2,013,449	2,131,090	90,258	197,509	2,221,348	18,468,774.64
2043	14,111	303	15,172	1	-	1,440,212	235,483	203,061	228,306	182,217	78	2,061,051	2,289,357	117,640	342,153	2,406,997	19,525,045.83
2044	14,137	303	15,279	2	-	1,601,503	241,334	112,641	153,288	199,548	88	2,155,114	2,308,402	117,640	-	2,426,042	20,548,727.45
2045	14,160	226	15,286	10	0	1,828,559	247,332	114,952	149,980	212,850	101	2,403,794	2,553,774	115,216	195,432	2,668,990	21,631,606.81
2046	14,183	312	15,464	8	0	1,989,053	208,359	138,718	145,301	215,708	103	2,551,940	2,697,241	124,358	114,233	2,821,599	22,732,373.06
2047	14,201	427	15,661	4	-	2,063,756	213,536	136,202	153,539	216,894	103	2,630,490	2,784,029	136,281	148,984	2,920,310	23,827,830.57
2048	14,212	566	15,860	10	0	2,157,633	218,843	143,571	170,054	218,191	106	2,738,343	2,908,396	152,377	201,128	3,060,774	24,931,818.71
2049	14,225	561	15,917	4	0	2,253,647	224,281	121,479	189,155	230,491	106	2,830,004	3,019,160	152,377	-	3,171,537	26,031,760.26
2050	14,242	581	15,999	4	0	2,761,161	56,754	150,142	166,640	188,890	127	3,157,075	3,323,715	153,750	17,146	3,477,465	27,191,416.33
2051	14,237	696	16,141	5	0	2,870,343	58,165	155,423	175,012	182,842	131	3,266,904	3,441,916	166,735	162,261	3,608,652	28,348,535.54

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 17,004.44	$ 2,088.08	$ 4,142.03	$ 2,101.16	$ 1,924.64	$ 1.62	$ 25,160.80	$ 27,261.96	$ 1,086.58		$ 28,348.54

Appendix A – Detailed PLEXOS Modeling Results

Table A-10 - Increased Electrification Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,365	-	105,232	54,737	41,957	118	968,672	1,023,409	-	-	1,023,409	1,023,408.70
2023	12,948	-	12,920	5	-	549,046	-	187,681	73,618	32,435	144	769,306	842,923	-	-	842,923	1,833,912.02
2024	13,057	-	12,995	3	-	438,728	-	231,371	75,420	26,837	116	697,052	772,472	-	-	772,472	2,548,105.80
2025	13,160	223	13,272	20	0	617,431	-	301,155	78,856	43,098	150	961,833	1,040,689	27,383	342,156	1,068,072	3,497,618.14
2026	13,250	255	13,381	8	0	601,668	27,616	256,650	81,413	48,448	139	934,520	1,015,933	27,383	-	1,043,316	4,389,448.92
2027	13,327	247	13,441	1	0	654,799	28,302	245,689	176,208	46,314	154	975,257	1,151,466	27,383	-	1,178,848	5,358,376.44
2028	13,399	300	13,567	0	0	678,773	29,005	260,354	86,887	50,106	140	1,018,378	1,105,265	33,952	82,083	1,139,217	6,258,716.37
2029	13,470	293	13,666	-	0	657,536	29,726	251,098	106,799	50,803	48	989,210	1,096,010	85,313	729,976	1,181,323	7,156,424.46
2030	13,534	361	13,856	-	0	528,333	136,412	244,462	100,963	76,138	38	985,382	1,086,346	85,313	-	1,171,659	8,012,544.18
2031	13,595	352	13,983	-	0	562,554	139,802	267,751	102,476	82,136	39	1,052,281	1,154,757	85,313	-	1,240,070	8,883,800.89
2032	13,654	346	14,124	-	0	611,129	143,276	256,458	100,179	89,445	43	1,100,351	1,200,530	85,313	-	1,285,843	9,752,470.24
2033	13,712	384	14,320	2	-	606,955	185,453	268,440	139,368	98,022	46	1,158,915	1,298,283	85,313	-	1,383,596	10,651,228.01
2034	13,764	384	14,484	0	0	637,695	190,062	292,426	107,286	106,637	48	1,226,867	1,334,153	85,313	-	1,419,466	11,537,822.12
2035	13,814	384	14,655	0	0	685,413	194,785	286,948	104,898	112,438	51	1,279,635	1,384,533	85,313	-	1,469,846	12,420,573.62
2036	13,862	384	14,831	1	-	741,641	207,725	275,531	158,990	122,123	56	1,347,076	1,506,066	85,313	-	1,591,379	13,339,555.22
2037	13,905	384	15,001	3	0	794,287	212,887	292,789	110,995	130,913	59	1,430,934	1,541,930	85,313	-	1,627,243	14,243,105.31
2038	13,949	413	15,215	2	1	859,885	218,177	278,234	138,739	135,504	58	1,491,858	1,630,597	88,786	43,394	1,719,383	15,161,098.07
2039	13,987	442	15,430	0	0	917,189	223,599	263,803	129,141	144,781	64	1,549,435	1,678,576	92,330	44,290	1,770,906	16,070,233.91
2040	14,024	456	15,634	7	0	992,149	229,155	299,505	152,671	152,663	65	1,673,538	1,826,208	94,136	22,558	1,920,344	17,018,169.66
2041	14,057	480	15,831	5	0	1,053,242	252,300	280,680	145,288	164,468	69	1,750,759	1,896,047	97,248	38,886	1,993,294	17,964,271.68
2042	14,085	480	15,991	2	0	1,342,593	258,569	278,529	126,623	180,020	88	2,059,799	2,186,423	126,491	365,406	2,312,914	19,019,855.29
2043	14,111	480	16,140	1	-	1,485,574	264,995	208,737	232,756	182,548	83	2,141,937	2,374,693	144,400	223,778	2,519,093	20,125,317.91
2044	14,137	480	16,284	2	0	1,656,394	271,580	119,260	157,852	200,446	93	2,247,773	2,405,626	144,400	-	2,550,026	21,201,314.92
2045	14,160	173	16,101	4	-	1,903,484	278,329	109,575	165,468	230,728	106	2,522,221	2,687,689	148,972	399,289	2,836,661	22,352,223.18
2046	14,183	173	16,227	4	-	2,072,372	240,126	129,404	158,717	233,803	108	2,675,813	2,834,530	148,972	-	2,983,502	23,516,151.34
2047	14,201	197	16,367	2	-	2,166,672	246,093	134,673	165,020	240,705	109	2,788,253	2,953,273	152,471	43,714	3,105,744	24,681,168.03
2048	14,212	351	16,620	6	0	2,270,645	252,209	142,660	181,718	240,894	112	2,906,519	3,088,237	172,597	333,566	3,260,834	25,857,315.85
2049	14,225	360	16,724	2	0	2,379,973	258,476	131,070	201,143	259,405	113	3,029,037	3,230,179	174,078	18,509	3,404,258	27,037,968.83
2050	14,242	475	16,937	2	0	2,871,222	91,799	141,922	181,471	215,278	132	3,320,353	3,501,824	187,947	173,289	3,689,770	28,268,424.16
2051	14,237	591	17,115	1	0	2,995,339	94,080	150,068	190,030	208,481	137	3,448,104	3,638,134	202,231	178,487	3,840,365	29,499,842.55

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 17,499.21	$ 2,334.74	$ 4,148.18	$ 2,175.98	$ 1,946.30	$ 1.67	$ 25,930.10	$ 28,106.07	$ 1,393.77		$ 29,499.84

Appendix A – Detailed PLEXOS Modeling Results

Table A-11 - Future Net Zero Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,785	41	-	199	-	5,803	1,014,751	54,737	15,890	76,628	1,091,380	-	-	1,091,380	1,091,379.87
2023	12,948	-	12,782	70	-	154	-	6,210	886,950	73,618	13,691	93,673	980,623	-	-	980,623	2,034,286.82
2024	13,057	-	12,838	52	-	208	-	6,403	803,438	75,420	14,456	96,487	899,925	-	-	899,925	2,866,318.33
2025	13,160	298	13,186	37	-	237	-	6,536	956,489	73,581	10,173	90,527	1,047,017	33,976	424,544	1,080,993	3,827,317.12
2026	13,250	321	13,267	10	-	254	27,616	6,691	926,235	76,129	10,618	121,307	1,047,542	33,976	-	1,081,519	4,751,803.84
2027	13,327	306	13,282	3	-	267	28,302	6,704	975,529	170,925	12,224	218,422	1,193,951	33,976	-	1,227,927	5,761,070.53
2028	13,399	307	13,320	1	-	278	29,005	6,897	1,033,240	80,257	13,958	130,396	1,163,636	33,976	-	1,197,612	6,707,561.02
2029	13,470	418	13,453	50	-	295	29,726	7,092	1,263,522	100,978	14,086	152,177	1,415,699	56,454	311,680	1,472,153	7,826,276.14
2030	13,534	682	13,827	26	-	293	136,412	7,283	1,105,762	95,539	24,112	263,639	1,369,401	68,995	187,527	1,438,396	8,877,297.98
2031	13,595	1,109	14,375	6	-	298	139,802	7,495	1,099,253	97,289	16,908	261,792	1,361,045	137,520	887,067	1,498,565	9,930,169.91
2032	13,654	1,364	14,745	1	-	308	143,276	7,701	1,089,990	95,216	12,746	259,247	1,349,238	225,779	1,133,645	1,575,017	10,994,195.08
2033	13,712	1,826	15,325	7	-	318	177,730	7,925	1,064,589	134,678	11,551	332,202	1,396,791	411,698	2,353,933	1,808,489	12,168,955.10
2034	13,764	2,250	15,881	2	-	333	213,517	8,161	998,021	102,856	11,804	336,671	1,334,692	616,094	2,584,814	1,950,786	13,387,410.48
2035	13,814	3,293	17,061	0	-	349	290,495	8,385	813,380	100,738	11,231	411,197	1,224,576	755,911	1,777,869	1,980,487	14,576,839.85
2036	13,862	3,500	17,407	0	-	367	305,813	8,597	836,901	155,104	11,205	481,087	1,317,988	887,926	1,680,388	2,205,914	15,850,700.04
2037	13,905	3,510	17,554	0	-	381	313,412	8,824	879,551	107,408	12,073	442,099	1,321,650	1,011,098	1,569,898	2,332,749	17,145,992.55
2038	13,949	4,215	18,406	-	-	261	371,209	5,027	773,302	134,638	11,456	522,591	1,295,893	1,162,399	1,921,369	2,458,292	18,458,494.84
2039	13,987	4,693	19,034	-	-	137	414,278	830	736,256	124,496	11,267	551,008	1,287,264	1,310,011	1,875,283	2,597,276	19,791,866.62
2040	14,024	5,425	19,926	-	-	273	467,624	4,850	678,219	147,875	10,245	630,867	1,309,086	1,537,451	2,872,749	2,846,537	21,196,997.30
2041	14,057	5,918	20,555	-	-	151	514,145	437	642,158	140,050	10,851	665,634	1,307,792	1,813,992	3,486,288	3,121,784	22,678,728.43
2042	14,085	5,902	20,660	-	-	460	526,921	9,123	889,732	105,085	12,051	653,641	1,543,373	2,097,821	3,577,351	3,641,194	24,340,521.87
2043	14,111	7,400	22,270	-	-	162	684,331	282	618,677	199,345	11,901	896,021	1,514,698	2,354,521	3,238,365	3,869,218	26,038,464.95
2044	14,137	7,525	22,503	-	-	249	701,336	2,426	633,371	124,418	13,264	841,693	1,475,064	2,726,064	4,673,361	4,201,127	27,811,153.31
2045	14,160	8,309	23,346	-	-	510	809,902	9,576	611,819	122,490	12,939	955,417	1,567,236	2,856,538	1,661,136	4,423,773	29,605,994.72
2046	14,183	9,998	25,153	5	-	525	988,073	9,863	550,195	116,190	13,656	1,128,308	1,678,503	3,177,773	4,044,751	4,856,276	31,500,532.11
2047	14,201	10,750	25,973	13	-	547	1,195,799	10,159	510,504	121,769	12,024	1,340,298	1,850,803	3,490,035	3,932,631	5,340,837	33,503,969.86
2048	14,212	11,236	26,475	64	-	573	1,431,072	10,464	428,969	134,411	10,571	1,587,091	2,016,060	3,968,303	6,006,935	5,984,363	35,662,465.24
2049	14,225	11,439	26,771	28	-	599	1,619,121	10,778	399,555	153,619	9,819	1,793,936	2,193,490	4,216,199	3,097,533	6,409,689	37,885,451.59
2050	14,242	11,702	26,065	1,059	-	6	1,771,794	18	89,169	130,773	0	1,902,591	1,991,761	4,736,324	6,499,125	6,728,084	40,129,116.12
2051	14,237	11,711	26,098	1,062	-	6	1,815,823	19	88,951	136,049	-	1,951,897	2,040,848	4,711,689	-	6,752,537	42,294,326.72

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 5.15	$ 6,296.87	$ 116.60	$ 15,303.93	$ 1,963.22	$ 225.96	$ 8,607.80	$ 23,911.73	$ 18,382.60		$ 42,294.33

Appendix A – Detailed PLEXOS Modeling Results

Table A-12 - Supplemental Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,785	41	0	835,287	-	163,837	55,273	16,187	115	1,015,425	1,070,698	-	-	1,070,698	1,070,698.32
2023	12,948	-	12,862	64	-	567,004	-	301,038	78,004	13,573	136	881,750	959,754	-	-	959,754	1,993,538.79
2024	13,057	-	12,940	57	-	458,365	-	333,151	80,945	14,317	112	805,946	886,891	-	-	886,891	2,813,519.30
2025	13,160	282	13,291	45	-	488,023	-	343,345	85,964	9,883	106	841,356	927,320	27,937	349,087	955,258	3,662,739.88
2026	13,250	315	13,403	8	-	462,520	27,616	260,982	89,865	10,377	99	761,594	851,459	27,937	-	879,396	4,414,451.46
2027	13,327	274	13,390	6	-	513,309	28,302	265,266	186,156	11,990	114	818,981	1,005,136	27,937	-	1,033,074	5,263,562.84
2028	13,399	308	13,445	0	-	523,636	29,005	266,616	97,177	13,396	101	832,754	929,931	27,937	-	957,869	6,020,580.49
2029	13,470	242	13,390	2	-	562,513	29,726	282,261	114,174	21,878	69	896,446	1,010,621	58,265	378,954	1,068,886	6,832,845.80
2030	13,534	504	13,522	131	-	421,351	136,412	280,329	66,642	27,638	17	865,747	932,389	70,342	150,904	1,002,731	7,565,531.55
2031	13,595	1,067	14,207	7	-	419,735	139,802	283,272	80,298	19,788	14	862,610	942,908	131,097	759,153	1,074,005	8,320,113.23
2032	13,654	1,328	14,465	12	-	437,728	143,276	269,443	94,399	16,649	13	867,109	961,508	193,142	775,270	1,154,650	9,100,153.28
2033	13,712	1,837	14,994	1	-	406,089	177,730	288,528	109,702	15,048	12	887,407	997,109	262,471	866,289	1,259,580	9,918,352.54
2034	13,764	1,924	15,090	-	0	405,860	182,147	298,931	134,089	13,935	11	900,883	1,034,972	370,521	1,350,115	1,405,493	10,796,219.23
2035	13,814	3,280	16,461	-	-	262,673	282,235	277,529	159,562	11,565	5	834,007	993,569	480,789	1,377,835	1,474,358	11,681,680.16
2036	13,862	3,361	16,558	-	0	286,135	289,249	267,343	186,653	11,235	6	853,967	1,040,620	593,160	1,404,116	1,633,780	12,625,147.55
2037	13,905	3,399	16,620	-	-	280,801	304,646	273,497	214,263	12,042	6	870,992	1,085,255	707,869	1,433,326	1,793,124	13,620,805.75
2038	13,949	3,478	16,732	-	-	301,693	312,216	253,527	243,875	11,169	5	878,611	1,122,486	824,955	1,463,026	1,947,441	14,660,560.36
2039	13,987	3,575	16,867	-	-	309,488	328,436	252,371	275,073	11,681	5	901,982	1,177,055	944,457	1,493,217	2,121,512	15,749,687.96
2040	14,024	4,935	18,273	-	-	187,514	439,920	246,517	308,492	10,705	3	884,660	1,193,151	1,066,189	1,521,070	2,259,340	16,864,961.65
2041	14,057	5,021	18,394	-	-	196,128	459,577	228,172	342,142	11,233	3	895,114	1,237,256	1,190,409	1,552,168	2,427,665	18,017,234.46
2042	14,085	4,982	18,374	-	0	328,253	470,998	228,175	362,527	14,012	6	1,041,444	1,403,971	1,317,097	1,583,012	2,721,068	19,259,094.43
2043	14,111	5,612	19,020	-	-	295,355	554,860	154,370	401,331	14,309	5	1,018,899	1,420,230	1,446,352	1,615,083	2,866,582	20,517,046.90
2044	14,137	5,738	19,159	-	-	356,789	568,648	53,451	442,661	15,527	6	994,421	1,437,082	1,577,959	1,644,466	3,015,041	21,789,259.53
2045	14,160	6,781	19,613	602	-	230,192	739,015	13,348	475,645	12,040	3	994,598	1,470,242	1,684,267	1,677,442	3,154,509	23,069,127.06
2046	14,183	7,470	20,826	89	-	226,683	874,792	13,087	519,507	13,429	3	1,127,994	1,647,502	1,821,192	1,710,916	3,468,693	24,422,338.73
2047	14,201	8,033	21,424	61	-	179,088	1,065,612	12,512	565,233	12,826	3	1,270,040	1,835,273	1,960,835	1,744,890	3,796,108	25,846,322.79
2048	14,212	8,491	21,870	69	-	146,719	1,268,285	8,059	614,442	10,742	2	1,433,807	2,048,249	2,104,866	1,799,714	4,153,115	27,344,306.62
2049	14,225	9,293	22,739	6	-	123,781	1,482,786	6,398	669,124	10,257	1	1,623,223	2,292,347	2,245,713	2,138,876	4,538,060	28,918,181.08
2050	14,242	9,738	22,512	687	-	15,441	1,738,874	3,771	758,529	-	-	1,758,086	2,516,615	2,472,257	3,080,101	4,988,872	30,581,857.35
2051	14,237	9,677	22,454	667	-	16,645	1,782,085	4,065	778,907	-	-	1,802,795	2,581,702	2,502,402	1,135,829	5,084,104	32,212,082.65

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 7,082.30	$ 5,754.83	$ 4,078.05	$ 3,999.94	$ 245.31	$ 0.83	$ 17,161.32	$ 21,161.26	$ 11,050.83		$ 32,212.08

Appendix A – Detailed PLEXOS Modeling Results

Table A-13 - Low Load Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,420	-	105,489	54,737	42,326	119	969,353	1,024,090	-	-	1,024,090	1,024,089.56
2023	12,948	-	12,227	3	-	502,441	-	177,746	73,618	31,605	130	711,922	785,540	-	-	785,540	1,772,222.87
2024	13,057	-	12,227	0	-	391,467	-	216,816	75,420	25,263	102	633,648	709,068	-	-	709,068	2,415,368.33
2025	13,160	-	12,104	17	-	424,157	-	297,604	73,581	30,230	88	752,079	825,661	-	-	825,661	3,128,605.13
2026	13,250	-	11,859	5	-	421,593	6,755	255,925	76,129	38,784	93	723,150	799,279	-	-	799,279	3,786,173.61
2027	13,327	-	11,850	1	0	462,486	6,990	248,371	170,924	44,959	113	762,919	933,843	-	-	933,843	4,517,864.37
2028	13,399	-	12,026	0	0	485,558	7,245	261,281	80,257	51,509	119	805,712	885,969	-	-	885,969	5,178,988.41
2029	13,470	-	12,128	-	0	449,454	7,484	249,732	100,192	36,875	37	743,583	843,775	46,692	663,615	890,467	5,811,826.68
2030	13,534	-	12,225	-	0	456,330	20,948	247,950	94,369	41,723	35	766,986	861,356	46,692	-	908,047	6,426,428.95
2031	13,595	-	12,151	-	0	468,647	21,676	270,867	95,718	42,751	33	803,973	899,691	46,692	-	946,383	7,036,476.16
2032	13,654	-	12,247	0	0	502,686	22,466	259,390	93,234	46,499	36	831,077	924,311	46,692	-	971,003	7,632,587.66
2033	13,712	-	12,290	0	0	528,366	23,206	268,624	132,278	47,872	37	868,105	1,000,383	46,692	-	1,047,075	8,244,790.55
2034	13,764	-	12,269	0	0	538,654	24,011	293,680	100,020	49,074	35	905,452	1,005,473	46,692	-	1,052,165	8,830,675.13
2035	13,814	-	12,467	-	0	577,136	24,842	286,840	97,455	52,799	38	941,656	1,039,111	46,692	-	1,085,803	9,406,499.39
2036	13,862	-	12,531	0	0	618,028	25,745	276,392	151,349	56,368	42	976,575	1,127,924	46,692	-	1,174,616	9,999,760.39
2037	13,905	-	12,593	-	0	639,307	26,591	285,347	103,188	58,650	41	1,009,935	1,113,122	46,692	-	1,159,814	10,557,650.95
2038	13,949	-	12,652	0	0	677,865	27,509	268,387	129,929	60,157	41	1,033,959	1,163,888	46,692	-	1,210,580	11,112,231.59
2039	13,987	-	12,708	-	0	716,082	28,459	264,482	119,282	65,384	45	1,074,452	1,193,734	46,692	-	1,240,426	11,653,425.34
2040	14,024	-	12,762	1	0	746,336	29,490	274,948	142,125	67,239	43	1,118,057	1,260,182	46,692	-	1,306,874	12,196,458.52
2041	14,057	-	12,813	-	0	777,961	30,455	250,731	133,781	71,767	46	1,130,960	1,264,741	46,692	-	1,311,433	12,715,437.00
2042	14,085	24	12,882	1	0	984,092	31,504	260,918	98,982	80,611	72	1,357,197	1,456,179	49,577	36,053	1,505,756	13,282,940.60
2043	14,111	38	12,938	2	0	1,066,014	32,588	196,184	193,125	85,699	74	1,380,560	1,573,684	51,320	21,775	1,625,004	13,866,223.40
2044	14,137	82	13,023	3	0	1,177,874	33,765	102,125	118,967	88,659	83	1,402,505	1,521,473	56,643	66,512	1,578,116	14,405,702.07
2045	14,160	81	13,062	3	0	1,336,787	34,866	82,233	129,113	92,387	94	1,546,368	1,675,481	73,915	215,823	1,749,396	14,975,255.37
2046	14,183	81	13,101	2	0	1,405,069	22,746	86,430	122,045	96,901	92	1,611,237	1,733,282	73,915	-	1,807,197	15,535,609.26
2047	14,201	77	13,136	0	0	1,457,840	23,526	81,175	127,177	100,832	93	1,663,466	1,790,643	73,915	-	1,864,558	16,086,218.39
2048	14,212	91	13,176	5	0	1,535,241	24,374	112,158	139,701	101,586	97	1,773,455	1,913,156	75,236	16,502	1,988,392	16,645,435.30
2049	14,225	152	13,274	0	0	1,588,156	25,167	83,676	160,411	107,684	96	1,804,779	1,965,190	83,564	104,064	2,048,754	17,194,190.63
2050	14,242	216	13,373	1	0	1,698,745	-	86,298	139,159	100,704	101	1,885,848	2,025,007	92,051	106,042	2,117,057	17,734,238.45
2051	14,237	284	13,449	1	0	1,770,200	-	89,807	146,135	98,385	108	1,958,499	2,104,633	100,792	109,223	2,205,425	18,270,038.38

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 11,285.62	$ 253.00	$ 3,588.16	$ 1,719.62	$ 878.35	$ 1.21	$ 16,006.33	$ 17,725.95	$ 544.08		$ 18,270.04

Appendix A – Detailed PLEXOS Modeling Results

Table A-14 - No Load Growth Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,456	-	105,556	54,737	42,060	119	969,191	1,023,928	-	-	1,023,928	1,023,928.05
2023	12,948	-	12,817	10	0	541,934	-	188,889	73,618	32,583	143	763,550	837,167	-	-	837,167	1,828,896.67
2024	13,057	-	12,856	1	-	424,950	-	217,639	75,420	26,479	113	669,182	744,602	-	-	744,602	2,517,322.95
2025	13,160	278	13,079	25	-	464,167	-	303,551	79,791	19,029	106	786,852	866,643	31,162	389,378	897,805	3,315,468.51
2026	13,250	260	13,076	11	-	492,275	-	263,198	82,356	27,185	117	782,775	865,132	31,162	-	896,294	4,081,624.05
2027	13,327	173	13,000	0	0	538,540	-	250,228	177,158	32,466	137	821,372	998,530	31,162	-	1,029,692	4,927,955.54
2028	13,399	181	13,038	-	-	554,812	-	263,410	86,515	37,098	144	855,464	941,979	31,162	-	973,141	5,697,043.01
2029	13,470	270	13,097	-	0	495,122	-	252,073	106,436	30,593	45	777,832	884,268	77,854	663,615	962,121	6,428,176.26
2030	13,534	285	13,112	-	0	483,971	20,282	248,714	100,608	34,173	39	787,180	887,788	77,854	-	965,642	7,133,761.09
2031	13,595	278	13,105	-	-	503,205	20,786	272,392	102,113	34,963	36	831,383	933,496	77,854	-	1,011,350	7,844,322.14
2032	13,654	280	13,137	-	0	520,968	28,229	260,151	99,807	39,128	36	848,512	948,319	77,854	-	1,026,173	8,537,568.02
2033	13,712	283	13,110	-	0	542,099	28,880	269,803	138,991	38,222	37	879,041	1,018,032	77,854	-	1,095,886	9,249,434.36
2034	13,764	279	13,105	-	0	554,503	29,596	293,967	106,900	38,726	34	916,826	1,023,726	77,854	-	1,101,580	9,937,477.92
2035	13,814	285	13,111	-	0	578,692	30,328	288,412	104,504	44,210	35	941,677	1,046,181	77,854	-	1,124,035	10,612,544.10
2036	13,862	281	13,138	-	0	615,843	31,130	274,735	158,587	45,586	39	967,333	1,125,921	77,854	-	1,203,775	11,307,694.00
2037	13,905	280	13,107	-	0	629,053	31,845	282,784	110,586	46,833	37	990,551	1,101,137	77,854	-	1,178,991	11,962,345.89
2038	13,949	279	13,106	-	0	662,474	32,630	264,020	137,510	48,222	35	1,007,381	1,144,891	77,854	-	1,222,745	12,615,179.57
2039	13,987	281	13,108	-	0	693,867	33,434	263,517	127,052	51,300	37	1,042,156	1,169,208	77,854	-	1,247,062	13,255,387.78
2040	14,024	281	13,138	-	-	720,052	34,314	267,238	150,102	50,305	36	1,071,944	1,222,046	77,854	-	1,299,900	13,897,055.17
2041	14,057	281	13,108	-	0	745,254	35,098	248,655	141,932	52,637	37	1,081,681	1,223,614	77,854	-	1,301,468	14,514,787.03
2042	14,085	294	13,121	-	0	937,105	35,960	242,692	106,619	49,770	63	1,265,590	1,372,209	77,854	-	1,450,063	15,176,577.01
2043	14,111	295	13,122	-	0	1,013,491	36,842	178,577	200,515	47,730	63	1,276,702	1,477,217	77,854	-	1,555,071	15,858,994.42
2044	14,137	316	13,172	1	0	1,121,447	37,807	84,026	125,209	51,364	72	1,294,716	1,419,925	77,854	-	1,497,778	16,490,990.12
2045	14,160	58	12,880	5	0	1,285,919	38,667	86,376	116,079	84,657	92	1,495,711	1,611,790	53,932	90,461	1,665,722	17,166,817.22
2046	14,183	58	12,866	19	0	1,324,533	39,611	107,821	108,871	91,174	88	1,563,226	1,672,098	53,932	-	1,726,029	17,840,178.26
2047	14,201	58	12,881	4	0	1,364,582	40,578	85,118	113,861	94,022	87	1,584,386	1,698,247	53,932	-	1,752,179	18,497,449.95
2048	14,212	58	12,904	10	0	1,435,617	41,636	110,448	125,867	95,244	91	1,683,037	1,808,904	53,932	-	1,862,836	19,169,354.66
2049	14,225	58	12,883	2	0	1,476,761	42,578	79,858	144,474	100,543	90	1,699,831	1,844,305	53,932	-	1,898,236	19,827,694.41
2050	14,242	58	12,881	4	0	1,617,831	10,655	96,741	120,980	100,463	99	1,825,789	1,946,769	53,932	-	2,000,701	20,494,883.02
2051	14,237	58	12,855	2	0	1,685,390	10,908	111,060	125,626	102,708	103	1,910,169	2,035,795	53,932	-	2,089,726	21,164,956.71

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 13,061.29	$ 339.53	$ 3,980.46	$ 1,994.94	$ 829.22	$ 1.40	$ 18,211.89	$ 20,206.83	$ 958.12		$ 21,164.96

Appendix A – Detailed PLEXOS Modeling Results

Table A-15 - High Load Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost		Plant O&M Costs									Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	-	821,347	-	105,331	54,737	40,990	118	967,785	1,022,522	-	-	1,022,522	1,022,521.90
2023	12,948	-	12,848	4	0	543,916	-	186,697	73,618	31,968	143	762,724	836,342	-	-	836,342	1,826,697.06
2024	13,057	-	13,183	5	-	447,617	-	235,237	75,420	26,853	120	709,826	785,246	-	-	785,246	2,552,701.44
2025	13,160	247	14,571	44	-	564,428	-	316,711	81,039	21,308	136	902,583	983,623	37,044	462,873	1,020,666	3,460,070.01
2026	13,250	242	14,763	12	-	556,244	27,549	270,580	83,610	32,451	137	886,961	970,571	37,044	-	1,007,615	4,321,383.24
2027	13,327	146	14,701	3	-	608,605	28,233	262,324	178,415	40,492	159	939,813	1,118,228	37,044	-	1,155,272	5,270,932.31
2028	13,399	175	14,772	1	-	629,005	28,982	272,510	87,779	44,023	169	974,689	1,062,468	37,044	-	1,099,512	6,139,892.27
2029	13,470	338	15,002	-	0	564,340	29,650	259,005	107,699	34,991	61	888,048	995,747	83,736	663,615	1,079,483	6,960,210.27
2030	13,534	356	15,106	0	0	602,457	30,384	256,548	101,874	37,694	65	927,149	1,029,022	83,736	-	1,112,758	7,773,291.74
2031	13,595	385	15,235	-	0	632,293	31,136	279,445	103,411	38,517	64	981,455	1,084,866	83,736	-	1,168,602	8,594,335.69
2032	13,654	406	15,373	-	-	675,908	31,958	267,108	101,141	42,574	68	1,017,616	1,118,757	83,736	-	1,202,493	9,406,696.67
2033	13,712	394	15,476	3	0	721,508	32,692	293,013	140,353	49,487	73	1,096,773	1,237,126	83,736	-	1,320,862	10,264,703.32
2034	13,764	404	15,613	3	0	746,169	33,498	309,644	108,298	54,267	73	1,143,650	1,251,948	83,736	-	1,335,684	11,098,967.43
2035	13,814	414	15,759	1	0	792,917	34,322	307,448	105,937	57,541	77	1,192,306	1,298,242	83,736	-	1,381,978	11,928,947.60
2036	13,862	416	15,906	1	-	857,066	35,225	298,549	160,059	63,982	84	1,254,905	1,414,964	83,736	-	1,498,700	12,794,409.33
2037	13,905	401	16,015	9	0	896,439	36,030	317,948	112,090	69,551	86	1,320,055	1,432,145	83,736	-	1,515,881	13,636,124.03
2038	13,949	398	16,168	1	0	953,127	36,914	291,322	150,579	67,474	75	1,348,912	1,499,490	97,780	175,484	1,597,270	14,488,919.36
2039	13,987	406	16,326	-	0	1,016,094	37,819	283,689	140,256	75,840	83	1,413,525	1,553,781	97,780	-	1,651,560	15,336,786.22
2040	14,024	412	16,492	4	0	1,071,496	38,809	309,875	163,480	83,679	83	1,503,942	1,667,422	97,780	-	1,765,202	16,208,139.32
2041	14,057	415	16,629	3	0	1,124,727	39,691	289,850	155,418	85,241	89	1,539,598	1,695,016	97,780	-	1,792,796	17,059,076.23
2042	14,085	376	16,712	-	0	1,238,918	40,660	267,343	251,876	115,812	55	1,662,788	1,914,664	166,348	974,541	2,081,013	18,008,823.19
2043	14,111	361	16,810	0	0	1,342,417	41,652	206,232	346,151	125,552	60	1,715,913	2,062,063	166,348	-	2,228,412	18,986,725.11
2044	14,137	384	16,945	1	0	1,472,354	42,738	113,898	271,638	122,250	69	1,751,309	2,022,947	166,348	-	2,189,295	19,910,509.97
2045	14,160	40	16,686	4	0	1,649,212	43,703	110,148	277,165	136,663	79	1,939,805	2,216,970	163,907	432,371	2,380,877	20,876,494.67
2046	14,183	157	16,895	1	0	1,787,521	-	112,505	273,204	125,312	82	2,025,420	2,298,625	175,598	146,083	2,474,223	21,841,742.23
2047	14,201	232	17,048	0	0	1,856,119	-	112,786	280,652	125,455	83	2,094,442	2,375,095	183,624	100,286	2,558,719	22,801,560.63
2048	14,212	335	17,218	4	0	1,945,069	-	130,599	296,643	133,672	88	2,209,427	2,506,070	195,758	151,621	2,701,829	23,776,081.19
2049	14,225	448	17,386	0	0	2,027,272	-	114,828	318,467	135,652	85	2,277,836	2,596,303	208,131	154,598	2,804,434	24,748,705.25
2050	14,242	564	17,565	0	0	2,105,123	-	119,194	298,816	142,430	85	2,366,832	2,665,649	220,738	157,535	2,886,387	25,711,250.35
2051	14,237	655	17,679	-	0	2,190,991	-	121,742	307,071	148,141	91	2,460,965	2,768,036	233,724	162,261	3,001,760	26,673,769.00

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 16,647.37	$ 410.70	$ 4,273.45	$ 2,657.36	$ 1,155.35	$ 1.75	$ 22,488.61	$ 25,145.97	$ 1,527.80		$ 26,673.77

Appendix A – Detailed PLEXOS Modeling Results

Table A-16 - High Fuel Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,381	-	105,232	54,737	42,116	118	968,848	1,023,585	-	-	1,023,585	1,023,584.68
2023	12,948	-	12,943	5	-	550,561	-	188,024	73,618	32,201	145	770,930	844,548	-	-	844,548	1,835,649.79
2024	13,057	-	13,054	3	-	442,007	-	231,938	75,420	27,035	117	701,098	776,517	-	-	776,517	2,553,583.76
2025	13,160	257	13,397	20	0	624,704	-	301,346	80,004	41,502	152	967,704	1,047,708	32,175	402,043	1,079,883	3,513,595.88
2026	13,250	302	13,544	8	-	609,945	27,549	256,398	82,569	45,250	142	939,284	1,021,853	32,175	-	1,054,028	4,414,583.67
2027	13,327	295	13,622	0	0	664,989	28,233	245,416	177,371	41,800	157	980,595	1,157,966	32,175	-	1,190,142	5,392,793.61
2028	13,399	313	13,713	0	0	689,454	28,982	260,806	86,730	47,025	143	1,026,410	1,113,140	32,175	-	1,145,315	6,297,952.98
2029	13,470	301	13,771	-	-	664,130	29,650	251,169	106,650	47,580	47	992,577	1,099,227	78,867	663,615	1,178,094	7,193,207.90
2030	13,534	370	13,904	-	-	523,443	136,332	243,828	100,823	71,111	34	974,747	1,075,570	78,867	-	1,154,437	8,036,743.80
2031	13,595	365	13,961	-	0	550,143	139,716	267,350	102,333	75,050	33	1,032,292	1,134,625	78,867	-	1,213,493	8,889,327.74
2032	13,654	354	14,009	-	0	589,574	143,237	255,743	100,033	81,709	36	1,070,299	1,170,332	78,867	-	1,249,199	9,733,242.14
2033	13,712	375	14,086	0	-	576,114	177,629	264,055	139,222	87,872	37	1,105,707	1,244,929	78,867	-	1,323,796	10,593,154.83
2034	13,764	382	14,146	-	-	595,259	182,037	288,195	107,137	92,415	36	1,157,942	1,265,079	78,867	-	1,343,946	11,432,579.62
2035	13,814	383	14,198	-	0	627,804	186,553	281,747	104,747	96,781	37	1,192,921	1,297,668	78,867	-	1,376,536	12,259,291.22
2036	13,862	384	14,246	0	-	672,578	191,239	269,948	158,837	103,736	40	1,237,540	1,396,377	78,867	-	1,475,245	13,111,208.35
2037	13,905	381	14,286	0	-	705,901	195,920	279,531	110,841	106,646	40	1,288,038	1,398,879	78,867	-	1,477,746	13,931,748.22
2038	13,949	377	14,325	-	-	754,660	200,777	263,735	137,772	110,961	40	1,330,173	1,467,945	78,867	-	1,546,812	14,757,603.93
2039	13,987	386	14,373	-	-	793,836	205,754	257,943	127,320	120,503	43	1,378,079	1,505,399	78,867	-	1,584,267	15,570,924.07
2040	14,024	394	14,417	1	-	838,263	210,918	270,434	150,377	125,430	41	1,445,085	1,595,462	78,867	-	1,674,330	16,397,420.28
2041	14,057	394	14,450	-	-	868,452	233,527	244,472	142,214	134,604	44	1,481,098	1,623,312	78,867	-	1,702,180	17,205,346.91
2042	14,085	394	14,477	2	0	1,133,502	239,313	251,971	106,908	159,579	68	1,784,433	1,891,341	78,867	-	1,970,208	18,104,524.30
2043	14,111	394	14,502	3	0	1,241,520	245,241	188,358	200,810	164,851	69	1,840,039	2,040,850	78,867	-	2,119,717	19,034,727.48
2044	14,137	431	14,565	3	0	1,376,554	251,386	91,026	126,712	173,737	78	1,892,781	2,019,493	83,639	59,623	2,103,132	19,922,155.22
2045	14,160	38	14,196	3	-	1,633,230	257,536	79,276	140,006	194,029	83	2,164,153	2,304,159	86,008	431,647	2,390,167	20,891,909.09
2046	14,183	38	14,219	2	0	1,774,790	219,147	85,391	133,023	195,871	83	2,275,282	2,408,304	86,008	-	2,494,313	21,864,994.07
2047	14,201	38	14,239	0	-	1,838,244	224,593	84,142	138,242	203,079	84	2,350,143	2,488,385	86,008	-	2,574,393	22,830,692.20
2048	14,212	53	14,261	4	0	1,922,817	230,174	97,965	151,049	210,404	89	2,461,449	2,612,498	87,924	23,941	2,700,423	23,804,705.54
2049	14,225	67	14,292	0	-	1,998,238	235,894	81,448	170,347	228,920	89	2,544,589	2,714,936	89,878	24,411	2,804,813	24,777,461.33
2050	14,242	82	14,322	1	0	2,466,581	68,655	98,069	147,647	176,970	107	2,810,383	2,958,030	91,869	24,875	3,049,899	25,794,533.86
2051	14,237	197	14,407	0	0	2,540,030	70,362	98,863	155,631	179,724	111	2,889,090	3,044,722	104,854	162,261	3,149,576	26,804,449.93

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 15,850.62	$ 2,182.30	$ 3,940.70	$ 2,063.30	$ 1,701.90	$ 1.50	$ 23,677.01	$ 25,740.31	$ 1,064.14		$ 26,804.45

Appendix A – Detailed PLEXOS Modeling Results

Table A-17- Regulated CO_2 Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost		Plant O&M Costs									Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,484	-	105,663	54,737	41,739	118	969,004	1,023,741	-	-	1,023,741	1,023,741.30
2023	12,948	-	12,943	5	0	550,210	-	188,230	73,618	32,307	145	770,892	844,510	-	-	844,510	1,835,769.85
2024	13,057	-	13,054	3	-	439,884	-	231,266	75,420	27,774	118	699,041	774,461	-	-	774,461	2,551,802.57
2025	13,160	280	13,420	20	-	485,852	-	303,871	80,004	19,424	112	809,260	889,264	32,175	402,043	921,439	3,370,958.63
2026	13,250	265	13,506	9	-	494,133	13,511	260,914	82,569	30,956	119	799,633	882,202	32,175	-	914,378	4,152,572.61
2027	13,327	178	13,505	1	0	547,494	13,846	254,613	177,371	34,744	140	850,838	1,028,209	32,175	-	1,060,384	5,024,131.25
2028	13,399	190	13,590	0	0	566,725	14,213	265,452	86,730	40,888	148	887,427	974,157	32,175	-	1,006,332	5,819,450.27
2029	13,470	289	13,759	-	0	512,666	14,541	252,890	106,650	33,098	49	813,244	919,894	78,867	663,615	998,762	6,578,427.15
2030	13,534	299	13,834	-	0	520,505	28,649	251,443	100,823	38,061	158,836	997,494	1,098,316	78,867	-	1,177,184	7,438,583.86
2031	13,595	306	13,901	0	-	544,036	29,359	274,219	102,333	38,956	165,256	1,051,825	1,154,159	78,867	-	1,233,026	8,304,891.80
2032	13,654	299	13,953	0	0	579,873	30,136	262,690	100,033	41,455	177,603	1,091,757	1,191,790	78,867	-	1,270,658	9,163,302.70
2033	13,712	314	14,025	1	0	611,124	30,829	275,646	139,222	42,230	188,629	1,148,458	1,287,680	78,867	-	1,366,547	10,050,985.82
2034	13,764	313	14,077	-	0	629,084	31,591	300,716	107,137	42,171	196,377	1,199,939	1,307,076	78,867	-	1,385,944	10,916,642.31
2035	13,814	318	14,132	-	0	660,322	32,370	292,022	104,747	47,710	209,935	1,242,359	1,347,106	78,867	-	1,425,973	11,773,044.93
2036	13,862	317	14,179	0	0	704,955	33,224	281,307	158,837	50,628	224,813	1,294,927	1,453,764	78,867	-	1,532,631	12,658,101.36
2037	13,905	327	14,231	1	-	728,838	33,984	294,734	110,841	50,343	234,611	1,342,510	1,453,351	78,867	-	1,532,219	13,508,887.98
2038	13,949	338	14,287	-	0	767,936	34,820	273,691	137,772	52,849	247,901	1,377,196	1,514,968	78,867	-	1,593,836	14,359,849.98
2039	13,987	321	14,308	0	0	809,358	35,675	268,273	127,320	60,285	266,132	1,439,723	1,567,043	78,867	-	1,645,911	15,204,816.55
2040	14,024	338	14,361	1	0	841,421	36,612	283,575	150,377	58,251	275,118	1,494,976	1,645,353	78,867	-	1,724,221	16,055,940.42
2041	14,057	345	14,402	-	-	874,003	37,445	256,702	142,214	60,917	295,084	1,524,152	1,666,366	78,867	-	1,745,233	16,884,302.22
2042	14,085	368	14,451	2	0	1,096,108	38,362	274,318	106,908	66,090	343,554	1,818,433	1,925,341	78,867	-	2,004,208	17,798,996.70
2043	14,111	363	14,469	5	0	1,183,044	39,300	211,329	200,810	70,699	370,113	1,874,485	2,075,295	78,867	-	2,154,163	18,744,315.72
2044	14,137	412	14,544	6	0	1,303,842	40,327	118,983	126,712	71,073	417,187	1,951,411	2,078,123	83,639	59,623	2,161,762	19,656,482.77
2045	14,160	38	14,195	4	0	1,484,441	41,240	99,851	140,006	100,693	469,066	2,195,291	2,335,296	86,008	431,647	2,421,305	20,638,869.86
2046	14,183	35	14,216	3	0	1,577,739	20,291	101,800	133,023	105,854	501,925	2,307,609	2,440,632	86,008	-	2,526,640	21,624,566.38
2047	14,201	38	14,239	0	0	1,633,253	20,786	99,684	138,242	110,603	529,294	2,393,621	2,531,863	86,008	-	2,617,871	22,606,573.91
2048	14,212	53	14,258	6	0	1,711,555	21,327	122,002	151,049	108,541	560,643	2,524,068	2,675,118	87,924	23,941	2,763,042	23,603,173.38
2049	14,225	62	14,287	0	0	1,773,263	21,809	100,639	170,347	117,992	587,531	2,601,234	2,771,581	89,878	24,411	2,861,459	24,595,574.71
2050	14,242	141	14,382	1	0	1,887,141	-	106,344	149,161	107,296	635,007	2,735,787	2,884,948	98,364	106,042	2,983,312	25,590,442.14
2051	14,237	211	14,420	0	0	1,956,829	-	106,699	156,690	102,578	675,602	2,841,708	2,998,398	109,156	134,844	3,107,554	26,586,883.67

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 14,596.41	$ 376.61	$ 4,107.12	$ 2,064.15	$ 931.43	$ 3,443.49	$ 23,455.05	$ 25,519.20	$ 1,067.68		$ 26,586.88

Appendix A – Detailed PLEXOS Modeling Results

Table A-18 - Net Zero Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
								Plant O&M Costs									
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost ($000)	Solar PPA Costs ($000)	Variable Cost ($000)	Fixed Cost ($000)	Start and Shutdown ($000)	Emission Cost ($000)	Variable Production Costs ($000)	Total Production Cost ($000)	Unit Additions Annualized Capital Costs ($000)	Unit Additions Capital Costs ($000)	Total System Cost ($000)	
2022	12,827	-	12,818	8	0	821,439	-	105,553	54,737	41,832	119	968,943	1,023,680	-	-	1,023,680	1,023,679.60
2023	12,948	-	12,943	5	-	550,184	-	188,141	73,618	32,533	145	771,003	844,620	-	-	844,620	1,835,814.66
2024	13,057	-	13,054	3	-	440,113	-	231,689	75,420	27,603	118	699,523	774,943	-	-	774,943	2,552,292.67
2025	13,160	287	13,427	20	-	486,205	-	305,125	79,794	18,942	113	810,385	890,179	32,674	408,274	922,853	3,372,705.92
2026	13,250	269	13,511	9	-	480,792	20,704	259,121	82,363	29,342	114	790,072	872,435	32,674	-	905,109	4,146,397.06
2027	13,327	172	13,499	1	-	520,115	27,857	252,170	177,169	35,993	132	836,268	1,013,438	32,674	-	1,046,112	5,006,224.62
2028	13,399	193	13,592	0	-	538,514	28,452	264,125	86,532	40,000	138	871,230	957,762	32,674	-	990,436	5,788,980.68
2029	13,470	211	13,671	10	-	595,244	28,961	287,547	89,103	43,202	124	955,078	1,044,181	32,674	-	1,076,855	6,607,301.71
2030	13,534	397	13,928	3	-	456,499	135,475	262,752	83,120	61,736	94	916,556	999,676	32,674	-	1,032,351	7,361,630.19
2031	13,595	500	14,094	1	-	468,667	138,684	281,149	86,381	62,028	91	950,619	1,037,001	41,427	109,374	1,078,428	8,119,319.57
2032	13,654	510	14,164	0	-	500,114	142,019	265,104	83,910	64,096	92	971,425	1,055,335	41,427	-	1,096,762	8,860,252.67
2033	13,712	1,013	14,722	3	-	436,846	207,114	278,489	133,061	60,027	78	982,554	1,115,615	87,075	570,377	1,202,690	9,641,496.97
2034	13,764	1,043	14,806	1	-	419,389	251,302	289,513	101,097	62,110	74	1,022,388	1,123,485	87,075	-	1,210,559	10,397,608.75
2035	13,814	1,067	14,880	1	-	417,962	321,078	281,943	98,825	67,313	73	1,088,369	1,187,194	87,075	-	1,274,269	11,162,901.57
2036	13,862	1,064	14,924	2	-	455,844	328,929	273,166	153,009	70,129	77	1,128,144	1,281,153	87,075	-	1,368,228	11,953,019.18
2037	13,905	1,265	15,170	0	-	449,362	345,067	279,017	109,583	69,570	72	1,143,088	1,252,671	106,840	246,969	1,359,510	12,707,906.90
2038	13,949	2,456	16,404	1	-	365,140	361,782	258,129	166,256	51,631	42	1,036,726	1,202,983	237,984	1,638,694	1,440,967	13,477,250.86
2039	13,987	3,550	17,537	-	-	299,270	387,496	245,060	190,136	42,837	26	974,689	1,164,825	385,709	1,845,866	1,550,534	14,273,253.37
2040	14,024	5,139	19,163	-	-	174,446	500,302	243,614	260,556	28,313	10	946,684	1,207,240	586,002	2,502,728	1,793,243	15,158,448.38
2041	14,057	5,593	19,649	-	-	164,011	521,186	223,396	303,160	27,164	10	935,767	1,238,927	797,238	2,639,456	2,036,165	16,124,898.72
2042	14,085	6,590	20,674	-	-	182,569	648,543	210,407	321,308	29,994	14	1,071,527	1,392,836	1,012,792	2,693,419	2,405,628	17,222,795.80
2043	14,111	7,302	21,414	-	-	143,743	788,135	141,263	471,252	28,885	10	1,102,035	1,573,288	1,232,630	2,746,941	2,805,917	18,454,126.66
2044	14,137	8,179	22,316	-	-	128,250	957,990	35,110	455,153	25,469	9	1,146,827	1,601,980	1,456,921	2,802,594	3,058,902	19,744,846.77
2045	14,160	8,976	23,136	-	-	114,269	1,137,727	3,644	508,668	22,444	8	1,278,093	1,786,760	1,669,067	3,059,102	3,455,828	21,146,967.00
2046	14,183	10,078	24,261	-	-	135,186	1,300,168	11,712	565,637	15,363	11	1,462,440	2,028,077	1,902,019	2,910,802	3,930,096	22,680,181.67
2047	14,201	10,401	24,602	-	-	126,874	1,489,435	4,476	637,702	13,271	10	1,634,067	2,271,769	2,139,619	2,968,889	4,411,388	24,334,967.49
2048	14,212	10,567	24,760	19	-	115,306	1,717,323	3,929	677,760	13,970	9	1,850,537	2,528,297	2,199,186	744,315	4,727,483	26,040,119.77
2049	14,225	11,143	25,364	4	-	104,208	1,942,982	13,120	742,333	10,966	7	2,071,284	2,813,617	2,340,303	1,763,299	5,153,920	27,827,584.73
2050	14,242	11,191	24,692	742	-	9,202	1,913,345	2,248	814,447	-	-	1,924,795	2,739,242	2,602,422	3,344,627	5,341,664	29,608,909.29
2051	14,237	11,241	24,744	707	-	10,132	1,960,891	2,475	838,305	-	-	1,973,498	2,811,803	2,546,494	162,261	5,358,297	31,327,054.84

	Fuel Cost ($1MM)	Solar Cost ($1MM)	Variable Cost ($1MM)	Fixed Cost ($1MM)	Start and Shutdown ($1MM)	Emission Cost ($1MM)	Variable Production Costs ($1MM)	Total Production Cost ($1MM)	Unit Additions Capital Costs ($1MM)		Total System Cost ($1MM)
CPWC ($1MM)	$ 7,160.01	$ 7,263.49	$ 3,718.27	$ 3,867.52	$ 706.37	$ 1.37	$ 18,849.51	$ 22,717.03	$ 8,610.02		$ 31,327.05

B Environmental Assessment

B.1 Introduction

JEA's generation fleet is subject to numerous environmental regulatory programs and requirements. While most of the environmental regulatory programs and requirements applicable to JEA generating units have already been addressed, a few recently proposed and finalized programs in various stages of administrative transition and judicial review could have impacts on future operations. The following sections provide a summary of the applicability of air, water and waste programs and permitting requirements, as well as the associated potential compliance risks associated with continued operation of the existing fossil fuel-fired generating units.

B.2 Assessment of Carbon, Air, Water, and Other Environmental Considerations

The following subsections outline the current and impending regulatory programs and requirements related to carbon, air, water, and other environmental concerns.

B.2.1 Carbon Assessment

B.2.1.1 Clean Power Plan/Affordable Clean Energy Rule

On August 3, 2015 the United States Environmental Protection Agency (EPA) released its final Clean Power Plan (CPP) rulemaking to establish standards for performance for greenhouse gas (GHG) emissions from existing electric generating units (EGUs) (i.e., EGUs for which construction was commenced prior to January 8, 2014) under Section 111(d) of the Clean Air Act (CAA). In the final CPP rule, the EPA set emission performance rates, phased in over the period from 2022 through 2030, for two subcategories of affected fossil fuel-fired EGUs – fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

The final CPP rule required each state to submit a final plan that outlines how the state will meet its goal by September 2016. However, on February 9, 2016 the U.S. Supreme Court issued an order to stay (suspend) the CPP until legal challenges to the rule could be resolved in federal court(s). In September of 2016, the District of Columbia (D.C.) Circuit Court of Appeals heard oral arguments on the legal challenges to the CPP. Following the hearings, however, the D.C. Circuit subsequently granted a petition from the new Trump Administration to hold the prior CPP litigation in abeyance pending the outcome of EPA's announced intentions to reconsider the CPP rule.

EPA published a proposal to repeal the CPP in its entirety on October 16, 2017. Then on August 21, 2018 EPA released an alternative proposal to revise the CPP. Entitled the Affordable Clean Energy (ACE) rule, this latest proposal seeks to reduce carbon dioxide (CO_2) emissions solely through heat rate improvements at existing fossil fuel-fired utility boiler EGUs. Units 1, 2, and 3 at Northside Generating Station and Scherer Unit 4, which is no longer in operation, are the only units in JEA's portfolio that would have been subject to regulation under ACE as the rule was proposed.

As with the CPP, the ACE rule proposed to regulate existing power plants under Section 111(d) of the CAA by establishing performance standards based on the Best System of Emission Reduction (BSER). In contrast to the CPP, however, and in accordance with EPA's most recent interpretation of its authority under the CAA, the ACE rule focused on only those measures that could be implemented "within the fenceline" of existing EGU facilities. Consistent with that approach, EPA proposed that BSER is to be limited to heat rate improvement measures at existing coal-fired

EGUs. Instead of setting numeric limits, EPA's ACE rule provided emission guidelines that states were to use in developing their individual State Implementation Plans (SIP) to regulate CO_2 emissions from EGUs within their jurisdictions. These guidelines included a list of "candidate technologies" and measures to achieve heat rate improvements.

However, on January 19th, 2021 the D.C. Circuit Court vacated the ACE rule, with instructions for the EPA to "consider the question afresh." Key takeaways of the vacated ACE rule are as follows:

- The D.C. Circuit rejected the Trump Administration's contention that—no matter the circumstances—Section 111 of the Clean Air Act unambiguously limits the "best system of emission reduction" to emissions-reducing measures operating at the physical source.
- The court's decision clears the way for the Biden EPA to issue a replacement rule regulating CO_2 emissions from existing power plants, potentially again considering generation shifting and other measures to more aggressively target power sector emissions.
- President Biden's choice for EPA Administrator, Michael Regan, testified that he views the opportunity as a "clean slate" for the Agency to chart next steps under Section 111(d).

On June 30, 2022, the U.S. Supreme Court issued their ruling regarding the CPP/ACE rule and in essence, limited EPA's authority to set standards on climate-changing greenhouse gases (GHG) emissions from existing power plants. The ruling surmised that for issues of major national significance; i.e., how people will get their energy, a regulatory agency must have clear statutory authorization from Congress to take certain actions and not rely on its general agency authority. Should any replacement rule still be issued by the EPA; it is unknown what type of requirements would be proposed at this time. With the current make-up of the Congress, it is anticipated any new legislature pertaining to limiting GHG emissions from existing power plants is unlikely to be proposed.

B.2.1.2 Florida Statewide Renewable Energy Goal

On April 21, 2022 the Commissioner of Agriculture and Consumer Services announced a new statewide renewable energy goal. This new goal seeks to increase the amounts of renewable energy used by the state to at least 40 percent by 2030 with an ultimate goal of 100 percent by 2050. However, under state law, the Public Service Commission (PSC) has the authority to force the utilities to meet these goals, and the PSC has been historically less aggressive in boosting standards for renewable energy. As such, it is unknown at the time this report was written how this might affect the portfolio requirements for JEA.

B.2.1.3 Clean Future Act

On March 2, 2021 representative Frank Pallone introduced H.R. 1512 also known as the Clean Future Act (CFA or H.R. 1512). H.R. 1512 creates requirements and incentives to reduce GHG emissions. In general, the bill establishes an interim goal that would reduce GHG emissions to levels that are 50 percent below 2005 values by the year 2030. The bill also sets a national goal to cut GHG emissions to a net zero level by 2050. The bill states that each federal agency must develop plans on how these levels can be achieved.

The bill goes on to state that by 2023, all retail electricity suppliers must provide an increasing percentage of electricity that produces "zero-emission electricity". The bill then states that by the year 2035, retail electricity suppliers must provide electricity that produces "zero-emissions" or show an alternative way to obtain compliance. The bill does indicate that retail electricity suppliers may obtain credits under a trading program that allows them to buy, sell, and trade credits to show compliance.

The bill establishes multiple requirements, programs, and incentives that are to be used to reduce or eliminate GHG emissions. A bullet list of some of these "other" requirements, programs, and incentives are listed below:

- Increasing energy efficiency in buildings, homes, and appliances;
- Supporting clean transportation, including electric vehicles and related charging infrastructure;
- Issuing greenhouse gas standards for certain vehicles, engines, and aircraft;
- Promoting manufacturing and industrial decarbonization, including through buy-clean programs;
- Supporting environmental justice efforts; and
- Reducing methane, plastics, and super pollutants.

It is unclear whether the CFA bill will advance in the U.S. House of Representatives and become law. It is likely that the CFA will face challenges within the U.S. House of Representatives and possibly the U.S. court system going forward.

B.2.1.4 45Q Tax Code

Congress added Section 45Q to the Internal Revenue Code in 2008 in an effort to incentivize additional investments in carbon capture and sequestration projects. In its original form, Section 45Q provided a tax credit for each metric ton of qualified carbon dioxide captured and either disposed of in secure geological storage or used for certain purposes, such as use in oil or natural gas extraction processes. However, the original code made available such credits only for the first 75 million tons of qualified carbon dioxide captured by all projects and each project was required to capture at least 500,000 metric tons of qualified carbon dioxide in a single taxable year.

The Bipartisan Budget Act of 2018 established a number of important changes to Section 45Q that made these credits more attractive to investors. It expanded Section 45Q to include carbon oxide in addition to the previously allowed carbon dioxide. The amendment eliminated the 75 million ton program limitation on the overall credits available in the market and it lowered thresholds for the amount of carbon that would have to be captured in a given year.

The amendment also clarified the credits would be available for 12 years, beginning when the carbon capture equipment is placed in service, in addition to increasing the value of Section 45Q credits. For taxpayers who dispose of qualified carbon oxide (includes certain types of carbon dioxide and carbon oxide) in secure geological storage spaces, a tax credit worth $22.66 per metric ton was available for 2017 and increasing linearly until reaching $50 per metric ton in 2026. A tax credit worth $12.83 per metric ton was available for 2017 and increasing linearly until reaching $35 per metric ton in 2026 for taxpayers who capture and then use qualified carbon oxide for certain activities. After 2026, the amount of the credit is subject to an inflation-adjusted increase. Lastly, the amendment clarifies that the taxpayer who owns the carbon capture facility does not need to own the facility that emits the qualified carbon oxide that is being captured to be eligible for the tax credits under Section 45Q.

B.2.1.5 Geologic Review for Carbon Sequestration

Compliance with the Safe Drinking Water Acts requires that all injection occurs below the underground source of U.S. drinking water (USDW), although EPA may grant exceptions. A USDW is an aquifer or part of an aquifer that is currently used as a drinking water source or contains fewer than 10,000 milligrams per liter (mg/L) total dissolved solids (40 CFR 146.3). Due to the presence of the Upper and Lower Floridan Aquifers at depths ranging from approximately 600 to 2000 feet below land surface (bls), potentially suitable geologic formations in the study area should be deeper than approximately 3,000 feet bls. If found to be suitable, the target reservoir formation will need to have a thick and extensive seal (i.e. geologic formation above the injection zone that has confining characteristics), have sufficient porosity, and be sufficiently permeable to permit injection at high flow rates without requiring excessively high pressure.

In Florida, there are numerous facilities that dispose municipal and industrial wastes using injection wells. These waste fluids are generally injected into permeable zones in the lower Floridan aquifer (LFA), in a zone commonly known as the Boulder Zone. The Boulder Zone is widely encountered in central and south Florida, making it suitable for an injection zone. In contrast, the Boulder Zone is not encountered in the northern portion of Florida. The permeable saline zones of the Cedar Keys formation and the Lawson Limestone are an alternative often studied in central Florida and could serve as an option in northern Florida. In Polk County for example, wastes are injected into the permeable zone of the Lower Cedar Keys Formation and Lawson Limestone, which are overlain by a thick sequence of impermeable anhydrites and dolomites positioned well below any USDW.

Although not explored in detail in this current assessment, the Lawson Limestone appears to be an attractive option for sequestering CO_2 below depths of 3,000 feet bls. Sequestering CO_2 below this depth with overlying confining geologic formations (i.e., the Cedar Keys) will decrease the likelihood of upward/lateral migration and protect the local USDW. Another advantage of using the Lawson Limestone as carbon storage reservoir is that the pressure-temperature (PT) conditions at that depth would ensure that the CO_2 remains in a supercritical state, thereby occupying less pore space than a gas. Further, CO_2 density is high enough to allow efficient pore filling and to decrease the buoyancy difference compared with in-situ fluids.

The Southeast Regional Carbon Sequestration Partnership, or SECARB, performed a study between 2003 and 2005, sparked by a research program launched by the U.S. Department of Energy (DOE). The researchers took a macro-level, dimensional, geographic identification approach to identify areas and particular geologic formations with sequestration potential. Data sets were composed using publicly available data that revealed three primary types of geologic sinks capable of storage (saline formations, coal seams and oil and gas reservoirs).

In the southeastern area of the region that include South Carolina, Georgia, and Florida, SECARB identified minimal opportunities for storage as part of the recovery of coal bed methane (CBM), oil or gas. Based on available data, the potential geological setting suitable for CO_2 sequestration were determined to be sedimentary brine or saline formations and offshore.

B.2.1.5.1 Sedimentary Saline Geologic Formations

The sedimentary geologic basins and saline basins (studied) are shown in Figure B-1. Within the area of interest, sedimentary saline geologic formations such as the Cedar Keys and Lawson Limestone appear to contain an extensive lateral porous area with saline conditions that is capped by an anhydrite and dolomite impermeable sequence that is approximately 500 feet thick. Although the extent of the potential reservoir capacity is currently unknown, in previous reports it has been described that the southwestern portion of Florida used to be a great back-barrier reef area while the deposition and formation of the Cedar

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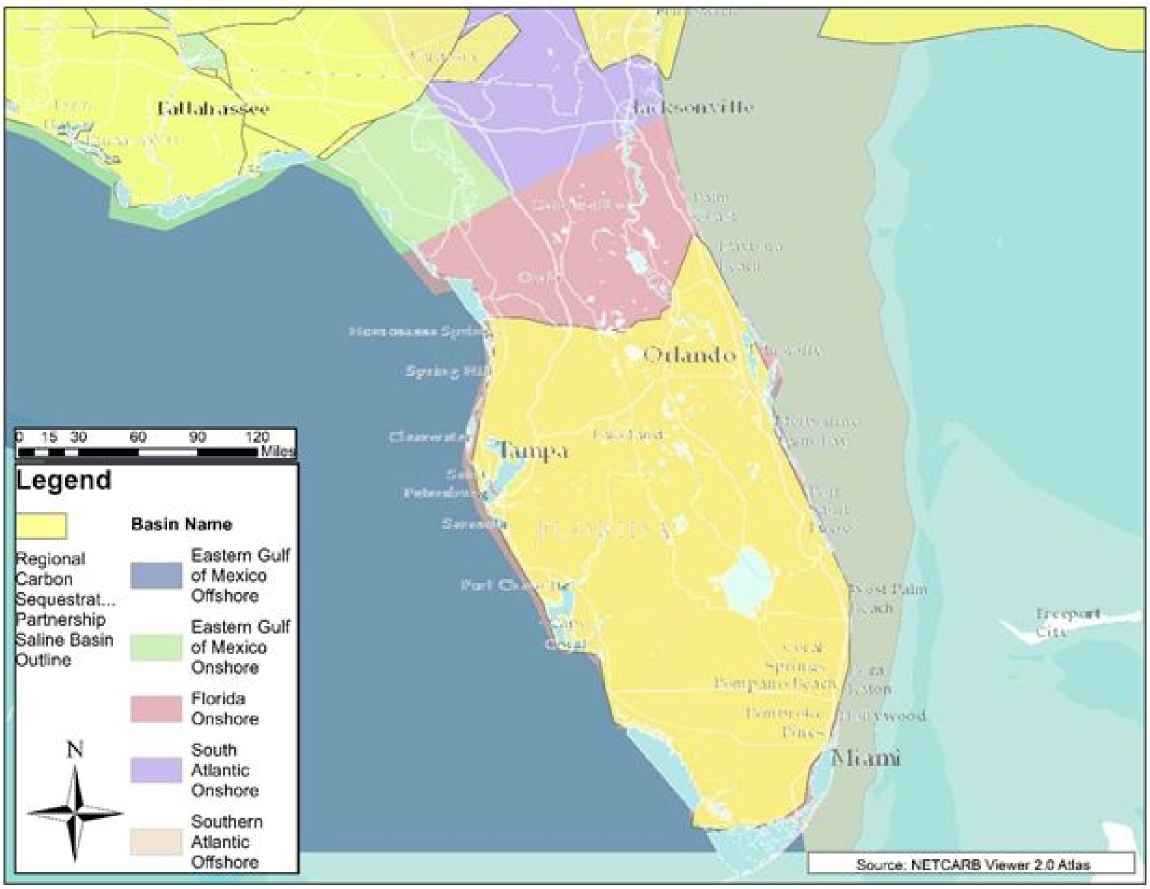
Keys and Lawson occurred, indicating that these units of carbonates and evaporates have the potential to be laterally extensive. In this case, the upper part of the Cedar Keys formation provides competent confinement due to its thick sequence of dolostone with interbedded anhydrite, while the lower portion near the base of the Cedar Keys formation and the Lawson Limestone could serve as a potential injection zone based on the increased permeability in these zones. In addition, the EPA determined that a saline formation suitable to sequester CO_2 must have a minimum 10,000 part per million (ppm) of total dissolved solids, which in this case, the permeable zones of the Cedar Keys and Lawson Limestone have.

Figure B-1 - Sedimentary Basins and Saline Basins Suitable for CO_2 Sequestration



B.2.1.5.2 Offshore

In regions where limited onshore geologic storage exists, offshore geologic storage could serve as an alternative option. Currently, the U.S. is studying the potential of offshore geologic storage for a safe and long-term capture zone able to sequester CO_2 efficiently.

The process of sequestering CO_2 in an offshore geologic setting involves obtaining the CO_2 from a stationary emission source, using a sub-sea pipeline or an ocean tanker to transport the CO_2 from the source to an injection system, and injecting it into a deep geologic formation below the sea bottom capable of retaining and isolating the CO_2 from the ocean water. However, when considering this option, there are numerous aspects like storage potential and the lack of experience in offshore CO_2 storage and monitoring that still need to be evaluated to close the knowledge gap for CO_2 to be injected safely in offshore geologic formations.

Assessments of potential CO_2 offshore geologic sequestration are ongoing by various research groups. The Bureau of Ocean Energy Management (BOEM) of the U.S. Department of Interior (DOI) acts as the authority under the Energy Policy Act of 2005 and is in the process of putting together rules to regulate carbon sequestration projects in the outer continental shelf, but as of now, no guidance or regulations exist for offshore applications (Nemeth 2006).

Listed below are some advantages of offshore CO_2 storage:

- Site located safely away from heavily populated onshore areas
- If on Federal lands, it minimizes issues when obtaining surface and mineral owner rights (single entity pore space owner)
- Typically injected into saline formations which reduces contamination potential to any USDW
- Similar chemistry and salinity from formation fluid and sea water (30,000 to 40,000 ppm total dissolved solids)
- Could utilize existing design and infrastructure from oil and gas facilities and right-of-ways
- Serves as potential storage of CO_2 to many large stationary emission sources along coastlines that have limited options for onshore CO_2 storage

While enormous opportunity exists for sequestering onshore CO_2 sources in offshore storage reservoirs, several key challenges remain to be solved before offshore storage can provide a viable alternative for onshore energy providers. These limitations include a high cost of implementation relative to onshore storage operations, unproven compatibility with existing oil and gas (O&G) infrastructure, lack of accurate / current cost data for O&G equipment, and the source-to-sink matching challenges associated with the disparate locations of carbon sources and offshore storage locations.

B.2.1.5.3 Geologic Confinement

Because the density of CO_2 is less than that of water, the CO_2 will tend to float. Therefore, an adequate seal, or “trap”, in the geologic unit overlying the target reservoir is a key component for the success of the carbon sequestration project. The seal must contain the buoyant column of CO_2 as well as be laterally continuous across the trap. Trapping mechanisms are typically stratigraphic or structural. Stratigraphic traps are those that rely on a change in lithology, such as a thick shale bed overlying more permeable units. Structural traps include anticlines, faults, and salt domes.

In the case of Duval County, the anhydrite and dolomitic beds of the Cedar Keys formation may serve as the geologic confinement necessary to protect the overlying potable water sources of the Upper and Lower Floridan Aquifers. To determine whether the Cedar Keys formation can function as an adequate stratigraphic trap for safe and effective sequestration of CO_2 in the underlying target reservoir, extensive upfront geological and geophysical studies will be required during the initial phases of any potential future assessment for suitability. These studies would need to assess the thickness, lateral extent, permeability, and other hydrogeologic and hydrogeochemical properties of the target storage reservoir and confining units.

B.2.1.5.4 Conclusion

Based on a high-level geologic review of the potential for carbon sequestration in the Jacksonville area, the Mesozoic carbonate sediments of the Lawson Limestone (~3,000 ft bls) appear to have marginal to good prospect for carbon sequestration. Factors that will influence the acceptability of the Lawson Limestone for injection of CO_2 include the injectability and hydrogeochemical compatibility of the Lawson Limestone as well as the permeability and lateral continuity of the anhydrite and dolomitic beds of the Cedar Keys formation, which would need to serve as the geologic trapping mechanism to prevent upward/lateral migration of sequestered carbon.

While unproven as of yet, carbon sequestration in offshore basins utilizing existing oil and gas infrastructure may be an alternative option for Jacksonville area carbon sources in the future. However, several economic, regulatory, and logistical challenges must be addressed before the opportunity offered by offshore carbon sink reservoirs can be realized.

B.2.2 Air Assessment

The following subsection outlines the current and impending regulatory programs and requirements related to air pollutant emissions from the JEA generation units.

B.2.2.1 New Source Review & Title V Air Operation Permits

Federal and State regulations require that an air construction permit be obtained to authorize construction of new emissions units or modifications to existing emissions units. The construction permitting process entails New Source Review (NSR), which begins with an analysis to determine the applicability of major source permitting requirements under the provisions of Prevention of Significant Deterioration (PSD), for those sources located in areas that are in attainment of the National Ambient Air Quality Standards (NAAQS) or unclassifiable, or Non-Attainment NSR (NA NSR) for those sources located in areas not in attainment of the NAAQS for one or more pollutants. Duval County, Florida, where all of JEA's existing generating assets are situated, is currently designated as attainment or unclassifiable for all criteria pollutants. Compliance with the various NAAQS is determined on an annual basis, and as such, the attainment status of a given county is certainly subject to change in the future.

Should JEA undertake any installations/ modifications in the future that trigger PSD and/or NA NSR (i.e., major source permitting), a construction permit will first need to be obtained. EPA has recently proposed changes to how NSR applicability is determined for major modifications (see project accounting memo).

Air permitting in Florida is under the jurisdiction of the Florida Department of Environmental Protection (FDEP). The EPA has given the FDEP authority to implement and enforce the federal CAA provisions and state air regulations under its approved SIP.

Each of the currently operating JEA generation assets is authorized by a Title V Air Operation Permit. These permits establish terms and conditions which the permitted facility must operate under, including operational requirements/restrictions, monitoring and reporting requirements, and emission limits. JEA maintains compliance with the terms and conditions of their various Title V Air Operation Permits. Additionally, the current terms and conditions do not present any significant risks of non-compliance or necessity to incur additional costs to maintain compliance in the future.

Concurrent with Northside Generating Station (NGS) Units 1 and 2 being converted to circulating fluidized bed (CFB) boilers, JEA entered into a Community Commitment to reduce overall sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) emissions from Units 1, 2, and 3 by 10 percent relative to previous annual emissions. These limits, in tons per year (tpy), which are now

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included in the NGS Title V Air Operation Permit are listed in Table B-1.

Based on the current operation of NGS Units 1 2, and 3, the SO_2 and PM emissions are well below their limits. The annual NO_X limit requires more careful management to ensure compliance. Based on facility NO_X CEMS data from 2016-2020, annual NO_X emissions have been within the prescribed limit. The emissions data and the annual operating hours of each unit is included in Table B-2.

Assuming future operation remains consistent with recent past operation, these emission limits should have no impact on operations at NGS. However, should market conditions dictate increased dispatch of the units in the future, operations (including the use of the existing selective non-catalytic reduction systems on NGS Units 1 and 2), will need to be managed carefully in order to maintain compliance with the annual NO_X emission limit.

Table B-1 - Northside Generating Station Community Commitment Emission Limits

Pollutant	Cumulative Annual Limit – Units 1, 2, and 3 (tpy)
NO_X	3,600
SO_2	12,284
PM	881

Table B-2 - Annual Cumulative Facility Emissions Northside Generating Station

Year	PM [1], tpy	SO_2 [2], tpy	NO_X [2], tpy	Unit ID	Annual Hours of Operation [2]	Percent of Full Year Operation
2016	355	3,041	2,555	1A	6,312	72
				2A	7,780	89
				3	5,857	67
2017	326	1,485	1,923	1A	4,762	54
				2A	3,239	37
				3	5,025	57
2018	59	2,473	2,714	1A	7,825	89
				2A	4,308	49
				3	7,126	81
2019	45	1,917	2,864	1A	8,007	91
				2A	1,790	20
				3	6,591	75
2020	54	2,318	3,212	1A	7,420	85
				2A	4,760	54
				3	7,907	90

NOTES [ ]:
1. Data obtained from the facility's annual air emissions reports. For PM, these values represent the entire facility, not just Units 1, 2, and 3.
2. Data obtained from the U.S. EPA's Clean Air Markets database.

B.2.2.2 National Ambient Air Quality Standards

The EPA has set NAAQS for six principal pollutants, which are called "criteria" air pollutants. Geographical areas (in this case counties) in Florida are designated for each pollutant as attainment, non-attainment, or unclassifiable based on actual air quality measurements and/or modeling. As noted above, currently, Duval County Florida is designated as attainment or unclassifiable for all the criteria pollutants.

The CAA requires that EPA periodically review the various NAAQS and promulgate revised standards if scientific evidence indicates that a revision is necessary. In 2010, EPA established new 1-hour standards for SO_2 and NO_X which has presented compliance challenges as a result of the short (one hour) averaging period. Of specific concern, the 1-hour SO_2 NAAQS Data Requirements Rule (DRR) required states to either monitor ambient air or conduct air dispersion modeling to demonstrate compliance with 1-hour SO_2 NAAQS. Again, Duval County is designated as attainment/unclassifiable for the 1-hour SO_2 and NO_X NAAQS.

In order to proactively ensure compliance with the 1-hr SO_2 NAAQS violations, JEA has implemented operating restrictions on NGS Unit 3 that apply to oil-fired operations. Future revisions to these standards to make them more stringent could potentially change the attainment designation of Duval and/or surrounding counties, which could further impact the operation of the JEA fleet should the Florida Department of Environmental Protection (FDEP) take steps to mitigate short term NO_X and/or SO_2 emissions from fossil fuel-fired electric generating facilities.

EPA is required to review the standards every five years and, if appropriate, revise existing air quality criteria to reflect advances in scientific knowledge on the effects of the pollutant on public health and welfare. On April 6, 2018, EPA issued their final decision to retain the current NO_X national ambient air quality standard (NAAQS). On February 25, 2019, EPA issued their final decision to retain the existing primary 1-hour SO_2 NAAQS.

In 2015, EPA finalized an 8-hour standard of 70 parts per billion (ppb) for ozone. On December 23, 2020, EPA completed their review and decided to retain the existing ozone NAAQS. In 2012, EPA finalized the 24-hour standard of 35 $\mu g/m^3$ for fine particulate matter, 24-hour standard of 150 $\mu g/m^3$ for particulate matter, the primary annual standard of 12.0 $\mu g/m^3$ for fine particulate matter, and the secondary annual standard of 15.0 $\mu g/m^3$ for fine particulate matter. On December 7, 2020, EPA announced it would retain the existing primary and secondary NAAQS for particulate matter. However, the new Biden Administration issued an executive order on January 20, 2021, in which it called for the review of several environmental regulations that were recently finalized. This includes the review of the ozone NAAQS, as well as the particulate NAAQS. EPA, under the Trump Administration, altered the review process, including but not limited to, alterations to the make-up of the Clean Air Scientific Advisory Committee, which is an independent committee of experts that assists EPA in reviewing the NAAQS. On June 10, 2021, EPA announced that it will reconsider the previous decision to retain the particulate matter NAAQS, as EPA believes there is available scientific evidence and technical information which indicates the current standards may not be adequate to protect public health and welfare.

On January 6, 2023, EPA announced it proposed rule to revise the primary annual $PM_{2.5}$ standard from its current level of 12.0 $\mu g/m^3$ to within the range of 9.0 to 10.0 $\mu g/m^3$. While this proposed rule did not revise the 24-hour standard, EPA will accept comments on retaining the current existing 24-hour standard. As this is a proposed rule, any requirements in the final rule cannot be assessed at this time. Nonetheless, should the proposed rule be finalized as-is, the revised annual standard should not pose any concern for facilities located in Duval County, Florida.

A review of the current design values for ozone and fine particulate matter was undertaken. Based on the 2018-2020 data for Florida's Air Quality System, the design values for Duval County are 60.3 ppb and 19.6 µg/m^3 for ozone and fine particulate matter (24-hour), respectively. Including current 2021 data would alter the designs to 60.0 ppb and 20.1 µg/m^3 for ozone and fine particulate matter (24-hour), respectively. Continued awareness of any potential changes to the NAAQS will be necessary to determine if any changes would have any effect on the existing JEA assets or any permitting activities for any future potential new facilities.

B.2.2.3 Acid Rain Program

The Acid Rain Program (ARP) is aimed at achieving major emission reductions of SO_2 and NO_X, the primary precursors of acid rain. NO_X reductions are achieved by imposing emission limits on various types of coal-fired boilers regulated under the ARP. SO_2 reductions, on the other hand, are achieved via a cap-and-trade program. Regulated emission units (i.e., fossil fuel-fired combustion devices that serve a generator capable of producing 25 megawatts (MW) of electricity for sale to the grid) are required to surrender allowances for each ton of SO_2 emitted annually.

JEA will continue to be required to surrender ARP allowances to cover the units' ARP compliance obligation into the future. Regulated units that were constructed prior to 2001 are allocated allowances annually. Sources constructed after 2001 are not provided an allocation of allowances, and must purchase them from government accounts, auctions and/or the open market. Compliance obligations over and above annual allocations can either be covered by banked allowances in owner-held accounts or obtained from the open market. JEA's current compliance strategy is to rely on banked allowances to cover the fleet's annual compliance obligation. ARP allowances are currently trading at less than $0.50 per ton. Assuming that allowance prices don't increase dramatically, in the event that JEA is required to obtain at least a portion of its ARP compliance obligation in the future, it should not represent a significant operational cost.

B.2.2.4 Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) is EPA's cap and trade program aimed at curbing cross-state transport of NO_X and SO_2 emissions in the eastern U.S. Ultimately, the purpose of the rule is to reduce the number of PM less than 2.5 microns ($PM_{2.5}$) and ozone nonattainment areas caused by cross-state air pollution from the power sector. Affected units under CSAPR are required to surrender allowances for both annual NO_X and SO_2 emissions and/or ozone season (May through September) NO_X emissions. For each affected unit, a given state allocates allowances for each regulated pollutant and compliance period. Any surplus allowances can be banked and held for future compliance and/or sold on the open market. Should a facility's emissions be in excess of its annual allocation, the deficit is required to be covered by banked allowances and/or allowances purchased on the open market.

As originally designed, CSAPR was intended to reduce NO_X emissions in order to help achieve attainment of the 1997 ozone standard. EPA issued an update to CSAPR in 2016 to incorporate the more stringent 2008 ozone standard. This update removed Florida from the requirement to participate in the ozone season NO_X emissions program. As such, facilities in Florida are no longer required to participate in CSAPR.

As of this writing, seasonal CSAPR NO_X allowances are trading for approximately \$2,425 per ton while annual NO_X allowances are trading for approximately \$8.50 per ton. SO_2 allowances are trading for approximately \$2.31 per ton.

B.2.2.5 Visibility and Regional Haze Rule

On June 2, 1999, the U.S. EPA issued regulations to improve visibility, or visual air quality, in 156 national parks and wilderness areas (i.e., Class I areas) across the country. The rule calls for state and federal agencies to work together to achieve a goal to return Class I areas to pristine conditions by 2064 and requires that states assess “reasonable progress” towards the goal every ten years. The first state plans were due in December 2007 and the next review due in 2018 has been extended to 2021. To the extent that states are not meeting the glide path towards compliance, revised plans to accelerate compliance in order to get back on track with compliance goals are required.

The initial emission reduction initiative to achieve compliance with the Regional Haze Program is known as Best Available Retrofit Technology (BART). BART represents the most effective control for visibility impairing pollutants that is also environmentally friendly, technologically feasible, and cost effective. BART can be applied to 26 different industrial sources, including coal-fired power plants, built between 1962 and 1977. In 2005, the EPA provided an amendment to the Regional Haze Program that provided states with guidelines for developing SIPs to determine which sources of visibility impairing pollutants, including NO_X, SO_2, and PM, will need to install BART. A BART determination in 2010 determined that no further controls would be needed for Northside Generating Station Unit 3.

FDEP has provided a notice in regard to the EPA guidance on the second implementation period (2019-2028) and requested comments be received by July 9, 2021. A public hearing was also conducted on July 15, 2021. Incidentally, JEA submitted an application requesting the establishment of an SO_2 emission limit for Boiler No. 3 and a conditional fuel oil sulfur content limit for the purpose of complying with Regional Haze Program. The new condition in the permit will impose an SO_2 emission limit of 3,500 pounds per hour on a 24-hour block average basis as determined by CEMS, which will become effective January 1, 2022. The specific condition for the fuel sulfur content will prohibit JEA from purchasing fuel oil with a sulfur content of greater than 1.0 percent by weight. Based on existing CEMS data for Unit No. 3, the maximum 24-hour block average was 2,583; 509; and 863 pounds per hour for 2018, 2019, and 2020, respectively.

B.2.2.6 National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP) are established under Section 112 of the CAA. The list of regulated hazardous air pollutants (HAPs) was set forth in the Clean Air Act Amendments of 1990. The EPA identified a list of source categories (e.g., electric utility boilers, industrial boilers, combustion turbines, reciprocating internal combustion engines) that included major sources of HAPs (i.e., those sources emitting 10 tpy or more of any one HAP or 25 tpy of any combination of HAPs) and area sources of HAPs (i.e., those sources that are not major sources). Once the various source categories were identified, EPA issued Maximum Achievable Control Technology (MACT) standards for each listed source category according to a prescribed schedule. MACT standards are required to be reevaluated every eight years to determine if additional controls are necessary to reduce health and environmental risks below acceptable levels.

B.2.2.6.1 40 CFR 63 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units

The most significant MACT standard for coal-fired power plants is known as the Mercury and Air Toxics Standard (MATS). The MATS rule, which was finalized by EPA in December of 2011, established a MACT standard in the form of numerical limits for emissions of mercury, no-mercury metallic HAPs, and acid gas HAPs from coal and oil-fired power plants with a capacity greater than 25 MW. Additionally, MATS established work practice standards for emissions of organic HAPs such as dioxins and furans. Under the MATS rule, affected units can comply with the non-mercury metallic HAPs standards by meeting a surrogate particulate matter emissions limit, a total metals limit, or individual emission limits for ten different metallic HAPs, such as lead, arsenic, and various others. Compliance with acid gas limits can be demonstrated by meeting either a hydrogen chloride limit or a SO_2 limit. Power plants that choose to demonstrate compliance with the acid gas limits by meeting a SO_2 limit must be equipped with add-on FGD systems.

Power plants regulated by MATS were required to demonstrate compliance with the rule by April 16, 2015 unless a one-year extension from the state permitting agency was granted for the "installation of controls". An additional year long extension could be granted by the U.S. EPA for sources that could demonstrate that their operation was critical to grid reliability.

Units 1 and 2 at Northside Generating Station are regulated under the MATS rule and are currently in compliance. Unit 3 at Northside Generating Station is currently exempt from emission limits under MATS given that fuel oil combustion is limited by JEA to 10 percent of the average annual heat input on a rolling three year average basis and 15 percent of the annual heat input during any one of those calendar years . Although EPA has recently announced its intention to revisit portions of the MATS rulemaking, it is not expected that any new requirements or additional impacts to the JEA fleet will result in the foreseeable future. However, given that NESHAPs such as MATS are required to be reviewed periodically, there is at least some possibility that EPA could increase the stringency of the MATS limits, thus requiring a greater degree of control for compliance.

B.2.2.6.2 40 CFR 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

On March 5, 2004, the EPA published the final NESHAP for stationary combustion turbines. This rule, found at 40 CFR §63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of HAPs. Northside Generating Station is classified as a major source of HAPs.

The CT MACT has been stayed by the EPA for natural gas-fired combustion turbines, however, there are still requirements under the rule for lean premix and diffusion flame oil-fired combustion turbines. According to the Northside Generating Station Draft Title V Renewal (issued August 10, 2018) the four combustion turbines at Northside Generating Station are not subject to regulation under Subpart YYYY. In addition, since Brandy Branch, Kennedy, and Greenland are classified as area (rather than major) sources of HAPs, the combustion turbines at these facilities are not subject to the Subpart YYYY requirements.

On April 12, 2019, EPA released a proposed rule to amend the CT MACT, specifically to address period of startup, shutdown, and malfunction (SSM) and to remove the stay of the effectiveness of the standards for new lean premix and diffusion flame gas fired turbines. However, a final rule was issued in the Federal

Register, which did not finalize the stay, but did require an operational standard in lieu of a numeric emission limit during periods of SSM; specifically, startup shall be limited to 1 hour for simple cycle operations and limited to 3 for combined cycle operation. EPA is reviewing a new petition (August 2019) to delist the stationary combustion turbines source category from regulation under CAA section 112. EPA is delaying taking final action on the stay until a determination regarding the source category delisting petition has been made. Should the source category not be delisted and the stay is removed, there is potential impact on the turbines at Northside unless they can demonstrate compliance with the formaldehyde limit of 91 ppbvd.

B.2.2.6.3 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

On June 15, 2004, the EPA established national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area source of HAP emissions. This rule has since been amended several times, with the most recent amendment on January 30, 2013. The stationary RICE MACT is applicable to the various emergency diesel generators and diesel fire pumps at the JEA facilities. Given that these engines are classified as emergency units under the rule, the requirements for each of these units are generally limited to recording keeping and reporting requirements and maintenance practices.

B.2.2.7 New Source Performance Standards

The CAA of 1970 authorized the EPA to establish technology-based emissions standards that apply to specific categories of stationary emissions sources that the EPA has determined "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." These standards, known as New Source Performance Standards (NSPS), apply to new, modified, and reconstructed stationary sources and regulate emissions of several pollutants including, but not limited to, the six criteria pollutants.

The CAA allows the EPA to identify specific facilities within a source category that should be regulated by NSPS and also allows the designation of subcategories. NSPS can be established for specific types of equipment located within a facility or for an entire facility belonging to a regulated source category. Generally, a particular NSPS will regulate facilities or equipment within a facility based on the type of unit, size of unit, material handled, and date of construction, modification, or reconstruction.

NSPS are designed to establish minimum control requirements for all facilities within a source category based on the emissions limitations and reductions that are achieved in practice at the time of the rulemaking. The CAA requires the EPA to review each NSPS every eight years in order to determine if the emission limits, controls, and other requirements need to be revised based on technological advancements and/or other changes affecting a particular industry.

B.2.2.7.1 40 CFR Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators

EPA finalized NSPS Subpart D on December 19, 1995. The rule has been amended several times with the most recent amendment dated June 13, 2007. The rule regulates emissions of particulate matter, SO_2, and NO_X from fossil-fuel-fired steam generating units with a heat input of more than 250 MMBtu/hr that commenced construction or modification after August 17, 1971, except for those sources that are applicable to NSPS Subpart Da or Subpart

KKKK. Compliance with these limits ensures compliance with NSPS Subpart D by default. This rule should have limited future impact on the JEA fleet unless EPA makes significant changes.

B.2.2.7.2 40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Generating Units

EPA finalized NSPS Subpart Da on June 13, 2007. The rule regulates emissions of PM, SO_2, and NO_X, from electric utility steam generating units that were constructed, modified, or reconstructed after September 18, 1978 and are capable of combusting more than 250 MMBtu/hr of fossil fuel. Units 1 and 2 at Northside Generating Station are currently the only units in JEA's fleet that are regulated under Subpart Da and are operating in compliance with the limits of the rule. This rule should have limited future impact on the boilers unless EPA makes changes to the rule.

B.2.2.7.3 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines

EPA finalized NSPS Subpart GG on September 10, 1979. The rule has been amended several times with the most recent amendment dated February 27, 2014. The rule regulates SO_2 and NO_X emissions from stationary gas turbines with a heat input greater than 10 MMBtu/hr that commenced construction, modification, or reconstruction after October 3, 1977. Gas turbines that are subject to NSPS Subpart KKKK are not subject to Subpart GG. The combustion turbines at Northside generating station were constructed prior to 1977 and, as such, are not applicable to Subpart GG. Subpart GG is, however, applicable to Unit 7 at Kennedy and Unit 1 at Brandy Branch. Given that new and/or modified combustion turbines are now regulated by NSPS Subpart KKKK, this rule should have no significant future impacts on the JEA fleet.

B.2.2.7.4 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

The final rule for Subpart KKKK was published in the Federal Register on July 6, 2006 with an amendment to the rule finalized on March 20, 2009. Subpart KKKK is applicable to stationary combustion turbines with a peak load heat input greater than 10 MMBtu/hour that commenced construction, modification, or reconstruction after February 18, 2005. The rule contains emission limits for NO_X and SO_2. NSPS Subpart KKKK is applicable to the combustion turbines at Greenland Energy Center and the combined cycle units at Brandy Branch Generating Station. These units are currently in compliance with the applicable emission limits. Should any new combustion turbines be installed at new or existing facilities or should any changes be made to any of the combustion turbines currently subject to Subpart GG that constitute a modification under the definition in 40 CFR Part 60, then NSPS Subpart KKKK could have future impacts on the JEA fleet. Otherwise, the future impacts of this rule should be minimal unless significant changes are made.

B.2.2.7.5 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

On July 11, 2006, the U.S. EPA published Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Subpart IIII applies to the various emergency diesel-fired RICE generators and fire pumps operating at JEA facilities. This rule should have minimal impact on future operations barring the installation of any non-emergency compression ignition RICE generators.

B.2.2.7.6 40 CFR 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

On October 23, 2015, the U.S. EPA published Standards of Performance for greenhouse gas emissions for electric generating units which commenced construction after January 18, 2014 or reconstruction/modification after June 18, 2014. The rule regulates carbon dioxide (CO_2) emissions from new, modified, and reconstructed steam generating units, integrated gasification combined cycle (IGCC) units, and fossil fuel-fired stationary combustion turbines which have a base loading rating greater than 250 mmBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system. For stationary combustion turbines, the rule stipulates separate emission standards based on the type of fuel combusted and the operation of the unit (i.e., base-loaded machines vs. peak-shaving machines). Black & Veatch notes that it can be difficult for SCCTs to meet these baseload CO_2 emission limits. However, if the SCCTs are operated as a "peaking" unit; i.e., limited number of hours of operation in the year, the SCCTs would be subject to a less onerous emission limit and may be able to achieve this limit. To meet the requirements of this rule, the hours of operation would need to be limited based on the efficiency of the turbine.

B.2.2.7.7 40 CFR 60 Subpart Y – Standards of Performance for Coal Preparation Plants

The final rule for NSPS Subpart Y was published in the Federal Register on October 8, 2009. The rule regulates particulate emissions from coal handling facilities constructed after October 27, 1974 and before April 28, 2008. Subpart Y is applicable to the crusher house and fuel silo dust collectors at Northside Generating Station. This rule is expected to have a minimal impact on future operations.

B.2.2.7.8 40 CFR 60 Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants

The final rule for NSPS Subpart OOO was published in the Federal Register on April 28, 2009. The rule regulates particulate emissions from mineral processing plants and is currently applicable to the limestone handling system at Northside Generating Station. This system is currently complying with the requirements of Subpart OOO. This rule is expected to have minimal impacts on future operations.

B.2.3 Water Assessment

B.2.3.1 Clean Water Act 316(b) Cooling Water Intake

EPA published its final Phase II 316b rule regulating cooling water intakes at existing facilities in August 2014. The rule establishes national requirements applicable to the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the Best Technology Available (BTA) for minimizing adverse impacts of impingement and entrainment. Existing power generation facilities, as well as manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) from surface waters of the U.S. and use at least 25 percent of the water exclusively for cooling purposes are subject to the rule.

The final rule established seven alternatives for meeting the impingement requirements – including use of modified traveling screens, reducing through screen design or actual flow velocities, utilizing closed cycle cooling systems, operating existing offshore velocity cap, or meeting a 24 percent mortality standard on a rolling 12-month basis. Although compliance with entrainment requirements are to be made on a site specific, case-by-case basis, since Northside withdraws over 125 MGD it is required to conduct extensive characterization studies to establish the appropriate BTA. In

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order to establish the appropriate BTA, affected facilities are required to conduct and submit certain data, studies and plans for compliance (outlined in Table B-3) to the National Pollutant Discharge Elimination System (NPDES) permitting authority (here the FDEP) for review and approval as part of the next NPDES permit renewal application.

JEA's Northside Generating Station is the only facility that is subject to the final Phase II 316b rule, as a result of once-through cooling water being drawn from the St. Johns River in amounts greater than 2 MGD with >25 percent of this withdrawn water used for cooling purposes. Because its actual intake flow is greater than 125 MGD, the facility is subject to the additional entrainment study requirements of this rule.

Table B-3 - Cooling Water Intake Structure Data and Studies

Regulation	Description
40 CFR 122.21 r(2)	Source Water Physical Data
40 CFR 122.21 r(3)	Cooling Water Intake Structure Data
40 CFR 122.21 r(4)	Source Water Baseline Biological Characterization Data
40 CFR 122.21 r(5)	Cooling Water System Data
40 CFR 122.21 r(6)	Chosen Method(s) of Compliance with Impingement Mortality Standard
40 CFR 122.21 r(7)	Entrainment Performance Studies
40 CFR 122.21 r(8)	Operational Status of each generating unit that uses cooling water
40 CFR 122.21 r(9)	Entrainment Characterization Study-
40 CFR 122.21 r(10)	Comprehensive Technical Feasibility and Cost Evaluation Study
40 CFR 122.21 r(11)	Benefits Valuation Study
40 CFR 122.21 r(12)	Non-water Quality Environmental and Other Impacts Study
40 CFR 122.21 r(13)	Peer Review

The previous NPDES permit, which was issued as a combined permit for both the Northside Generating Station and the St. Johns River Power Park, expired on May 8, 2017. JEA submitted an application for renewal of the NPDES in November 2016. Since that submittal the St Johns River Power Park has been demolished and no longer needs to be included in the permit. Currently the permit is still under review by the FDEP. JEA has recently completed the following:

- Entrainment sampling was conducted at Northside from March 2018 to March 2020 to complete the required 2 years of baseline characterization.
- Baseline Entrainment Characterization (r9) report was drafted and submitted to JEA for review
- Baseline data was used to estimate reductions in entrainment mortality associated with mechanical draft cooling towers (MDCT) and fine-mesh screens (FMS) (2020)
- Preliminary benefits valuations (Veritas) and subsequent fine-tuning of the biological models were completed in 2021

- Biological models have been revised and draft benefits valuations for MDCT and FMS are currently under final review (Veritas)

As noted above the NPDES permit has yet to be issued by the FDEP. The schedule for submission of 316b materials is still anticipated to be at the end of this next permit cycle (4.5 years following issuance).

As the permit has yet to be issued, JEA has adequate time to complete the 316(b) submittals. The next steps in the process are below:

- Finalize the engineering and cost evaluations for the three technologies (MDCT, FMS and variable frequency drives (VFD))
- Estimate mortality reductions associated with VFD and include in benefit valuations
- Develop social cost estimates for each technology (Veritas)
- Develop r(10) – Comprehensive Technical Feasibility and Cost Evaluation Study
- Develop r(11) – Benefits Valuation Study

In accordance with a previous agreement between the FDEP and the FCG Environmental Committee, a condition will be included in the renewal permit setting forth a timeline for discussion and submittal of the relevant §122.21r data requirements. JEA has several options to consider in selecting a preferred method of compliance, including a combination of upgrading of existing screen systems, shutting down units, and cooling tower installations.

The feasibility of these options will be assessed and costs determined concurrent with completion of the outstanding §122.21r studies. Once the studies and preferred solutions are submitted to the FDEP, the agency will determine the appropriate BTA for the Northside cooling water intake, and will set the schedule for implementing the upgrades and final compliance deadlines.

B.2.3.2 Effluent Limit Guidelines

The final steam electric effluent limit guidelines (ELG) rule establishing more stringent technology-based wastewater discharge standards for steam electric generation plants was published on November 3, 2015. Changes include new standards for wet flue gas desulfurization (WFGD), flue gas mercury control, gasification, and landfill leachate water streams that were previously included under low volume wastes. Additionally, the rules establish a zero discharge standard for fly ash and bottom ash transport waste streams for both new and existing point sources. The final rule did not include any changes to the previously specified cooling tower blowdown, once-through cooling, or coal pile runoff effluent standards.

These ELG standards are to be used by the NPDES permitting authority (FDEP in Florida) in setting applicable discharge limits for specified effluents in new and renewed NPDES and pretreatment permits for steam electric generation facilities. All new ELG limits were not to apply until a date determined by the permitting authority to be "no sooner than" November 1, 2018, but no later than December 31, 2023. Subsequently EPA released a final rule on September 12, 2017 extending the "no sooner than" compliance deadline for bottom ash and WFGD effluents to November 1, 2020. FDEP has not issued a renewal of the NPDES permit yet, so currently there are no new ELG requirements enacted at this time. To address the only ELG requirement that applies to NGS (Combustion residual leachate – CRL), FDEP and JEA have agreed to implement a new internal monitoring location (sump 11) to sample the combined leachate and contact stormwater discharged from the BSA ponds. The CRL ELG limits would apply at that monitoring location.

No additional treatment measures are anticipated to be necessary to meet the ELG limits.

Currently JEA does not have any other effluents that are affected by the ELG rulemaking revisions - as a result of its dry ash handling systems, and absence of WFGD, landfill and gasification at its generation facilities. JEA remains in compliance with the existing ELGs that have already been incorporated into its NPDES permits.

B.2.3.3 Other Water Considerations

B.2.3.3.1 NPDES Groundwater Discharge Decision

On April 23, 2020, the U.S. Supreme Court opined that the reach of the Clean Water Act (CWA) includes regulation of indirect groundwater discharges to surface water. The ruling concluded that a NPDES permit is required "where there is a direct discharge from a point source into navigable waters or where there is a functional equivalent of a direct discharge." The decision by the supreme court is counter to an Interpretative Statement issued by the USEPA in April 2019 which concluded that the release of pollutants to groundwater is excluded from the Clean Water Act and regulation is left to the states and the EPA under different statutes. In its ruling the court recognized that the primary factors to determine if an NPDES permit would be required for a groundwater discharge would be travel, time, and distance from the point of discharge to the waterway. Other factors that could be used to determine CWA and NPDES authority include:

- The nature of material through which the pollutant travels
- Extent of dilution or chemical change of the pollutant
- Amount of pollutant entering the navigable water relative to the amount discharged
- The area over which, or the means by which, a pollutant enters the waters
- The degree to which the pollutant can be identified.

Furthermore a guidance document titled "Applying the Supreme Court's *County of Maui v. Hawaii Wildlife Fund* decision in the Clean Water Act Section 402 National Pollutant Discharge Elimination System Permit Program" was issued on January 21, 2021 and then rescinded on September 15, 2021, stating it was issued without proper deliberation within EPA or with other federal partners. The EPA reverts back to guidance provided in the Supreme Court ruling and listed above as guiding factors to determine if groundwater discharge is jurisdiction under the CWA. The EPA in the September 15, 2021 memo states that the Office of Water will be evaluating appropriate next steps and will continue to apply site-specific, science-based evaluations to determine whether a discharge from a point source through groundwater requires a NPDES Permit under the CWA.

Groundwater discharges at the Northside Generation Station could potentially be considered "functionally equivalent" to a direct discharge and hydrologically connected to nearby surface waters. FDEP Currently regulates groundwater discharges and standards under Florida Administrative Code (FAC) 62-520 Ground Water Classes, Standards and Exemptions but potentially could require an NPDES permit in the future. Absent further guidance from EPA or FDEP, this ruling leaves uncertainty and significant risk for facilities that fail to obtain a NPDES permit for potentially covered groundwater discharges, or at least disclose them during the permitting process.

B.2.3.4 Florida Assumption of U.S. Army Corp of Engineers Clean Water Act Section 404 Permitting

B.2.3.4.1 Background

On Dec. 22, 2020, the U.S. EPA published the approval of Florida's State Clean Water Act Section 404 Program in the Federal Register, and the FDEP began administering the State 404 Program on that date.

In 2018, Florida's legislature passed a bill that gave FDEP authority to begin the public rulemaking process to assume the federal dredge and fill permitting program under section 404 of the federal CWA within certain waters of the US. The rulemaking process was completed on July 21, 2020. Through this process, Chapter 62-331, FAC, "State 404 Program," was created to bring in the requirements of federal law not already addressed by the existing Environmental Resource Permitting (ERP) program. Minor changes were also made to the ERP rules in Chapter 62-330, FAC, to facilitate assumption. Florida submitted its assumption package to the EPA on Aug. 20, 2020.

State assumption of the 404 program provides a streamlined permitting procedure where both federal and state requirements are addressed by state permits. The State 404 Program is a separate program from the existing ERP program, and projects within state-assumed waters require both an ERP and a State 404 Program authorization. As noted by the FDEP, approximately 85 percent of review requirements overlap between programs, and this assumption eliminates duplicated federal and state reviews.

B.2.3.4.2 Permit Process

The State 404 Program is responsible for overseeing permitting for any project proposing dredge or fill activities within state assumed waters. Such projects include, but are not limited to: utility projects; environmental restoration and enhancement; linear projects; governmental development; and in-water work within assumed fresh water bodies. Retained waters generally include traditional navigable waters, such as larger navigable rivers, coastal waters, and wetlands adjacent to such waters up to a 300-foot administrative boundary. Assumed waters include all other waters of the U.S. (WOTUS), and in Florida, this generally consists of inland features, such as smaller rivers, streams, creeks, lakes, and their adjacent wetlands. JEA should utilize FDEP resources, including an online geographic information system (GIS) tool that FDEP has developed, to determine whether the U.S. Army Corp of Engineers (USACE) or the state agency (in Florida, the FDEP) will issue a 404 permit for a project.

If a project will result in discharges of dredged or fill material in retained waters, the 404 application generally should be submitted to the USACE. If the proposed project impacts only assumed waters (and does not impact retained waters), FDEP will generally process the application. In Florida, even if most WOTUS impacts from a proposed project will occur within assumed waters, if the project impacts any retained waters, the 404 permit will be processed by the USACE for all WOTUS impacts.

FDEP's 404 program adopted a general permit process that is similar to the USACE nationwide permit (NWP) program, and FDEP has also assumed management of seven USACE Regional General Permits. The state program, however, is based on the USACE 2017 NWPs (not the 2021 modifications). Therefore, there are some key differences. For example, the USACE 2021 modifications of the NWP 12 for utility lines into NWPs specific to the type of utility (e.g., telecommunication, oil and natural gas, or water). FDEP has established one state general permit for "Utility Line Activities." The state general permit authorizes activities related to the construction, maintenance, repair, and removal of any type of utility line, provided the activity does not result in the loss of greater than ½-acre of state-assumed waters. FDEP has also assumed administration of seven USACE regional general permits (RGPs) in state-assumed waters, including SAJ-13 (Aerial Transmission Lines) and SAJ-14 (Sub-aqueous Utility and Transmission Lines in Florida). In some circumstances, the conditions of a USACE RGP may be preferable to the state general permit.

Within 10 days of the determination that the application is "administratively complete," FDEP will publish the public notice. Copies of the public notice will be distributed to the relevant and appropriate parties and commenting agencies. This triggers interagency coordination with the State Historical Preservation Officer (SHPO) and the Tribal Historical Preservation Officer (THPO), the Florida Fish and Wildlife Conservation Commission (FWC), U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), Florida's Water Management Districts (WMDs) and EPA. A commenting agency may submit questions or comments for FDEP to include in a Request for Additional Information (RAI). A commenting agency may also provide comments to EPA and request that EPA object to a proposed activity. FDEP will forward the applicant's response to the RAI to each commenting agency for review, if applicable. Additional conditions may be included in the final authorization based upon the recommendation of a commenting agency to avoid or minimize potential adverse effects due to the project.

The EPA will continue to play a role in the process and under the federal regulations, unless EPA has waived review, FDEP will provide EPA with the public notice for the proposed activity. EPA may choose to comment, condition or object to the proposed activity. EPA is prohibited from waiving review of permit applications for discharges with reasonable potential for affecting endangered or threatened species. Within 30 days of receipt of the public notice, EPA may notify FDEP of its intent to comment on the proposed activity. If EPA does not notify FDEP of an intent to comment, FDEP will make a final permit decision to issue or deny the permit 60 days after the end of the public comment period and after the application is technically complete. When EPA notifies FDEP of an intent to comment, FDEP will provide EPA 90 days to comment on the proposed activity. When necessary, FDEP may use the RAI to communicate any of EPA's comments or concerns with the applicant. FDEP will make a final agency action to issue or deny the permit after receiving EPA's comments (and RAI response). FDEP may choose to add EPA's conditions and make a final permitting decision to issue or deny the permit within 90 days of receipt of the objection or condition.

B.2.3.4.3 Permit Issuance Challenges

FDEP's permitting actions are subject to review. Because the issuance of the new 404 permits is a state action, parties may initiate an administrative proceeding by written petition to FDEP. If the petition identifies disputed issues of material facts, the petition will be referred to the Florida Division of Administrative Hearings (DOAH) for the assignment of an administrative law judge (ALJ) for a hearing. The DOAH hearing includes live witnesses and discovery (with the burden of proof on the petitioner). Upon completing the hearing, the ALJ submits to FDEP a recommended order consisting of findings of fact, conclusions of law and a recommended disposition. FDEP then issues a final order. Prior to the FDEP assumption, challenges to a 404 permit would have to be brought in federal court. Such federal challenges are record review cases based on the deferential standards of the Administrative Procedure Act. One possible result of the assumption is that there will be more challenges as they move to the state process. However, one major benefit is that assumption by the state will eliminate challenges under the National Environmental Policy Act (NEPA).

On December 30, 2022 the EPA and USACE announced a final rule addressing a pre-2015 definition of "waters of the United States" (WOTUS). This final rule was issued to clarify the definition of WOTUS which has been changed via court decisions and final rules issued by the EPA and USACE in 2015, 2019 and 2020. The following our considered WOTUS under the 2022 rule:

- Traditional Navigable Waters
- Territorial Seas
- Interstate Waters
- Impoundments
- Tributaries
- Adjacent Wetlands

Additional Waters (Do not meet the categories above but qualify under the relatively permanent standard or the significant nexus standard.)

The Relatively Permanent Standard is a test that provides important efficiencies and clarity for regulators and the public by readily identifying a subset of waters that will virtually always significantly affect paragraph (a)(1) waters. To meet the relatively permanent standard, the waterbodies must be relatively permanent, standing, or continuously flowing waters connected to paragraph (a)(1) waters or waters with a continuous surface connection to such relatively permanent waters or to paragraph (a)(1) waters.

The Significant Nexus Standard is a test that clarifies if certain waterbodies, such as tributaries and wetlands, are subject to the Clean Water Act based on their connection to and effect on larger downstream waters that Congress fundamentally sought to protect. A significant nexus exists if the waterbody (alone or in combination) significantly affects the chemical, physical, or biological integrity of traditional navigable waters, the territorial seas, or interstate waters.

There will likely be court and regulatory challenges to this new rule and close attention should be paid to the evolving regulatory environment regarding this rule and the definition of WOTUS.

B.2.4 Other Environment Considerations

B.2.4.1 Coal Combustion Residuals

The Coal Combustion Residuals (CCR) rule published in April 2015 under 40 CFR 257, establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule is intended to address risks from coal ash disposal, such as leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the rule sets out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly accessible website.

The CCR rule contains specific requirements that are to be met in order to continue operation of landfills and surface impoundments (CCR units) at active coal-fired power generation facilities. These requirements include the following:

- Location restrictions.
- Design criteria, including liner design and structural integrity
- Operating criteria including air criteria, hydrologic and hydraulic capacity requirements, and inspection requirements.
- Groundwater monitoring and corrective action.
- Closure and post-closure care.
- Recordkeeping, notification, and internet posting.

Existing CCR units were to demonstrate compliance with the first four criteria by deadlines staged over 2015-2018 (with one aquifer locational standard deadline recently extended to 2020). Failure to meet or document these items generally results in requirements to cease operation and begin closure or retrofit of the CCR unit. For units that are required to close, the CCR allows two options: (1) leave the CCR in place and install a defined final cover system or (2) remove the CCR and decontaminate the unit.

Although the St. John's River Power Park has ceased operations, its CCR by-products storage area is subject to the EPA rule. JEA has timely demonstrated compliance with the relevant CCR rule requirements to date. The Area A landfill has already been closed, and JEA plans on closing the Area B Phase 1 in place once receipt of CCR or removal of CCR for beneficial use no longer occurs. JEA has filed and posted a Closure Plan outlining the methods and timing of the Area B Phase 1 area closure.

Because Northside Generation Station fires a combination of fuels, the majority (>50 percent on a heat input or mass basis) being natural gas and petroleum coke, the CCR rule does not apply to management of these combustion by-products at the facility per 40 CFR 257.50(f).

It is worth noting that a recent August 21, 2018 decision by the federal D.C. Circuit Court of Appeals vacated and remanded several provisions of the CCR rule regarding unlined, clay-lined surface impoundments, and those located at inactive (legacy) plants. on August 28, 2020, EPA published its final rule in the Federal Register (85 Fed. Reg. 53,516), entitled "Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure" (Part A Rule). The Part A Rule amends several regulatory provisions that govern coal combustion residuals and includes amendments that require certain CCR units (unlined or clay-lined surface impoundments and units failing the aquifer separation location restriction) to cease waste receipt and initiate closure "as soon as technically feasible" but no later than April 11, 2021. The final Part A Rule becomes effective on September 28, 2020.

B.2.4.2 Polyfluoroalkyl Substances (PFAS) Review

B.2.4.2.1 PFAS Contamination in Florida and the Jacksonville Area

Existing per- and polyfluoroalkyl substances (PFAS) contamination is documented at multiple sites in the vicinity of JEA operations, Jacksonville International Airport, and at three Navy Facilities (Naval Air Stations Cecil Fields and Jacksonville, and Naval Outlying Field Jacksonville). Also, FDEP is currently overseeing cleanup at 5 industrial sites in or near Jacksonville. Local news media has extensively reported on PFAS issues in the Jacksonville Area. It should be noted however, that during their preliminary analysis of PFAS in drinking water at 3 U.S. Navy facilities near Jacksonville, the U.S. Navy found no detectable levels of PFAS in JEA-supplied drinking water.

PFAS contamination has been documented, reported on, and studied throughout Florida – especially in the vicinities of Miami, Tampa Bay, Jacksonville, and military facilities on the emerald coast. The widespread occurrence of PFAS in drinking water and environmental media throughout the state has prompted state environmental (FDEP) and public health (Florida Department of Health (FDH)) officials to investigate its occurrence, and to develop and implement strategies to assess and mitigate the impacts of PFAS contamination – including the development of screening and provisional target cleanup levels in a variety of media, and execution of projects to sample well systems and perform pilot studies of cleanup technologies.

B.2.4.2.2 Federal and State PFAS Regulatory Considerations

The regulatory status affecting the PFAS family of chemicals is complex for several reasons, including: 1) Over 2,000 PFAS compounds have been identified, although PFAS regulation has so far focused on less than 10 of the most prevalent congeners (this is dynamic and expanding); 2) PFAS regulations are being developed across nearly every environmental regulatory regime (RCRA; Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); CWA; Safe Drinking Water Act (SDWA); CAA; NEPA; Toxic Substances Control Act (TSCA); etc.) – but on much different timetables, and 3) non-statutory factors are applying pressure to minimize or stop using PFAS chemicals (i.e. public pressure / media / several billion dollars in legal settlements), all while the properties of PFAS chemicals make them indispensable in many consumer and industrial products, and in firefighting flammable liquids (especially petroleum hydrocarbons).

Currently, Florida is monitoring and managing impacts from PFAS contamination through FDEP and through FDH. The Florida program comprises: 1) use of the EPA lifetime drinking water health advisory level (HAL) for perfluorooctanoic acid (PFOA) and/ or perfluorooctane sulfonic acid (PFOS) of 70 ng/L as a basis for assuring safety of drinking water sources and as a basis for developing screening and provisional cleanup standards in environmental media, 2) investigation of targeted industrial cleanup sites (federal facilities, airports, dry cleaners, and state-led cleanup sites) for PFAS contamination, and 3) development of a coordinated approach to PFAS issues (PER AND POLYFLUOROALKYL SUBSTANCES (PFAS) DYNAMIC PLAN, FDEP DWM, Aug 21). If JEA has any cleanup sites where aqueous film-forming foam (AFFF) or other PFAS-containing substances are stored or used, they may eventually have to sample environmental media for PFAS compounds. If PFAS compounds are found in any environmental media associated with JEA facilities or cleanup sites, it is likely that current cleanup regulations (i.e., the FDEP Cleanup Program) would be invoked to guide the investigation and potential cleanup, even though promulgated cleanup standards do not yet exist.

Federal regulations and federal regulatory activity might also significantly impact the use of PFAS compounds and the steps required to mitigate impact from PFAS released into the environment. To date, EPA has not established enforceable national drinking water limits for any PFAS substance. EPA has, however, issued notices of proposed rulemaking to develop drinking water limits for PFOA and PFOS (and possibly perfluorobutane sulfonic acid (PFBS)). A national drinking water limit will require the entire country to evaluate the concentration of these two compounds in drinking water, and to implement treatment systems and permit limits to achieve the drinking water limits. In addition, the next round of Unregulated Contaminate Monitoring Rule sampling will include all 29 PFAS that are within the scope of EPA Methods 533 and 537.1 – indicating potential future maximum contaminant levels (MCLs) for many more PFAS.

On 22 June 2020 the EPA issued a final rule (85 CFR 37354), which clarified reporting requirements for entities that use or have used certain PFAS. The rule mandated that, starting with the July 2021 Toxic Release Inventory (TRI) Report, 172 PFAS compounds (threshold limit 100 pounds each) must be listed. The de minimis level is 1 percent for all listed PFAS, except PFOA (CASRN: 335-67-1), which has a de minimis level of 0.1 percent. It is possible that AFFF kept on-site for fire response in bulk fuel storage areas could exceed TRI reporting levels. Also, EPA has indicated they will be seeking to add more PFAS compounds to the TRI reporting list, and to eliminate some existing reporting exemptions.

Regulations governing cleanup of PFAS-contaminated sites are being developed. EPA has publicly stated plans to 1) designate PFOA and PFOS as hazardous substances under CERCLA, 2) add PFOA, PFOS, PFBS, and GenX as RCRA Hazardous Constituents under 40 CFR 261, and 3) initiate rulemaking to broadly clarify that states can require clean-up of any emerging contaminant that meets the RCRA statutory definition of a hazardous waste. If JEA has any sites where AFFF has been stored or used, for example (by any JEA or municipal fire department firefighting or training activities), these sites should be considered for screening environmental media for PFAS contamination to understand potential future liability. The hazardous substance/constituent designations of PFAS compounds will also affect due diligence / all appropriate inquiries, meaning that property values could be affected, and any buying or selling of property should consider including PFAS sampling in the Phase I Environmental Assessment (note: “consider including” until CERCLA or RCRA designations are law, in which case PFAS analysis will be required wherever it may exist).

EPA is also moving ahead aggressively to investigate, and in some cases limit the discharge of PFAS in industrial water through the NPDES system and the development of new effluent limit guidelines. At this time the focus of this regulatory activity is on targeted industries, but the work will (along with a large amount of research on eco-toxicity of PFAS in surface water and sediment) likely have a broad impact on all NPDES permits in the future. JEA may want to consider evaluating whether and which PFAS substances are present in any wastewater streams or other discharges.

Although EPA has indicated it may seek to designate some PFAS as hazardous air pollutants, at this time they are still “building the technical foundation necessary to evaluate and potentially propose PFAS air emissions under the CAA”.

B.2.4.3 Environmental Justice

Environmental justice (EJ) has been defined as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.

Fair treatment means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.

Meaningful involvement means:

- People have an opportunity to participate in decisions about activities that may affect their environment and/or health;
- The public's contribution can influence the regulatory agency's decision;
- Community concerns will be considered in the decision making process; and
- Decision makers will seek out and facilitate the involvement of those potentially affected.

Executive Order 12898, signed on February 11, 1994, directed federal agencies to develop environmental justice strategies to help federal agencies address disproportionately high and adverse human health or environmental effects of their programs on minority and low-income populations. On February 27, 2012, federal agencies, led by the Council on Environmental Quality (CEQ) and the EPA, released environmental justice strategies, implementation plans, and progress reports outlining the steps that agencies will take to protect certain communities facing health and environmental risks. These strategies constitute a significant increase in the integration of environmental justice into federal decision-making and programs.

Incorporation of environmental justice analysis in siting and expansion of power generation projects should be considered in siting analyses. For there to be a significant concern that low-income or minority population areas may receive a disproportionate share of negative impacts from a facility, the following factors generally need to be met: 1) high percentages of minority and low income populations would need to be present in close proximity to the site, 2) negative cultural, economic, or health impacts on such populations would need to be expected, and 3) minority and low-income areas would be expected to bear a disproportionate share of negative impacts from the facility. The EPA has created the EJSCREEN Mapping tool to help provide a high-level look at EJ data for siting and preliminary screening purposes. EJSCREEN allows users to access environmental and demographic information for locations in the U.S. and compare their selected locations to the rest of the state, EPA region, or the nation.

The tool may help users identify areas with:

- Minority and/or low-income populations
- Potential environmental quality concerns
- A combination of environmental and demographic indicators that is greater than usual
- Other factors that may be of interest

An EJSCREEN review as well as other census and available socioeconomic data should be analyzed in siting and expansion of future facilities.

B.2.4.4 Climate Justice

The draft legislation of the CLEAN Future Act has provisions related to EJ. The main concern for existing facilities is a provision which could potentially require agencies to not allow a permit to be renewed for a major source in an overburdened census tract after January 1, 2025. An overburdened census tract is defined as:

- Has been identified within the National Air Toxics Assessment published by the Administrator as having a greater than 100 in 1,000,000 total cancer risk: or
- Has been determined to have an annual mean concentration of $PM_{2.5}$ of greater than 8 micrograms per cubic meter ($\mu g/m^3$), as determined over the most recent 3-year period for which data are available.

Secondly, after the date of enactment of the CLEAN Future Act, no permit shall be granted by a permitting authority for a proposed major source that would be in an overburdened census tract. The potential impact of this rule, if enacted, would be enormous as a large percentage of the U.S., including most industrial areas, has an annual mean $PM_{2.5}$ concentration greater that the 8 $\mu g/m^3$ threshold, meaning that no permitting of major sources in those areas would be allowed, and no permit could be renewed after January 2025. It is unlikely that legislation as stringent as these provisions in the CLEAN Future Act will be enacted in the near future, however one should pay close attention to the evolution of this Act and the other proposed EJ legislature.

Current EJSCREEN data suggests that the areas around Northside, Brandy Branch, and Greenland Energy Center are less than the 100 in 1,000,000 total cancer risk, but above the 8 $\mu g/m^3$ annual $PM_{2.5}$ concentration.

B.2.4.5 Climate Resiliency Discussion

Climate change impacts can be assessed by looking at multiple parameters. The impacts and associated risks most relevant to the project are discussed in this section and include temperature increases, sea-level rise, ocean acidification and increased variability and intensity of rainfall, wind, and severe weather events. This discussion is a summary of third-party reviews and data and does not constitute a specific projection for this assessment.

The primary data source for the global information discussed in this section is Climate Change 2021: The Physical Science Basis, Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC 2021). The key source of data for climate change impacts specific to the southeastern U.S. is the Coupled Model Intercomparison Project, Phase 6 (CMIP6), which was used to inform the IPCC's Sixth Assessment Report (AR6) and is overseen by the World Climate Research Program.

To illustrate possible climate futures, multiple scenarios were assessed in the IPCC report and CMIP6 data, all with varying levels of future GHG emissions. The results presented in this section will cover the best- and worst-case scenarios, representing net negative GHG emissions and GHG emissions that roughly double from current levels by 2050, respectively.

B.2.4.5.1 Increased Temperatures

According to the IPCC 2021 report, the global surface temperature has risen by 1.09 degrees Celsius (°C) across the globe from 1850-1900 to 2011-2020 with human-induced warming contributing 1.07°C of the increase. Around Jacksonville, average temperatures have increased by around 0.44°C (0.8 °F) within the last 30 years.[1]

Increased temperatures will result in significant consequences for human health, agriculture, ecosystems, and water resources. As related to the proposed Project, higher temperatures will increase the demand for water, and result in higher cooling and air conditioning requirements as well as a fall in efficiency for thermal power generation.

B.2.4.5.2 Sea Level Rise

Global mean sea level (GMSL) has increased by 0.20 meters between 1901 and 2018 because of ocean expansion due to water temperature warming and melting of glaciers and ice sheets. Since 1928 sea level has risen an average of 2.76 millimeters (0.11 inches) per year near Jacksonville, Florida.[2]

Sea level rise is expected to accelerate in the coming years with median model levels of 0.20-0.24 additional meters by 2050 and 0.44-0.83 total additional meters by 2021 at Fernandina Beach, Florida. These projection tools encompass multiple levels of Global Warming.[3]

B.2.4.5.3 Impacts of Increased Variability and Intensity of Rainfall, Wind and Extreme Weather Events

Areas in northeast Florida have experienced slight increases in overall annual precipitation since the early 1900's. Heavy single rainfall events have also shown an increase since the early 1900's.[4] Future annual rainfall and heavy precipitation projections associated with climate change for northeast Florida are not clear overall, however tropical activity and associated rainfall is expected to increase during hurricane season going forward.[5] Additional heavy rainfall events have the potential to cause property and road infrastructure damage. In addition, if runoff levels increase, the likelihood of natural disasters such as floods would rise.

[1] United States Global Climate Change Research Program, national temperature map. Jacksonville, Florida area
[2] Sea Level Trends – National Oceanic and Atmospheric Association Tides and Currents Fernandina Beach, Florida
[3] IPCC Sixth Assessment Sea Level Projection Tools
[4] United States EPA, Climate Change Indicators: Annual Rainfall and Heavy Precipitation
[5] Geophysical Fluid Dynamics Laboratory, Princeton University. Supported by NOAA and based on IPPC AR6 Projections.

B.2.4.5.4 Ocean Acidification

Ocean Acidification is caused by excess CO_2 dissolving in the ocean, the additional CO_2 changes the composition of the ocean and causing the seawater to become more acidic. Globally, upper ocean stratification has increased in the last 50 years and seawater pH has declined, with human influence the main driver. Under all scenarios, ocean acidification and associated reductions in the saturation state of calcium carbonate are forecast to increase this century.

As the climate has warmed, the ocean has become more stratified, inhibiting the necessary mixing of heat, oxygen, and CO_2 from the surface to be transported into the deeper ocean levels. Per the 2021 IPCC report, stratification, acidification, deoxygenation, and marine heatwave frequency will continue to increase throughout this century.

Increased acidity can cause further damage to ocean ecosystems also harmed by ocean temperature rise. With a more stratified ocean, oxygen that is absorbed at the surface does not mix as easily with the cooler waters below, causing it to become more difficult for marine life to flourish.

B.2.4.5.5 Climate Risks and Recommended Mitigation Measures

Climate change contributes to an increased risk on the natural environmental, public health and infrastructure. The climate change impacts discussed in the previous section will lead to different degrees of risks to JEA's assets around Jacksonville. These potential risks and mitigation measures are summarized in Table B-4.

Table B-4 - Climate Risks and Recommended Mitigation Measures

Key Risk	Climate Drivers	Recommended Mitigation Measures
Flooding and Water Damage	Increased Precipitation, Increased Thunderstorm Severity, Sea Level Rise	• Elevate water-sensitive equipment to address high water levels, incorporating projected rather than historic sea level rise and flood heights • Storm-harden energy infrastructure • Develop a flood risk management plan • Develop effective storm water pollution control measures and ensure proper secondary containment is designed with climate change impacts considered • Ensure drainage capacity can handle increases in precipitation and sea level/river level rise (Northside and Kennedy) • Ensure flood design loads consider sea level/river level rise (Northside and Kennedy)
Increased Sediment Load from Rivers	Increased Precipitation	• Perform due diligence to properly understand the maintenance dredging that could be required due to increased sediment load from rivers (Northside and Kennedy) • Develop a sediment monitoring plan to plan dredging procedures and avoid disruptions, delays, or costly large-scale dredging efforts (Northside and Kennedy)
Partial or Full Power Disruption	Increased Precipitation, Sea-Level Rise, Increased Thunderstorm Intensity	• Build redundancy into facilities • Provide back-up power supply and distributed generation, capable of responding to disruptions

Key Risk	Climate Drivers	Recommended Mitigation Measures
Increased Energy Demands and Lower Power Plant Efficiency	Increased Temperature, Sea-Level Rise	• Seek efficient solutions and plan accordingly for the increase in energy that may be required for treatment, drainage, and pumping • Counter the effect of increased ambient temperatures with advanced cooling technologies, including design elements such as additional cooling to intake air.
Risk associated with structural damage	Increased Ambient Temperature, Increased Thunderstorm Intensity	• Optimize structure design by employing building, storage, and transmission material that can withstand high heat, and severe winds.

B.2.4.6 Assessment of Cooling Tower Blowdown Versus Wastewater Treatment

Evaluation of injection wells for cooling tower blowdown versus wastewater treatment due to salinity or sodium concerns is discussed in the following subsections.

B.2.4.6.1 Brandy Branch

Based on a review of information provided by JEA, there are indications of a fairly consistent and low constituent concentration discharge stream from the facility. The samples were not analyzed for salinity, sodium and chlorides, and as such a determination as to the level of salinity in the water cannot be made. Comparing the sample analyses to the cooling water discharge requirements found in information provided by JEA, there were no constituents in exceedance found. Likewise, a review of the NPDES permit application also did not find any constituents in exceedance. Based on these findings, we see no reason to treat the wastewater prior to discharge or else bypass and send to an injection well.

B.2.4.6.2 Northside

This analysis is based on a review of information provided by JEA. Based on this review, no analysis was found showing the effluent characteristics with regards to salinity, sodium or chlorides, nor any restrictions. However, a daily maximum value for chemical oxygen demand (COD) of 750 mg/L is a bit concerning as this level of COD, if continuous and coupled with adequate nutrients, could sustain a biological mass leading to biofouling issues. Further understanding of the main cause of this level of COD would help indicate the appropriate level of treatment.

Further review of the documents provided by JEA indicates the cooling system is a "once-through" system. These systems typically require very large flows of water and evaporation is negligible, so no significant change in water chemistry occurs and treatment needs are negligible with the exception of chlorination.

B.2.4.6.3 Costs

A high-level cost, rough order of magnitude cost estimate for well development is approximately $1 million. Additionally, approximately $550,000 would be estimated for the cost to purchase and install a high flow high head well pump. The approximate cost for any desalination or seawater reverse osmosis (RO) system is $10 per 1,000 gallons throughput.

B.3 Environmental Considerations for New Sites and Gas Delivery Options

The following subsections assess the environmental considerations specific to the Northside option (i.e., new generation, retirement, life extension), as well as the options for the existing and potential new sites for future JEA generating units.

B.3.1 Socioeconomics

Table B-5 - Socioeconomic Assessment

Site	Proximity to Existing Roadways	Proximity to Sensitive Receptors	Resident Displacement
North Jax	Nearest Interstate is I-295 roughly 0.45 miles away.	No sensitive receptors are in the immediate 1 mile area.	No resident displacements would be required.
Northside Generating Station New Generation	Nearest Interstate is I-295 roughly 0.45 miles away.	No sensitive receptors are in the immediate 1 mile area.	No resident displacements would be required.
Greenland Energy Center	Nearest Interstate or highway is US-1 roughly 0.5 miles away.	The closest sensitive receptors are residential structures 1,650 feet to south of the property and new apartments that are 0.3 miles to the east. Newer development to the east could be as close as 200 feet to the property line.	No resident displacements would be required.
Brandy Branch Generation Station	Nearest Interstate or highway is US-90 roughly 1 miles away.	The closest sensitive receptors is a residential structure and dairy farm 2,800 feet to south of the property.	No resident displacements would be required.

B.3.2 Land Use

Table B-6 - Land Use Assessment

Site	Site Ownership	Land Use Compatibility	Environmental Justice and Site Risks
North Jax	Site owned by JEA	No land use compatibility concerns.	• Low Environmental Justice Risk • High Potential for contaminated soil and water on the site.
Northside Generating Station New Generation	Site owned by JEA	No land use compatibility concerns.	• Low Environmental Justice Risk • High Potential for contaminated soil and water on the site.
Greenland Energy Center	Site owned by JEA	No land use compatibility concerns.	• Low Environmental Justice Risk • Potential for contaminated soil and water on the site. • Potential for additional development restrictions due to nearby residential and commercial development
Brandy Branch Generation Station	Site owned by JEA	No land use compatibility concerns.	• Low Environmental Justice Risk • Potential for contaminated soil and water on the site.

B.3.3 Air Quality – Proximity Review

B.3.3.1 Proximity to Nonattainment/ Maintenance Areas

Nonattainment areas are those areas not meeting the NAAQS. Locating adjacent to or near a nonattainment area or maintenance area (i.e., an area previously in nonattainment) can have permitting implications via specific state regulations. This is due to the fact that often times states recognize that if an area is considered to be in nonattainment or maintenance that nearby sources of air pollution contribute to the attainment status and certain measures/precautions must be taken upon the surrounding source in order to bring the area back into attainment or continue its maintenance of the air quality standards.

The nearest nonattainment area is a 2010 1-Hour SO_2 area located in northeast Nassau County. The non-attainment area is located sufficiently far from the proposed locations as to not pose a concern. Figure B-2 illustrates the location of the non-attainment area.

Figure B-2 - Nearby Non-Attainment Areas

B.3.3.2 Proximity to Class I Areas

Class I areas are geographical areas of special national or regional natural, scenic, recreational, or historic value for which the NSR PSD air permitting regulations provide special protection. The existence of Class I areas near the site can pose significant permitting hurdles as the modeling required to be performed often results in very restrictive operation or extreme controls upon a plant. Based on guidance from the Federal Land Managers, a source located more than 50 kilometers (km) from a Class I area will have negligible impacts with respect to all Class I air quality related values if its total SO_2, NO_X, PM less than 10 microns (PM_{10}), and sulfuric acid (H_2SO_4) annual emissions (in tons per year, based on the 24-hour maximum allowable emissions) divided by the distance (in km) from the Class I area is 10 or less. For those sites located within 50 km of a Class I area, an analysis using a steady-state model following the EPA modeling guidelines would be necessary.

The study sites have five Class I areas within a 300 km radius. The Class I areas and the distance from the sites are listed in Table B-7 and depicted in Figure B-3. Based on emissions for a state-of-the-art combined cycle system, negligible impacts should occur for both the Northside and Greenland Energy Center locations. Since the Brandy Branch site is located within 50 km of the Okefenokee Wilderness area, an air dispersion modeling analysis would be required to determine the effects a proposed facility's emissions would have on the Class I area.

Table B-7 - Class I Areas Proximity to JEA Facilities

Class I Area	Northside	BBGS	GEC
Okefenokee Wilderness	60.03	33.63	76.11
Wolf Island Wilderness	100.65	125.03	128.46
Chassahowitzka Wilderness	211.14	184.58	188.62
Saint Marks Wilderness	235.06	196.22	236.66
Bradwell Bay Wilderness	284.25	245.71	286.67
All distances are in units of kilometer.			

Figure B-3 - Nearby Class I Areas

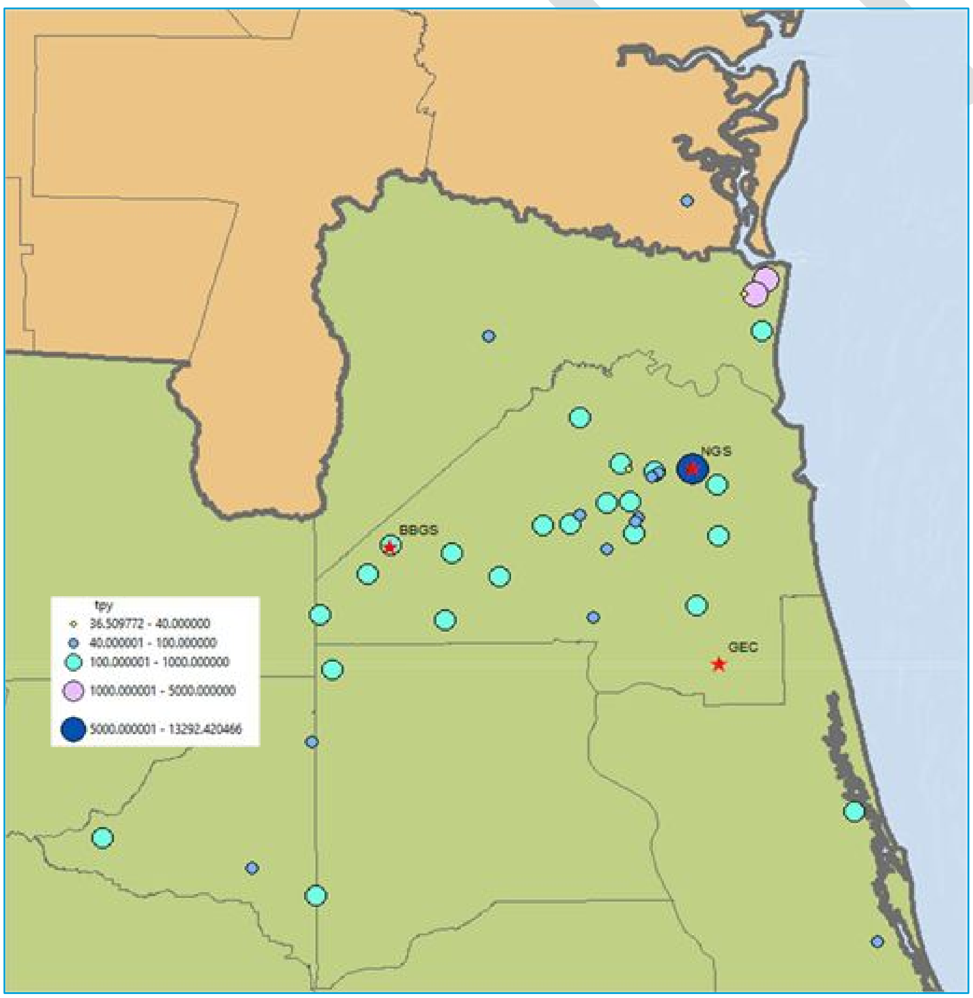
Appendix B – Environmental Assessment

B.3.3.3 Proximity to Nearby Sources

With sources of the magnitude considered in this assessment, it is often pertinent to understand if there are any large sources of air pollution located nearby. Should the air quality modeling demonstrate a need for interactive cumulative source modeling, the existence of large nearby sources of air pollution may pose a significant hurdle due to the reduced air quality room available to the proposed source. This review looked for those facilities which emit more than 100 tpy of any criteria pollutant and is located within 50 km of the proposed site locations.

According to the EPA's 2017 National Emission Inventory, there are 24 facilities that emit more than 100 tpy of any criteria pollutant and is located within 50 km. Figure B-4 illustrates the location of the large emitters. Locating near large emission sources can pose a hurdle for permitting activities, however, it is not a necessity as there are options available (design changes, etc.) to allow the permitting process to continue forward.

Figure B-4 - Nearby Emission Sources



B.3.4 Permitting Considerations

Table B-8 - Permitting Considerations

Site	Air Quality Permit Ability	Environmental Permit Ability
North Jax	High- Air Quality Permitting for new generation at the North Jax site would likely require a modification of the Northside Generation Station permit since it would likely be considered a single source.	High- Already developed and cleared site with limited wetlands, species or historical impacts likely. Potential constraints could be remediation of contaminated soils and surface and ground water. Additionally, a new cooling water intake structure or reuse system would need to be implemented.
Northside Generating Station New Generation	High- Air Quality Permitting for new generation at the site would require a modification of the existing permit.	High- Already developed site with limited wetlands, species or historical impacts likely. Potential constraints could be remediation of contaminated soils and surface and ground water, or expansion of the project area which could cause impacts to wetlands and species. Additionally, a new cooling water intake structure or reuse system would likely need to be implemented.
Greenland Energy Center	High- Air Quality Permitting for new generation at the site would require a modification of the existing permit.	High- Already developed site with limited wetlands, species or historical impacts likely.
Brandy Branch Generation Station	High- Air Quality Permitting for new generation at the site would require a modification of the existing permit.	High- Already developed site with limited wetlands, species or historical impacts likely. Potential constraints could be remediation of contaminated soils and surface and ground water, or expansion of the project area which could cause impacts to wetlands and species. Additionally, a new cooling water intake structure or reuse system would likely need to be implemented.

B.3.5 Ecology

Table B-9 - Ecology Assessment

Site	Potential for Threatened and Endangered Species Habitat	Potential for Wetlands/Waters of the US
North Jax	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Northside Generating Station New Generation	Low- Already developed site with limited wetlands, species or historical impacts likely. Expansion of the project area which could cause impacts to wetlands and species.	Low- Already developed site with limited wetlands, species or historical impacts likely. Expansion of the project area which could cause impacts to wetlands and species.
Greenland Energy Center	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Brandy Branch Generation Station	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.

B.3.6 Culture Resources

Table B-10 - Culture Resource Assessment

Site	Potential for Threatened and Endangered Species Habitat	Potential for Wetlands/Waters of the US
North Jax	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Northside Generating Station New Generation	Low- Already developed site with limited wetlands, species or historical impacts likely.	Low- Already developed site with limited wetlands, species or historical impacts likely.
Greenland Energy Center	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Brandy Branch Generation Station	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.

B.3.7 Technical Considerations Site Development Factors

Table B-11 - Technical Considerations

Site	Site Development	Site Expansion	Wastewater Disposal Options	Water Availability
North Jax	Already developed site with limited wetlands, species or historical impacts likely.	Site is already cleared and the site of a generating station. Additional constraints may include remediation of contaminated soils and waters.	High- Could use existing infrastructure to tie into Northside Water Intake System	High- Could use existing infrastructure to tie into Northside Water Intake System
Northside Generating Station New Generation	Already developed site with limited wetlands, species or historical impacts likely.	Limited space for expansion. Existing facilities could be retooled and modernized. Additional constraints include contaminated soil and water remediation.	High- Could use existing infrastructure. Other options to comply with new state regulations regarding waste water discharges will need to be evaluated.	High- Could use existing infrastructure. Updates would need to be made to intake structures to comply with 316(b) requirements
Greenland Energy Center	Already developed site with limited wetlands, species or historical impacts likely.	Space on site for expansion or addition of units. However, nearby development and sensitive receptors may limit expansion.	High- Could use existing infrastructure	High- Could use existing infrastructure

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Site	Site Development	Site Expansion	Wastewater Disposal Options	Water Availability
Brandy Branch Generation Station	Already developed site with limited wetlands, species or historical impacts likely.	Limited space on the already developed site area. However, JEA owns some adjacent property which if developed, would require additional permitting and potential wetlands, species or historical impacts.	High- Could use existing infrastructure	High- Could use existing infrastructure

C New Generating Resource Options Characterization

C.1 Background and Methodology

JEA directed Black & Veatch to characterize several new generating resource options that JEA could implement in the future to serve customer load (Resource Options). The range of Resource Options was developed through discussions between JEA and the B&V Team and are focused on those that were most relevant and most likely to be viable for JEA. The Resource Options included solar photovoltaic (PV) systems with and without battery storage, biomass, hydrogen, and firming resources consisting of natural gas-fired frame combustion turbine generators (CTGs), aeroderivative CTGs, compression ignition reciprocating internal combustion engines (RICEs), and nuclear generating technologies. This report summarizes the Resource Options and the methodologies, assumptions and results of their characterization.

Characterization of the Resource Options was based on order-of-magnitude estimates of capital costs, O&M costs, energy production profiles for the renewable resources, and thermal performance and stack emissions for gas-fired power plants operating in both simple cycle (SC) and combined cycle (CC) configurations.

The characterization was performed by Black & Veatch leveraging their experience with similar generation options, including both recent studies and recent project installations. Where applicable, Black & Veatch has incorporated recent performance and cost data provided by major Original Equipment Manufacturers (OEMs). This information has been adjusted using engineering judgment to provide values that are considered representative for potential projects that may be implemented by JEA.

This report is structured to first describe at a high level the type and size of the Resource Options studied. A more detailed description of each Resource Option is then provided including the key assumptions as to the technology, features, location and other factors which are used for the performance and cost estimating (the design basis). The results of the estimating are then provided.

The resulting information and data presented herein are preliminary, screening-level characteristics suitable for the initial evaluation of the Resource Options as part of the IRP process. If a Resource Option is selected for implementation as a result of the IRP, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development.

C.2 Solar, Solar plus Storage, and Storage Resources

The solar, solar plus storage and storage Resource Options that were studied along with their typical utility system use type are summarized in Table C-1 below:

Table C-1 – Solar, Solar plus Storage, and Storage Resource Options Studied

ID	Resource Option	Plant Configuration	Battery Type	Solar PV Rating (MW)	Battery Rating (MW)	Battery Capacity (MWh)
1	75 MW Photovoltaic Solar Array	No integrated battery storage	N/A	75	N/A	N/A
2	75 MW Photovoltaic Solar Array with 0.5 hour integrated storage	Integrated battery storage (37.5 MW capacity, 37.5 MWh Energy), used for load firming / smoothing, using cell type battery technology	Lithium Ion	75	37.5	37.5
3	75 MW Photovoltaic Solar Array with 4 hour integrated storage	Integrated battery storage (74.9 MW, up to 4 hours of capacity) for peak shifting to 3-7pm, using cell type battery	Lithium Ion	75	75	300
4	37.5 MW Battery Storage 1 hour	Battery storage (25 MW, 25 MWh) used for load firming / smoothing using cell type battery technology	Lithium Ion	N/A	25	25
5	Battery Storage 4 hour	Battery storage (50 MW, up to 4 hours of capacity) used for peak shifting to 3-7pm using cell type battery technology	Lithium Ion	N/A	50	200

Load firming / smoothing means the ability to manage ramp rates when output from a solar array has a large drop in output (greater than 50 percent) or long-term deviation from the facility rated output (greater than 30 minutes). These resources will also provide the ability to eliminate minor (less than 50 percent) and / or short-term (less than 30 minutes) output deviations.

Peak shifting means charging the battery during periods of low demand and discharging during periods of high demand. This will typically occur during the evening ramp down in output as the sun sets with the battery providing firm supply until the stored energy is depleted.

C.2.1 Solar PV

C.2.1.1 Technology Overview

Solar PV modules can be classified into either thin-film or crystalline silicon. First Solar is the largest thin-film module supplier while crystalline silicon is the most common type manufactured by global suppliers. Within crystalline silicon, the technology is further classified into mono- and poly-crystalline. Mono-crystalline silicon provides greater efficiencies and therefore higher wattage modules than poly-crystalline but is generally more expensive (on a cost per Watt of dc power [$ / Wdc] basis). However, industry demand is to reduce overall project costs and higher wattage modules support reduced Balance of System costs, therefore the industry is converging, and now most major suppliers of silicon cells utilize the same technologies for high-end modules. Additionally, larger cells are being used to increase overall module wattage, with a corresponding increase in overall module size. Suppliers are beginning to consolidate production lines and eliminate older product lines (lower wattage and / or mono-facial) to streamline production as much as possible, therefore reducing cost while increasing module output. A further artifact of this convergence is that there is no discernible performance difference (efficiency and degradation) among suppliers at the 50 percent probability (i.e., P50) level of confidence at which projects are typically evaluated.

The latest major technology trend is the increase of bi-facial modules. These modules are similar to the mono-facial modules, but with a clear back panel; either clear glass or plastic is used on the back of the panel allowing light reflected from the ground to also enter the cells, resulting in additional energy. Bi-facial modules are only now being installed in significant quantities, so long-term performance history is not available.

In recent years, the widespread adoption of the most advanced cell and module technologies and production methodologies has driven a rapid increase in module wattage and decline in costs. This rate is anticipated to decrease, but the trend is likely to continue for the foreseeable future. Further, new advances in technology (such as a switch to n-type cells) will continue to drive further efficiency gains while reducing output degradation over time.

Fixed racks and single-axis trackers (SATs) are currently the most common types of racks used for solar projects. Over the last few years, the trend has been toward SATs for all projects except for projects located in areas with high wind loads (i.e., greater than 120 mph), typically coastal areas subject to tropical storms and hurricanes. In those areas, fixed racks are the only option as SATs are not available to meet the high wind loads.

The major advantage to fixed racks is the lower procurement and installation cost (as much as 20 percent less than trackers) as well as low operating and maintenance costs as there are no moving parts (as much as 30 percent less than SATs). However, there is a significant energy production reduction (as much as 30 percent) when compared to SATs.

SATs have become popular due to the large gain in production over fixed racks and the declining price as the products have matured. The specific type of SAT commonly available today is the Horizontal Single-Axis Tracker where the modules are laid flat relative to the ground and follow the sun from east-to-west throughout the day. Other versions of SATs are available, but not at the quantities needed in utility scale systems. Most SAT systems also have the capability of adaptive or intelligent sun tracking options that can help recover lost energy due to east and west sloped project sites from increased row-on-row shading and also during overcast sky conditions. Adaptive tracking energy gains can be as much as 1 to 2 percent depending on site topography and cloudy / clear sky ratios.

SATs use either an independent-row drive (i.e., each row has a motor driven actuator) or central driveline system (i.e., one motor drives multiple rows). Independent-row drives provides more flexibility in design, improved site access, and a single drive failure affects fewer modules. However, independent-row drives do have more parts that can fail and are generally more expensive to maintain. The central driveline system, with its fewer components is generally less expensive to maintain. However, the driveline restricts access between rows and a single failure affects more site DC capacity. Independent-row drive is more common within the industry as only one significant manufacturer (Array Technologies, Inc., or ATI) uses the driveline approach. The decision between these two methods usually comes down to total installed cost.

Historically, SATs were available in a one-in-portrait (1p) configuration where the long axis of the module was oriented east-to-west across the torque tube. Now, two-in-portrait (2p) SATs are available where the long axis of two modules, one on either side of the torque tube, are oriented east-to-west. This configuration allows for more modules to be driven by a single actuator, fewer posts are required to support the same quantity of modules, and there are fewer parts to install, therefore reducing overall installation costs. However, with the increasing size and weight of modules, the 2p configuration requires more steel in the torque tubes and other design accommodations that have reduced the cost advantages compared to 1p.

Inverters convert the DC energy to AC for supply to the grid. On utility scale projects, the standard approach is to use large central inverter skids, consisting of the inverter(s) and step-up transformer on a single steel base. Central inverter skid options are available from multiple suppliers in the 3.6-4.5 MVA range, with the largest available up to 7 MVA. The larger inverter skids are actually multiple large inverter modules tied together and sharing a single step-up transformer.

Generally, larger inverters are more cost-effective. However, there is a point of diminishing returns; if an inverter is too large, the number of modules wired to a single inverter drive the cost of the DC collection system up and the cost efficiency of the inverter is more than offset. With the current range of module sizes (450 to 550W), the most commonly applied range of inverter is the 3.6 to 4.5 MVA range.

C.2.1.2 Study Basis

The study basis for these Resource Options includes the following:

The technical characteristics for the Solar PV Resource Option are based on a 75 MWac / 105 MWdc project in Jacksonville, Florida. The solar cost and performance estimates reflect the following assumptions:

- Use of the best available technology
- Azimuth of 180°
- Panel tilt of 0°
- Single-axis tracking. With a maximum tracker angle of + / -50°.
- Crystalline-silicon, bi-facial modules
- The estimated annual solar resource is 1,674 kWh / m2 / year and is based on Global Horizontal Irradiance; derived from NSRDB (Jacksonville Airport TMY2). The first year estimated generation is 196,600 MWh (ac), and the net capacity factor (ac) is 29.9 percent. Both values are based on an energy simulation result with a standard annual degradation of 0.5 percent.
- The selected site is generally flat, cleared of trees, rectangular, and contiguous.
- The selected site has no nearby features (e.g., trees or tall buildings) that can cause shading of the solar modules.
- The selected site is close to the point-of-interconnect or at an existing facility with existing interconnection facilities.
- The battery energy storage system (BESS) is AC-coupled and co-located near the PV collector substation.
- Capacity is limited to 75 MW to avoid the more stringent permitting process in Florida.

- BESSs were evaluated at 1- and 4-hour durations, representing the typical minimum and maximum application of the commercially mature lithium-ion technology.
- BESSs are assumed to be containerized and modular for easy scalability.

It will be necessary to refine the study basis in a subsequent resource planning step if specific sites are identified for solar development to account for additional variables (e.g., land use conditions, presence of environmental resources such as wetlands or waterbodies, and distance of the site from transmission resources). Study basis parameters for the storage selected solar Resource Options characterized are summarized in Table C-1.

C.2.1.3 Capital and O&M Costs

The capital costs for the solar PV Resource Option are summarized in Table C-2. The costs assume owner's cost as 20 percent of EPC cost. Equipment costs include modules, inverters, trackers, and electrical / structural balance of system.

In estimating the O&M cost per kW-year, it was assumed that the solar project would be built with equipment from top tier manufacturers and that module washing would not be performed. Black & Veatch considered annual O&M costs, as well as major equipment corrective maintenance. The values in Table C-2 are exclusive of asset management and non-technical costs (e.g., taxes and lease payments) and assumes that buildings with not require heating and cooling. Some variables that can impact the O&M price forecasting, but are currently unknown, are agreement scopes, EPC warranty term and terms, major equipment warranties term and terms, plant layout specifics, and number of inverters.

The anticipated major maintenance corrective costs are dependent on the scope of major equipment repair and replacement included within the base service fee of the O&M agreement. Assuming that no major equipment repair or replacement is included in the base fee, Table C-4 includes reasonable major maintenance assumptions (inverters, modules, transformers, trackers) for a 25-year project duration. Black & Veatch notes that these are budgeted spend amounts, and that tracker, module, and transformer replacement do not necessarily need to be modeled as reserves.

Table C-2 - Solar PV Resource Option Capital Cost Estimate

Component	Price ($ / Wdc)	Price ($ / WAc)
Equipment	$0.602	$0.843
Installation	$0.125	$0.175
Engineering	$0.007	$0.010
Overhead, Construction Management, Profit	$0.132	$0.185
Total EPC Cost	$0.867	$1.213
Owner's Cost	$0.17	$0.243
Total Installed Cost: $ / Wdc	$1.04	$1.456

Table C-3 - Solar PV Resource Option O&M Cost Estimate

Description	Period	Cost	
Includes 0 module wash per year; excludes asset management, major equipment corrective maintenance, interconnection costs, non-technical costs (tax / leases), includes preventative / corrective maintenance	Years 1-10	$5 / kWdc / year	$7 / kWac / year
	Years 11-25	$6 / kWdc / year	$8.40 / kWac / year

Table C-4 - Solar PV Resource Option Major Maintenance Corrective Cost Estimate

Maintenance	Years 0-5	Years 6-10	Years 11-25
Nominal Major Equipment Overhaul / Replacement Cost	$0 / kWdc	$2 / kWdc	$4 / kWdc
	$0 / kWac	$2.80 / kWac	$5.60 / kWac

C.2.2 Energy Storage

C.2.2.1 Technology Overview

Although it is not a generation resource, energy storage can perform many of the same applications as a traditional generator by using stored energy from the grid or from other generation resources such as solar. These applications range from traditional uses such as providing capacity or ancillary services to more unique applications such as microgrids or renewable energy integration applications. Utility scale energy storage applications with their brief descriptions are provided below:

- Electric Energy Time-Shift (Arbitrage): The use of energy storage to purchase energy when prices are low and shift that energy to be sold when prices are higher (during peak times).
- Electric Supply Capacity: The use of energy storage to provide system capacity during peak hours.
- Frequency Regulation: The use of energy storage to mitigate load and generation imbalances on the second to minute interval to maintain grid frequency.
- Spinning Reserve: The use of energy storage that is online and synchronized to supply generation capacity within 10 minutes.
- Non-Spinning Reserve: The use of energy storage that is offline but can be ramped up and synchronized to supply generation capacity within 10 minutes.
- Voltage Support: The energy storage converter can provide reactive power for voltage support and respond to voltage control signals from the grid.
- Variable Energy Resource Capacity Firming: The use of energy storage to firm energy generation of a variable energy resource so that output reaches a specified level at certain times of the day.
- Variable Energy Resource Ramp Rate Control: Ramp rate control can be used to limit the ramp rate of a variable energy resource to limit the impact to the grid.
- Transmission and Distribution Upgrade Deferral: The use of energy storage to avoid or defer costly transmission and distribution upgrades.

Some of the applications listed above such as Ramp Rate Control or Capacity Firming are location specific and require nearby renewable energy sources such as utility scale solar or wind generation, whereas applications such as Electric Energy Time-Shift or Frequency Regulation can be location independent and be performed at different locations on the grid.

Applications are often grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to one hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control / smoothing are examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems. Electric Supply Capacity, Electric Energy Time-Shift, and Transmission and Distribution Upgrade Deferral are examples of energy applications.

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The main components of a battery are the positive electrode (cathode), the negative electrode (anode), and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[6] Batteries store direct current (DC) charge, so power conversion is necessary to interface a battery with an alternative current (AC) power system.

BESSs employ multiple (up to several thousand) batteries that are connected in series and / or parallel and are charged via an external source of electrical energy. The BESS discharges this stored energy to provide a specific electrical function.

A fully operational BESS comprises of an energy storage system that is combined with a bidirectional converter (also called a power conversion system). The BESS also contains a Battery Management System (BMS) and a Site or BESS Controller and is summarized in Table C-5.

Table C-5 - BESS Components

Component	Definition
Energy Storage System (ESS)	The ESS consists of the battery modules or components as well as the racking, mechanical components, and electrical connections between the various components.
Power Conversion System (PCS)	The PCS is a bi-directional converter that changes AC to DC and DC to AC. The PCS also communicates with the BMS and BESS controller.
Battery Management System (BMS)	The BMS can be comprised of various BMS units at the cell, module, and system level. The BMS monitors and manages the battery state of charge (SOC) and charge and discharge of the ESS.
BESS / Site Controller	The BESS controller communicates with all the components and is also the utility communication interface. Most of the advanced algorithms and control of the BESS resides in the BESS / Site Controller.

[6] T. B. Reddy, "Linden's Handbook of Batteries," 4th Edition, November 2010.

Appendix C - New Generating Resource Options Characterization

When considering different energy storage technologies, there are several key performance parameters to understand:

- **Power Rating**: The rated power output (MW) of the entire ESS.
- **Energy Rating**: The energy storage capacity (MWh) of the entire ESS.
- **Discharge Duration**: The typical duration that the BESS can discharge at its power rating
- **Response Time**: How quickly an ESS can reach its power rating (typically in milliseconds).
- **Ramp-rate**: how quickly an energy storage system can change its power output, typically in MW / min
- **Charge / Discharge Rate (C-Rate)**: A measure of the rate at which the ESS can charge / discharge relative to the rate at which will completely charge / discharge the battery in one hour. A one-hour charge / discharge rate is a 1C rate, while a 2C rate completely charges / discharges the ESS in 30 minutes.
- **Round Trip Efficiency**: The amount of energy that can be discharged from an ESS relative to the amount of energy that went into the battery during charging (as a percentage). Typically stated at the point of interconnection and includes the ESS, PCS and transformer efficiencies.
- **Depth of Discharge (DOD)**: The amount of energy discharged as a percentage of ESS overall energy rating.
- **State of Charge (SOC)**: The amount of energy an ESS has charged relative to its energy rating, noted as a percentage.
- **Cycle Life**: Number of cycles before ESS reaches 80 percent of initial energy rating. The cycle life typically varies for as a function of the DOD.

Battery types employed within energy storage systems typically include lithium ion (Lithium-ion), flow, lead-acid, or sodium sulfur (NaS) batteries. Lithium-ion batteries are the dominant component in battery energy storage, and the demonstrated experience is increasing. Lithium-ion batteries are anticipated to be a major industry component in the years to come and are well suited for both power and cycling applications as well as some energy applications.

Sodium-ion batteries are very similar to lithium-ion and were recently introduced by a major battery manufacturer. They exhibit some advantages over lithium-ion (such as lower flammability and greater material availability) that offset the disadvantages to lithium-ion (lower energy density). The sodium-ion battery market is anticipated to rapidly increase, and stationary battery applications could migrate rapidly from lithium to sodium over the next few years.

Redox flow battery installations are more limited; however, redox flow batteries are also projected to likely have a considerable market share for large stationary applications in the future and are best suited for energy applications that require longer durations of discharge. As large-scale applications of flow batteries have not been demonstrated, these applications are not considered further in this Characterization of Resource Options report.

Lithium-ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode.

The battery cells are integrated to form modules. These modules are then strung together in series and / or parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

Lithium-ion battery energy storage systems are typically used for both power and energy applications. The primary strength of lithium-ion batteries is the strong cycle life. For shallow, frequent cycles, which are common for power applications, lithium-ion systems demonstrate good cycle life characteristics. Additionally, lithium-ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- **Excellent Cycle Life**: Lithium-ion technologies have superior cycling ability to other battery technologies such as lead acid.
- **Fast Response Time**: Lithium-ion technologies have a fast response time which is typically less than 100 milliseconds.
- **High Round Trip Efficiency**: Lithium-ion energy conversion is efficient and has around 94 percent round trip efficiency (DC-DC).
- **Versatility**: Lithium-ion solutions can provide many relevant operating functions.
- **Commercial Availability**: There are many top tier lithium-ion vendors.
- **Energy Density**: Lithium-ion solutions have a high energy density to meet space constraints.

Over the last two years, significant Lithium-ion battery capacity has been installed in the United States and around the world. According to Bloomberg New Energy Finance (NEF) estimates, more than 75 GWh of capacity will be installed around the world by the end of 2021. System sizes of 100MWh and larger are common, with GWh systems coming on-line and continuing to advance in the planning stages.

O&M activities for Lithium-ion energy storage systems typically involve annual scheduled maintenance. During this maintenance, visual inspection of the system components and status check is performed as well as expendable parts such as filters are replaced. Software updates regarding BMS can be applied during this maintenance period.

Different lithium-ion vendors employ different lithium-ion chemistry for their product. Each chemistry composition is slightly different in terms of its performance characteristics, namely, cycle life, charge rate capabilities, and energy density. They also vary in terms of the typical applications (which are primarily dictated by the performance parameters) they perform and their relative safety characteristics.

The main types of lithium-ion chemistries are shown in Table C-6 as well as the associated strengths and weaknesses of the chemistries. It should be noted that the chemistries listed are relevant chemistries for grid scale energy storage. The source of the information is from Battery University, Linden’s Handbook of Batteries, and Black & Veatch experience.

Black & Veatch maintains a database of more than 80 energy storage providers in the industry. Of these, there are a significant number of lithium-ion suppliers. Black & Veatch’s recent EPC experience has allowed us to narrow the long list of suppliers to the top tier candidates. The top tier lithium-ion battery suppliers Black & Veatch frequently engages are listed in Table C-7.

Appendix C - New Generating Resource Options Characterization

Table C-6 - Lithium-Ion Chemistries for Energy Storage

Chemistry	Cycle Life [1]	Charge Rate	Specific Energy [7]	applications	Safety
Lithium Manganese Oxide (LMO)	4000 – 5000 cycles	0.25C to 3C	100-150 Wh / kg	Both power and energy applications	Good
Lithium Nickel Manganese Cobalt Oxide (NMC)	4000 – 5000 cycles	0.25C to 3C	150-220 Wh / kg	Often have separate power and energy cells	Good
Lithium Iron Phosphate (LFP)	3000 – 5000 cycles	0.25C to 2C. 4C with power cells.	90-120 Wh / kg	Often have separate power and energy cells	Very good
Lithium Nickel Cobalt Aluminum Oxide (NCA)	3000 (better at shallow DODs)	0.5C to 3C	200-260 Wh / kg	Often have separate power and energy cells	Good
Lithium Titanate (LTO)	5000 – 10000 cycles	1C to 6C	50-80 Wh / kg	Power applications	Good

Notes:

1. Cycle life is based on cycles to reach 80 percent initial energy storage capacity at 1 C rate. DoD for each cycle is assumed to be around a full DOD, or 90 percent.

Table C-7 - Lithium-Ion Battery Storage Providers

Chemistry	Manufacturer
Lithium Manganese Oxide (LMO)	Samsung SDI
Lithium Nickel Manganese Cobalt Oxide (NMC)	LG Chem
Lithium Iron Phosphate (LFP)	CATL, FHR
Lithium Nickel Cobalt Aluminum Oxide (NCA)	Saft, Tesla
Lithium Titanate (LTO)	Toshiba

[7] Battery University, "BU-205: Types of Lithium-ion," http: / / batteryuniversity.com / learN/Article / types_of_lithium_ion, October 2018.

C.2.2.2 Battery Energy Storage Augmentation

Due to the continuous degradation of Lithium-ion batteries, the overall system capacity will decline over time. Some system owners account for this degradation in the pro forma and plan to do no augmentation. Other strategies include an initial overbuild of capacity or installation of additional capacity at planned intervals (i.e., 1-, 3-, or 5-year intervals).

With an initial overbuild of capacity, enough additional capacity is installed to offset the total expected degradation over the design life of the battery system. This has the advantage of not requiring work to be performed in the future on an operational asset and there is no cost uncertainty in regard to future cost of installation or equipment.

Alternatively, additional capacity can be installed at planned intervals. These intervals can be of any duration, but most are no less than annual, with 3- to 5-year intervals typical. Initially, sufficient capacity will be installed to offset expected degradation between install and the scheduled augmentation. Advantages of this method include reduced initial cost, the ability to take advantage of future technology advances, and expected cost reductions in batteries. A disadvantage of this approach is that costs are less certain (though likely to decline, there is still some uncertainty in that forecast), and system availability may be impacted during installation of additional capacity.

C.2.2.3 Capital and O&M Costs

Cost parameters for the different battery storage options are provided in Table C-8 and Table C-9. The costs assume that an overbuild of capacity will be installed in year 1 such that the battery will still meet the Facility Energy Rating in year 10 after accounting for degradation and round trip efficiency losses. After year 10, an annual degradation loss of approximately 1.0 percent can be expected for typical usage scenarios. Because no augmentation/capacity management of the battery is planned for the first year no costs for same are included in the Fixed O&M costs. It is assumed that buildings will not require heating or cooling. Auxiliary power for the cooling of the batteries is netted out of the energy produced (i.e., it is assumed auxiliary power is provided by the batteries themselves and the batteries are then oversized to compensate for this load). When paired with solar, the costs below would be in addition to the solar cost.

Table C-8 - Battery Energy Storage for the Solar plus Storage Resource Options

Location	Application	Rating (MW)	Size (MWh)	Battery Technology
Greenfield 74.9 MW Solar Facility	Load firming / smooth	37.5	37.5	Cell Battery
Greenfield 74.9 MW Solar Facility	Peak Shifting	74.9	300.0	Cell Battery
Existing Site	Load firming / smooth	25.0	25.0	Cell Battery
Existing Site	Peak Shifting	50.0	200.0	Cell Battery

Table C-9 - Representative Costs for Energy Storage Systems

Parameter	37.5 MW Battery Storage 1 Hour	25 MW Battery Storage 1 Hour	50 MW Battery Storage 4 Hour	75 MW Battery Storage 4 Hour
Facility Power Rating, MW	37.5	25	50	75
Facility Energy Rating, MWh	37.5	25	200	300
ESS Cost[1] ($M)	$11.99	$7.99	$63.84	$95.77
PCS Cost ($M)	$2.25	$1.50	$3.00	$4.50
Balance of System Direct Cost[2] ($M)	$2.34	$1.67	$7.80	$11.58
Balance of System Indirect Cost[3]($M)	$2.13	$1.66	$4.46	$5.66
Installed EPC Costs[4] ($M)	$18.71	$12.82	$79.11	$117.51
EPC Cost per kW ($)	$499	$513	$1,582	$1,567
EPC Cost per kWh ($)	$499	$513	$396	$392
Fixed O&M Costs $ / kW-yr[5]	2.44	2.44	8.20	8.20

Notes:

1. Inclusive of containerization
2. Direct costs are inclusive of balance of system electrical, civil, interconnection, SCADA, equipment, and labor
3. Indirect costs are inclusive of engineering and project management, builder's insurance bonding and warranty. Sales tax, EPC markup, and development costs are not considered.
4. Installed costs are based on 2021 COD
5. Battery replacement and capacity maintenance not included in Fixed O&M Cost

C.3 Biomass Resources

The biomass Resource Options that were studied are summarized in Table C-10.

C.3.1.1 Technology Overview

Biomass power generating resources are those where plant (wood, energy crops and waste from forests, yards, or farms) or animal material is used as fuel to produce electricity or heat. The biomass Resource Options that was studied was a 50 MW biomass burning wood waste.

Biomass firing for power generation is both a well-established technology as well as an increasingly popular option for generators looking to reduce or eliminate carbon emissions.

Table C-10 – Biomass Resource Options Studied

ID	Resource Option	Plant Configuration	Duty	Net Output (MW)	Annual Capacity Factor (%)	Annual Number of Starts
6	50 MW Biomass	BFB, with SCR, Baghouse, sorbent injection	Base	47.403	80	5

Notes

1. Net Output value based on ambient conditions of 80°F and relative humidity of 60 percent.

During the next phases of project development, a biomass resource assessment can be performed to identify and quantify the currently available biomass resources in the anticipated location that could potentially be used for this new generating asset. In addition to looking at currently available resources, other potential sources that could be developed as fuel sources are considered, but not evaluated in detail on a quantitative basis in this study. At this time it is understood that JEA's focus of the study was on woody biomass.

Forest residues are remnants of forest clearing and thinning operations and include treetops, branches and stumps. Forest residues are produced by commercial logging and forest management practices. This resource category comprises a very large volume of material, but can be quite dispersed geographically. The amount of forest residue available for use as biomass fuel depends primarily on the cost to collect/remove the material and distance from the point of extraction to the end-use point.

The woody biomass fuel anticipated by JEA for this option will be an un-treated pine originating from the southeastern US. The woody biomass will be chipped to size required by the BFB and will be stored outdoors. Suppliers have noted that this general fuel criteria is estimated to be about 45% moisture on average but may be as high as 60% moisture during rainy weather. A BFB combustion system is recommended to effectively fire this fuel.

BFB units feature a furnace equipped with a bed of solid, inert material in the bottom of the unit. Pressurized air is blown upward through the bed, fluiding it to the point of "bubbling" operation. Fuel is introduced into this bubbling bed where it is combusted under low temperature. Because of the low temperature in the furnace, fluidized bed units often produce lower NO_x compared with traditional suspension fired units. BFBs are well suited for high moisture fuels and do not require as finely milled fuel particles as suspension fired units. The low bed temperatures also allow for some in-bed sorbent injection and may, therefore, not require additional scrubbing of the flue gas post-combustion.

C.3.1.2 Study Basis

The study basis for the biomass resource option includes the following:

- The design is based on a single nominal 50 MW biomass-fired bubbling fluidized bed (BFB) unit. The unit has standard emissions control technology to meet U.S.-based requirements. The performance estimates are based on high level heat balances and combustion calculations, and the installed cost estimates are based on rough order of magnitude pricing from vendors.
- The unit will fire wood chips based on a composition analysis provided by JEA. The woody biomass fuel anticipated by JEA will be an un-treated pine originating from the southeastern US. The woody biomass will be chipped to size required by the BFB and will be stored outdoors.
- This generating unit evaluated in this scenario would include combustion air fans, fluidizing fans, air heater, boiler, emissions controls, stack, and other balance of plant equipment. At this time, air emissions limits have not been established yet for this project. Boiler vendors were requested to include a "typical" scope for emissions controls equipment. The bidder carried in this estimate has included sorbent injection, a selective catalytic reduction (SCR) system, and a baghouse.

A summary of the estimated capital and O&M costs are provided in Table C-11 and Table C-12.

C.3.1.3 Capital and O&M Costs

Table C-11 - Summary of Biomass Overnight EPC Capital Cost Estimates

ID	Resource Option	EPC Cost ($M)
6	50MW Biomass	178.075

Table C-12 - Summary of Biomass Screening-Level Non-Fuel O&M Cost Estimates

Supply Side Option	Unit	50MW Biomass
Supply Side Option ID	--	6
Case Number	--	6
Annual Capacity Factor	%	80
Starts Per Year	Count	5
Number of Full Time Equivalent Personnel	Count	44
Reference Year for Cost Estimates	Year	2021
Net Plant Output (Note 1)	MW	47.403
Annual Net Generation	MWh / year	332,200
Fixed Costs, Annual	$1000 / year	7,375
Variable Costs, Annual	$1000 / year	2,685
Total O&M Costs, Annual	$1000 / year	10,061
Fixed Costs, Annual	$ / kW-year	155.59
Variable Costs, Annual	$ / MWh	8.08
Notes: 1. Net Output value based on ambient conditions of 80°F and relative humidity of 60 percent.		

C.4 Natural Gas-Fired Resources

C.4.1 Technology Overview

C.4.1.1 F-Class and Advanced Class Combustion Turbines

F-class combustion turbine technologies provide a demonstrated operating record in the United States and around the world. GE's 7F fleet includes over 900 units, and these units have compiled over 45 million operating hours. The latest iteration of the F-class combustion turbine offered by GE is the 7F.05.

Advanced class machines offer the highest efficiency among frame combustion turbines, with CC efficiencies exceeding 60 percent. For large-scale gas-fired applications (i.e., with SC output greater than 250 MW) at 60 Hz, GE offers an advanced class combustion turbine option, the 7HA.02.

The purpose of using only GE CTGs as the basis for these resource options is to provide a consistent comparison within typical combustion turbine technology classes and is not intended to be an implicit recommendation of GE CTGs. This approach helps to minimize the cost and duration of IRP modeling versus modeling of CTGs from several different manufacturers. If one of these GE CTG based Resource Options is selected for implementation as a result of the IRP, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development, including consideration of CTGs from other manufacturers. For example, if an advanced class GE 7HA.02 CTG option is selected, JEA should also consider and evaluate comparable advanced-class CTGs offered by Mitsubishi Power Americas (MPA) and Siemens as well as GE.

C.4.1.1.1 GE 7F.05

The 7F.05 is an air-cooled frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low nitrogen oxide (NO_x) (DLN) combustors. The 7F.05 is GE's fifth-generation 7F machine. Advancements integrated into the 7F.05 design include a redesigned compressor with three variable stator stages and a variable inlet guide vane for improved turndown capabilities. The 7F.05 was introduced in 2009, and the first unit shipped in 2013.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 megawatts per minute (MW / min) ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes (excluding purge).
- Natural gas interface pressure requirement of 435 pounds per square inch gauge (psig) at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.
- DLN combustion with CTG NO_x emissions of 9 parts per million (ppm) on natural gas.
- Capable of turndown to 45 percent of full load.
- High exhaust temperature increases the difficulty of implementing post-combustion NO_x emissions controls (i.e., SCR).

Cost and performance characteristics have been developed for the following GE 7F.05 combustion turbine configurations:

- 1x0 SC natural gas-fired GE 7F.05 combustion turbine facility.

- 1x1 CC natural gas-fired GE 7F.05 combustion turbine facility.
- 2x1 CC natural gas-fired GE 7F.05 combustion turbine facility.

C.4.1.1.2 GE 7HA.02

The GE 7HA.02 is an air-cooled frame CTG with a single shaft; 14-stage axial compressor; 4-stage axial turbine; and can-annular DLN combustor. The machine includes a single inlet guide vane stage and three variable stator vane stages to vary compressor geometry for part load operation. The 7HA.02 represents one of the largest and most advanced frame CTG technologies from GE, with the 7HA.03 CTG being the largest and most recent CTG from GE. The compressor design is scaled from GE's 7F.05 and 6F.01 (formally 6C) designs. The 7HA.02 uses the DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system, which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees; providing stable operations; and allowing for increased fuel variability.

Besides the 7HA.03 CTG, the 7HA.02 is the newest 60Hz combustion turbine technology offered by GE. GE has sold 59 7HA.02 gas turbines around the world with 34 of those in commercial operation and 8 more being commissioned, as of November 2021. The first four 7HA.02 gas turbines entered commercial operations at two separate Exelon sites in Texas in June 2017. The total 7HA fleet, including 7HA.01 and 7HA.02, has more than 780,000 hours and almost 6,000 starts. The 7HA.02 fleet leader has over 32,000 operating hours.

Key attributes of the GE 7HA.02 include the following:

- High availability.
- 60 MW / min ramp rate.
- Capable of turndown to approximately 25 percent of full load (ambient temperature dependent).
- Natural gas interface pressure requirement of approximately 540 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.
- DLN combustion with CTG NO_x emissions of 25 ppm on natural gas.

Cost and performance characteristics have been developed for the following advanced class combustion turbine configurations:

- GE 7HA.02
  - 1x0 SC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 1x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 2x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 3x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.

C.4.1.2 Aeroderivative Combustion Turbines

Aeroderivative CTGs were derived from aerospace jet turbine technology. An aeroderivative CTG is generally a two- or three-shaft turbine with a variable-speed compressor and power turbine. The variable-speed drive is advantageous for part-load efficiency because airflow is reduced with the lower speed.

Turbine inlet temperatures in aeroderivative CTGs are generally higher than in frame CTGs. Aeroderivatives generally offer higher efficiencies than frame CTGs. Furthermore, aeroderivative CTGs are smaller and lighter for a given power output and can be started more rapidly because of the inherently low inertia. The faster start times allow for less fuel consumption during startup. This feature allows the machine to more easily follow load for peaking applications. Aeroderivative CTGs are available in sizes ranging from single digits up to approximately 100 MW. The machines with the largest market share are in the range of 40 to 60 MW.

Aeroderivative CTGs have higher compressor pressure ratios than frame CTGs resulting in much higher fuel gas pressure requirements. This higher-pressure requirement can result in the need for onsite fuel gas compressors.

C.4.1.2.1 GE LMS100

The LMS100 is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor (LPC) section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor (HPC) section. A mixture of compressed air and fuel is combusted in a single annular combustor (SAC). Hot flue gas then enters the two-stage high pressure turbine (HPT). The high-pressure turbine drives the high-pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine (IPT), which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine (LPT) drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to / from the intercooler and the external heat exchanger. NO_x emissions are minimized utilizing water injection (for the LMS100PA+) or the use of Dry Low Emission (DLE) combustion technology (for the LMS100PB+).

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of approximately 41:1. The single annular combustor and high-pressure turbine are derived from GE's LM6000 aeroderivative turbine and CF6-80C2 and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 MW / min ramp rate.
- 8 minutes to full power (excluding purge).
- Capable of turndown to 25 percent of full load.
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 850 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.

The LMS100 is available in several configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and DLE in lieu of water injected combustion for applications when water availability is limited.

Cost and performance characteristics have been developed for the following GE LMS100 combustion turbine configuration:

- 1x0 SC natural gas-fired GE LMS100PA+ combustion turbine facility.

C.4.1.2.2 GE LM6000

The LM6000 was introduced in 1991, and the LM6000 family of gas turbines has accumulated more than 37 million operating hours with over 1,200 units produced. The baseline LM6000 is a derivative of the CF6-80C2 (Commercial Aircraft) flight gas turbine, and more recently, the CF6-80E1. Models currently commercially offered by GE include the LM6000PC, LM6000PG, LM6000PF, and LM6000PF+.

The LM6000 employs a 5-stage LPC and a 14 stage HPC, an annular combustor, two-stage air-cooled HPT, and a five-stage LPT. All stages of the LPC and six stages of the HPC feature variable-geometry inlet guide vanes. The LPT drives both the LP compressor and the generator load.

The LM6000 SPRINT (SPRay INTercooling) configuration increases power output of the engine by injecting air-atomized demineralized water droplets into the compressor to cool the air flow as the water evaporates on its way through the compressor, increasing power by approximately 9 percent at ISO conditions.

The LM6000PC and LM6000PG employ SAC combustion systems. The LM6000PC was introduced in 1997 after approximately 1 million operating hours on models PA / PB. The LM6000PG and PH engines were announced in 2008. Upgrades of LM6000PG, relative to the LM6000PC design, include upgraded materials and increased rotor speed (with addition of a gearbox) to increase power output.

The LM6000PF and LM6000PF+ employ DLE combustion systems. GE introduced the LM6000PF in 2005. The LM6000PF is an upgrade of the LM6000PD. The LM6000PF was the first LM6000 model to employ DLE1.5 technology, which utilized improved combustor design to achieve NO_x emissions of 15 ppm. In 2016, GE announced an upgrade of the LM6000PF: the LM6000PF+. Like the LM6000PG, the LM6000PF+ operates at increased rotor speeds to allow for greater airflow and firing temperature. Additional modifications allow for greater airflow and firing temperature, increasing power output relative to the LM6000PF. In April of 2017, an LM6000PF+ unit was placed into demonstration at a utility host site.

Key attributes of the GE LM6000 include the following:

- High full and part load efficiency.
- High availability.
- 50 MW / min ramp rate.
- 5-minute fast start to full power (excluding purge).
- Capable of turndown to 25 percent of full load (50 percent for DLE).
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 640 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.

Cost and performance characteristics have been developed for the following GE LM6000 combustion turbine configuration:

- 1x0 SC natural gas-fired GE LM6000PF SPRINT combustion turbine facility.

C.4.1.3 Reciprocating Internal Combustion Engines

A reciprocating internal combustion engine (RICE) resource option utilizes a utility-size spark-initiated or compression initiated gas-fueled piston driven engine as the prime mover for the generating facility. A reciprocating engine is a heat engine that uses the expansion of hot gases to convert the linear movement of the piston into the rotating movement of a crankshaft to generate power.

Modern reciprocating engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICE units are characterized by the type of combustion utilized: spark-ignited or compression-ignited, also known as diesel. The spark-ignited engine is based on the Otto thermodynamic cycle and uses a spark plug to ignite an air-fuel mixture injected at the top of the cylinder.

The size and power of a reciprocating engine is a function of the volume of fuel and air combusted. Therefore, the size of the cylinder, the number of cylinders, and the engine speed determine the amount of power the engine generates. The output of reciprocating engine generator sets is currently limited to approximately 20 MW. In a power plant, multiple units are grouped together in a power block to provide generating capacity in standardized sizes. Reciprocating engine power plants are highly efficient with SC efficiencies of 40 to 49 percent (LHV), generally surpassing the performance of SC CT power plants. The biggest concession with reciprocating engines is the operation and maintenance costs often make them less appealing in life-cycle cost analyses.

Many RICE units use a compressed air start system in which compressed air is used to initiate rotation of the crankshaft. RICE units can start quickly (approximately two hours after shutdown) and require a minimal amount of electricity and fuel during startup.

The technology selected to represent the RICE options was the Wartsila 18V50DF in SC configuration. Consideration of only the Wartsila RICE for this resource option is not intended to be an implicit recommendation of the Wartsila RICE. If this resource options is selected for implementation as a result of the IRP, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development, including consideration of RICE from other manufacturers.

The Wartsila 18V50DF reciprocating engine is a turbocharged, four-stroke compression-ignited dual fuel engine. The DF is always started on liquid fuel and requires a small amount of liquid pilot fuel even during natural gas operation to maintain combustion. The 18V50DF utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11 / 16 inches) and a stroke of 580 millimeters (22-13 / 16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. These engines employ individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. Currently there are approximately 260 18V50DF engines in operation around the world used for power generation, and at least another forty sold to date, with initial commercial operations starting in 2004.

For this characterization, it is assumed that engine heat is rejected to the atmosphere using an air-cooled heat exchanger, or "radiator." An 18V50DF power plant utilizing air cooled heat exchangers requires very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50DF include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- 5 minutes to full power (excluding purge); purge is performed during the shutdown sequence.
- Each engine is capable of turndown to 40 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 75 psig.
- Dual fuel capable.

Cost and performance characteristics have been developed for the following Wartsila 18V50DF RICE configuration:

- 5x0 SC natural gas-fired Wartsila 18V50DF RICE facility.

C.4.2 Study Basis

There were twelve (12) gas-fired combustion turbine generator (CTG) based Resource Options studied including four simple cycle (SC) options and eight combined cycle (CC) options. The SC options are expected to operate as peaking resources while the CC options are expected to operate as intermediate / base duty resources.

The gas-fired Resource Options include those using current, commercial large frame CTGs as the prime movers. Consideration was made for backup fuel oil firing capability to mitigate gas supply interruptions during operations. The following CTGs manufactured by General Electric (GE) were used as the basis for the characterization of these options:

- GE 7FA.05 (in both SC and CC configurations)
- GE 7HA.02 (in both SC and CC configurations)
- GE LMS100 (in SC configuration)
- GE LM6000 (in SC configuration)
- Existing GE 7F.03 SC units upgraded to include a 7FA.05 compressor and advanced gas path (AGP) upgrade, and converted from SC to CC configuration

The study basis utilized to evaluate the gas-fired Resource Options includes the following:

- Gas-fired Resource Options will be constructed at either the existing Greenland Energy Center (GEC) or at a brownfield location currently referenced as the North Jax site.
- The GEC site was originally designed for an ultimate buildout of two 2x1 F-Class CTG units in CC configuration plus one SC CTG. There are currently two 7FA.03 SC CTGs in SC configuration on the site along with service water, fire water, control room, fuel oil storage, electrical substation, gas supply line, and other common site equipment already constructed.
- The North Jax site is anticipated to be parceled out from the now-retired St. Johns River Power Park (SJRPP) site which is owned by JEA. The potential site is anticipated to be cleared and restored to level ground with no site infrastructure in place except the original SJRPP substation. There is also a low-pressure gas line to the site, formerly used for startup burners.
- CTGs and RICE technology will be dual fuel capable, with natural gas as the primary fuel and Ultra Low Sulfur No. 2 distillate as the secondary fuel.
- For CC Resource Options:
  - CTG(s) will be located outdoors in a weather-proof enclosure; the CTGs will be close-coupled to a three-pressure heat recovery steam generator (HRSG). Ancillary CTG skids will also be located outdoors in weather-proof enclosures.
  - The steam turbine will be located outdoors in a weather-proof enclosure.
  - A generation building will house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms. This facility already exists at GEC but may need to be expanded.
  - Wet surface condenser with a mechanical draft cooling tower-based heat rejection systems (WMDCT) will be utilized. To

demonstrate the impacts of utilizing an air-cooled condenser (ACC) based dry heat rejection system, an ACC option will be considered for the 1x1 7HA.02 CC Resource Option.

- Oxidation catalysts and selective catalytic reduction (SCR) will be utilized to meet current market Best Available Control Technology (BACT) stack emission rate targets.
- Supplemental HRSG duct firing will be included.
- Conventional start times will be achievable and black start capability will be provided.
- Note that CC units constructed in the state of Florida (over 80MW steam) are subject to regulation under the Florida Power Plant Siting Act (PPSA), which is regulated by the Florida Public Service Commission (PSC). The minimum duration for completing this regulatory process is three years.

- For SC Resource Options:
  - The CTG / RICE will be located outdoors in a weather-proof enclosure. Ancillary CTG / RICE skids will also be located outdoors in weather-proof enclosures.
  - A generation building will house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms. This facility already exists at GEC but may need to be expanded.
  - Fast-start capability along with black start capability will be provided.
  - Frame type CTGs will meet New Source Performance Standards (NSPS) through good combustion practices and will not have oxidation catalysts or SCR.
  - Aeroderivative type CTGs will meet NSPS through good combustion practices and will also have oxidation catalysts and SCR.
  - RICE technology will meet NSPS through good combustion practices, oxidation catalysts and SCR.
  - Note that peaking technologies are not regulated by the Power Plant Siting Act (PPSA) and therefore permitting duration is approximately 18 months total.
- At the GEC facility, upgrades (proposed by PGS) are sufficient to support the frame CTGs and RICE, but fuel gas compression costs are included in the capital cost of the aeroderivative CTGs.[8] At the North Jax site, upgrades (proposed by PGS) would be required for all options except for the RICE option, and fuel gas compression costs are included in aeroderivative CTG capital costs.[9]

Study basis parameters for the selected gas-fired Resource Options are summarized in Table C-13 and Table C-14 below.

[8] Because of the structure of the existing supply contract for the GEC site, incremental costs for increased delivery or pressure from the Peoples Gas System (PGS) owned Seacoast Pipeline to the JEA-owned GEC Lateral serving the GEC have been captured in the IRP as a transportation cost adder to the GEC unit fuel forecast price, rather than as a capital cost added to the unit construction cost or Owner's Cost.

[9] Pressure and flow to the NGS and SJRPP sites, and to the proposed adjacent or co-located North Jax site via the existing supply system co-owned by JEA and PGS are limited. Costs to serve the potential upgrades from the PGS system have been captured in the IRP as a transportation cost adder to the NGS and SJRPP unit fuel forecast price, rather than as a capital cost added to the unit construction cost or Owner's Cost.

Appendix C - New Generating Resource Options Characterization

Table C-13 - Study Basis Parameters for Gas-Fired Peaking Resource Options

ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output[1] (MW)	Annual Capacity Factor (%)	Annual Number of Starts
7	2x0 GE LM6000 PF SPRINT	Combustion Turbine: GE LM6000 PF SPRINT AQC: SCR, CO Catalyst	Peaking	91	10	250
8	1x0 GE LMS100PA+	Combustion Turbine: GE LMS100PA+, with dry interstage cooling AQC: SCR, CO Catalyst	Peaking	111	10	250
9	1x0 GE 7FA.05	Combustion Turbine: GE 7F.05 AQC: Good Combustion Practices	Peaking	226	10	250
10	1x0 GE 7HA.02	Combustion Turbine: GE 7HA.02 AQC: Good Combustion Practices	Peaking	329	10	250
11	5x0 Wartsila 18V50DF	Reciprocating Engine: Wartsila 18V50SG AQC: SCR, CO catalyst	Peaking	89	11	250

Notes

1. Average Ambient Net Output values based on ambient conditions of 69°F and relative humidity of 70 percent, with no inlet chilling.

Table C-14 - Study Basis Parameters for Gas-Fired Intermediate / Base Resource Options

ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output[1] (MW)	Annual Capacity Factor (%)	Annual Number of Starts
12	1x1 GE 7FA.05	Combustion Turbine: GE 7F.05 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	373	35 / 80	325 / 5

Appendix C - New Generating Resource Options Characterization

ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output[1] (MW)	Annual Capacity Factor (%)	Annual Number of Starts
13	2x1 GE 7FA.05	Combustion Turbine: GE 7F.05 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	749	35 / 80	325 / 5
14	1x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	558	35 / 80	325 / 5
15	2x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	1,119	35 / 80	325 / 5
16	3x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	1,684	35 / 80	325 / 5

Appendix C - New Generating Resource Options Characterization

ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output[1] (MW)	Annual Capacity Factor (%)	Annual Number of Starts
17	1x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Air-Cooled Condenser	Intermediate / Base	552	35 / 80	325 / 5
18	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor / AGP upgrade	Combustion Turbine: GE 7F.03 with .05 compressor / AGP upgrade HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	318	35 / 80	325 / 5
19	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor / AGP upgrade	Combustion Turbine: GE 7F.03 with .05 compressor / AGP upgrade HRSG: Triple Pressure, Reheat Duct Firing: 15 percent STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	638	35 / 80	325 / 5

Notes
1. Average Ambient Net Output values based on ambient conditions of 69°F and relative humidity of 70 percent, with no inlet chilling.
2. Output for Resource Option ID options 17 and 18 is total capacity, not incremental capacity associated with the conversion.

C.4.2.2 Non-fuel Operating & Maintenance Estimating Basis

Black & Veatch developed non-fuel O&M cost estimates for each Resource Option under consideration. Non-fuel O&M cost estimates were developed as representative estimates based on previous Black & Veatch experience with projects of similar design and scale, and relevant vendor information available to Black & Veatch. Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components:

- Fixed O&M costs include labor, routine maintenance, and other expenses (e.g., training, office, and administrative expenses).
- Non-fuel Variable O&M costs include outage maintenance (including the costs associated with Long Term Service Agreements [LTSAs] or other maintenance agreements), parts and materials, water usage, chemical usage, and equipment.
- Non-fuel Variable O&M costs exclude the cost of fuel (e.g., natural gas).

Additional assumptions regarding O&M cost estimates include the following:

- SC facilities are assumed to operate in peaking service, while CC facilities are assumed to operate in intermediate duty service or base-load service. Assumed annual operating profiles for SC and CC facilities are summarized in Table C-16.
- Plant staffing assumptions are summarized in Table C-17 for the various facility configurations under consideration.
- Labor rates for O&M staff were assumed based on Black & Veatch experience with similar facilities in the southeastern United States.
- All major maintenance for CTG / RICEs is assumed to be conducted under an LTSA with the OEM. LTSA costs were estimated based on confidential and proprietary recent LTSA proposals (provided to Black & Veatch) for the CTG / RICEs under consideration.
- All plant water consumption (including cooling water) was assumed to be sourced from the local water utility (JEA). Water rates were assumed to be $2.50 per 1,000 gallons.
- Cost for additional plant consumables based on Black & Veatch experience with similar facilities in the region.
- All non-fuel O&M cost estimates are presented in mid-year 2021 United States dollars.

Appendix C - New Generating Resource Options Characterization

Table C-15 - Potential Owner's Costs for a Power Generation Project

Project Development
- Site selection study
- Land purchase / rezoning for greenfield sites
- Transmission / gas pipeline right-of-way
- Road modifications / upgrades
- Demolition
- Environmental permitting / offsets
- Public relations / community development
- Legal assistance
- Provision of project management

Spare Parts and Plant Equipment
- Combustion and steam turbine materials, supplies, and parts
- HRSG and / or boiler materials, supplies, and parts
- SCR and CO catalyst materials, supplies, and parts
- Balance-of-plant equipment / tools
- Rolling stock
- Plant furnishings and supplies
- Recip. engine materials, supplies, and parts

Plant Startup / Construction Support
- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals and reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchases
- Acceptance testing
- Construction all-risk insurance

Utility Interconnections
- Natural gas service
- Gas system upgrades
- Electrical transmission (including switchyard)
- Water supply
- Wastewater / sewer

Owner's Contingency
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreements (i.e., interconnection contract costs)

Owners Project Management
- Preparation of bid documents and the selection of contractors and suppliers
- Performance of engineering due diligence
- Provision of personnel for site construction management

Financing
- Financial advisor, lender's legal, market analyst, and engineer
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

Taxes/Advisory Fees/Legal
- Taxes
- Market and environmental consultants
- Owner's legal expenses
- Interconnect agreements
- Contracts (procurement and construction)
- Property

Table C-16 - Annual Operating Profile Assumptions for Gas-fired Facilities

CT Facility Configuration	Annual Number of Starts	Annual Number of Hours	Annual Capacity Factor
SC CT / RICE Facility	250	876 / 1,000	10% / 11.4%
CC CT Facility	325 / 5	3,066 / 7,008	35% / 80%

Table C-17 - Plant Staffing Assumptions for Facilities

CT Facility Configuration	Plant Staffing (FTEs)
1x0 SC CT	9
1x1 CC CT	17
2x1 CC CT	19
3x1 CC CT	23
5x0 Simple Cycle RICE	13
Utility Scale Solar & Solar + BESS	0.5
Biomass	44

C.4.2.3 Duct Firing Considerations

All duct firing represents a trade-off between increased output and operational flexibility achieved at the expense of worse heat rate, plant footprint, and operational complexity. The level of duct firing can be sized based on material temperature limits, transmission limits, or operational goals. The relevant Resource Options are duct fired to an output corresponding to 15 percent of steam turbine (STG) unfired output to allow for future gas turbine upgrades. CTG manufacturers regularly iterate their technology and offer increased performance on existing units. For example, a 10 percent increase in output may be realized following upgrades made available at the first major inspection (typically between 50,000 and 65,000 hours of operation). However, these CTG upgrades require large engineering and capital cost efforts to resize the rest of the plant if one sizes the STG and balance-of-plant (BOP) cycle (pumps, pipes, condenser, etc.) only for the original CTG exhaust energy.

Sufficient margin for future CTG upgrades can be incorporated by sizing the level of duct firing output 15 percent higher than unfired STG output. This intermediate-range planning avoids large rework on the STG and BOP. Even after a CTG upgrade, the duct firing allows flexibility in operation such as on hot days when the CTG output falls due to high ambient temperature.

C.4.2.4 Black Start Considerations

A black start system allows the starting of a primary generator with no grid connection. Generally, black start systems consist of some number of small diesel or natural gas generators. They are sized for the minimum required starting loads, which can vary based on plant features.

Large frame CTGs can draw significant electrical load for their static frequency converter starting mechanisms, in addition to critical loads such as oil pumps and vent fans. Minimal gas compression and BOP equipment needs also need assessed. Finally, proper load sequencing and electrical design can bring up sequentially larger pieces of equipment—for example, starting one of the CTG / HRSG trains in a 3x1, then sequentially bringing the other trains online.

C.4.2.5 Wet vs. Dry Cooling Considerations

CC power plants require large heat rejection systems for proper operation. For a CC power plant with adequate water supply and water discharge capacity, the combination of a surface condenser and wet mechanical draft cooling tower (WMDCT) is the most common method of rejecting heat from a steam bottoming cycle to atmosphere. This method of heat rejection allows for a low steam turbine exhaust pressure and temperature, which results in a greater thermal efficiency of the bottoming cycle. However, water losses for this heat rejection method are high compared to alternative, dry cooling methods. For example, operation of a 2x1 7F.05 CC would require approximately 2,000 to 3,000 gallons per minute (gpm) of water during full load operation, depending on ambient conditions.

In areas where water conservation is a high priority or water discharge is not available, air cooled condensers (ACCs) are usually employed. Water losses with an ACC-based heat rejection system are minimal. This method of heat rejection is more expensive in terms of capital cost than a surface condenser and wet mechanical draft cooling tower. Also, the steam turbine exhaust pressure and temperature are typically higher with an ACC, which results in a lower bottoming cycle efficiency compared to wet cooling methods. The reduction in cycle efficiency results in reduced plant output, and increased plant heat rate (less electrical output for the same amount of fuel used).

Cost and performance characteristics have been developed for the following dry cooling configuration:

- 1x1 CC natural gas-fired GE 7HA.02 combustion turbine facility with ACC.

O&M costs required to maintain an air-cooled condenser are higher than the costs required to maintain a surface condenser and wet mechanical draft cooling tower. However, the cost savings in water usage and water treatment chemicals would likely offset the additional maintenance cost. Table C-18 provides a summary comparison for a typical CC operating during hot day conditions. The performance difference during average day conditions would be reduced.

Table C-18 - Typical CC Wet versus Dry Cooling Comparison

Variable	Wet Surface Condenser / Wet Mechanical Draft Cooling Tower	Air Cooled Condenser
Capital Cost	Base	+3 to +5 percent
Net Plant Output	Base	-1.5 to -2.0 percent
Net Plant Heat Rate	Base	+1.5 to +2.0 percent

C.4.3 Summary of Capital, Owners, and O&M Cost Estimates

Black & Veatch developed order-of-magnitude capital and owners cost estimates for generic gas-fired power plants constructed within the state of Florida, considering the Resource Options in this Characterization of Resource Options report. Estimates are based on similar studies and project experience and have been adjusted using engineering judgement.

C.4.3.1 Overnight EPC Capital Cost Estimates

Overnight EPC cost estimates have been prepared considering the estimating basis defined in Section 2. Screening-level estimates of EPC capital costs for both GEC and North Jax are included in Table C-19 and Table C-20. Owner's costs have been included in these tables as well.

Table C-19 - Summary of GEC Gas-Fired Overnight EPC Capital and Owner's Cost Estimates

ID	Resource Option	EPC Cost ($M) (Typical Greenfield)	EPC Cost ($M) (Site-Specific)	Owner's Cost ($M)	Total EPC + Owner's Cost ($M)	Optional Adder for Black Start ($M)
7	2x0 GE LM6000 PF SPRINT	92.7	89.7	14.6	104.3	0.50
8	1x0 GE LMS100PA+	109.9	106.9	17.3	124.2	1.25
9	1x0 GE 7F.05	97.1	94.1	15.3	109.4	6.25
12	1x0 GE 7HA.02	153.9	149.9	24.2	174.1	6.25
19	5x0 Wartsila 18V50DF	112.7	111.2	18.0	129.2	N/A
10	1x1 GE 7F.05	391.1	384.1	61.7	445.8	6.25
11	2x1 GE 7F.05	605.1	596.1	145.6	741.7	6.25
13	1x1 GE 7HA.02	460.5	452.5	72.6	525.1	6.25
14	2x1 GE 7HA.02	676.5	666.5	206.8	873.3	6.25
15	3x1 GE 7HA.02	885.6	873.6	240.0	1,113.6	6.25
16	1x1 GE 7HA.02	483.1	475.1	76.2	551.3	6.25
17	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor / AGP upgrade	269.9	261.9	42.1	304.0	6.25
18	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor / AGP upgrade	487.1	477.1	76.5	553.6	6.25

Table C-20 - Summary of North Jax Gas-Fired Overnight EPC Capital and Owner's Cost Estimates

ID	Resource Option	EPC Cost ($M) (Typical Greenfield)	EPC Cost ($M) (Site-Specific)	Owner's Cost ($M)	Total EPC + Owner's Cost ($M)	Optional Adder for Black Start ($M)
7	2x0 GE LM6000 PF SPRINT	92.7	92.7	20.2	112.9	0.50
8	1x0 GE LMS100PA+	109.9	109.9	23.0	132.9	1.25
9	1x0 GE 7F.05	97.1	97.1	20.9	118.0	6.25
12	1x0 GE 7HA.02	153.9	153.9	30.0	183.9	6.25
19	5x0 Wartsila 18V50SG	112.7	112.7	23.4	136.1	N/A
10	1x1 GE 7F.05	391.1	391.1	68.0	459.1	6.25
11	2x1 GE 7F.05	605.1	605.1	102.2	707.3	6.25
13	1x1 GE 7HA.02	460.5	460.5	79.1	539.6	6.25
14	2x1 GE 7HA.02	676.5	676.5	113.6	790.1	6.25
15	3x1 GE 7HA.02	885.6	885.6	147.1	1,032.7	6.25
16	1x1 GE 7HA.02	483.1	483.1	82.7	565.8	6.25

The scope of these cost estimates includes all facility generation equipment up to the high-side of the generator step-up transformers. The cost estimates presented include dual fuel systems (to allow operation on either natural gas or distillate oil fuels) for the CTG and RICE options.

Within a given estimate, EPC capital costs may be divided into two categories: direct EPC costs and indirect EPC costs. Direct EPC costs include the costs associated with the purchase and installation of major equipment and balance of plant (BOP) equipment. Indirect costs include costs such as engineering, construction management, construction indirects[10], pre-operational plant startup and testing, bonding and insurance, and EPC contractor contingency and profit.

C.4.3.2 Non-Fuel O&M Cost Estimates

Non-fuel O&M cost estimates have been prepared considering the estimating basis defined in Section 4.3. Estimates of annual non-fuel O&M costs are heavily dependent upon operating profile assumptions such as the number of annual operating hours and the number of annual starts.

For resource planning or general comparison purposes, it is often useful to consider O&M costs on various normalized bases. Fixed O&M costs may be evaluated on a $ / kW-year basis, while variable O&M costs may be evaluated on a $ / MWh basis. Given the operating profiles defined for Resource Options in Table C-16, screening-level estimates of non-fuel O&M costs and normalized O&M costs for each Resource Option are presented in Table C-21, Table C-22 and Table C-23.

[10] Construction indirect costs encompass a variety of items including construction supervision, purchase of small tools and consumables, site services, construction safety program (including development and compliance), installation of temporary facilities and utilities, rental of construction equipment, and heavy haul of construction materials and equipment.

Appendix C - New Generating Resource Options Characterization

Table C-21 - Summary of Screening-Level Non-Fuel O&M Cost Estimates for Resource Options 7,8,9,10,11, 12 and 19

Resource Option	Unit	2x0 GE LM6000 PF Sprint	1x0 GE LMS100PA+	1x0 GE 7F.05	1x0 GE 7HA.02	5x0 Wartsila 18V50DF	1x1 GE 7F.05	1x1 GE 7F.05	2x1 GE 7F.05	2x1 GE 7F.05
Resource Option ID	--	7	8	9	12	19	10	10	11	11
Case Number	--	7	8	9	12	19	10A	10B	11A	11B
Annual Capacity Factor	%	10%	10%	10%	10%	11%	35%	80%	35%	80%
Starts Per Year	Count	250	250	250	250	250	325	5	325	5
Number of Full Time Equivalent Personnel	Count	9	9	9	9	13	17	17	19	19
Reference Year for Cost Estimates	Year	2021	2021	2021	2021	2021	2021	2021	2021	2021
Net Plant Output (Note 1)	MW	91	111	226	329	89	373	373	749	749
Annual Net Generation	MWh / year	79,817	97,485	198,257	288,095	89,237	1,144,056	2,614,985	2,297,812	5,252,142
Fixed Costs, Annual	$1000 / year	1,443	1,467	1,931	2,040	2,030	3,805	3,805	4,947	4,947
Variable Costs, Annual	$1000 / year	564	443	2,032	3,944	810	4,766	6,342	9,357	12,305
Total O&M Costs, Annual	$1000 / year	2,007	1,910	3,963	5,984	2,840	8,571	10,147	14,304	17,252
Fixed Costs, Annual	$ / kW-year	15.84	13.18	8.53	6.20	22.71	10.20	10.20	6.60	6.60
Variable Costs, Annual	$ / MWh	7.07	4.55	10.25	13.69	9.08	4.17	2.43	4.07	2.34

Notes:

1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for CC units.
2. Different case with the same Resource Option ID represents different capacity factors.

Table C-22 - Summary of Screening-Level Non-Fuel O&M Cost Estimates for Resource Options 13, 14, 15 and 16

Resource Option	Unit	1x1 GE 7HA.02	1x1 GE 7HA.02	2x1 GE 7HA.02	2x1 GE 7HA.02	3x1 GE 7HA.02	3x1 GE 7HA.02	1x1 GE 7HA.02	1x1 GE 7HA.02
Resource Option ID	--	13	13	14	14	15	15	16	16
Case Number	--	13A	13B	14A	14B	15A	15B	16A	16B
Annual Capacity Factor	%	35%	80%	35%	80%	35%	80%	35%	80%
Starts Per Year	Count	325	5	325	5	325	5	325	5
Number of Full Time Equivalent Personnel	Count	17	17	19	19	23	23	17	17
Reference Year for Cost Estimates	Year	2021	2021	2021	2021	2021	2021	2021	2021
Net Plant Output (Note 1)	MW	558	558	1,119	1,119	1,684	1,684	552	552
Annual Net Generation	MWh / year	1,709,870	3,908,274	3,432,057	7,844,701	5,163,372	11,801,993	1,692,677	3,868,977
Fixed Costs, Annual	$1000 / year	4,127	4,127	5,592	5,592	7,388	7,388	4,134	4,134
Variable Costs, Annual	$1000 / year	8,298	9,677	16,416	18,938	24,520	28,194	7,110	6,963
Total O&M Costs, Annual	$1000 / year	12,424	13,804	22,008	24,530	31,908	35,582	11,244	11,097
Fixed Costs, Annual	$ / kW-year	7.40	7.40	5.00	5.00	4.39	4.39	7.49	7.49
Variable Costs, Annual	$ / MWh	4.85	2.48	4.78	2.41	4.75	2.39	4.20	1.80

Notes:

1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for CC units.
2. Different cases with the same Resource Option ID represent different capacity factors.

Appendix C - New Generating Resource Options Characterization

Table C-23 - Summary of Screening-Level Non-Fuel O&M Cost Estimates for Resource Options 17 and 18

Resource Option	Unit	Conversion of Existing GEC CTGs to 1x1 GE 7F.03 with .05 Compressor / AGP Upgrade	Conversion of Existing GEC CTGs to 1x1 GE 7F.03 with .05 Compressor / AGP Upgrade	Conversion of Existing GEC CTGs to 2x1 GE 7F.03 with .05 Compressor / AGP Upgrade	Conversion of Existing GEC CTGs to 2x1 GE 7F.03 with .05 Compressor / AGP Upgrade
Resource Option ID	--	17	17	18	18
Case Number	--	17A	17B	18A	18B
Annual Capacity Factor	%	35%	80%	35%	80%
Starts Per Year	Count	325	5	325	5
Number of Full Time Equivalent Personnel	Count	17	17	19	19
Reference Year for Cost Estimates	Year	2021	2021	2021	2021
Net Plant Output (Note 1)	MW	318	318	638	638
Annual Net Generation	MWh / year	973,762	2,225,741	1,956,108	4,471,104
Fixed Costs, Annual	$1000 / year	3,687	3,687	4,703	4,703
Variable Costs, Annual	$1000 / year	4,658	6,125	9,173	11,943
Total O&M Costs, Annual	$1000 / year	8,345	9,811	13,876	16,647
Fixed Costs, Annual	$ / kW-year	11.61	11.61	7.37	7.37
Variable Costs, Annual	$ / MWh	4.78	2.75	4.69	2.67

Notes:

1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for CC units.
2. Different cases with the same Resource Option ID represent different capacity factors.

C.5 Nuclear Generation Resources

A nuclear generating plant can provide both carbon-free baseload energy and, if contractually provided, the flexibility to adjust generation to compensate for variable grid demands and variable renewable generation.

The range of potential nuclear resource options includes both traditional large light water reactors (LLWRs) and new small modular reactor (SMR) technologies. However, only the SMR technologies were considered for the IRP. This is primarily because JEA has already committed to purchase a large amount of power from a new nuclear resource that utilizes the LLWR technology, namely 200 MW from the new Vogtle 3 and 4 nuclear generating units that utilize the AP1000 technology at 1,117 MW each. Its also because while LLWRs are still being constructed internationally, LLWRs are becoming less common in the United States due to the large capital cost and extended construction schedules. Vogtle is the only new LLWR scheduled to enter service in the region within the next 10 years. SMR based resources include those using the light water reactors typically less than 300 MWe and non-light water micro-reactors that are typically less than 10 MWe. These would be less capital-intensive than LLWRs and could be pursued by JEA in the future either directly or by participating in an ownership opportunity or in a PPA with a nuclear utility developer.

C.5.1.1 Large Light Water Reactors

LLWRs are the most prevalent of the current nuclear operating fleet in the United States. LLWRs in the United States consist of both Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs). While the current operating fleet is composed of Generation III (Gen III) reactors, which have active safety components and require emergency diesel generators for support of the active safety equipment, any new LLWRs constructed in the future would be Generation III+ (Gen III+) reactors that have passive safety features. Gen III+ reactors rely on passive safety features, such as gravity drainage and passive heat transfer. Active systems are used to back-up the passive safety features but do not have to be safety related. Because of the added passive safety features, the Gen III+ reactors are typically an order of magnitude safer (in terms of core damage frequency or CDF) than the current fleet of Gen III reactors.

There are several LLWR technologies that have been licensed by the NRC, including the Gen III Advanced Boiling Water Reactor (ABWR), the Gen III+ Advanced Power Reactor 1400 (APR1400), the Gen III+ Advanced Passive 1000 (AP1000), and the Gen III+ Economic Simplified Boiling Water Reactor (ESBWR). The two primary Gen III+ LLWR technologies that are licensed by the NRC and have been issued Combined Licenses (COLs) are the Westinghouse AP1000 and the General Electric-Hitachi Nuclear Energy ESBWR. Any new LLWRs built in the United States in the next 15 to 20 years would likely be either AP1000 or ESBWR units.

C.5.1.1.1 Westinghouse AP1000

The AP1000® Plant is a two-loop pressurized water reactor (PWR) that uses a simplified approach to safety. With a gross power rating of 3,415 megawatt thermal (MWt) and a nominal net electrical output of 1,110 megawatt electric (MWe), the AP1000® Plant, with a 157-fuel-assembly core, is suitable for new baseload generation.

Simplifications in overall safety systems, normal operating systems, the control room, construction techniques, and instrumentation and control systems provide a plant that is easier and less expensive to build, operate and maintain. Plant simplifications yield fewer components, cable, and seismic building volume, all of which contribute to considerable savings in capital investment, and lesser operation and maintenance costs. At the same time, the safety margins for the AP1000® Plant have been increased over currently operating plants.

The AP1000® PWR is comprised of components that incorporate many design improvements distilled from 50 years of operating nuclear power plant experience. The reactor vessel and internals, steam generator, fuel and pressurizer designs are improved versions of those found in currently operating Westinghouse-designed PWRs. The reactor coolant pumps are canned-motor pumps, the type used in many other industrial applications where reliability and long life are requirements.

Note, while AP1000 units have been constructed and are in operation in China, the two units at the Vogtle site in Georgia are still in the final stages of construction and start-up testing. Two AP1000 units that were being built at the V.C. Summer site in South Carolina have stopped construction due to cost overruns.

C.5.1.1.2 General Electric-Hitachi ESBWR

The Economic Simplified Boiling Water Reactor (ESBWR) is a 1,520 MWe Generation III+ boiling water reactor. Certified by the NRC in 2014, the ESBWR has the lowest core damage frequency (industry standard measure of safety) of any Generation III or III+ reactor and can safely cool itself with no AC electrical power or human action for more than seven days.

Using natural circulation, the ESBWR has 25 percent fewer pumps and mechanical drives than existing active safety plants. The ESBWR is projected to have the lowest operating, maintenance, and staffing costs per megawatt hour of any LLWR reactor technology currently available.

C.5.1.2 Small Modular Reactors

SMRs can be subdivided into Generation III+ (Gen III+) light water reactors (LWRs) and Generation IV (Gen IV) advanced reactors. Gen III+ reactors are similar to the existing (large) Gen III reactors that are operating in the fleet but have reduced capacity and advanced features that are incremental improvements from existing technology. Therefore technology risks with Gen III+ SMRs are expected to be limited. Gen IV reactors are different from the existing fleet and may have technology risks that could impact the long-term operability of new designs. It is assumed that Gen III+ SMRs can be economically implemented with commercial operation dates (CODs) beginning in 2030 and Gen IV advanced reactors (both SMRs and micro-reactors) can be economically implemented with CODs beginning in 2035. JEA would need to initiate project work at a minimum of eight years ahead of the planned COD. For example, assuming a desired 2035 COD, JEA would need to begin development in 2027. If JEA pursues incremental nuclear capacity additions through a PPA, this full development timeline would be different.

The following SMR nuclear generation options were considered as Resource Options:

- Small Modular Reactor (LWR Designs)
  - NuScale Power Module™
  - General Electric-Hitachi (GEH) BWRX-300
  - Holtec SMR-160
- Nuclear Advanced Reactors (non-LWR Designs)
  - Kairos Power FHR
  - TerraPower Natrium Reactor
  - X-energy Xe-100
  - Terrestrial Energy Integral Molten Salt Reactor (IMSR®)
- Nuclear Advanced Micro-Reactors (non-LWR Designs)
  - Oklo Power LLC
  - General Atomics
  - HolosGen
  - NuGen
  - Westinghouse eVinci
  - X-energy

Early adoption of SMRs may include added First of a Kind (FOAK) design / development costs from the reactor OEMs that would increase the cost of these Resource Options. Waiting for the nuclear Resource Options to mature further would reduce implementation costs, solidify the supply chain, and provide more schedule certainty. The time that this takes will depend on the market demand for nuclear technology. The primary driver hindering SMR development has been low natural gas prices.

Gen III+ SMRs are all light water reactors and use conventional BWR or PWR fuel like the existing fleet. The following provides a technology overview of three SMRs that would be available for a 2030 COD.

C.5.1.2.1 NuScale

NuScale originally developed the integral PWR (iPWR) to be a standalone reactor with a capacity of approximately 50 MWe. To take advantage of greater economies of scale, NuScale has designed a plant around having multiple reactor modules that can be operated depending upon the load requirements. NuScale's scalable design (power plants that can house up to four, six, or 12 individual power modules) offers the benefits of carbon-free energy and reduces the financial commitments associated with gigawatt sized nuclear facilities. A fully factory fabricated NuScale Power Module™ (NPM) generates a gross output of 50 (or 77) MWe using a safer, smaller, and scalable version of pressurized water reactor technology (the greater output resulted from NuScale uprating the reactor power to improve the $ / MW capital cost).

- Original power module = 160 MWth, 50 MWe
- Each NPM-20 module = 250 MWth, 77 MWe (gross)
- Up to 12 modules in a single Reactor Building
- NPM 4-Module Plant – 308 MWe
- NPM 6-Module Plant – 462 MWe
- NPM 12-Module Plant – 924 MWe

C.5.1.2.2 GEH BWRX-300

The BWRX-300 is a 300+ MWe water-cooled, natural circulation SMR with passive safety systems. As the tenth evolution of the Boiling Water Reactor (BWR), the BWRX-300 represents the simplest BWR design since GE began developing nuclear reactors in 1955.

The BWRX-300 is based on the NRC-licensed, 1,520 MWe ESBWR and is designed to provide clean, flexible baseload electricity generation that is competitively priced and estimated to have the lifecycle costs of typical natural gas combined-cycle plants targeting $2,250 / kW for NOAK (nth of a kind) implementations.

The BWRX-300 has the following benefits and features:

- Mitigates loss-of-coolant accidents (LOCA) enabling simpler passive safety
- Projected to have reduced capital cost per MW when compared with typical water-cooled SMR
- Steam condensation and gravity allow BWRX-300 to cool itself for a minimum of seven days without power or operator action
- Uses existing GNF2 fuel that is the primary BWR fuel in the current operating fleet, therefore, no fuel development program is required

C.5.1.2.3 Holtec SMR-160

The Holtec SMR-160, developed by Holtec International, is a small modular reactor designed to produce 160 megawatts of electricity using low enriched uranium fuel. The SMR-160 is a pressurized water reactor (PWR) with passive safety systems. The reactor, steam generator, and spent fuel pool are located in containment with the reactor core well below grade. The SMR-160 was sized so that it would be possible to use either conventional cooling towers or air-cooled condensers for sites that have limited water.

C.5.1.2.4 Study Basis

The study basis parameters for the SMR LWR Resource Options are summarized in Table C-24. Each SMR LWR Resource Option is in the pre-application stage with the United States Nuclear Regulatory Commission (NRC). Both the NuScale Power Module™ and the GEH BWRX-300 designs have a licensing advantage because the NPM-20 is the uprated version of the NuScale design that has gone through the design certification process and the BWRX-300 is a derivative SMR plant based on the larger ESBWR LWR design that has been through design certification. All three of the SMR LWR Resource Options below are also currently in the Canadian Nuclear Safety Commission (CNSC) Vendor Design Review (VDR) process. Therefore, the three SMR LWR Resource Options can be deployed in a broader North American fleet that could provide both capital and operational savings.

Table C-24 - Study Basis Parameters for Small Modular Reactor Resource Options

ID	Resource Option	Plant Configuration	Plant TYPE	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
20	NuScale Power Module™	Four, six, or 12 individual power modules.	Gen III+ iPWR	160 or 250 per module	50 or 77 per module	NRC (design certification)
21	General Electric-Hitachi (GEH) BWRX-300	Water-cooled, natural circulation Small Modular Reactor (SMR) with passive safety systems.	Gen III+ BWR	870	300+	NRC (pre-application)
22	Holtec SMR-160	Small modular reactor designed to produce 160 megawatts of electricity using low enriched uranium fuel.	Gen III+ PWR	480	160	NRC (pre-application)

C.5.1.3 Advanced Reactors

The Gen IV or advanced reactors are still in development, with the technology developers working on the reactor technology, fuel technology, and nuclear licensing. While there are two technologies that were selected for the Department of Energy (DOE) Advanced Reactor Demonstration Project (ARDP) with a goal for a 2028 COD, a more likely date for commercially available reactors would be 2035.

C.5.1.3.1 Kairos Power FHR

The Kairos Power fluoride salt-cooled high temperature reactor (KP-FHR) is a novel advanced reactor technology that is cost competitive with natural gas in the United States electricity market and to provide a long-term reduction in cost. Higher process temperature allows for industrial heating in addition to power production. The KP-FHR plant uses accident tolerant TRISO fuel to provide a high-degree of fuel safety. Use of TRISO fuel in the FHR plant also eliminates the complicated chemical processing plant that is required for more conventional Molten Salt Reactor (MSR) plants.

C.5.1.3.2 TerraPower Natrium Reactor

The TerraPower Natrium™ technology consists of a cost-competitive sodium fast reactor combined with a molten salt energy storage system. This combination will provide clean, flexible energy and stability, and integrate into power grids. TerraPower and GE-Hitachi Nuclear Energy developed the Natrium technology with a 345 MWe sodium fast reactor. The integral salt storage allows the unit to produce a peak of 500 MWe for a period of 5.5 hours when needed to help balance renewables or supply peak demands.

C.5.1.3.3 X-energy Xe-100 Reactor

X-energy's reactor designs are based on HTGR technology — a Gen-IV reactor technology with a proven operational pedigree. The Xe-100 plant is modular and scalable with up to 4 modules per group and is helium cooled with TRISO fuel.

C.5.1.3.4 Terrestrial Energy Integral Molten Salt Reactor

The Integral Molten Salt Reactor (IMSR®) uses a molten salt as coolant and fuel. Molten salts are thermally very stable, which permits lower pressure and high temperature operation.

When a molten salt coolant and molten salt fuel are used in combination, the reactor has the potential to incorporate the characteristics of passive and inherent reactor safety. Operating at greater than 44 percent thermal efficiency, an IMSR® power plant generates 195 megawatts of electricity with a thermal-spectrum, graphite-moderated, molten-fluoride-salt reactor system. It uses standard nuclear fuel, comprising standard-assay low-enriched uranium (less than 5 percent 235U), critical for near-term commercial deployment. The IMSR® does require a chemical processing plant to remove the "spent" nuclear fuel from the molten salt.

C.5.1.4 Micro-Reactors

Like the Gen IV or advanced reactors, micro-reactors are still in development, with the technology developers working on the reactor technology, fuel technology, and nuclear licensing. Several Gen IV developers are developing the same technology in both SMR and micro-reactor sizes to address different segments of the industry.

Some of the early micro-reactors are being developed for DoD applications and may take advantage of High Assay Low-Enriched Uranium (HALEU) fuel or higher enriched fuels. Micro-reactors at DoD facilities will have inherent security and security response capabilities that non-DoD facilities would not have and therefore may be able to use higher enriched fuel. Micro-reactors may be connected to the grid, but also can serve in micro grids to supply power to more remote areas or as backup power sources for critical power infrastructure needs. Some of the designs are intended to be a form of nuclear battery that can provide remote power for a period of 10 or more years before replacement. While there are several technology developers that are actively pursuing the development of micro-reactors for remote locations and for DoD applications, not all of these technology developers may be successful in the marketplace. However, the need for reliable remote power and green reliable power for DoD applications will lead to development and eventual commercialization. These advanced micro-reactors should be available commercially starting in 2035.

Because of the wide range in Gen IV technologies, a technology overview will not be presented for each of the five micro-reactor Resource Options. By 2035, there should be several commercially available and economically viable options in the <10 MWe size range that could be deployed to meet energy needs in JEAs generation fleet. It would also be possible to purchase power or to partner with others on the development of these micro-reactors.

C.5.2 Study Basis

Study basis parameters for the Advanced Reactor Resource Options are summarized in Table C-25. All have received some level of funding and / or have current customer interest. The four SMR advanced reactor Resource Options represent the most probable advanced reactor designs that could be developed by a utility in the United States market based on the current development and licensing status. All four of the advanced reactor Resource Options are in the pre-application stage with the NRC. The X-energy and Terrestrial Energy advanced reactor Resource Options are also currently in the CNSC VDR process.

Table C-25 - Study Basis Parameters for Advanced Reactor Resource Options

ID	Resource Option	Plant Configuration	Plant Type	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
23	Kairos Power FHR	Salt-cooled high temperature reactor; Higher process temperature allows for industrial heating in addition to power production.	Gen IV FHR	311.1	140	No Pre-Application Status with NRC
24	TerraPower Natrium Reactor	Sodium fast reactor combined with a molten salt energy storage system.	Gen IV Sodium Cooled Fast Reactor	767 est.	345	No / Pre-Application Status with NRC
25	X-energy Xe-100	Modular and scalable with up to 4 modules per group.	Gen IV HTGR	200 per module 800 per 4 module plant	80 per module 320 per 4 module plant	No / Pre-Application Status with NRC
26	Terrestrial Energy Integral Molten Salt Reactor (IMSR®)	Molten salt as coolant and fuel that permits lower pressure and high temperature operation.	Gen IV MSR	443	195	No / Pre-Application Status with NRC

C.5.2.1 Advanced Micro-Reactors

Study basis parameters for the nuclear Advanced Micro-Reactor Resource Options are summarized in Table C-26. Note, some of the early micro-reactors are being developed for Department of Defense (DoD) applications and may use High Assay Low-Enriched Uranium (HALEU) fuel or higher enriched fuels. Micro-reactors at DoD facilities will have inherent security and security response capabilities that non-DoD facilities would not have and therefore may be able to use higher enriched fuel. Micro-reactors may be connected to the grid, but also can serve in micro grids to supply power to more remote areas or as backup power sources for critical power infrastructure needs. Some of the designs are intended to be a form of nuclear battery that can provide remote power for a period of 10 or more years before replacement. While there are several technology developers that are actively pursuing the development of micro-reactors for remote locations and for DoD applications, not all of these technology developers may be successful in the marketplace. However, the need for reliable remote power for DoD applications will lead to the development and eventual commercialization of the technology. These advanced micro-reactors are anticipated to be available commercially beginning in 2035.

Table C-26 - Study Basis Parameters for Advanced Micro-Reactors

ID	Resource Option	Plant Configuration	Plant Type	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
27	Oklo Power LLC	Heat is transported using heat pipes that function as thermal superconductors.	Sodium-cooled fast reactor	4	1.5	COL Application submitted to NRC
28	General Atomics	Modular autonomous system	Gas-cooled reactor	N/A	10	No / Pre-Application Status with NRC
29	HolosGen	Distributable modular nuclear power generator	Liquid metal	N/A	3 per module 13 in Holos Quad plant	No
30	NuGen	Compact and versatile configuration	Fission fuel core integrated into jet engine	N/A	1-3	No
31	Westinghouse eVinci	Micro reactor	Solid Core Heat Pipe Reactor	N/A	1-5	No / Pre-Application Status with NRC
32	X-energy	Mobile Microreactor Project – Xe Mobile	HTGR	N/A	1 to 5	No / Pre-Application Status with NRC

C.5.3 General Assumptions

C.5.3.1 General Site Assumptions

In addition to the study basis parameters provided in the tables above, general site assumptions employed by Black & Veatch for these Resource Options include the following:

- The site has sufficient area available to accommodate construction activities including office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, service, and fire water will be supplied from the local water utility.

- Cooling water, if required, will be supplied from the local water utility, and is expected to be municipal reclaim water with well water backup.
- Wastewater disposal will utilize local sewer systems or existing JEA infrastructure.

C.5.3.2 Capital Cost Estimating Basis

Screening-level capital cost estimates were developed for each of the Resource Options evaluated. The capital cost estimates were developed based on Black & Veatch's experience on projects either serving as engineering, procurement, and construction (EPC) contractor or as owner's engineer (OE). Capital cost estimates are market-based and are based on recent and on-going experiences. The market-based numbers were adjusted based on technology and configuration to arrive at capital cost estimates developed on a consistent basis and reflective of current market trends.

The estimates presented herein have been developed using recent historical and current project pricing and then adjusted to account for differences in region, project scope, technology type, and cycle configuration. The basic process flow is as follows:

- Leverage confidential and proprietary information, including in-house database of project information from EPC projects recently completed and currently being executed as well as EPC pursuits currently being bid and our knowledge of the market from an OE perspective to produce a list of potential reference projects based primarily on technology type and cycle configuration.
- Review differences in region and scope.
- Exclude references that differ significantly from study basis.
- Adjust the remaining references by categorizing into several cost categories and accounting for differences such as major equipment pricing, labor, and commodities escalation.
- Scale the remaining reference projects by generating a scaling curve and compare. That scaling curve forms the basis for the screening-level capital cost estimates and is ultimately used to arrive at the EPC capital cost estimate.

The estimating process described above maximizes the value of past experiences and reduces bias resulting from project outliers such as differences in scope and location with the objective of providing current market pricing for generic power projects in and around the JEA service territory.

Capital cost estimates are based on site development, under fixed, lump sum EPC contracting. Cost estimates are overnight estimates (i.e., excluding escalation and finance costs) and are presented on a mid-year 2021 United States dollars basis. EPC cost estimates are based on Black & Veatch's knowledge of current market trends.

Financing fees and interest during construction will be captured as part of the fixed charge rate that will be applied during the LCOE screening and other analysis of the Resource Options in the IRP and are therefore not included in the capital cost estimates developed as part of this Characterization of Resource Options report. Land costs, supporting infrastructure (e.g., gas delivery upgrades, transmission upgrades, and water and wastewater upgrades), taxes, project management costs, and OE costs, are considered to be Owner's Costs and need to be added to the EPC cost estimates to arrive at a total installed cost. A listing of potential Owner's Costs is provided in Table C-15. Owner's Cost percentages are estimated for the North Jax site and the GEC site, and applied to capital costs as appropriate. Typically, Owner's Costs may be equivalent to 20 to 50 percent of the project's EPC contract cost.

C.5.4 Summary of Capital and O&M Cost Estimates

Developers of new generation focus on both cost and schedule certainty from a reactor technology; however, costs for new nuclear can vary significantly. When reviewing new build cost data, the most significant issue is the relatively low amount of input data as very few new reactors have been built in the United States. Cost data from international projects is available, but it is not likely to represent what the cost of new nuclear will be in the United States. In international countries that have continued to build new nuclear in a repetitive manner, state-sponsored or state-controlled supply chains and construction entities have assisted in the delivery of the units. In the United States, consistency in the cost and schedule certainty of new nuclear is important and will need to be developed through execution and repeat projects. The global push to decarbonization may assist with having more repeat projects to improve learning and future delivery performance.

LLWR plants have significant capital costs. Not only is the nuclear technology expensive but the BOP and site infrastructure costs to support the large plants are also expensive. The previous target for LLWR plants during the early 2000s was $4500 / kW; however, recent LLWR construction has not been able to achieve this target. Most new plant construction has resulted in cost overruns nearly doubling the original cost of the units. This is evidenced by capital costs of approximately $9,000 / kW for recent LLWR AP1000 nuclear plant projects in Georgia and South Carolina. As a result, the AP1000 units in South Carolina have been cancelled due to these cost overruns. The AP1000 units in Georgia at the Vogtle site are in construction and costs are likely to go up further due to delays. The final cost for the Vogtle units will likely be more than $9,000 / kW before they are fully commercial.

LCOE values for LLWR range from $100 / MWh on the lower end to values of $160-180 / MWh on the upper end.

Capital costs and LCOE values for SMRs and advanced reactors can be estimated; however, actual as-built and actual operating values are not available. The following provides information on anticipated costs for various SMR and advanced reactor technology. Advertised capital costs and LCOE values should be reviewed carefully to understand the cost assumptions that went into development. Nth-of-a-kind (NOAK) figures are often presented that make optimistic assumptions about cost savings for NOAK units that may or may not be realized.

NuScale NPM-20 has an NOAK overnight capital cost of approximately $3,600 / kW, backed by AACE Class IV cost estimates. The cost estimate for NuScale increased from $1,200 / kWe, an early preconceptual cost estimate, to $5,078 / kWe (2014$) in Fluor's estimates prior to the uprating to the NPM-20 size. The target LCOE for NuScale's first 12-module power plant is $65 per megawatt hour. [Reference: NuScale website] An estimate of the NuScale NOAK LCOE is in the range of $51 / MWh–$54 / MWh calculated using NuScale's design estimates.

For the BWRX-300, the NOAK overnight capital cost is in the range of $4,000 / kW. The BWRX-300 LCOE is in the range of $44–$51 / MWh. This LCOE was calculated for the NOAK BWRX-300 using GE-Hitachi's (GEH's) design-to-cost and target pricing input.

A cost summary for SMR advanced reactors is provided in Table C-27. The average costs below are reasonable for NOAK costs. FOAK and early plants will be higher as discussed previously. Costs for micro-reactors on a per kW or per MWh basis may be greater than this due to the smaller output; however, some of the micro-reactors will have low BOP costs and lower operational costs, which may bring the levelized costs down. Limited data are available to support validation of these cost values for micro-reactors.

Table C-27 - Cost Summary for SMR Advanced Reactors

Cost	Average	Minimum	Maximum
Capital Cost Total	$3,782 / kW	$2,053 / kW	$5,855 / kW
Operating Cost Total	$21 / MWh	$14 / MWh	$30 / MWh
Levelized Cost of Electricity	$60 / MWh	$36 / MWh	$90 / MWh

The average levelized cost of electricity (LCOE) of $60 / MWh from the Energy Options Network (EON) study participants is 39 percent less than the $99 / MWh expected by the United States Energy Information Agency for PWR nuclear plants entering service in the early 2020s.

An important consideration in the cost review of nuclear plants is that they are expected to have a minimum design / operating life of 60 years. Similar to the existing operating fleet, many of the LWR SMRs and the advanced reactors would be capable of additional life extension, likely out to 80 years. This is significantly longer than the operational life of other generation technologies.

C.6 Hydrogen

C.6.1.1 Technical Characteristics

Hydrogen is a versatile chemical substance globally used across numerous industries and is being considered to be a leading low-carbon fuel for power generation. Currently, hydrogen is primarily used in refining, petrochemical, and commodity chemical industries. However, it is also being used to a minor extent as a transportation fuel in fuel cell electric vehicles and has been used for long-duration energy storage applications. The hydrogen value chain is depicted in Figure C-1 below to demonstrate the wide variety of feedstocks, production processes, and end uses for hydrogen.

The most common forms of hydrogen are "green" hydrogen generated from electrolysis and "blue" hydrogen generated from steam methane reforming (SMR) coupled with carbon capture, utilization, and storage (CCUS) technologies.

C.6.1.1.1 Electrolysis

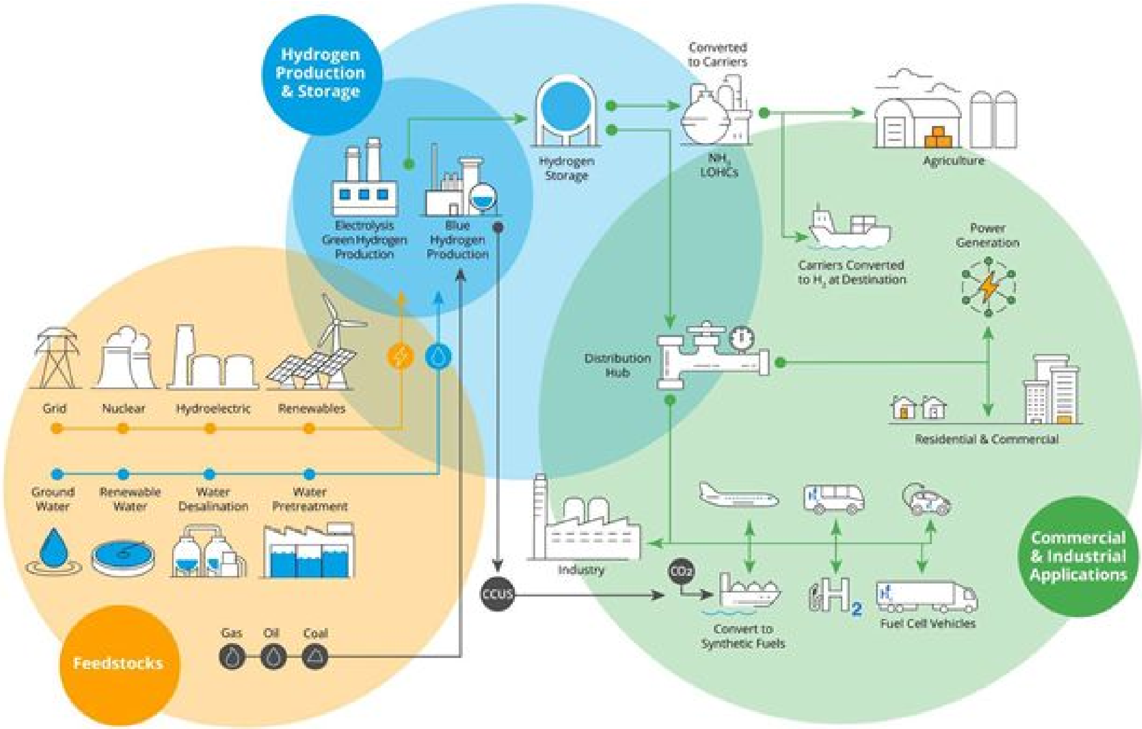
Electrolysis is the process of splitting water into hydrogen and oxygen using electricity in an electrochemical cell. Electrolyzers come in a variety of capacities and chemistries, but the fundamental concept remains the same. Electrolyzers have electrodes (i.e., anodes and cathodes) separated by an electrolyte. The combination of electrodes and electrolyte vary by the type of chemical reactions taking place. Unlike SMR, electrolyzers are considered "green" sources of hydrogen when the electricity consumed is provided by a renewable energy resource. Instead of using carbon as an energy carrier, electrolysis-derived hydrogen uses the splitting and combining of water. There are two primary types of electrolyzers: proton exchange membrane (PEM) and alkaline water electrolysis (AWE).

PEM electrolyzers exchange a proton through the electrolyte between the electrodes. In a PEM electrolyzer, water is split into oxygen and hydrogen, with the hydrogen ions traveling from the anode to the cathode and exiting out the cathode side of the stack. Oxygen, in turn, exits out of the anode side of the stack. Recent research and development initiatives have optimized the catalytic activity of the cell while minimizing the amount of expensive electrocatalysts, thereby lowering the cost.[11]

[11] Vichard, L., et al. "Degradation Prediction of PEM Fuel Cell Based on Artificial Intelligence." International Journal of Hydrogen Energy, vol. 45, no. 29, 16 Apr. 2020, pp. 14953–14963., doi:10.1016 / j.ijhydene.2020.03.209.

Appendix C - New Generating Resource Options Characterization

Figure C-1 – Illustration of the Hydrogen Value Chain



AWEs fundamentally function similarly to PEM electrolyzers; however, the ion transported in the electrolyte is OH^- and travels from the cathode to the anode. The hydrogen then exits out the cathode side of the stack and the oxygen exits out of the anode side of the stack. Because AWEs have a lower current density, they also require a larger footprint compared to PEMs. However, the technology is considered more mature for large-scale hydrogen production.[12]

C.6.1.1.2 Steam Methane Reforming

In an SMR process, natural gas reacts with steam over a catalyst and in presence of heat to produce syngas, which is subsequently cleaned/upgraded (via water-gas shift and pressure swing adsorption) to hydrogen. The process can generate large quantities of hydrogen that are typically utilized in production of various petrochemicals and ammonia for fertilizers. Waste heat from the burner flue gas is recovered for feed pre-heating and boiler feed water heating and steam production. Heat for steam production is also recovered from the process gas exiting the reactor in a waste heat boiler.

SMR processes also generate large amounts of carbon dioxide emissions and without carbon capture and storage (CCS) can be counterproductive to electric utility industry efforts of generating low-carbon electricity via hydrogen fuel blending and co-firing solution (i.e., the carbon intensity of "gray" hydrogen from SMR is roughly 80 to 90 percent higher

[12] Brauns, Jörn, and Thomas Turek. "Alkaline Water Electrolysis Powered by Renewable Energy: A Review." Processes, vol. 8, no. 2, 2020, p. 248., doi:10.3390 / pr8020248.

than that of fossil-based natural gas). SMR is the most common approach for hydrogen production at scale in the industry, although autothermal reforming and partial oxidation technologies (or combinations thereof) are also used in some cases for lower cost hydrogen.

C.6.1.1.3 Hydrogen Storage and Transportation

Because hydrogen is typically produced and consumed on-demand, there is a need to store the hydrogen for later use in power generation/ energy storage applications. Hydrogen is the lightest molecular element; therefore, it can be challenging to store large quantities. Methane is approximately eight times denser than hydrogen at standard conditions on a gravimetric basis, so the pressures and temperatures required to store hydrogen in an economical manner are more extreme than that of natural gas.

Compressed hydrogen storage is the most common method of storage for industrial hydrogen consumers. Depending on the amount of hydrogen being stored, pressures can range from 2,000 to 10,000 psig with the high end of this range more suitable for small cylinders used in the transportation sector rather than large bulk tanks for industrial users. Depending on the pressure and storage volume, many smaller vessels may be more economical than one large bulk tank. Hydrogen also presents an issue with leakage. Some compressed storage applications may require special materials to line the inside of the vessel to prevent leakage.

Hydrogen liquefaction is more energy intensive than compressed storage. The storage volumes for liquefied hydrogen would be much less than the storage volumes for compressed for the same mass. However, liquefied hydrogen requires more complex auxiliary equipment and requires cryogenic temperatures, boil-off compressors, and other ancillaries. An additional consideration with the liquefaction equipment is the thermal cycling and ramp time.

Geological formations such as salt caverns, rock caverns, and depleted gas fields provide an opportunity to store large volumes of hydrogen in existing features. Conceptually, hydrogen is compressed and stored in an existing geological formation and then withdrawn for later use. Salt caverns provide the most suitable geological storage feature followed by rock caverns and then depleted gas fields as the least suitable of the three. Depending on the geological feature, upgrades such as a liner may need to be added to prevent leakage. Another consideration associated with geological storage is contamination from substances such as methane or water. Additional clean up equipment may be required depending on the geographic location and the hydrogen user quality requirements.

Pipelines are the most cost-efficient way to transport large quantities of hydrogen over long distances. There are currently approximately 1,600 miles of hydrogen pipelines installed in the United States, primarily in the Gulf Coast region, which are predominantly owned / operated by major industrial gas companies. Hydrogen pipelines are considered mature technologies and can typically cost approximately up to 10 percent more than a traditional natural gas transmission pipeline. For dry hydrogen service, the use of carbon steel is acceptable for the typical temperatures/ pressures associated most electrolysis projects. In instances where corrosive contaminants or condensate are present, a stainless-steel pipeline material would be selected instead, which can increase costs.[13]

[13] Chen, Tan-Peng. "Hydrogen Delivery Infrastructure Options Analysis." DOE Hydrogen Program, FY 2006 Annual Progress Report; March 2007, US Department of Energy, Mar. 2007, www.hydrogen.energy.gov / pdfs / progress07 / iii_a_1_chen.pdf.

One option is to blend hydrogen in the existing natural gas pipeline network, which includes more than 400,000 miles of infrastructure. It is estimated that at typical pressures and diameters associated with natural gas pipelines, approximately 21 tons of hydrogen could be stored per linear mile. Hydrogen is generally limited to 5 to 10 percent blending throughout most of the United States, primarily due to safety and pipeline integrity concerns. While greater percentages may be possible if natural gas pipelines and supporting infrastructure are converted for use with hydrogen, these costs and the required modifications are the subject of significant research and development.[14]

C.6.1.2 Hydrogen-Fueled Resource Options

The use of hydrogen as a fuel has not yet been implemented for utility scale power generation and therefore, specific hydrogen fuel Resource Options have not been evaluated for this Characterization of Resource Options report. Additional information regarding the use of hydrogen, including costs relative to natural gas units, is provided below to reflect the current state of hydrogen as a supply-side option.

Hydrogen can be utilized directly in fuel cell power generation equipment and is currently being developed for 100 percent firing in RICE / CTG equipment, although most CTG OEMs have only achieved up to approximately 60 percent hydrogen by volume with natural gas (or as part of a biogas / syngas stream fed directly to a CTG). In many cases, Black & Veatch anticipates that hydrogen co-firing will be limited to 35 percent by volume in existing plants to avoid costly modifications to the CTG island. Some of the technical challenges in hydrogen firing and / or co-firing in traditional power plants include:

- Rate of change in Wobbe index and associated monitoring equipment
- Design of mixing drum and blending skid
- Replacement of combustors, including premixing devices (e.g., flashback, fluid dynamics / pressure fluctuations, combustion stability, etc.)
- Higher density exhaust gas and air quality control implications
- Increased nitrogen oxide production
- Hazardous gas detection
- Hazardous area classification

Beyond the energy conversion system itself, hydrogen can cause embrittlement in piping, which is typically constructed from low strength carbon steel designed for lower operating stress (i.e., lower pressures or thicker pipe walls). Pressures greater than 650 psig and temperatures greater than 400°F have been demonstrated to accelerate the effects of embrittlement, particularly in high strength carbon steels and harder steels that may be present in an existing power plant. Fully welded piping is preferred for hydrogen with very limited number of flanges. In many cases, stainless steel piping is used in high cleanliness applications, such as gas turbine fuel piping; however, 304 stainless steel is more likely to embrittle while 316 stainless is the preferred grade due to better performance and greater resistance to the degradation mechanism. Additionally, firing 100 percent hydrogen can change pipe velocities by factor of 3.5 relative to natural gas on a calorific value basis and at same pressure / temperature conditions, thus plant fuel gas piping areas must increase to maintain velocity conditions. Pipe sizing impacts stress analysis, pipe hangers, pipe racks, OEM enclosures and requires the evaluation of specialty equipment in some cases.

[14] Domptail, Kim, et al. Pipeline Research Council International Inc., 2020, Emerging Fuels - Hydrogen State of the Art, Gap Analysis, and Future Project Roadmap.

Hydrogen has a higher flame temperature than that of natural gas; therefore, blending hydrogen into the fuel will result in the CTG burning at a higher temperature. This higher temperature correlates directly to a higher production of nitrogen oxide emissions (e.g., at 35 percent hydrogen in natural gas, nitrogen oxide emissions are estimated to increase by 20 percent). Steam can be injected into the CTG to reduce burner temperature and prevent increased nitrogen oxide emissions, but at a cost to efficiency. Alternatively, increased ammonia feed to the selective catalytic reduction unit may be required to keep nitrogen oxide emissions within the limits of the plant's air permit. However, other criteria air pollutants are expected to improve as a result of firing higher percentages of hydrogen.

From a decarbonization perspective, it is important to note that carbon dioxide emissions are not proportionally decreased by an increase in volumetric hydrogen in the fuel. Because carbon emissions are measured on a mass basis, consideration for the mass of carbon displaced by hydrogen needs to be accounted. In general, co-firing of hydrogen with natural gas up to 35 percent by volume is only anticipated to result in an approximate 15 percent reduction in GHG emissions. Greater reductions in GHG emissions will only be possible when RICE / CTG manufacturers are able to achieve suitable performance / reliability using higher blends of hydrogen with natural gas, up to 100 percent hydrogen.

C.6.1.3 Capital and O&M Costs

Capital, O&M, and levelized costs associated with different types of power generation with hydrogen, similar to liquid and gaseous low-carbon fuels, can vary substantially depending on the production capacity, storage / transportation requirements, and range of feedstock (i.e., natural gas, electricity, water, etc.) costs. For co-firing hydrogen in an existing power plant up to 35 percent hydrogen by volume (corresponding to an LHV of 666 BTU / scf or 75 percent of the volumetric energy density of pure natural gas), these systems should be modeled in the same manner (e.g., capacity, capital / O&M costs, heat rate, etc.) as traditional natural gas fueled plants with the main difference being in fuel pricing. However, it may be warranted to also include a $5 / kW increase in capital cost and 10 percent increase in variable O&M costs to account for minor modifications in air quality control equipment and associated reagent consumption.

For a greenfield power generation station with 100 percent hydrogen fueling, the capital, O&M, and levelized costs are not yet well understood, given that these facilities have not been constructed or operated to-date. However, in the near term, a 10 percent increase in capital cost would be considered (relative to natural gas fueled plant) and 25 percent increase in variable O&M costs to account for differences in air quality control equipment differences and associated reagent consumption as well as additional regulatory requirements associated with this significant quantity of hydrogen.

With respect to hydrogen production and on-site storage fuel pricing, estimates are shown in United States dollars per MMBTU in Table C-28.

Table C-28 - Hydrogen Production and Storage Fuel Pricing

Fuel Type (Notes 1,2)	Minimum	Maximum
Green Hydrogen, 2021-2030	$55.00	$70.00
Green Hydrogen 2030+	$10.00	$24.00
Blue Hydrogen, 2021-2030	$18.00	$35.00
Blue Hydrogen, 2030+	$17.00	$26.00
Hydrogen Storage (All Options)	$2.00	$40.00
All pricing is provided in 2021 $ / MMBTU. Pricing based on Black & Veatch analysis and market data.		

C.6.1.4 Development Timeline

Large quantities of low-carbon hydrogen are not yet available to enable large-scale hydrogen power generation applications. This is anticipated to remain the case at least through 2030 while the industry continues to ramp up to address this emerging market and CTG manufacturers continue to pursue the research and development needed to enable 100 percent hydrogen fueled systems. The price of "blue" hydrogen is anticipated to fall faster over the next 10 years than the price of "green" hydrogen, primarily driven by economies of scale in the CCUS industry. However, the availability of low-cost electrolysis equipment coupled with low-cost, abundant electricity from interconnected renewable energy resources are expected to drive low prices for "green" hydrogen in the 2030 to 2045 timeframe and beyond.

C.6.1.5 Conclusions

The following are the major conclusions for hydrogen fuels:

- Hydrogen can be produced via numerous pathways and has utility across many different end use applications. Most of the focus on low-carbon hydrogen is with respect to hydrogen produced via steam methane reforming coupled with CCUS or produced via water electrolysis using renewable energy resources.
- Co-firing of hydrogen with natural gas in existing power plants is anticipated to be limited to 35 percent by volume, which only corresponds with a 15 percent reduction in GHG emissions and 20 percent increase in nitrogen oxide emissions. Pursuit of such a project in the near-term is feasible but could be expensive relative to other decarbonization options.
- Hydrogen can be used in at large scales and is anticipated to be feasible in purpose-built 100 percent hydrogen fueled power generation stations beyond the 2030 timeframe.

D Remote Solar Siting

D.1 Background and Methodology

Black & Veatch performed a high-level siting study to identify potential sites for development of new solar electric generation facilities for Jacksonville Electric Authority (JEA) throughout the State of Florida. JEA is developing an Integrated Resource Plan (IRP), which evaluates various options for future power generation, including replacement of existing coal-generated power. In this study, Black & Veatch identifies and evaluates potential sites for development of future solar power generation for JEA. The following analysis provides a summary of potential sites for solar development identified using geographic information system (GIS) datasets for various siting factors, including environmental considerations and infrastructure access. Renewable energy generation, including solar generation, is an efficient and reliable energy generation resource that reduces carbon dioxide emissions and can effectively supplement and/or replace fossil fuel generation and is critical in the pursuit of decarbonization objectives.

The objective of this solar siting study is to assist JEA in identifying potential sites for development of approximately 4,000 Megawatts (MW) of new solar assets to replace current fossil fuel generation and support future community growth. Development of 4,000 MWs of solar generation would involve the use of approximately 24,000 to 32,000 acres of land (assuming 6 to 8 acres per MW of energy production). A certain amount of overbuild and storage is recommended to provide useful replacement generation. This study focuses on parcels capable of generating approximately 75 MW of energy to facilitate project approval and minimize timely and costly permitting processes.

When selecting sites for development, it is essential to define what resources are required to support the project, availability and cost of the land, and accessibility of a reliable electric transmission system. Though it may require investment in transmission upgrades, selection of geographically diverse new solar production sites may be prudent as it can mitigate intermittency challenges and risk of loss from environmental disasters, such as tornados, flooding and hurricanes.

In the following study, potential locations for new solar generation facilities were identified through a high-level GIS analysis. The study evaluated parcels of land across the entire State of Florida and scored each parcel for feasibility of development utilizing 22 different environmental and technical criteria. Sites were scored and ranked for having desirable development criteria. The following sections discuss the GIS-analysis method and results. Results were evaluated and summarized by county since the following study is a high-level evaluation of more than 100 potential development sites and was completed in support of the IRP.

This report did not evaluate any specific parcels or aggregate parcels that may currently be owned or considered for development by JEA and/or the City of Jacksonville. Likewise, the analysis did not consider whether the identified potential sites are available for purchase or lease. To mitigate real estate concerns, this study only evaluated sites consisting of a single parcel to minimize real estate discussions with multiple owners. Additional analyses in later phases of the site selection process should consider other real estate hurdles and/or opportunities, including opportunities for sites composed of multiple parcels.

D.2 Florida Regulatory Framework

Construction and operation of new commercial scale solar facilities in the State of Florida are subject to several federal, state and local permits, which may be applicable depending upon the project location, size and design specifications. When selecting a site, or sites, for development, it is important to consider what permits/approvals will be required because they can significantly impact project schedule and costs.

At the current siting phase of this project, Black & Veatch recommends JEA consider a Florida-specific regulatory requirement, which has an applicability threshold based upon production of the new generation facility. Pursuant to the Florida Electrical Power Plant Siting Act (PPSA) (Fla. Stat §403.501), solar power plants with a capacity at or above 75 MW are subject to a rigorous Florida Public Service Commission (FPSC) need determination review and permitting process. The PPSA is the state's centralized process for licensing large power generation facilities. Under this framework, one certification replaces all local and state permits. This certification grants approval for the location of the power plant and its associated facilities, such as a natural gas pipeline supplying the plant's fuel, rail lines for bringing coal to the site, roadways and electrical transmission lines carrying power to the electrical grid. To avoid triggering this review process a best practice is to limit each project (or phase) below 75 MW.

D.3 Environmental GIS Analysis

D.3.1 GIS Analysis Procedure

Black & Veatch's Environmental team regularly provides siting and routing services to a variety of electric utility clients. Our solar siting studies are designed to screen, evaluate, score, and rank potential site locations for future solar development.

Our team of regulatory professionals, engineers, GIS specialists, biologists and archaeologists identify and analyze environmental issues and site constraints before capital decisions are made. Analysis of environmental and sensitive resources can not only identify opportunities to streamline project timelines and minimize project environmental compliance and permitting costs, but can reduce project development costs as well.

Using data from GIS tools, desktop research, online resources, and, if applicable, conceptual design considerations, potential sites are evaluated based on specific scoring criteria to identify optimal candidate sites. Scoring criteria emphasize critical aspects of the siting region and potential sites based on environmental suitability for constructing commercial-scale solar electric generating facilities. Criteria may include features such as to proximity to existing infrastructure like electric transmission lines, substations, natural gas pipelines, railways, and highways; permitting requirements; and site condition/constructability considerations, such as land cover, topography, soil conditions, floodplains, wetlands, global horizontal irradiance (GHI), parcel size, and property ownership.

For the following study, site selection criteria were defined to identify, evaluate and score each potential site for development of solar generating facilities. Best professional judgment was used to select the relative desirability of each criterion. Scores for each criterion were ordered with 9 being most desirable and 1 or 0 being least desirable for proposed site development. Site selection criteria are defined in Attachment A, Solar Site Selection Scoring Criteria. Potential sites identified through this process have higher scores, and are thus ranked higher for site selection since they have been defined as having favorable conditions for ease of design, constructability, and environmental permitting/approvals.

Note the following GIS analysis was based upon high-level publicly available datasets. A high-level GIS analysis can identify absence/presence and proximity of various constraints and resources, and serves as useful first step in the site selection process.

D.3.2 GIS Analysis Results

The following section summarizes results of the GIS analysis.

Florida is mostly flat with generally gentle slopes in areas (i.e., >15%), making ideal ground conditions for solar development. Much of the landscape is characterized by rivers, small waterways and wetlands, which are often associated with flood risk and additional permitting hurdles; therefore, identification and avoidance of these features is recommended during the site selection process. Florida is also characterized by forested areas with dense vegetation which can make solar development challenging. Due to the geography of the siting region, this study utilized land cover as an initial siting criterion. A majority of the identified candidate sites are characterized by agricultural, pastureland or grassland land cover. Sites with forested areas are still eligible for development, but are slightly less desirable due to the cost of tree removal and potential permitting challenges.

Black & Veatch performed a high-level GIS analysis siting study to identify candidate sites for development of new solar generation of up to 4,000 MW. The GIS analysis identified 101 candidate sites in 24 counties in Florida, including 32 candidate sites in Duval County (refer to Attachment B, Florida Solar Siting Overview Map). A summary of the candidate sites identified by GIS analysis by county is found in Table D-1 below. The 101 candidate sites include a total of 51,583 acres of real estate with a total of 43,627 buildable acres (i.e., non-wetland acres). Maps illustrating the total number of sites and total number of acres identified for solar development in each county can be found in Attachment C. If all non-wetland space could be developed, these 101 sites would yield between 5,453 and 7,271 MW assuming it would take 6 to 8 acres to yield 1 MW of production. This exceeds the 4,000 MW generation goal of this study; however, it is likely there will be other site development constraints and setbacks when designing each site, as well as real estate challenges.

Twenty-one (21) of the 101 candidate sites are greater than 600 acres in size, and thus may be capable of producing 74.9 MW of power. Larger sites can be developed in smaller phases, if necessary, to stay below the 75 MW threshold. There is also the ability to aggregate smaller sites to achieve the 74.9 MW goal.

All of the 101 identified potential sites are feasible for development of new large scale solar generation facilities based upon available GIS data. All candidate sites have the following favorable site conditions/characteristics:

- Composed of a single parcel of 200 acres or larger
- Transmission lines within 1 mile
- Highway/interstate within 10 miles
- Railroad within 20 miles
- Substation within 2 miles
- Slopes of 15% or less
- No designated scenic, natural, recreational or wildlife areas onsite
- Approximately 200 acres or more of non-wetland area for development
- Approximately 200 acres or more of non-floodplain area for development
- No seismic activity concerns onsite
- No federal superfund sites recorded onsite
- No federal National Register of Historic Places (NRHP) properties onsite
- No known threatened or endangered species areas intersecting the site
- Medium to low risk of natural disasters (based on history of frequent natural disasters, such as forest fires, tornados, etc.)

Appendix D – Remote Solar Siting

- No lands owned by The Nature Conservancy (TNC) onsite

Of the 101 potential sites, the minimum distance to Jacksonville city center is 7.5 miles, the maximum distance is 348 miles, and the average distance is 129 miles.

All sites are located within 3 miles of a major highway. The average distance to a major highway is 0.5 miles; however, several sites are located immediately adjacent to a major highway.

All sites are located less than 2 miles from an existing substation. The average distance to a substation is 0.8 miles; however, at least 9 sites are located immediately adjacent to an existing substation and an additional 12 sites are within 0.25 miles of a substation.

Table D-1 - Summary of Potential Sites Identified for Solar Production in each Florida County

County	Total Number of Parcels	Total Estimated Production at 6 acres/MW	Total Estimated Production at 8 acres/MW	Total Land Area (Acres)	Total Non-Wetland Area (Acres)
Alachua	1	47	35	280	280
Bay	2	148	111	1,063	889
Bradford	1	39	29	280	231
Calhoun	3	152	114	1,073	915
Clay	4	393	295	2,553	2,360
Columbia	2	83	63	500	500
Duval	32	3,229	2,422	25,523	19,373
Escambia	6	367	275	2,394	2,204
Gadsden	3	172	129	1,094	1,033
Hamilton	2	89	67	552	535
Hernando	1	133	33	265	264
Highlands	2	87	65	536	523
Jackson	7	361	271	2,247	2,164
Lake	3	141	106	856	845
Leon	1	183	32	281	253
Liberty	2	147	110	963	879
Madison	2	79	59	493	474
Marion	6	369	276	2,276	2,212
Okaloosa	3	239	179	1,551	1,432
Orange	1	325	65	559	518
Polk	1	359	25	219	203
Sumter	3	133	99	797	796
Walton	8	465	349	3,174	2,791
Washington	5	326	244	2,054	1,955
Total	**101**	**8,065**	**5,453**	**51,583**	**43,627**
Note: The table includes total estimated energy production, total area (acres) and total buildable area (i.e., non-wetland area).					

Based upon GIS analysis, 70 parcels were identified as having favorable slope (i.e., 1 to 9%) across a majority of the site. The remaining 31 parcels have pockets of slopes slightly less favorable, <1% and/or 10 to 15%, slopes, but would not prevent development.

During visual analysis of the candidate sites, it was noted that some candidate sites were located adjacent to other candidate sites. These may pose favorable opportunities to aggregate sites to minimize construction costs, transmission upgrades and future maintenance needs. Sites would be selected and developed in phases, preferably no more than 450 acres at a time, thus targeting approximately 75 MW of energy generation.

D.4 Conclusions and Recommendations

Florida is rich with solar energy potential, and there is a legislative push to move electric utilities towards renewables. However, due to limited land availability, land-grab challenges could be encountered when multiple companies develop solar at the same time.

Environmental regulations require facilities be built to minimize impact to wetlands and environmentally sensitive areas. This siting study has assisted with the initial step in that process. Through continued thoughtful planning, ecologically sensitive areas that should be preserved and protected will be identified and potentially restored, where possible. Considerations for stormwater management, as well as long term erosion and sediment control, should also be considered when selecting sites for development.

D.4.1 GIS Results

The GIS analysis identified 101 candidate sites in 24 counties in Florida, including 32 candidate sites in Duval County. The 101 candidate sites include a total of 51,583 acres of real estate with a total of 43,627 buildable acres. If all non-wetland space could be developed, these 101 sites would yield between 5,453 and 7,271 MW assuming 6 to 8 acres/MW. This exceeds the 4,000 MW generation goal of the study.

D.4.2 Site Selection

Selection of sites for solar development should involve a multi-faceted approach, including consideration of high-level GIS data to determine feasibility of development, site availability, including purchase and lease options, electric transmission accessibility and upgrades requirements, and current and future customer needs, among other factors. Solar development of selected candidate sites will likely encounter two foreseeable challenges, including competition for desirable development sites and transmission upgrades to deliver solar energy from remote locations.

This high-level GIS analysis identifies sites that are feasible for solar development; however, it does not confirm availability, account for line loss, or interconnection agreement requirements. If a site has an estimated production greater than 75 MW, phased construction is recommended to expedite the state approval process.

Recently Environmental Justice (EJ) concerns have been raised at newly proposed solar facilities in Florida, due to their proximity to vulnerable communities. This concern could lead to growing community opposition to the development of a project and the denial of special or conditional use permits through jurisdictions. To mitigate or avoid this issue, we recommend consideration of EJ factors and proximity of community resources, such as residences, during site selection. Solar facilities can provide environmental enhancement using native, pollinator friendly plant species, protection of wildlife corridors, reduction in water use, and improvements in stormwater quality. Local economies can benefit as well through career opportunities, providing a use for unused or abandoned land which can improve the aesthetic value, property value, and overall quality of life of a community which can potentially offset some of the local or EJ concerns.

D.4.3 Recommended Next Steps

Once JEA selects sites for the first phase of solar development, Black & Veatch recommends an evaluation of local, state, and federal environmental regulatory and permitting requirements for the selected sites. A permitting evaluation will provide insight regarding the permits that will be required for construction and operation of the facility, as well as a timeline and cost estimate. This initial assessment is critically important to help ensure likely permits and approvals are identified, and that project information required for applications are developed in time to support the application schedule.

Desktop and/or onsite studies such as wetland delineation, protected species surveys, and cultural resources surveys, and initiation of applicable agency consultations, are also recommended to support the permitting process. Onsite studies can be utilized to ground-truth GIS data, update current site conditions, and identify opportunities to avoid and/or minimize impact to environmental resources through site design, and thus simplify permitting obligations. Black & Veatch has the expertise to perform many of these services and/or offer consultation on the next steps required to bring these solar projects to fruition.

Attachment A. Solar Site Selection Scoring Criteria

This attachment summarizes the environmental and technical evaluation criteria used to evaluate the siting region to identify potential sites for development. Best professional judgment was used to select the relative desirability of the criteria. Scores are ordered with 9 being most desirable and 1 or 0 being least desirable. If any criteria have site features that must be avoided for solar project development, these are noted as exclusions.

Following GIS analysis for each criterion, best professional judgement was used to apply assumptions for some criteria to ensure alignment with project needs and to arrive at a manageable list of candidate sites meeting the most favorable development conditions. Any assumptions applied are identified in the project summary report.

A. Land Cover

- Ideal: agricultural, scrub/shrub, grassland, pasture, cultivated, barren land
- Data Source: Online sources.
- Analysis Notes: None
- Scoring
  - 9: Agricultural, grassland, pastureland, barren
  - 3: Forested
  - 1: Developed (industrial/commercial, residential)
  - 0: Open water, Wetlands
- Exclusion: None

B. Proximity to existing transmission lines

- Ideal: Transmission lines along site (transecting okay especially if owned by client)
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest transmission line provided.
- Scoring
  - 9: Transect/border site
  - 3: <0.5 miles away
  - 1: 0.5 to 1 mile away
- Exclusion:>1 mile away

C. Proximity to Highway/Interstate

- Ideal: Access nearby (<1 mile)
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest highway/interstate provided.
- Scoring
  - 9: Border site and up to 1 mile away
  - 3: >1 mile and up to 10 miles away
  - 1: >10 and up to 20 miles away
- Exclusion: Transect site and >20 miles from highway or interstate

D. Proximity to Railroad

- Ideal: Near railroad but not onsite to avoid ROW agreements
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest railroad provided.
- Scoring
  - 9: <10 miles from site
  - 3: 10 to 20 miles away
  - 1: >20 miles
- Exclusion: Transect site

E. Proximity to existing substation

- Ideal: Existing substation within 1 mile of site.
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest substation provided.
- Scoring
  - 9: Existing substation within 1 mile of site
  - 3: Existing substation located >1 mile, but less than 2 miles from site
  - 1: No existing substation within 2 miles of site; therefore, project must construct new substation.
- Exclusion: None

F. Potential Site Size

- Ideal: Prefer contiguous parcels of same owner at least 200 acres, but larger the better.
- Data Sources: Online sources, Pivvot
- Analysis Notes: None
- Scoring
  - 9: >800 acres
  - 3: 500-800 acres
  - 1: 200-499 acres
- Exclusion: Less than 200 acres

G. Topography

- Ideal: less than 10% slope. A minimum 1-2% slope is preferred over 0% slope for drainage purposes.
- Data Source: Online sources.
- Analysis Notes: Topography score based on majority of parcel being of that slope category.
- Scoring
  - 9: 1-2% slope
  - 3: 3-9% slope
  - 1: <1% slope or 10-15%
- Exclusion: greater than 15% slope

H. Proximity to Designated Scenic, Natural, Recreational, or Wildlife Areas

- Definition: Parks, state or federal forests, monuments, recreational areas, wildlife areas, wilderness/wilderness study areas, wild and scenic rivers, and scenic transportation routes.
- Ideal: Outside of designated area and greater than 1 mile to avoid any indirect impacts that may complicate permitting (and/or require studies).
- Data Source: State and federal natural resource agency websites.
- Analysis Notes: None
- Scoring
  - 9: No designated areas within 1 miles of site.
  - 3: Designated areas present within 1 mile of site (but not onsite).
- Exclusion: Designated areas onsite.

I. Proximity to population center

- Ideal: Just outside of large population center
- Data Sources: Online sources and maps. Use ESRI population density areas as high-level review.
- Analysis Notes: None
- Scoring
  - 9: 0-15 miles away (just outside and within 15 miles)
  - 3: 16-30 miles away
  - 1: 31-50 miles away
- Exclusion: Inside Population Center

J. Wetlands/Waters of the US

- Definition: Jurisdictional waters of the US
- Data Source: NWI maps, online sources.
- Analysis Notes: Subtract acreage of jurisdictional wetland/waters onsite from total site size to determine how many acres of non-wetland area, i.e., usable for development, are onsite.
- Scoring
  - 9: >/=400 acres of non-regulated wetlands/waters development area onsite
  - 3: 200-399 acres of non-regulated wetlands/waters development area onsite
  - 1: < 200 acres of non-regulated wetlands/waters development area onsite
- Exclusion: None

K. Flood Potential

- Ideal: Outside floodplain, upland location to minimize flooding risk
- Data Sources: Online sources.
- Analysis Notes: Subtract acreage of FEMA 100-year floodplain onsite from total site size to determine how many acres of non-floodplain area, i.e., usable for development, are onsite.

Appendix D – Remote Solar Siting

- Scoring
  - 9: >/=400 acres of non-100-year floodplain development area onsite
  - 3: 200-399 acres of non-100-year floodplain development area onsite
  - 1: <200 acres of non-100-year floodplain development area onsite
- Exclusion: None

L. Global Horizontal Irradiance (GHI)

- Definition: GHI measures the total solar resource on a horizontal plane. Composed of three components: direct beam, diffuse horizontal irradiance and ground reflected radiation. Long term average of annual sum. Assume higher GHI is associated with higher solar resource, and therefore, yield.
- Ideal: >5.0 kWh/m2/day (FL); >4.5 kWh/m2/day (GA)
- Data Sources: Online sources and maps.
- Analysis Notes:
- Scoring
  - 9: >5.0 kWh/m2/day
  - 3: 4.5 – 4.9 kWh/m2/day
  - 1: <4.5 kWh/m2/day
- Exclusion: None

M. Proximity to airports

- Ideal: Greater than 3.8 miles from airports (FAA notification required for tall structures within 20,000 feet, i.e., 3.8 miles, of public or military airport.)
- Data Sources: Online sources.
- Analysis Notes: Prefer >3.8 miles but at least >1 mile. Do not remove any sites due to airport proximity – just influences FAA notices, glare studies, lighting requirements, etc.
- Scoring
  - 9: >3.8 miles away
  - 3: 3.8-1 miles away
  - 1: <1 mile away
- Exclusion: None

N. Existing Oil & Gas Activity

- Ideal: Avoid areas with heavy oil and gas activity
- Data Sources: Online sources. Note that data is high level.
- Analysis Notes: None
- Scoring
  - 9: Oil and gas lines >0.25 mile away
  - 3: Oil and gas lines adjacent (i.e., bordering and up to <0.25 mile away)
  - 1: Oil and gas lines transecting site
- Exclusion: None

O. Seismic Zone

- Definition: Potential for seismic activity. Fault zone.
- Data Sources: Online sources.
- Analysis Notes: None
- Scoring
  - 9: No seismic activity concerns.
  - 3: Medium probability of seismic activity.
  - 1: High probability of seismic activity.
- Exclusion: None

P. Potential for Hazardous Material Contamination

- Definition: Proximity to Superfund site (NPL – National Priority List, EPA)
- Data Source: https://services.arcgis.com/cJ9YHowT8TU7DUyn/ArcGIS/rest/services/Superfund_National_Priorities_List_(NPL)_Sites_with_Status_Information/FeatureServer
- Analysis Notes: None
- Scoring
  - 9: No Superfund (NPL) sites located within parcel.
  - 1: Superfund (NPL) site located within parcel.
- Exclusion: None

Appendix D – Remote Solar Siting

Q. Soil Corrosivity

- Definition: Degree that conditions onsite could accommodate construction and installation work. Use steel and concrete corrosivity ratings for soil.
- Ideal: low corrosivity soils
- Data Sources: USDA soils survey.
- Analysis Notes: Both Steel and Concrete Corrosivity
- Scoring
  - 9: Favorable Conditions: low corrosivity soils
  - 3: Moderate Challenges: moderate corrosivity soils
  - 1: Significant Challenges: high corrosivity soils
- Exclusion: None

R. Depth to Restrictive Layer

- Ideal: Deep, >80 inches
- Data Sources: USDA soils survey.
- Analysis Notes: None
- Scoring
  - 9: > 80 inches
  - 1: < 80 inches
- Exclusion: None

S. Cultural Resources

- Definition: Historic sites listed in the National Register of Historic Places (NRHP). Note this is not a cultural resources desktop review evaluating potential project impacts to known and/or unknown cultural resources, but rather an emphasis on available GIS data for known/listed federal sites. Does not include state-listed resources or confidential resources that must be requested from SHPO by a professional archaeologist.
- Data Source: Online sources (NPS website)
- Analysis Notes: None
- Scoring
  - 9: No listed resources onsite or within 1 mile of site. [resources >1 mile]
  - 3: No listed resources onsite but resource located within 1 mile of site.
  - 1: Listed resource onsite
- Exclusion: None

T. Documented Threatened and Endangered Species

- Definition: Critical habitat area. Species (or habitats) that are federally listed as endangered or threatened. This is not a biological desktop review but rather a high-level review based on publicly available data.
- Data Source: Online sources, USFWS IPaC
- Analysis Notes: 3 and 1 are essentially the same permitting result; therefore, prefer score of 9, but note that absence of intersecting area does not necessarily mean no threatened or endangered species or habitat may exist onsite. Would need to be confirmed with consultation and onsite investigation.
- Scoring
  - 9: No known threatened or endangered species areas intersecting parcel.
  - 3: Threatened species area intersects parcel.
  - 1: Endangered species area intersects parcel.
- Exclusion: None

U. Historical Natural Disasters

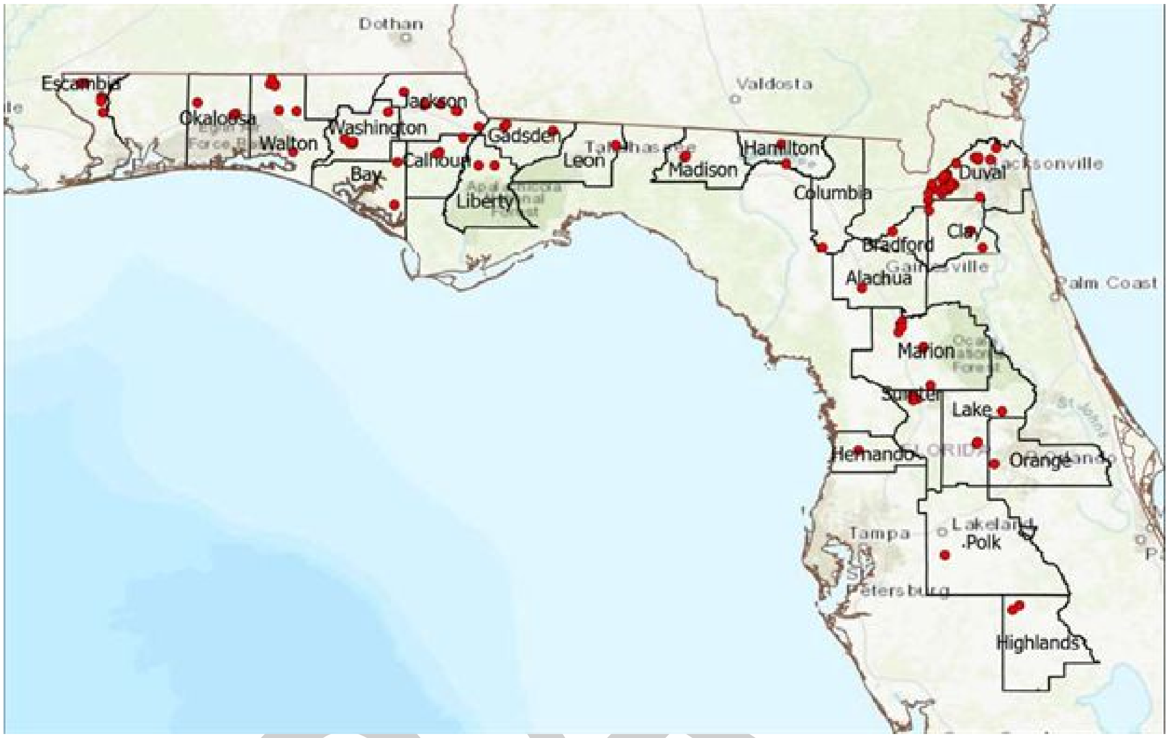
- Ideal: Avoid areas with history of frequent natural disasters such as forest fires, tornados, etc.
- Data Source: NOAA data for past 20 years.
- Analysis Notes: None
- Scoring
  - 9: Low risk of natural disasters based on historical activity.

    - 3: Medium risk of natural disasters based on historical activity.
    - 1: High risk of natural disasters based on historical activity.
- Exclusion: None

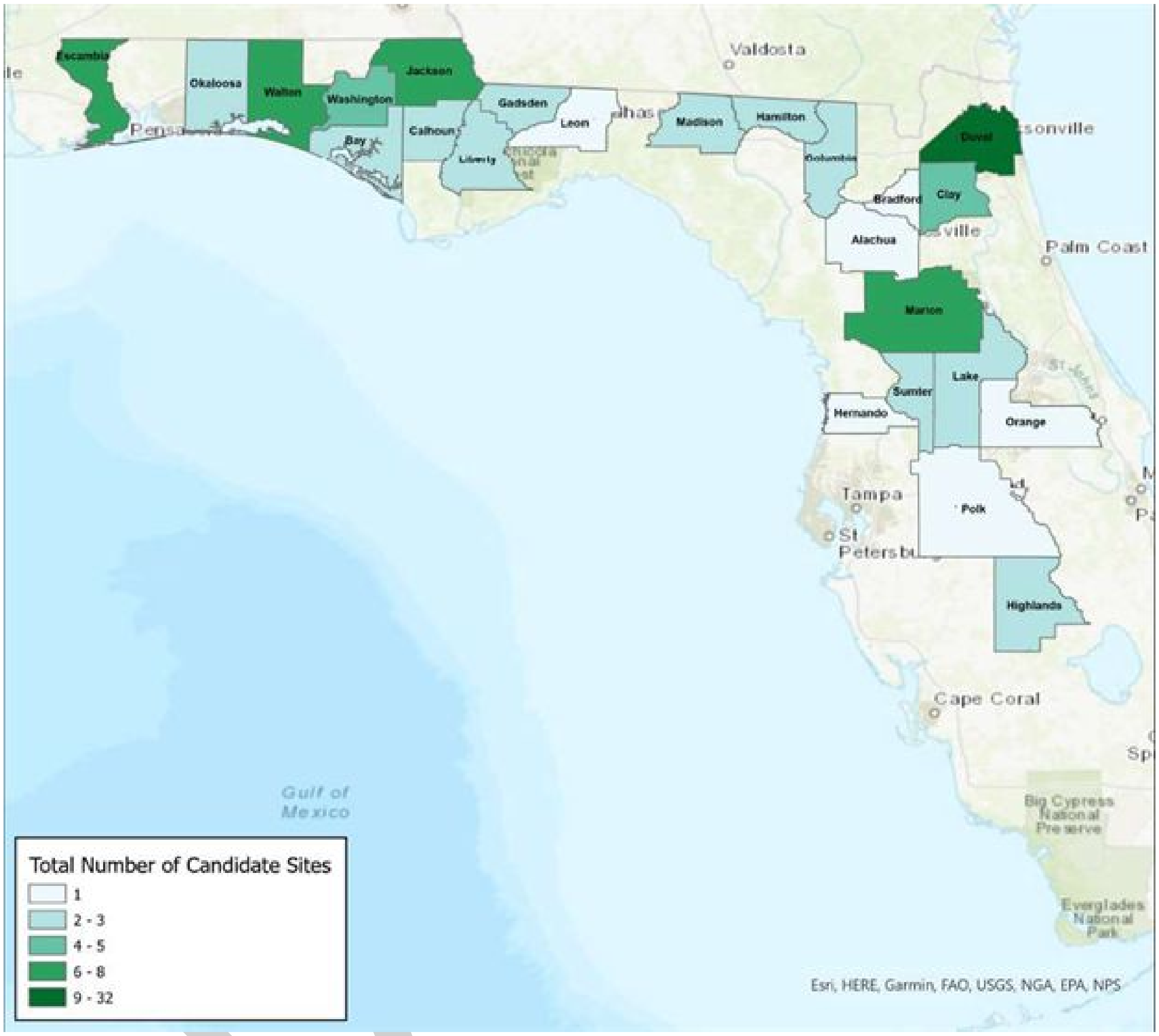
V. The Nature Conservancy

- Definition: TNC lands including conservation easements, deed restrictions, agreements, leases, permits, access right of ways, right of way tracts and transfers/assists.
- Data Source: The Nature Conservancy data, tnclands.tnc.org
- Analysis: None
- Scoring
    - 9: No TNC resources onsite. (no)
    - 0: TNC resource onsite. (yes)
- Exclusion: None

Attachment B. Florida Solar Siting Overview Map



Attachment C. Total Number of Candidate Sites per County



E Stakeholder Engagement Details

Stakeholder engagement occurred primarily through a series of formal meetings that occurred during the term of the IRP preparation. The topics and dates for the meetings were synchronized with planned key milestones of the IRP development so that feedback from the Stakeholders could be incorporated immediately into the IRP rather than after the fact. The milestones included development of the Scenarios, development of the key forecasts and supply side options that were foundational to the IRP modeling, the preliminary results of the modeling, the final results of the modeling, and identification of the most common near-term resources for possible implementation by JEA. A list of the meeting dates and topics is provided in Table E-1.

Table E-1 Stakeholder Engagement Meetings and Topics

Meeting #	Topic
1. January 2022	Introduction to JEA and the IRP Process
2. February 2022	Planned Scenarios
3. March 2022	Key Forecasts
4. June 2022	New Resource Options
5. September 2022	Preliminary PLEXOS Modeling Results
6. November 2022	Updated PLEXOS Modeling Results
7. February 2023	Final PLEXOS Modeling Results and Implementation Plan
8. May 2023	Final IRP and Implementation Plan

Appendix E – Stakeholder Engagement Details

Figure E-1 – Stakeholder Invitation Letter

Building a more reliable and sustainable community

November 24, 2021

Over the course of 2022, JEA will develop an Integrated Resource Plan (IRP) to help guide operations of the electric system that serves our community for the next twenty-plus years.

In order to properly weigh the many factors that go into serving Northeast Florida with reliable and sustainable power at a reasonable cost, we need input from a diverse set of area stakeholders. Therefore, we are forming a Stakeholder Advisory Committee to advise our IRP process. Because of your leadership role in Jacksonville and Northeast Florida, I would like to invite you to participate as a member of this Committee.

This letter provides you with some background information about the IRP, plans for convening the Committee, and contact information for learning more. I appreciate your consideration of this invitation and hope that you will add your voice to this important endeavor.

JEA's Integrated Resource Plan

The 2022 IRP will result in a comprehensive approach for meeting the forecasted energy demands of our community. JEA is responsible for looking at a range of operational, environmental, and technological considerations, while balancing the needs of a diverse set of residential, commercial, and government customers in a rapidly growing region.

As we prepare for the 2022 IRP, the Committee's review and feedback will give us valuable advice and perspectives. The IRP will consider several scenarios while addressing the following essential requirements and trends:

- System reliability, resiliency and resource adequacy
- Carbon emission reduction goals and future potential requirements
- Retirement or replacement of aging generation resources
- Integration of planned and future utility-scale solar facilities
- Land requirements and site locations for new resources
- Distributed energy resources, demand-side management, and energy efficiency
- Electric vehicle and other electrification technology
- New and emerging supply-side resource technologies
- Population growth and economic development in Northeast Florida

IRP Stakeholder Advisory Committee Roles and Responsibilities

The Committee will be invited to a series of eight meetings with JEA leaders and external subject matter experts. The meetings will provide Committee members with informational briefings about the planning considerations listed above and invite you, as a representative of your organization, to share perspectives and ask questions.

Committee participants will be asked to:

- Participate in meetings beginning in January 2022 and concluding in January 2023. These meetings will be approximately 90 minutes long and conducted in person with virtual attendance options.
- Represent your organization's interests
- Review background materials provided in advance of meetings
- Engage in positive, productive communication with other participants, the facilitator, and project staff
- Communicate disagreement respectfully
- Provide advice and input on how JEA can engage other community members on IRP matters

Please feel free to contact Laura Schepis, our Chief External Affairs Officer with questions about this invitation as well as your suggestions for the Stakeholder Advisory Committee. She can be reached at schela@jea.com. You can also reply to IRP@jea.comwith your response regarding participation. We look forward to partnering with you as we undertake this critically important initiative for our community.

Sincerely,

Jay C. Stowe
Managing Director and CEO

Appendix E – Stakeholder Engagement Details

Figure E-2 – Key Factors Considered in IRP Development

Appendix E – Stakeholder Engagement Details

Meeting #1 was held at the JEA headquarters and focused on introducing Stakeholders to JEA and the IRP process. Presenters included Jay Stowe (Managing Director and CEO); Raynetta Curry Marshall, P.E., (Chief Operating Officer); Ricky Erixton (Vice President of Electric Systems); Laura Schepis (Chief External Affairs Officer); and Brad Kushner (IRP Lead from Black & Veatch). The presentation included an overview of JEA's electric system, including historical and projected electric customer demands, historical number of customers, and historical and projected carbon emissions associated with JEA's electric generation. Key utility industry trends relevant to the IRP were also presented along with key drivers for the IRP. A preliminary timeline for completion of the IRP and future Stakeholder meetings was also covered. Stakeholder comments during and after the meeting were primarily about accounting for carbon emissions, the impact of limited battery material availability and disposal requirements, and environmental justice considerations.

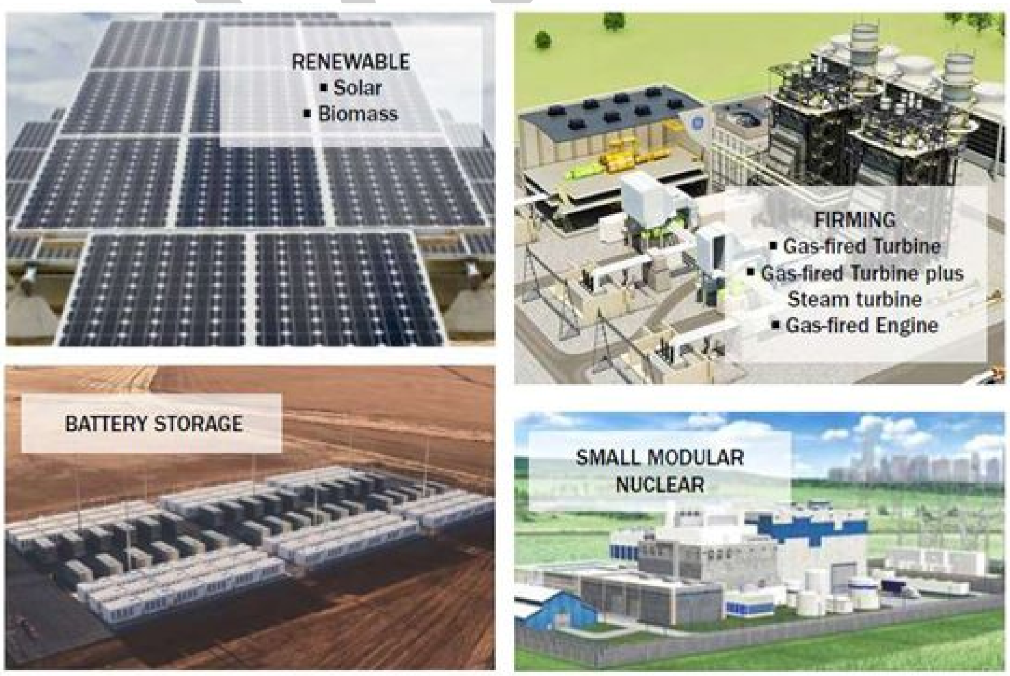
Meeting #2 was held at the JEA headquarters and focused on introducing Stakeholders to the multiple planning scenarios that were going to be studied as a foundation for the IRP. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Cantrece Jones (Stakeholder Lead from Black & Veatch); and Brad Kushner (IRP Lead from Black & Veatch). The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Several planning concepts were then presented. These included IRP variables (considered quantitatively; fuel cost, environmental regulations, cost of generating technologies, etc.) and IRP considerations (considered qualitatively; affordability, environmental justice, economic development and CO_2 emissions reductions). The concepts also included scenarios and sensitivities. A scenario is a set of simultaneous changes to multiple variables that are modeled simultaneously to reflect a potential future, whereas a sensitivity is a change to one variable within a potential future to test the sensitivity of results to that variable. The preliminary list of scenarios planned for the IRP were then presented, including Current Outlook, Economic Downturn, etc., along with the key characteristics of each.

Meeting #3 was held at the JEA headquarters and focused on presenting the key forecasts that had been or were planned to be developed for the IRP. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer), Laura Schepis (Chief External Affairs Officer); Melinda Fischer (Electric Generation Planning Manager); Brian Pippen (DSM/EE Program Manager); Felise Man (Electric Vehicle Lead for Black & Veatch); Jim Herndon (DSM/EE Lead for Black & Veatch); and Brad Kushner (IRP Lead for Black & Veatch). The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Forecasts were then presented concerning future JEA loads, electric vehicles, JEA's existing DSM/EE programs, potential new DSM/EE and customer-sited generation. The proposed scenarios were then revisited with a discussion of how different variables within each proposed scenario would change relative to the proposed Current Outlook scenario. Throughout the presentation, Stakeholder feedback was welcomed and addressed as the presentation progressed. Stakeholders were encouraged to share what they would like to see at upcoming Stakeholder meetings and how the Stakeholder experience could be improved. The Stakeholders were informed that a written report on IRP activities would be provided in mid-May given the time between the March and scheduled June meeting.

Meeting #4 was held at the JEA system operations control center (SOCC) and was focused on the new resource options that had been or were planned to be developed for the IRP. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Garry Baker (Senior Director, Energy Operations); Brad Kushner (IRP Lead for Black & Veatch); Paul Maxwell (IRP Manager for Black & Veatch); and Darren Bishop (Resource Option Lead for Black & Veatch). The meeting began with a brief visual overview of the SOCC floor, including the various operating desks and their function. A recap of the prior Stakeholder meeting was then presented, including key takeaways and post-meeting comments received from Stakeholders. The focus then shifted to the new resource options that were being studied. These included renewables (solar, solar plus storage, standalone storage, battery storage), natural gas-fired firming (gas turbine, reciprocating engine, combined cycle, and combined cycle conversion), and advanced nuclear (small modular reactor). An illustration of the new resource options presented is shown on Figure E-3. Hydrogen as a potential future fuel was also discussed. More detail was then presented on the solar options, particularly the large land need for new solar resources and the transmission to bring the solar energy to JEA loads. The availability of space at the existing JEA GEC, Northside and SJRPP sites to host the renewable and gas-fired options was also presented. The presentation then shifted to the upcoming planned scenario modeling and some sample results.

Meeting #5 was held at the JEA headquarters and was focused on presenting preliminary IRP modeling results from the PLEXOS modeling tool. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); and Brad Kushner (IRP Lead for Black & Veatch). A photograph taken during the meeting is shown on Figure E-4.

Figure E-3 – Presentation of New Resource Options



Appendix E – Stakeholder Engagement Details

Figure E-4 – Photograph of Meeting #5

The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. The focus then shifted to presentation of preliminary modeling results for the Current Outlook scenario and a sensitivity with assumptions similar to the planned Future Net Zero scenario. Results were also presented for a similar but special sensitivity that had been run in response to Stakeholder comments received prior to the meeting (Riverkeepers Sensitivity). These sets of results were intended to serve as "bookends" to illustrate how the type, quantity and timing of new resource additions could vary widely across the scenarios when the scenario modeling is completed.

Meeting #6 was held at the JEA Conservation Center and was focused on presenting updated PLEXOS modeling results. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Pedro Melendez (Vice President of Planning, Engineering & Construction); Brad Kushner (IRP Lead for Black & Veatch); and Paul Maxwell (IRP Manager for Black & Veatch).

The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Some key changes that had been made to the IRP modeling assumptions since the prior meeting were then discussed. The changes included promotion of the Riverkeepers Sensitivity to a full scenario (the "Supplemental Scenario"). This new scenario replaced the Efficiency + DER + Lower Emissions Scenario because that scenario was judged to be not significantly different than the other scenarios. Other changes included modeling of the expanded investment tax credit (ITC) provisions under the recently passed federal Inflation Reduction Act (IRA), which caused reduction of the solar PPA price forecasts and elimination of the solar plus storage resource options. Changes also included reduced energy storage costs due to expected future technology improvements and performance degradation. Modeling assumptions for each of

Appendix E – Stakeholder Engagement Details

the scenarios was then presented along with detailed modeling results. Resulting forecasts for each scenario across the entire JEA system included the type and capacity of existing and added new resource options that would be added, the energy that would be produced, the amount of CO_2 emissions that would be produced, and the total capital and operating costs to JEA. In addition to these detailed results, an analysis across the results was presented that identified the resources that appeared most frequently across all the scenarios for the first 10 years of the planning period ("Most Common Resources"). This analysis should prove useful to JEA and Stakeholders as they consider which resources to begin implementing in the near term to regardless of which potential future (which scenario) will occur.

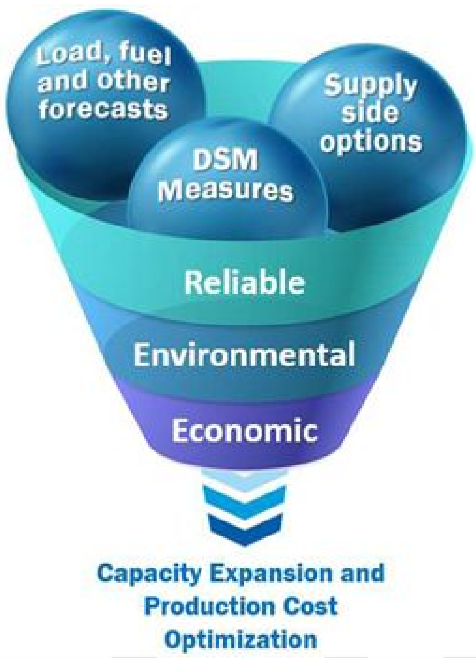
Meeting #7 was held at the JEA headquarters and was focused on presenting final PLEXOS modeling results. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Pedro Melendez (Vice President of Planning, Engineering & Construction); and Brad Kushner (IRP Lead for Black & Veatch). The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Some key changes that had been made to the IRP modeling since the prior meeting were then discussed. The key changes included increased PPA prices for the Tier 0 solar resources due to increased cost estimates of electrical transmission interconnections based on more detailed transmission system analysis and discussions with JEA transmission planning staff. The changes also included performance of six sensitivities off the Current Outlook scenario to address questions that Stakeholders had raised about the scenario modeling results presented during the prior meeting. Results for the six scenarios and the six sensitivities were presented in a similar format to results presented at the prior meeting.

Meeting #8 will be held in May 2023 and will focus on presentation of the final IRP report to Stakeholders and the general public.

F Overview of PLEXOS

Black & Veatch utilized PLEXOS to evaluate the combination of resources available to JEA to meet future demand and energy requirements in the 2022-2051 planning horizon. PLEXOS is an industry standard, capacity expansion and production cost model used by multiple utilities and other utility industry professionals to perform a variety of analysis..

Figure F-1 - PLEXOS Constrained Optimization



PLEXOS is an industry preferred model for a variety of reasons such as its ability to run scenario analysis as well as its optionality. PLEXOS has the flexibility to modify granularity, chronology, and performance targets so that the model will produce the lowest cost solution in a reasonable amount of time. The PLEXOS model performs its evaluation in four phases: Long Term (LT), Projected Assessment of System Adequacy (PASA), Middle Term (MT) and Short Term (ST). These phases can be utilized together or independently depending on the user's needs. Black & Veatch utilized all four phases for the purpose of the JEA IRP. Each Phase of the model passes the solution to the next phase.

The LT is responsible for capacity expansion. Capacity expansion refers to finding the optimal combination of existing generating resources, generation new builds, transmission upgrades, and retirements that minimizes the net present value of the total costs over the long-term planning horizon while adhering to all the constraints applied on the model. The LT was set to evaluate the entire 30-year planning horizon in one step and every day in the planning horizon was evaluated with full chronology, meaning each period of the day followed the one before it as opposed to a load distribution curve. This is important when evaluating renewables or storage resources, where the operation of these assets is time-period sensitive.

The PASA phase calculates several reliability indices and schedules planned outages. This phase of the model was only used in the JEA IRP to provide scheduled maintenance for the new generation assets.

The MT phase pre-solves the optimization problem for the ST. The MT is particularly important for items that require planning across multiple days or longer periods of time. The MT is crucial for optimizing storage, fuel supply and emissions constraints. The MT was set to evaluate an entire year per step, this was necessary given the annual constraints associated with the Future Net Zero scenario and sensitivity as well as the Supplemental scenario.

The ST model is the final and most detailed phase of the model and produces the final hourly production cost. The ST is set to evaluate 1 day per step and each hour is evaluated individually. The ST model builds on all the outputs of the other phases to produce the detailed hourly production cost.

Appendix F – Overview of PLEXOS

The fundamental objective of PLEXOS in developing the optimal capacity expansion plans within each scenario and sensitivity is to minimize the net present value of costs (systemwide production costs as well as fixed O&M and capital costs associated with new generating resource additions) over the IRP time horizon while maintaining system reliability. The model is required to carry sufficient capacity to meet annual peak demand plus reserve margin requirements and meet the annual energy requirements of the JEA system. For scenarios and sensitivities in which there are annual targets for percent of generation from renewable and/or clean energy resources (i.e., the Future Net Zero and Supplemental scenarios, and the Net Zero sensitivity), the optimal capacity expansion plans are determined by considering economic and reliability while meeting the annual targets for renewable and/or clean energy generation).

Appendix F – Overview of PLEXOS

END OF VOLUME 2

JEA Board of Directors Meeting
March 28, 2023
Public Comments

Wednesday, March 8, 2023 8:59 AM

Subject: Please Reduce Emissions and Transition to Renewable Energy

Holly Rothkopf
12575 Crystal Pointe Dr, Unit D
Boynton Beach, FL 33437
ishtenum@rocketmail.com
(561) 865-3812

Dear JEA Board Services Manager,

Since its inception the Jacksonville Electric Authority (JEA) has primarily focused on delivering affordable, reliable electricity. With the acceleration of global warming JEA should also focus on reducing its greenhouse gas emissions. It is time for JEA to reduce its dependence on fossil fuels by transitioning to renewable energy sources. As a citizen-owner and customer I am asking you to accelerate JEA's transition to clean, renewable energy sources.

Wednesday, March 8, 2023 11:01 AM

Subject: Please Reduce Emissions and Transition to Renewable Energy

Debbie Griffin
9524 Crown Prince Lane
Windermere, FL 34786
dkgriff@gmail.com
(256) 325-2583

Since its inception the Jacksonville Electric Authority (JEA) has primarily focused on delivering affordable, reliable electricity. With the acceleration of global warming JEA should also focus on reducing its greenhouse gas emissions. It is time for JEA to reduce its dependence on fossil fuels by transitioning to renewable energy sources. As a citizen-owner and customer I am asking you to accelerate JEA's transition to clean, renewable energy sources.

Wednesday, March 15, 2023 8:20 PM

Subject: Please Reduce Emissions and Transition to Renewable Energy

Margaret Reynolds
720 15th Ave N
St Petersburg, FL 33704
revmarg33@gmail.com
(727) 821-3272

Since its inception the Jacksonville Electric Authority (JEA) has primarily focused on delivering affordable, reliable electricity. With the acceleration of global warming JEA should also focus on reducing its greenhouse gas emissions. It is time for JEA to reduce its dependence on fossil fuels by transitioning to renewable energy sources. As a citizen-owner and customer I am asking you to accelerate JEA's transition to clean, renewable energy sources.

Tuesday, March 28, 2023 9:33 AM

Subject: Please Reduce Emissions and Transition to Renewable Energy

Todd Randolph
207 N Matanzas Ave.
Tampa, FL 60051
toddrrandolph@gmail.com
(815) 347-2421

Since its inception the Jacksonville Electric Authority (JEA) has primarily focused on delivering affordable, reliable electricity. With the acceleration of global warming JEA should also focus on reducing its greenhouse gas emissions. It is time for JEA to reduce its dependence on fossil fuels by transitioning to renewable energy sources. As a citizen-owner and customer I am asking you to accelerate JEA's transition to clean, renewable energy sources.

---

ph 743 9146

Roberta S Thomas
3470 Lenczyk Drive W
Jacksonville, FL 32277

Mar 3, 2023

Dear CEO/Mr Stowe + Board Members -

Can you please, please do something about this JEA rate hike for us single, old, low income users? I am 78, live alone, + only income is social security. I am money-stretched. I don't use much electricity - especially during the winter because I have propane heat. No, I can't swap to electricity because of the way the house + gas unit (only 13 inches wide) fits into my 1968 garage walls. Propane gas is outrageous price in the winter!! Amerigas over $5/gallon.

But, Sir, I don't use the base unit ?? I think you said 500 kilw. of electricity. Sir, this price increase taxes me unfairly + really HURTS my income. I try to use as little utilities as I can. I always pay my bills on time - since 1968. I monitor my usage every month. I am a LOW user of electricity.

Sir, can you please do something to lower the price hike? OR can you please do some kind of exception or waiver or reduction if we use only a low amount of electricity?

* A credit if below 500??

Sincerely -
Roberta Thomas
Sr Citizen, age 78

743-9146

Roberta Sue Thomas
3470 Lenczyk Drive W
Jacksonville, FL 32277

2023
2022
2021
2020
gas Heat
gas heat

Month and Year	USED: Water gal	USED: Electric kwh	Elec charge	sewer charge	water service	total charge				
Dec-23										
Nov-23										
Oct-23										
Sep-23										
Aug-23										
Jul-23										
Jun-23										
May-23										
Apr-23										
Mar-23										
Feb-23	2000	421	74.04	25.46	17.23	116.73			rates increase $15	
Jan-23	3000	412	67.37	30.93	18.70	117.00			x cold, then mild	
Dec-22	3000	515	77.17	30.93	18.70	126.80			mild, xx cold Xmas we	
Nov-22	3000	395	57.19	30.93	18.70	106.82			very mild, pleasant	
Oct-22	2000	455	83.05	25.46	17.23	125.74			mild, mild cold 3 nites	
Sep-22	3000	1042	186.86	30.93	18.70	236.49			9-20 hurricane Ian	
Aug-22	3000	1212	198.40	30.93	18.70	248.03			rate inc again for gas	
Jul-22	3000	1275	192.69	30.93	18.70	242.32		32	rec heat !!	rain ev day
Jun-22	3000	1180	166.70	30.93	18.70	216.33			heat wave	rec heat wa
May-22	3000	806	109.01	30.93	18.70	158.64			hot x dry	water flowe
Apr-22	3000	414	60.69	30.93	18.70	110.32			very mild	
Mar-22	4000	356	52.38	36.40	20.16	108.94		31	mild pressure washer	
~~Feb-22~~	2000	405	62.13	25.46	17.23	104.82			cold half/ veryhot half	
Jan-22	4000	534	76.45	36.40	20.16	133.01				new rates
Dec-21	3000	488	66.62	30.93	17.70	116.25			very warm	gas incr to
Nov-21	3000	380	50.85	30.93	18.70	100.48		29	mild	
Oct-21	3000	675	85.34	30.93	18.70	134.97			mild	
Sep-21	2000	972	120.07	25.46	17.23	162.76		30		
Aug-21	3000	1177	144.04	30.93	18.70	193.67			humid/hot	need to tur
Jul-21	3000	1070	131.53	30.93	18.70	181.16			hot/ humid	
Jun-21	4000	1029	126.73	36.40	20.16	183.29			mild/rain/ wash clothe	
May-21	4000	613	78.08	36.40	20.16	134.64	28/28		still fairly mild.AC, Dry	
Apr-21	3000	464	60.66	30.93	18.70	110.29			peeling paint--wash w	
Mar-21	4000	415	54.93	36.40	20.16	111.49	29/29		pressure wash a little/	
Feb-21	2000	393	52.34	25.46	17.23	95.03	29/29		cold raining /used gas	
Jan-21	4000	516	66.74	36.40	20.16	123.30	34/34		Xmas lites	freeze 12-2
Dec-20	3000	452	59.25	30.93	18.70	108.08	30/30		mild, rain	
Nov-20	3000	473	61.71	30.93	18.70	111.34	31/31		mild, humid, rain	
Oct-20	3000	592	75.63	30.93	18.70	125.26	29/29		mild, humid, rain	
Sep-20	2000	1029	126.73	25.46	27.23	169.42	30/30		x rainy, xx hurricanes	
Aug-20	3000	1064	130.82	30.93	18.70	180.45	29/29		x hot	grocery wa
Jul-20	4000	1551	187.78	36.40	20.16	244.34	33/33		x hot/ dry/virus	
Jun-20	3000	1064	129.65	30.93	18.70	179.28	33/33		x hot/ dry	hand wash
May-20	4000	677	67.62	36.40	20.16	124.18	29/29		Virus wash	drought/jea
Apr-20	4000	577	73.87	36.40	20.16	130.43	30/30		Virus wash	clothes wa
Mar-20	3000	460	60.20	30.93	18.70	109.83	29/29		warm	
Feb-20	3000	422	55.75	30.93	18.70	105.38	31/31		mild	
Jan-20	2000	422	58.09	25.46	17.23	100.78	32/32		mild,2 days freeze	
Dec-19	4000	476	58.79	36.40	20.16	115.35	32/32		mild/nice/no freezes	
Nov-19	2000	448	52.07	25.46	27.23	104.76			mild/ rain	
Oct-19	3000	781	97.73	30.93	18.70	147.36	20/29		mild/nice	
Sep-19	3000	1201	146.86	30.93	18.70	196.49	32/32		xx hot, washed lot clot	
Aug-19	3000	1102	135.26	30.93	18.70	184.89	29/29		rained ev day	

Jul-19	3000	1184	144.86	30.93	18.70	194.49	rain		xx hot, AC broke and	
Jun-19	3000	1198	146.50	30.93	18.70	196.13		32/32	xx record hot	
May-19	3000	815	101.70	30.93	18.70	151.33		30/30	xx record hot, no rain	
Apr-19	4000	466	60.87	36.40	20.16	117.43		30/30	very nice.	caladiums
Mar-19	2000	411	54.45	25.46	17.23	97.14		31/31	very nice.	
Feb-19	3000	398	52.93	30.93	18.70	102.56		29/29	very nice.	
Jan-19	4000	472	61.58	36.40	20.16	118.14		34/34	very mild. Dishes, Mu	
Dec-18	3000	428	56.46	30.93	18.70	106.09			very mild, no freezes	
Nov-18	3000	425	56.09	30.93	18.70	105.72			oven broke, use toast	
Oct-18	3000	910	112.81	30.93	18.79	162.44			still very hot	
Sep-18	3000	1206	147.44	30.93	18.79	197.07		31/31	record heat for all Sep	
					108.56	I paid				
Overage	extra I had to pay running hose			29.93	98.87	128.80	207.43	411.75 tot	water hose ran 5 days	
Aug-18	27000	1268	154.69	30.93	18.70	204.32		30/30	XXX hot and rain/ hun	
Jul-18	3000	1003	123.59	30.93	18.70	173.32			Rained every day.	
Jun-18	4000	1096	134.58	36.40	20.16	191.14		32/32	Alberto rain! X-hot, hu	
May-18	3000	678	85.68	30.93	18.70	135.31		30/30	humid x rain, mild to h	
Apr-18	4000	306	53.87	36.40	20.15	110.42		29/29	cool or cold Apr	
Mar-18	3000	445	58.45	30.93	18.70	108.08		32/32	mild or cold	
Feb-18	3000	377	50.48	30.93	18.70	100.11		29/29	super warm, xx mild	
Jan-18	4000	553	71.06	36.40	20.16	127.62		34/34	x-cold	several x-h
Dec-17	3000	455	59.61	30.93	18.70	109.24		30/30	very mild, Xmas lites c	
Nov-17	3000	380	50.84	30.93	18.70	100.47		29/29	very mild, new hot wa	
Oct-17	3000	813	101.47	30.93	18.70	151.10		29/29	very mild	
Sep-17	3000	1006	124.03	30.93	18.70	173.66		31/31	IRMA, power out 2 da	
Aug-17	3000	1189	145.46	30.93	18.70	195.09		30/30	humid, x-rain,x hot	
Jul-17	3000	1232	150.47	30.93	18.70	200.10		29/29	humid, x-rain,x hot	
Jun-17	3000	1005	123.93	30.93	18.70	173.56		33/33	humid, x-rain,x hot	
May-17	3000	791	98.91	30.93	18.70	148.54		29/29	ran AC on 77 some ni	
Apr-17	3000	598	76.33	30.93	18.70	125.96		28/28	ran AC on 76, steamc	
Mar-17	3000	479	62.42	30.93	18.70	112.05		33/33	warm, cold	steamclear
Feb-17	3000	347	46.98	30.93	18.70	96.61		29/29	mild	
Jan-17	4000	385	51.42	36.40	20.16	107.98		30/30	Jan 6 -1700 h20 used	
Dec-16	3000	513	66.39	30.93	18.70	116.02		34/34	warm, mild	Xmas lites,
Nov-16	4000	400	53.29	36.40	20.16	109.85		29/29	ave, mild	
Oct-16	2000	622	79.32	25.46	17.23	122.01		29/29	hurricane Matthew/mil	
Sep-16	4000	1075	132.43	36.40	20.16	189.99		32/32	washed a lot	
Aug-16	2000	1292	157.85	25.46	17.23	200.54		30/30	hot	
Jul-16	3000	1331	162.44	30.93	18.70	212.07		29/29	Record hot for 2 week	
Jun-16	4000	1249	152.81	36.40	20.16	209.37		33/33	Ran AC on 78, 1 wk H	
May-16	4000	773	97.02	36.40	20.16	153.58		29/29	Ran AC on 77, ave te	
Apr-16	3000	419	55.51	30.93	18.70	105.14		29/29	Read on 25, very mild	
Mar-16	3000	502	65.25	30.93	18.70	114.88		33/33	new AC on 3/26/16 af	
Feb-16	3000	454	60.30	30.93	18.70	109.93		29/29		
Jan-16	4000	680	91.05	36.40	20.16	147.61		34/34	cleaned carpet, wash	
Dec-15	3000	456	63.18	30.93	18.70	112.81		30/30	x-hot! Xmas lites outs	
Nov-15	3000	523	71.50	30.93	18.70	121.13			x hot. Not cold	
Oct-15	2000	562	41.96	25.46	17.23	84.65			JEA refund 36.40	
Sep-15	3000	945	124.06	30.93	18.70	173.69		30/30		
Aug-15	3000	1213	157.42	30.93	18.70	207.05		29/29		
Jul-15	3000	1424	183.70	30.93	18.70	233.33		33/33	x-hot, rained	
Jun-15	3000	1355	175.11	30.93	18.70	224.74		33/33	washed sheets a lot/w	
May-15	3000	668	89.55	30.93	28.90	139.18		28/28	set at 77/steam clean	
Apr-15	4000	471	36.84	36.40	20.16	93.40		29/29	JEA refund 26.46/set	
Mar-15	2000	396	55.70	25.46	17.23	98.39		29/29		
Feb-15	3000	445	61.80	30.93	18.70	111.43		29/29		

Jan-15	3000	555	75.48	30.93	18.70	125.11		35/35	some cold	Dec 24-Jai
Dec-14	3000	506	69.40	30.93	18.70	119.03		32/32	mildish	22-Dec
Nov-14	3000	388	54.70	30.93	18.70	104.33		29/29	x-cold-Nov-solieu hea	
Oct-14	2000	510	69.90	25.46	17.23	112.59		29/29		
Sep-14	3000	975	123.79	30.93	18.70	177.42			rained	23-Sep
Aug-14	3000	1379	178.08	30.93	18.70	227.71			xx-hot	25-Aug
Jul-14	3000	1224	159.67	30.93	18.70	183.23	209.30	31/31	CPAP/ lower thermom	
Jun-14	3000	981	128.54	30.93	18.70	178.17		32/32	wash GA sheets/hot/C	
May-14	3000	591	79.98	30.93	18.70	129.61		29/29	Steam clean/AC hi -2	
Apr-14	3000	400	56.20	30.93	18.70	105.83		29/29	AC on Apr 24	
Mar-14	2000	409	57.31	25.46	17.23	100.00		29/29		
Feb-14	3000	427	59.55	30.93	18.70	109.18		29/29	were some cold days	
Jan-14	3000	976	127.92	30.93	18.70	177.55		35/35	Xmas, cold, used wat	
Dec-13	4000	535	73.01	36.40	20.16	129.57		32/32		
Nov-13	2000	347	49.62	25.46	17.23	92.31		29/29	in Ga a wk	
Oct-13	3000	535	73.01	30.93	18.70	122.64		29/29		
Sep-13	2000	1051	137.25	25.46	17.70	179.94		29/29	living rm lites	
Aug-13	3000	1311	169.62	30.93	18.70	219.25		32/32	ran front lites	
Jul-13	3000	1059	138.24	30.93	18.70	187.87		30/30		
Jun-13	2000	1075	140.25	25.46	17.70	182.94				
May-13	3000	492	67.66	30.93	18.70	117.29		30/30		
Apr-13	2000	441	42.03	25.46	17.23	84.72			JEA refunds, fuel cred	
Mar-13	3000	492	67.66	30.93	18.70	117.29				
Feb-13	3000	487	67.03	30.93	18.70	116.66			steam clean, dead mc	
Jan-13	2000	540	73.61	25.46	17.23	116.30			Xmas lights, candles,	
Dec-12	3000	469	64.79	30.93	18.70	114.42		30/30		
Nov-12	4000	489	67.28	36.40	20.15	123.84		33/33	steam clean	
Oct-12	3000	568	77.10	30.93	18.70	126.73		29/29		
Sep-12	2000	949	124.66	25.46	17.23	164.24		30/30		
Aug-12	3000	1192	154.81	30.93	18.70	204.44		32/32		
Jul-12	3000	1405	182.36	30.93	18.70	231.99		30/30	press/pt hse	
Jun-12	4000	950	128.85	36.40	20.16	185.41			steam clean	
May-12	3000	698	96.39	30.93	18.70	142.02		29/29	new refrig	
Apr-12	4000	491	69.67	36.40	20.16	123.23		29/29	wash porc	water yard
Mar-12	2000	416	60.03	25.46	17.23	102.72		29/29	WAP attic	washer?
Feb-12	3000	485	68.92	30.93	18.70	118.55		29/29		
Jan-12	3000	546	76.77	30.93	18.70	126.40		32/32		
Dec-11	2000	457	65.18	25.46	17.23	107.87		30/30		
Nov-11	4000	441	63.10	36.40	20.16	119.66		33/33		
Oct-11	2000	582	81.25	25.03	17.14	123.42		29/29	rate hike	10 from las
Sep-11	3000	1072	144.27	26.63	17.75	188.65		30/30		
Aug-11	2000	1853	244.72	21.30	16.45	282.47		32/32	xx-hot	
Jul-11	3000	1481	196.89	26.63	17.75	241.27		30/30		
Jun-11	2000	1558	206.78	21.30	16.45	244.53		32/32		
May-11	3000	837	114.05	26.63	17.75	158.43		29/29		
Apr-11	2000	655	90.65	21.38	16.45	128.40		29/29		
Mar-11	3000	495	70.06	26.63	17.75	114.44		29/29		
Feb-11	3000	477	67.73	26.63	17.75	112.11		32/32	x-cold	
Jan-11	2000	510	71.99	21.38	16.45	109.74		30/28	new meter	
Dec-10	3000	592	82.55	26.63	17.75	126.93		30/31	x-cold	
Nov-10	5000	576	80.47	37.28	20.38	138.13		33/35		
Oct-10	2000	550	76.55	20.94	16.27	113.76		28/29	rate hike	
Sep-10	3000	1341	164.71	23.13	16.06	203.90		33/34 days		
Aug-10	3000	1677	204.38	23.13	16.06	243.57		29/32 days		
Jul-10	2000	1752	213.24	17.94	14.88	246.06		28 days		
Jun-10	3000	1683	205.08	23.13	16.06	244.27		31 days		

May-10	2000	980	122.1	17.94	14.88	154.92		28 days	
Apr-10	4000	474	62.36	28.33	17.23	107.92		29 days	
Mar-10	2000	431	57.28	17.94	14.88	90.10		29 days	
Feb-10	3000	624	80.07	23.13	16.06	119.26		32 days	
Jan-10	4000	595	76.65	28.33	17.23	122.21		34 days	
Dec-09	4000	579	74.75	28.33	17.23	120.31		34 days	
Nov-09	3000	396	53.15	23.13	16.06	92.34	hospital	17day charge out of 25	
Oct-09	3000	770	97.72	22.78	15.90	136.40		29 days	
Sep-09	4000	1293	166.11	23.50	15.36	204.97		32 days	
Aug-09	2000	1345	172.53	15.89	13.77	202.19			
Jul-09	4000	1611	205.39	23.50	15.36	244.25			
Jun-09	4000	1379	176.74	23.50	15.36	215.60			
May-09	5000	981	127.57	27.31	16.93	171.81			
Apr-09	3000	426	59.02	19.69	14.56	95.27			
Mar-09	3000	546	73.84	19.69	14.56	108.09			
Feb-09	4000	509	69.27	23.50	15.36	108.13			
Jan-09	3000	533	72.23	19.69	14.56	106.48			
Dec-08	4000	608	81.50	23.50	15.36	120.36			
Nov-08	3000	473	64.81	19.69	14.56	99.06			
Oct-08	3000	671	88.63	19.52	14.47	122.61			
Sep-08	3000	1251	153.41	18.92	13.99	186.32			
Aug-08	3000	1100	135.66	18.92	13.99	168.57			
Jul-08	3000	1349							
Jun-09	2000	1158							
May-08	3000	889							
Apr-08	3000	554							
Mar-08	3000	476							
Jan-08	3000	515							
Dec-07	4000	571							
Nov-07	2000	575							
Oct-07	3000	783							
Sep-07	3000	1225							

please
help.