ARP EXECUTIVE COMMITTEE AGENDA PACKAGE

OCTOBER 23, 2025

9:15 a.m. [NOTE TIME] (or immediately following the Board of Directors meeting)

Dial-in info: 1-321-299-0575

Meeting ID Number: 227 822 568 360#

Committee Members

Javier Cisneros, Fort Pierce – Chair
Robert Page, Green Cove Springs – Vice Chair

Christina Simmons, Bushnell
Lynne Mila, Clewiston
Steve Doyle, Fort Meade
Kendrah Wilkerson, Havana
Allen Putnam, Jacksonville Beach
Lynne Tejeda, Key West
Brian Horton, Kissimmee
Brad Chase, Leesburg
Rance Green, Newberry
Doug Peebles, Ocala
Drew Mullins, Starke

Meeting Location
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819
(407) 355-7767

MEMORANDUM

TO: FMPA Executive Committee

FROM: Jacob A. Williams, General Manager and CEO

DATE: Thursday, October 14, 2025

RE: FMPA Executive Committee Meeting - **Thursday, OCTOBER 23, 2025 at 9:15 a.m. [NOTE TIME]**
(or immediately following the Board of Directors meeting)

PLACE: Florida Municipal Power Agency
8553 Commodity Circle, Orlando, FL 32819
Fredrick M. Bryant Board Room

DIAL-IN: **321-299-0575, Meeting Number 227 822 568 360#**

LINK: **Join the meeting now**

(If you have trouble connecting via phone or internet, call 407-355-7767)

Chairman Javier Cisneros, Presiding

AGENDA

8. Action Items

9. Information Items

***Item also on the Board of Directors Agenda.**

****** Item(s) Subject to Super Majority Vote**

NOTE: One or more participants in the above referenced public meeting may participate by telephone. At the above location there will be a speaker telephone so that any interested person can attend this public meeting and be fully informed of the discussions taking place either in person or by telephone communication. If anyone chooses to appeal any decision that may be made at this public meeting, such person will need a record of the proceedings and should accordingly ensure that a verbatim record of the proceedings is made, which includes the oral statements and evidence upon which such appeal is based. This public meeting may be continued to a date and time certain, which will be announced at the meeting. Any person requiring a special accommodation to participate in this public meeting because of a disability, should contact FMPA at (407) 355-7767 or (888) 774-7606, at least two (2) business days in advance to make appropriate arrangements.

AGENDA ITEM 1 - CALL TO ORDER, ROLL CALL, DECLARATION OF QUORUM

Executive Committee
October 23, 2025

AGENDA ITEM 2 – Set Agenda (by Vote)

Executive Committee
October 23, 2025

AGENDA ITEM 3 – RECOGNITION OF GUESTS

Executive Committee
October 23, 2025

AGENDA ITEM 4 – PUBLIC COMMENTS (INDIVIDUAL COMMENTS TO BE LIMITED TO 3 MINUTES)

Executive Committee
October 23, 2025

AGENDA ITEM 5 – COMMENTS FROM THE CHAIR

Executive Committee
October 23, 2025

AGENDA ITEM 6 – REPORT FROM THE GENERAL MANAGER

Executive Committee
October 23, 2025

AGENDA ITEM 7 – CONSENT AGENDA

a. Approval of Meeting Minutes – Meetings Held September 18, 2025, and ARP Telephonic Rate Workshop Held September 11, 2025

Executive Committee
October 23, 2025

CLERKS DULY NOTIFIED ..... September 18, 2025
AGENDA PACKAGES POSTED ..... September 18, 2025

MINUTES
EXECUTIVE COMMITTEE MEETING
THURSDAY, SEPTEMBER 18, 2025
FLORIDA MUNICIPAL POWER AGENCY
8553 COMMODITY CIRCLE
ORLANDO, FL 32819

PARTICIPANTS PRESENT:
Christina Simmons, Bushnell (virtual)
Javier Cisneros, Fort Pierce
Bob Page, Green Cove Springs
Allen Putnam, Jacksonville Beach
Brian Horton, Kissimmee
Brad Chase, Leesburg (virtual)
Doug Peebles, Ocala
Drew Mullins, Starke

OTHERS PRESENT
Danny Retherford, Fort Pierce
Kurtis Wilson, Jacksonville (virtual)
Jason Terry, Kissimmee
Justin Buckman, Kissimmee (virtual)
Kevin Crawford, Kissimmee (virtual)
Ed Liberty, Lake Worth Beach
Eric Walters, Tallahassee (virtual)
Johnathen Bishop, Williston (virtual)

STAFF PRESENT
Jacob Williams, General Manager and CEO
Jody Finklea, General Counsel and Chief Legal Officer
Ken Rutter, Chief Operating Officer
Rich Popp, Chief Financial Officer
Chris Gowder, Chief System Operations and Technology Officer
Dan O'Hagan, Deputy General Counsel and Manager of Regulatory Compliance
Sue Utley, Executive Asst. /Asst. Secy. to the Board
Sharon Adams, Chief People and Member Services Officer
Susan Schumann, Public Relations and External Affairs Manager
Emily Maag, Public Relations Specialist
Jason Wolfe, Financial Planning Rates and Budget Director
Navid Nowakhtar, Member Services Strategic Planning & Analytics Director
Mary Kathryn Patterson, Senior Public Relations Specialist
John Bradley, Business Development Analyst
Mike McCleary, Senior Manager of Member Services
Lindsay Jack, Executive Assistant Support Coordinator
Andrei Benjamin, Cloud Systems Administrator

ITEM 1 - CALL TO ORDER, ROLL CALL, AND DECLARATION OF QUORUM

Chair Javier Cisneros, Fort Pierce, called the FMPA Executive Committee meeting to order at 12:06p.m., Thursday, September 18, 2025. A video and audio connection for public attendance and participation was broadcast in the Frederick M. Bryant Board Room at Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida. The roll was taken, and a quorum was declared with 8 members present out of a possible 13.

ITEM 2 – SET AGENDA (BY VOTE)

MOTION: Brian Horton, Kissimmee, moved approval of the agenda as presented. Allen Putnam, Jacksonville Beach, seconded the motion. Motion carried 8-0.

ITEM 3 – RECOGNITION OF GUESTS

None

ITEM 4 – PUBLIC COMMENTS

None

ITEM 5 – COMMENTS FROM THE CHAIRMAN

Chair Javier Cisneros recognized Allen Putnam's, Jacksonville Beach, comments about having a good, healthy discussion in the Board meeting and the origin of FMPA and having strength in numbers.

ITEM 6 – REPORT FROM GENERAL MANAGER

No additional comments.

ITEM 7 –CONSENT AGENDA

a. Approval of Meeting Minutes – Meetings Held August 21, 2025, and ARP Telephonic Rate Workshop Held August 13, 2025

b Approval of Treasury Reports – As of July 31, 2025

c Approval of the Agency and All-Requirements Project Financials as of July 31, 2025

d ARP 12-month Capacity Reserve Margin Report

MOTION: Allen Putnam, Jacksonville Beach, moved approval of the Consent Agenda as presented. Doug Peebles, Ocala, seconded the motion. Motion carried 8-0.

ITEM 8 – ACTION ITEMS:

a. Approval of FY 2026 Goals

Jacob Williams presented the FY 2026 Goals.

MOTION: Allen Putnam, Jacksonville Beach, moved approval of FY26 Goals with the modification of removing Goal 12. This item will be revisited and brought forward for consideration at a later date. Doug Peebles, Ocala, seconded the motion. Motion carried 8-0.

b. Approval of Proposed Revisions to Fuel Portfolio Management Policy

John Bradley Presented the Proposed Revisions to Fuel Portfolio Management Policy.

MOTION: Allen Putnam, Jacksonville Beach, moved approval of the Proposed Revisions to Fuel Portfolio Management Policy as presented. Doug Peebles, Ocala, seconded the motion. Motion carried 8-0.

c. Approval of Quarterly Natural Gas Price Stability Program Update

Rich Popp and John Bradley presented the Quarterly Natural Gas Price Stability Program Update.

MOTION: Brian Horton, Kissimmee, moved approval of the change to the ARP cash target for rate setting as presented. Allen Putnam, Jacksonville Beach, seconded the motion. Motion carried 8-0.

d. Approval of CY 2026 Meeting Schedule

Jacob Williams presented the CY 2026 Meeting Schedule.

MOTION: Drew Mullins, Starke, moved approval of the CY 2026 Meeting Schedule as presented. Allen Putnam, Jacksonville Beach, seconded the motion. Motion carried 8-0.

e. Approval of FGT Phase IX Expansion Capacity

Rich Popp presented the FGT Phase IX Expansion Capacity.

MOTION: Drew Mullins, Starke, moved approval of the FGT Phase IX Expansion Capacity. Allen Putnam, Jacksonville Beach, seconded the motion. Motion carried 8-0.

ITEM 9 – INFORMATION ITEMS:

a. Quarterly Compliance Update*

Dan O'Hagan and LaKenya VanNorman presented the Quarterly Compliance update at the Board of Directors meeting. No further discussion.

b. Quarterly HR Update*

Sharon Adams presented the Quarterly HR update at the Board of Directors meeting. No further discussion.

ITEM 10 – Member Comments

None.

ITEM 11 – Adjournment

There being no further business, the meeting was adjourned at 12:49 p.m.

Javier Cisneros Chairman, Executive Committee	Sue Utley Assistant Secretary

Approved: _____ Seal

PUBLIC NOTICE SENT TO CLERKS.....**September 4, 2025 & September 11, 2025**
AGENDA PACKAGES SENT TO MEMBERS ..... **September 11, 2025**

MINUTES
EXECUTIVE COMMITTEE
ALL-REQUIREMENTS POWER SUPPLY PROJECT
TELEPHONIC RATES MEETING
THURSDAY, SEPTEMBER 11, 2025
FLORIDA MUNICIPAL POWER AGENCY
8553 COMMODITY CIRCLE
ORLANDO, FLORIDA 32819

MEMBERS PRESENT VIA TELEPHONE

Danny Retherford, Fort Pierce
Robert C. Page, Green Cove Springs
Allen Putnam, Jacksonville Beach
Lynne Tejeda, Key West
Jason Terry, Kissimmee
Kevin Crawford,
James Braddock, Wauchula

OTHERS PRESENT

Andrea Trasferini, Fort Pierce
Jessie Perloff, Key West
Aaron Haderle, Kissimmee
Larry Mattern, Kissimmee
Justin Buckman
Thomas Geoffroy, Florida Gas Utility
Jenni Sweat, Florida Gas Utility

STAFF PRESENT

Jacob Williams, General Manager and CEO
Rich Popp, Chief Financial Officer
Ken Rutter, Chief Operating Officer
Sue Utley, Executive Assistant to General Manager and CEO / Asst. Secy. to the Board
Lindsay Jack, Administrative Services Supervisor
Jason Wolfe, Financial Planning, Rates and Budget Director
Denise Fuentes, Budget and Financial Analyst III
John Bradley, Business Development Analyst

Item 1 – Call to Order and Roll Call

Robert Page, Green Cove Springs, called the Executive Committee All-Requirements Telephonic Rate Workshop to order at 2:00p.m. on Thursday, September 11, 2025, via telephone. A speaker telephone for public attendance and participation was located in the Executive Conference Room at Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida.

Jason Wolfe advised that St. Lucie generation data had a minor error which will impact the rate slightly.

Item 2 – Review of August ARP Rate Calculation

Denise Fuentes gave an update on the August natural gas markets, provided an overview of the August loads, and reviewed the August ARP rate calculation.

Item 3 – Information Item

a. FGT IX Expansion Capacity

Rich Popp presented on the FGT IX Expansion Capacity item which will be brought to the Executive Committee for approval at the September meeting.

Item 4. Member Comments

None

Item 5 - Adjournment

There being no further business, the meeting was adjourned at 2:22p.m.

_____

Approved

BP/lj

AGENDA ITEM 7 – CONSENT AGENDA

b. Approval of Treasury Reports as of August 31, 2025

Executive Committee
October 23, 2025

AGENDA PACKAGE MEMORANDUM

TO: FMPA Executive Committee

FROM: Sena Mitchell

DATE: October 14, 2025

ITEM: EC 7(b) – Approval of the All-Requirements Project Treasury Reports as of August 31, 2025

Introduction

- This report is a quick summary update on the Treasury Department's functions.
- The Treasury Department reports for August are posted in the member portal section of FMPA's website.

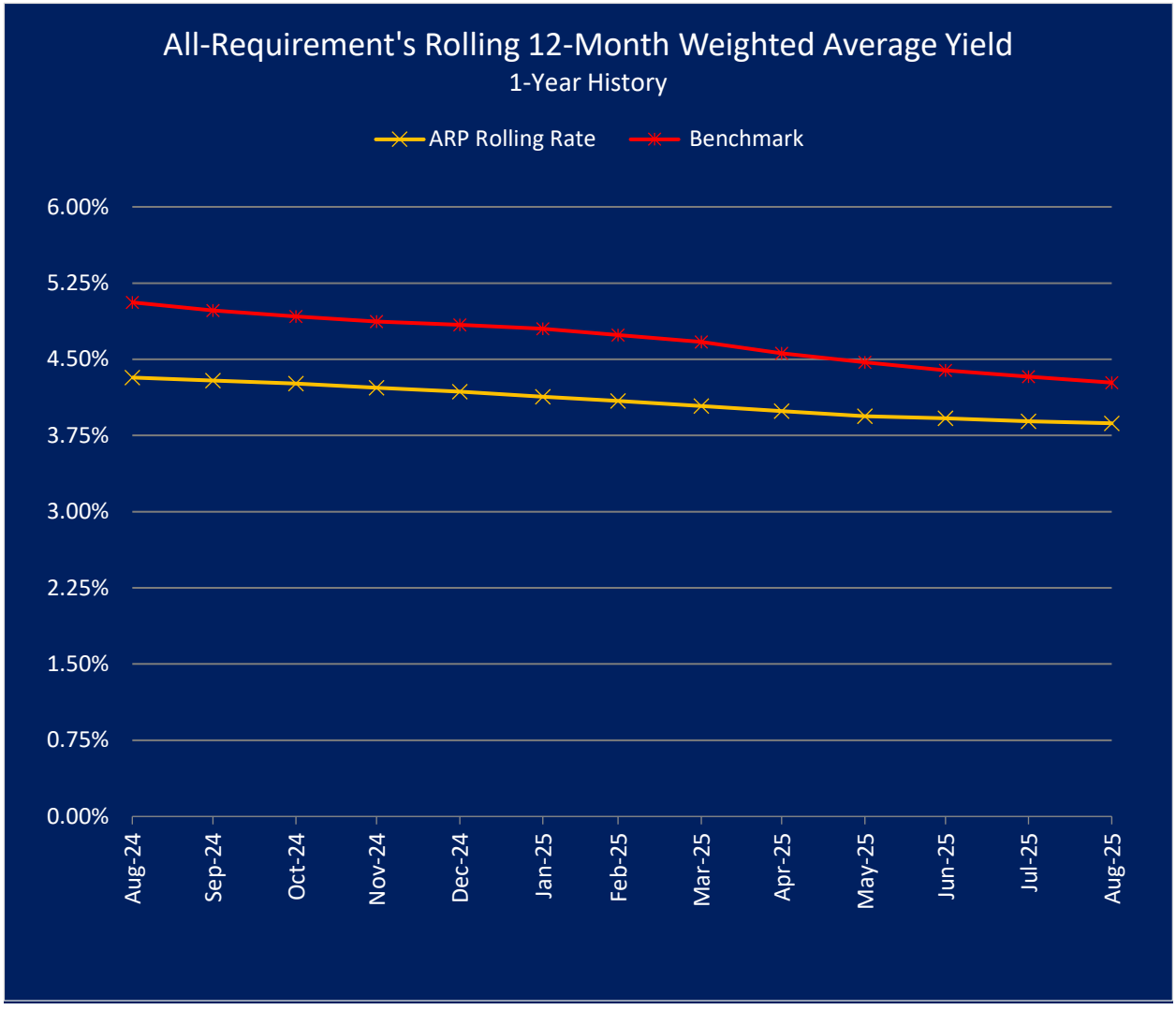
Debt Discussion

The All-Requirements Project's debt is entirely fixed-rate. In August 2025, the Project issued $209 million of tax-exempt bonds, consisting of $50 million in new money, $54 million in a current refunding, and $105 million in tender refunding. Following this issuance, the estimated debt interest funding for fiscal year 2025 as of August 31, 2025, is $25,065,009. The total amount of debt outstanding is $719,485,000.

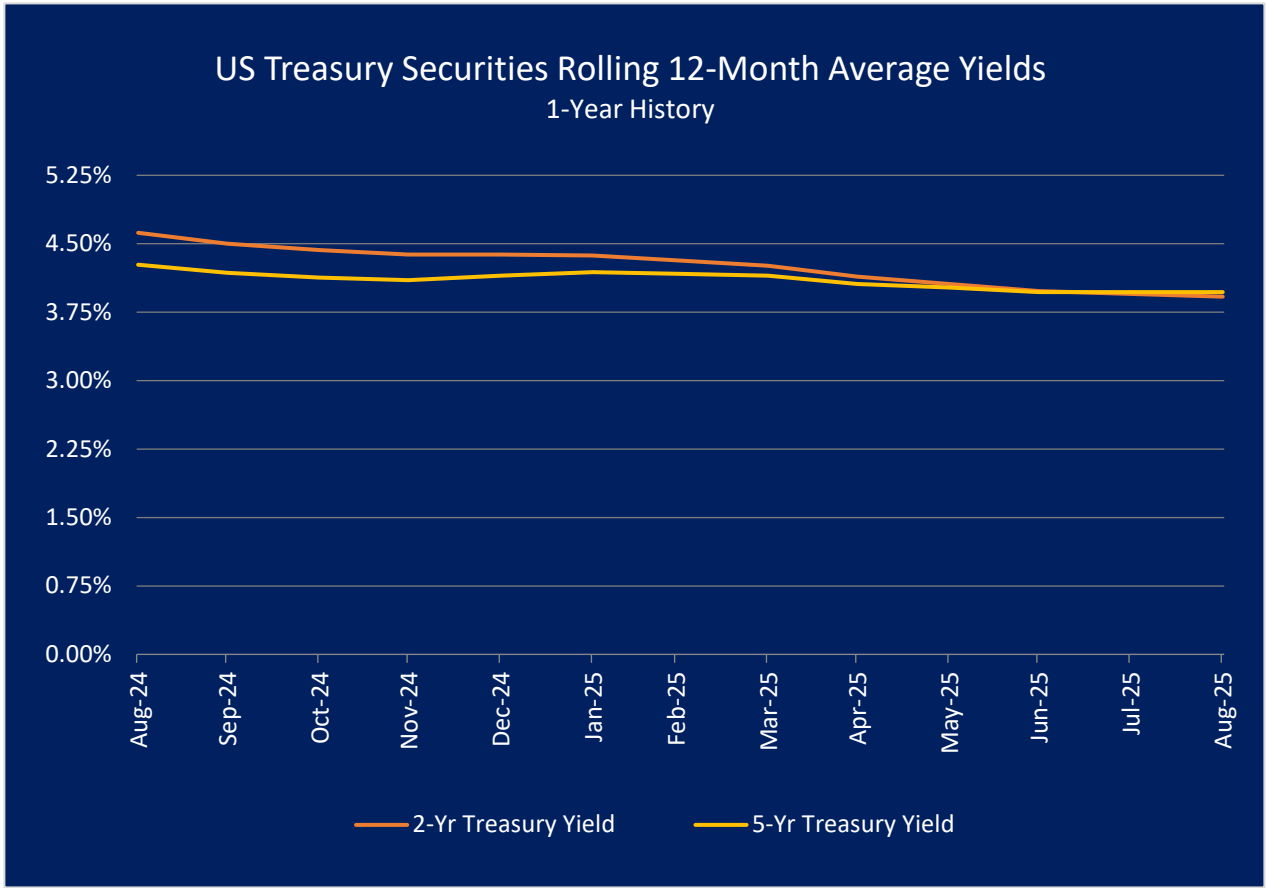
Investment Discussion

The investments in the Project are comprised of debt from the government-sponsored enterprises such as the Federal Farm Credit Bank, Federal Home Loan Bank, Federal Home Loan Mortgage Corporation (Freddie Mac), and Federal National Mortgage Association (Fannie Mae), as well as investments in U.S. Treasuries, Municipal Bonds, Certificates of Deposits, Corporate Notes, Commercial Paper, Local Government Investment Pools, and Money Market Mutual Funds.

As of August 31, 2025, the All-Requirements Project investment portfolio had a rolling 12-month weighted average yield of 3.87%. This reflects slower reinvestment into higher-yielding securities as longer-term bonds mature. The benchmarks (SBA's Florida Prime Fund and the 2-year US Treasury Note) and the Project's rolling 12-month weighted average yields are graphed below:



Below is a graph of the rolling 12-month average US Treasury yields for the past year. The orange line is the 2-year Treasury which had a rolling 12-month average yield on August 31, 2025, of 3.92%. The yellow line is the 5-year Treasury rolling 12-month average yield which was 3.97%.



The Investment Report for August is posted in the "Member Portal" section of FMPA's website.

Recommended Motion

Move for approval of the Treasury Reports for August 31, 2025

AGENDA ITEM 7 – CONSENT AGENDA

c. Approval of the Agency and All-Requirements Project Financials as of August 31, 2025

Executive Committee
October 23, 2025

Rich Popp
Chief Financial Officer

AGENDA PACKAGE MEMORANDUM

TO: **FMPA Executive Committee**

FROM: **Rich Popp**

DATE: **August 14, 2025**

SUBJECT: **EC 7c– Approval of the Agency and All Requirements Project Financials as of the period ended June 30, 2025**

Discussion: The summary and detailed financial statements, which include GASB #62 transactions, of the Agency and All Requirements Project for the period ended June 30, 2025, are posted on the Document Portal section of FMPA's website.

Recommended: Move approval of the Agency and All-Requirements Project Financial Reports for the month ended June 30, 2025.

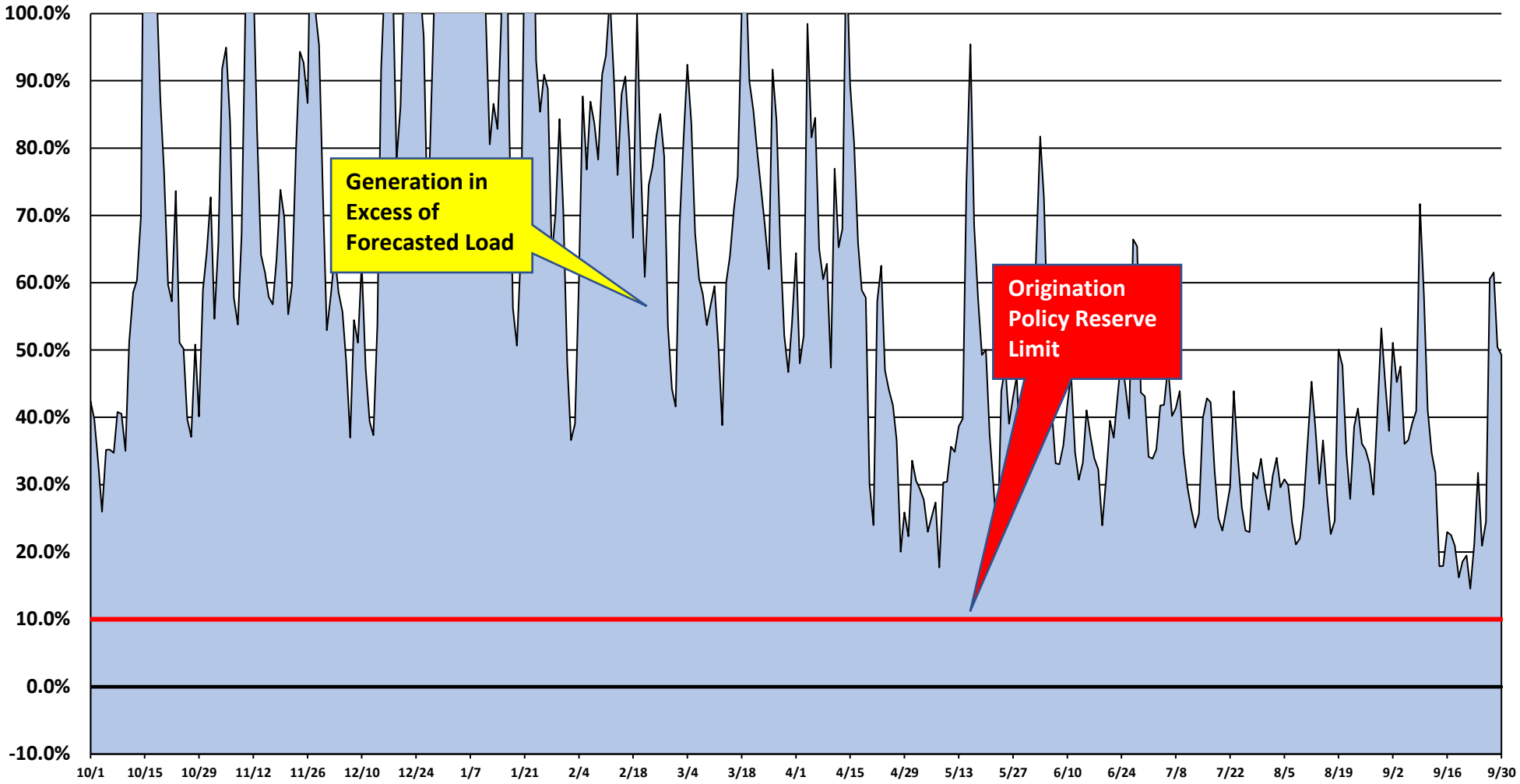
RP/GF

AGENDA ITEM 7 – CONSENT AGENDA

d. ARP 12-month Capacity Reserve Margin Report

Executive Committee
October 23, 2025

ARP Daily Reserve Margins
October 2025 through September 2026



AGENDA ITEM 8 – ACTION ITEMS

a. Approval of Revised FY26 Last Goal

Executive Committee
October 23, 2025

Proposed Edit for FY 2026 Last Goal

- Goal: Maintain a seat at table in discussions at Federal level for abundant, low cost and reliable power – Representing ARP
- Comment: Continue being market knowledgeable "Honest Broker" representing electric customers/stakeholders in discussions for low-cost & reliable energy/environment policy
- SMART Goal – Will report monthly/quarterly coinciding with PMLC meeting, noting activity and successes as federal policy is rolled out

FMPA MUNICIPAL POWER

Low-Cost and Reliable Priorities Given AI Demand

6 Main Focus Areas Representing Florida and FMPA ARP

- **Pausing retirement of reliable coal and natural gas** - till DOE/Region verifies no reliability harm – Good for reliability and prevent sudden shift to more natural gas
- **Existing Natural Gas Unit Expansion** - Expedite transmission studies for expansion of natural gas units for immediate capacity – Lowest cost capacity increases
- **Provide pipeline permitting reform** to increase the supply and deliverability of natural gas to the markets – abundant, affordable and reliable natural gas
- **Battery Storage** - where appropriate, add battery storage to reliably store excess natural gas generation for peaking needs
- **Next Generation Nuclear** - Streamline next generation nuclear permitting process for more reliable and diverse generation
- **Repeal Clean Power Plan 2** – enable new natural gas combined cycles operating over 40% utilization & allow existing solid fuel continued operations

FMPA MUNICIPAL POWER

Recommended Motion

- Move approval of goal #12

AGENDA ITEM 8 – ACTION ITEMS

b. Approval of Revised Rate Schedule B-1 to be Effective October 1, 2025

Executive Committee
October 23, 2025

EC 8b – Approval of Revised Rate Schedule B-1 to Be Effective Oct. 1, 2025

Executive Committee

Oct. 23, 2025

Summary

- Each October, staff brings a revised Rate Schedule B-1 to EC for approval to update base rates to reflect new fiscal year budget
- Demand rate based on avg. of Summer CP Demands (Net of Excluded Resources) for Fiscal Years 2023 through 2025
- Methodology change for ARP cash target for rate setting in paragraph 9 separately approved by EC in August
- Additional edit: Phase III solar references deleted from paragraph 10.1 due to termination of agreement
- Redline and clean versions of Rate Schedule B-1 attached

FY 2026 ARP Rates – Based on Approved Budget

Demand Rate Reflects Final Billing Demands for FY 2026

Rate Category	FY25 Base Rate		FY 26 Base Rate
Demand	$16.04	/kW-mo.	$16.43 /kW-mo.
Transmission (all except KUA)	$5.06	/kW-mo.	$5.25 /kW-mo.
Transmission (KUA)	$0.65	/kW-mo.	$0.55 /kW-mo.
Energy	$32.66	/MWh	$35.79 /MWh

FMPA MUNICIPAL POWER

Recommended Motion

- Move approval of revised ARP Rate Schedule B-1, effective Oct. 1, 2025*

* Subject to Super Majority vote

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

1. **Applicability.** Electric service for All-Requirements Services and Back-up and Support Services as defined in the All-Requirements Power Supply Project Contract for their own use and for resale.

2. **Availability.** This Schedule B-1 is available to the Project Participants purchasing electric capacity and energy from FMPA under the terms of the All-Requirements Power Supply Project Contracts as All-Requirements Services and, if applicable, as Back-Up and Support Services.

3. **Character of Service.** Electricity furnished under this Schedule B-1 at one or more Points of Delivery as set forth in Schedule A shall be sixty-hertz, three phase, alternating current.

4. **Billing Rate for All-Requirements Services.**
   (a) For electricity furnished hereunder as All-Requirements Services, the charges for each month shall be determined as follows:

Customer Charge	For each Project Participant, the charge is $1,000.00 per Point of Delivery. Notwithstanding the above, the charge for a Project Participant that has both (1) established its Contract Rate of Delivery and (2) does not receive Network Integration Transmission Service under an ARP agreement is $0.00.
Demand Capacity Charge	$ 16.43~~16.04~~ per kilowatt ("kW") of capacity billing demand
Demand Transmission	$ 5.25~~5.06~~ per kilowatt ("kW") of transmission billing demand
Demand Transmission Kissimmee Utility Authority	$ 0.55~~0.65~~ per kilowatt ("kW") of transmission billing demand
Energy Charge	$ 35.79~~32.66~~ per megawatt-hour ("MWh") for all energy supplied as All-Requirements Services

Solar Energy Surcharge	A $ per megawatt-hour ("MWh") rate, as calculated monthly in accordance with 10 below, for all energy pursuant to the applicable solar Power Purchase Agreement(s) (“PPA”), as specifically agreed to by individual Project Participants pursuant to Solar Participant Agreements between the ARP and individual Project Participants (hereinafter “Solar Participants”).
Reactive Demand Charge	$0.00 per kilo-var ("kVAR") of excess billing reactive demand

(b) Delivery Voltage Adjustment for All-Requirements Services. The Billing Rates under paragraph (a) are based on delivery of electric capacity and energy to the Project Participant at 115,000 volts or higher. Where capacity and energy are delivered at voltages less than 115,000 volts, the Billing Rates under paragraph (a) shall be increased as follows:

Delivery Voltage	Demand Charge Adjustment	Energy Charge Adjustment
69,000 volts	$0.000/kW	$0.0000/kWh
12,000/25,000 volts	$0.722/kW	$0.0000/kWh
Under 12,000 volts	$0.722/kW	$0.0000/kWh

5. **Billing Metering for All-Requirements Services.** The metered demand in kW in each month shall be the individual Project Participant's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the total of all ARP system Project Participants (or corrected to a 60 minute basis if demand registers other than 60 minute demand registers are installed) measured during the month.

The metered reactive demand in kVAR in each month shall be the reactive demand, which occurred during the same 60-minute demand interval in which the metered kilowatt demand occurred.

Demand and energy meter readings shall be adjusted, if appropriate, as provided in Schedule A of the All-Requirements Power Supply Project Contract.

6. **Billing Demand-Capacity for All-Requirements Services.** The billing demand capacity in any period shall be the arithmetic average of the metered demands, as determined under paragraph 5, giving effect to all adjustments, less the Project Participant's Excluded Power Supply Resources capacity, if any, for the

months of June, July, August, and September for the preceding three fiscal years. For avoidance of doubt, unless otherwise adjusted as follows in this paragraph 6, the monthly billing demand capacity for each Project Participant shall be based on the arithmetic average of 12 data points and shall remain fixed over the current fiscal year.

If a Project Participant has permanently lost a large load during the preceding three fiscal years that would cause the metered demands utilized for that Project Participant in the billing demand capacity calculation not to be representative of its current load, the metered demands utilized in the calculation for that Project Participant may be adjusted accordingly by a majority vote of the Executive Committee in its sole discretion. Such load must represent a minimum of five percent of the Project Participant's total load based on demonstrable load data. It is the responsibility of the Project Participant to notify FMPA of any such loss of load, and no adjustments shall be made to billings for months prior to the effective date of any adjustment approved by the Executive Committee.

If a Project Participant has added a large load during the preceding three years for which a demand-related financial incentive will be provided through a rider to this Rate Schedule B-1, the metered demands utilized in the calculation for that Project Participant will be adjusted as set forth in the respective rider.

Anomalous loads for an individual Project Participant may be excluded from the billing demand capacity calculation by majority vote of the Executive Committee.

7. **Billing Demand-Transmission for All-Requirements Services.** The billing demand capacity in any period shall be the metered demand for the period as determined under paragraph 5, giving effect to all adjustments, but including the Project Participant's, Excluded Power Supply Resources capacity, if any.

8. **Billing Reactive Demand for All-Requirements Services.**
The billing reactive demand for any month shall be the amount of reactive demand in kVAR by which the metered reactive demand exceeds one-half of the metered kilowatt demands, or such other amount as shall be determined from time to time by FMPA.

9. **Energy Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base energy rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

ER = $0.03579~~$0.03266~~/kWh ±ETCA

Where:

ER = Energy Rate to be applied to each kWh of billed energy.
ETCA = Energy Total Cost Adjustment to be determined according to the following procedure:

1. *Energy rate adjustment:* The total projected energy costs for the current billing month, including the cost of energy and physical natural gas sold to other utilities, net of any energy revenues projected to be collected from sources other than the Energy Rate, will be computed and then divided by the total kWh energy sales for providing the All-Requirements Project power supply the current billing month. This $/kWh rate, less the base energy rate, will become an adder (if positive) or reduction (if negative) to the base energy rate..

2. *Cash adjustment to energy rate:* Each billing month, staff will prepare a twelve-month projection, beginning with the current billing month, of total All-Requirements Project expenses, including the cost of sales to other utilities, net of any revenues projected to be collected from sources other than Project Participant rates. From this projection, staff will determine the Highest 60-Day Cash Target, defined as the maximum estimated net cash required to fund any sixty (60) consecutive days within the twelve-month projection period. The Highest 60-Day Cash Target will be compared to the current cash balance for the All-Requirements Project to determine the current amount of cash above or below the target. Amounts greater or less than the Highest 60-Day Cash Target will be modeled to be returned to or collected from Project Participants, respectively, over the current and subsequent three billing months based on projected total kWh sales for providing the All-Requirements Project power supply over that same period. The resulting $/kWh rate will be added to the sum of the base energy rate and the energy rate adjustment.

10. Solar Energy Surcharge.

The Solar Energy Surcharge shall equal the difference between the adjusted energy rate calculated in 9 above (ER) and the actual monthly cost per MWh of the solar energy (note the surcharge could be negative). The following provisions shall apply to the calculation of the surcharge:

1. Solar energy costs shall equal the sum of the applicable solar PPA charges, FMPA A&G charges allocated to the solar PPA(s), the return to the Agency Development Fund of the costs advanced to enter into and implement the solar PPA(s), and other costs or charges that the ARP may incur related to utilizing solar energy as part of its resource portfolio, e.g. increased regulation charges assessed by the ARP's Balancing Authority.

2. The following All-Requirements Project Participants have responsibility for solar energy (MWh) in each hour that solar energy is produced under the applicable solar PPA(s):

Phase I solar PPAs between the ARP and NextEra Florida Renewables, or its successor or assigns:

The City of Jacksonville Beach	17.241%
Fort Pierce Utilities Authority	5.173%
Utility Board, City of Key West	8.621%
Kissimmee Utility Authority	51.724%
The City of Ocala	17.241%

Phase II solar Rice Creek PPA between the ARP and Origis Energy, or its successors or assigns:

The City of Jacksonville Beach	15.584%
Fort Pierce Utilities Authority	15.584%
The Town of Havana	0.260%
Utility Board, City of Key West	25.975%
Kissimmee Utility Authority	20.779%
The City of Newberry	1.039%
The City of Ocala	20.779%

Phase II solar Whistling Duck PPA between the ARP and Origis Energy, or its successors or assigns:

Utility Board, City of Key West	100.000%

~~Phase III solar PPA between the ARP and Origis Energy, or its successors or assigns:~~

~~Utility Board, City of Key West~~	~~21.751%~~
~~The City of Ocala~~	~~6.869%~~

3. In the event that one or more of the Solar Participants defaults by not paying the Solar Energy Surcharge, the defaulting Project Participant(s) shall remain liable for all payments to be made on its part pursuant to this Rate Schedule B-1. In such event, each non-defaulting Solar Participant's All-Requirements bill shall be increased, on a pro rata basis based on its

respective Solar Energy Surcharge percentage of the applicable solar PPA(s), the amount in default unless and until FMPA shall recover from the defaulting Solar Participant(s) all amounts owed, upon which FMPA shall reimburse the non-defaulting Solar Participants. If all Solar Participants default by not paying the Solar Energy Surcharge, the All-Requirements Project will be obligated for the applicable Power Purchase Agreement(s) and the solar costs will become part of the Energy Rate (ER) above applicable to all All-Requirements Project Participants, including the defaulting Solar Participants, unless and until FMPA shall recover from at least one of the defaulting Solar Participants all amounts owed by all Solar Participants, upon which FMPA shall reimburse the All-Requirements Project Participants either through rates or through such other method as directed by the Executive Committee

4. A Solar Participant may only exit from the financial obligation to pay the Solar Energy Surcharge if one of the following four conditions are met, subject to approval of the Executive Committee:

   a. One or more Solar Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   b. One or more All-Requirements Project Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   c. One or more FMPA Members that is not an All-Requirements Project Participant assumes the financial entitlement to the Solar Participant's percentage share of the applicable solar PPA(s) and commits that it will take on the (i) associated financial obligation and (ii) obligation to take solar energy, in a form suitable to the ARP; or

   d. Pay stranded cost obligations, as determined by FMPA in its sole discretion, to hold the other Solar Participants harmless from the costs associated with the Solar Participant's exit.

      Stranded cost obligations are defined as an estimate of the solar energy costs (defined in 10.1) that the ARP will pay for the exiting Solar Participant's solar energy entitlement during each remaining month of the remaining term of the applicable solar PPA(s) based on (i) a forecast of expected solar production and (ii) a reasonable assessment of unforeseen costs, and are to be paid at the time of exit. The forecast of expected solar

production is defined as a P50 (probability of exceedance is 50 percent) production estimate under typical meteorological year conditions using an industry standard modeling tool (PV Syst or its successor/peer products) reflective of a degradation rate of 0.3% per year relative to the original nominal alternating current capacity of the solar resource in the current year (prorated over a partial year as applicable) and each subsequent remaining year of the applicable solar PPA(s) term.

11. **Demand Cost True-up for All-Requirements Services.**
Each Project Participant shall be charged or credited, as applicable, during the twelve months commencing with the billing for October service of a subsequent fiscal year by a dollar amount equal to one twelfth of the dollar amount share of the difference between the Project Participant's actual demand costs (excluding transmission) and the demand charges collected during the previous fiscal year. The amount to be charged or credited to each Project Participant shall be calculated on the basis of each Project Participant's demand costs (excluding transmission) collected during the previous fiscal year as a percentage of the total demand costs collected from all Project Participants.

12. **Transmission Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base demand transmission capacity rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

TR = Transmission per kW/month ±TTCA

Where:
TR = Demand Transmission Rate to be applied to each kW of billed transmission demand.

TTCA = Transmission Total Cost Adjustment to be determined based on the current All-Requirements Project over-recovery or under-recovery balance for transmission expenses as listed in the All-Requirements Project Comparative Statement of Net Asset report. This balance will be applied over the current and subsequent three billing months based on projected total kW transmission sales (excluding Kissimmee Utility Authority) for providing the All-Requirements Project power supply.

13. **Funding for Participants' Load Retention Programs.**
Each Participant shall be credited with an amount equal to the Participants monthly billing energy times $0.30 per MWh. This credit may be used by the Participant to fund Load Retention Programs approved by the Participants' governing body, or for other lawful usage.

14. **Tax Adjustment Clause for All-Requirements Services.** In the event of the imposition of any tax, or payment in lieu thereof, by any lawful authority on FMPA for production, transmission, or sale of electricity, the charges hereunder may be increased to pass on to the Project Participant its share of such tax or payment in lieu thereof.

15. **Late Payment Charge.** FMPA may impose a late payment charge on the unpaid balance of any amount not paid when due. Such charge shall be equal to the interest on the unpaid balance from the due date to the date of payment, with the interest rate being the arithmetic mean, to the nearest one-hundredth of one percent (.01%) of the prime rate values published in the Federal Reserve Bulletin for the fourth, third, and second months prior to the due date. The interest required to be paid under this clause will be compounded monthly.

16. **Month.** The month shall be in accordance with a schedule established by FMPA.

17. **Special Jacksonville Beach Charge**. In the event that FMPA pays or is billed for any amounts by the JEA for back-up transmission capability and/or transmission services and /or back-up electric service supplied by JEA for the City of Jacksonville Beach, such amounts shall be added to any amounts otherwise billed to the City of Jacksonville Beach by FMPA pursuant to this Schedule B-1, less one-third of such amounts, at such times as FMPA shall determine.

REVISIONS APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON OCTOBER 23, 2025 ~~NOVEMBER 14, 2024~~

FLORIDA MUNICIPAL POWER AGENCY
POWER SUPPLY RATE SCHEDULE
FOR
ALL-REQUIREMENTS PROJECT PARTICIPANTS

1. **Applicability.** Electric service for All-Requirements Services and Back-up and Support Services as defined in the All-Requirements Power Supply Project Contract for their own use and for resale.

2. **Availability.** This Schedule B-1 is available to the Project Participants purchasing electric capacity and energy from FMPA under the terms of the All-Requirements Power Supply Project Contracts as All-Requirements Services and, if applicable, as Back-Up and Support Services.

3. **Character of Service.** Electricity furnished under this Schedule B-1 at one or more Points of Delivery as set forth in Schedule A shall be sixty-hertz, three phase, alternating current.

4. **Billing Rate for All-Requirements Services.**
   (a) For electricity furnished hereunder as All-Requirements Services, the charges for each month shall be determined as follows:

Customer Charge	For each Project Participant, the charge is $1,000.00 per Point of Delivery. Notwithstanding the above, the charge for a Project Participant that has both (1) established its Contract Rate of Delivery and (2) does not receive Network Integration Transmission Service under an ARP agreement is $0.00.
Demand Capacity Charge	$ 16.43 per kilowatt ("kW") of capacity billing demand
Demand Transmission	$ 5.25 per kilowatt ("kW") of transmission billing demand
Demand Transmission Kissimmee Utility Authority	$ 0.55 per kilowatt ("kW") of transmission billing demand
Energy Charge	$ 35.79 per megawatt-hour ("MWh") for all energy supplied as All-Requirements Services

Solar Energy Surcharge	A $ per megawatt-hour ("MWh") rate, as calculated monthly in accordance with 10 below, for all energy pursuant to the applicable solar Power Purchase Agreement(s) (“PPA”), as specifically agreed to by individual Project Participants pursuant to Solar Participant Agreements between the ARP and individual Project Participants (hereinafter “Solar Participants”).
Reactive Demand Charge	$0.00 per kilo-var ("kVAR") of excess billing reactive demand

(b) Delivery Voltage Adjustment for All-Requirements Services. The Billing Rates under paragraph (a) are based on delivery of electric capacity and energy to the Project Participant at 115,000 volts or higher. Where capacity and energy are delivered at voltages less than 115,000 volts, the Billing Rates under paragraph (a) shall be increased as follows:

Delivery Voltage	Demand Charge Adjustment	Energy Charge Adjustment
69,000 volts	$0.000/kW	$0.0000/kWh
12,000/25,000 volts	$0.722/kW	$0.0000/kWh
Under 12,000 volts	$0.722/kW	$0.0000/kWh

5. **Billing Metering for All-Requirements Services.** The metered demand in kW in each month shall be the individual Project Participant's total 60 minute integrated demand at the time of the highest 60 minute integrated demand for the total of all ARP system Project Participants (or corrected to a 60 minute basis if demand registers other than 60 minute demand registers are installed) measured during the month.

The metered reactive demand in kVAR in each month shall be the reactive demand, which occurred during the same 60-minute demand interval in which the metered kilowatt demand occurred.

Demand and energy meter readings shall be adjusted, if appropriate, as provided in Schedule A of the All-Requirements Power Supply Project Contract.

6. **Billing Demand-Capacity for All-Requirements Services.** The billing demand capacity in any period shall be the arithmetic average of the metered demands, as determined under paragraph 5, giving effect to all adjustments, less the Project Participant's Excluded Power Supply Resources capacity, if any, for the months of June, July, August, and September for the preceding three fiscal years. For avoidance of doubt, unless otherwise adjusted as follows in this

paragraph 6, the monthly billing demand capacity for each Project Participant shall be based on the arithmetic average of 12 data points and shall remain fixed over the current fiscal year.

If a Project Participant has permanently lost a large load during the preceding three fiscal years that would cause the metered demands utilized for that Project Participant in the billing demand capacity calculation not to be representative of its current load, the metered demands utilized in the calculation for that Project Participant may be adjusted accordingly by a majority vote of the Executive Committee in its sole discretion. Such load must represent a minimum of five percent of the Project Participant's total load based on demonstrable load data. It is the responsibility of the Project Participant to notify FMPA of any such loss of load, and no adjustments shall be made to billings for months prior to the effective date of any adjustment approved by the Executive Committee.

If a Project Participant has added a large load during the preceding three years for which a demand-related financial incentive will be provided through a rider to this Rate Schedule B-1, the metered demands utilized in the calculation for that Project Participant will be adjusted as set forth in the respective rider.

Anomalous loads for an individual Project Participant may be excluded from the billing demand capacity calculation by majority vote of the Executive Committee.

7. **Billing Demand-Transmission for All-Requirements Services.** The billing demand capacity in any period shall be the metered demand for the period as determined under paragraph 5, giving effect to all adjustments, but including the Project Participant's, Excluded Power Supply Resources capacity, if any.

8. **Billing Reactive Demand for All-Requirements Services.**
The billing reactive demand for any month shall be the amount of reactive demand in kVAR by which the metered reactive demand exceeds one-half of the metered kilowatt demands, or such other amount as shall be determined from time to time by FMPA.

9. **Energy Cost Adjustment for All-Requirements Services.**
The monthly bill computed hereunder shall adjust the base energy rate by an amount to the nearest one-thousandth of a cent, determined by use of the formula below:

$$ER = \$0.03579/kWh \pm ETCA$$

Where:
ER = Energy Rate to be applied to each kWh of billed energy.
ETCA = Energy Total Cost Adjustment to be determined according to the following procedure:

1. *Energy rate adjustment:* The total projected energy costs for the current billing month, including the cost of energy and physical natural gas sold to other utilities, net of any energy revenues projected to be collected from sources other than the Energy Rate, will be computed and then divided by the total kWh energy sales for providing the All-Requirements Project power supply the current billing month. This $/kWh rate, less the base energy rate, will become an adder (if positive) or reduction (if negative) to the base energy rate..

2. *Cash adjustment to energy rate:* Each billing month, staff will prepare a twelve-month projection, beginning with the current billing month, of total All-Requirements Project expenses, including the cost of sales to other utilities, net of any revenues projected to be collected from sources other than Project Participant rates. From this projection, staff will determine the Highest 60-Day Cash Target, defined as the maximum estimated net cash required to fund any sixty (60) consecutive days within the twelve-month projection period. The Highest 60-Day Cash Target will be compared to the current cash balance for the All-Requirements Project to determine the current amount of cash above or below the target. Amounts greater or less than the Highest 60-Day Cash Target will be modeled to be returned to or collected from Project Participants, respectively, over the current and subsequent three billing months based on projected total kWh sales for providing the All-Requirements Project power supply over that same period. The resulting $/kWh rate will be added to the sum of the base energy rate and the energy rate adjustment.

10. Solar Energy Surcharge.

The Solar Energy Surcharge shall equal the difference between the adjusted energy rate calculated in 9 above (ER) and the actual monthly cost per MWh of the solar energy (note the surcharge could be negative). The following provisions shall apply to the calculation of the surcharge:

1. Solar energy costs shall equal the sum of the applicable solar PPA charges, FMPA A&G charges allocated to the solar PPA(s), the return to the Agency Development Fund of the costs advanced to enter into and implement the solar PPA(s), and other costs or charges that the ARP may incur related to utilizing solar energy as part of its resource portfolio, e.g. increased regulation charges assessed by the ARP's Balancing Authority.

2. The following All-Requirements Project Participants have responsibility for solar energy (MWh) in each hour that solar energy is produced under the applicable solar PPA(s):

Phase I solar PPAs between the ARP and NextEra Florida Renewables, or its successor or assigns:

The City of Jacksonville Beach	17.241%
Fort Pierce Utilities Authority	5.173%
Utility Board, City of Key West	8.621%
Kissimmee Utility Authority	51.724%
The City of Ocala	17.241%

Phase II solar Rice Creek PPA between the ARP and Origis Energy, or its successors or assigns:

The City of Jacksonville Beach	15.584%
Fort Pierce Utilities Authority	15.584%
The Town of Havana	0.260%
Utility Board, City of Key West	25.975%
Kissimmee Utility Authority	20.779%
The City of Newberry	1.039%
The City of Ocala	20.779%

Phase II solar Whistling Duck PPA between the ARP and Origis Energy, or its successors or assigns:

Utility Board, City of Key West	100.000%

3. In the event that one or more of the Solar Participants defaults by not paying the Solar Energy Surcharge, the defaulting Project Participant(s) shall remain liable for all payments to be made on its part pursuant to this Rate Schedule B-1. In such event, each non-defaulting Solar Participant's All-Requirements bill shall be increased, on a pro rata basis based on its respective Solar Energy Surcharge percentage of the applicable solar PPA(s), the amount in default unless and until FMPA shall recover from the defaulting Solar Participant(s) all amounts owed, upon which FMPA shall reimburse the non-defaulting Solar Participants. If all Solar Participants default by not paying the Solar Energy Surcharge, the All-Requirements Project will be obligated for the applicable Power Purchase Agreement(s) and the solar costs will become part of the Energy Rate (ER) above applicable to all All-Requirements Project Participants, including the defaulting Solar Participants, unless and until FMPA shall recover from at least one of the defaulting Solar Participants all amounts

owed by all Solar Participants, upon which FMPA shall reimburse the All-Requirements Project Participants either through rates or through such other method as directed by the Executive Committee

4. A Solar Participant may only exit from the financial obligation to pay the Solar Energy Surcharge if one of the following four conditions are met, subject to approval of the Executive Committee:

   a. One or more Solar Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   b. One or more All-Requirements Project Participants assumes the exiting Solar Participant's entire Solar Energy Surcharge financial obligation to the ARP;

   c. One or more FMPA Members that is not an All-Requirements Project Participant assumes the financial entitlement to the Solar Participant's percentage share of the applicable solar PPA(s) and commits that it will take on the (i) associated financial obligation and (ii) obligation to take solar energy, in a form suitable to the ARP; or

   d. Pay stranded cost obligations, as determined by FMPA in its sole discretion, to hold the other Solar Participants harmless from the costs associated with the Solar Participant's exit.

      Stranded cost obligations are defined as an estimate of the solar energy costs (defined in 10.1) that the ARP will pay for the exiting Solar Participant's solar energy entitlement during each remaining month of the remaining term of the applicable solar PPA(s) based on (i) a forecast of expected solar production and (ii) a reasonable assessment of unforeseen costs, and are to be paid at the time of exit. The forecast of expected solar production is defined as a P50 (probability of exceedance is 50 percent) production estimate under typical meteorological year conditions using an industry standard modeling tool (PV Syst or its successor/peer products) reflective of a degradation rate of 0.3% per year relative to the original nominal alternating current capacity of the solar resource in the current year (prorated over a partial year as applicable) and each subsequent remaining year of the applicable solar PPA(s) term.

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REVISIONS APPROVED BY THE FMPA EXECUTIVE COMMITTEE ON OCTOBER 23, 2025

AGENDA ITEM 9 – INFORMATION ITEMS

a. Potential for Expansion of ARP Membership

Executive Committee
October 23, 2025

EC 9a - Potential for Expansion of ARP Membership

Executive Committee

October 23, 2025

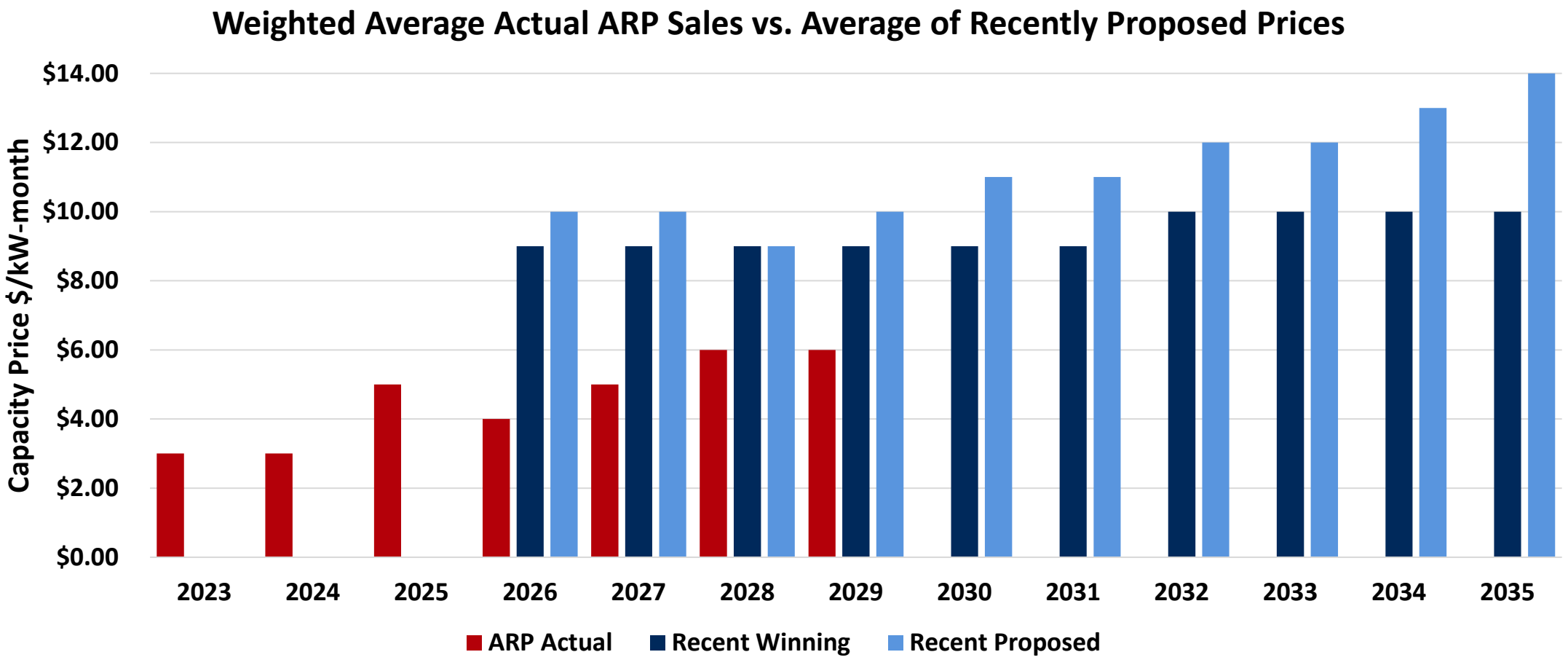
Market Factors Driving Interest in Potential Expansion

Is This A Desired Path And What Considerations Are Key?

- Capacity shortage creating price pressure for Members relying on short term market (reduced bidder pool and much higher capacity pricing)
- FMPA's ARP has as much as ~105 MW of excess capacity until 2030 (more excess in earlier years, declining with load growth & expiring PPAs) for some needs
- ARP future costs projections starting to line up with "market" post 2030 as ARP "core debt" is paid off on low-cost assets
- FL Municipals' need for new capacity by 2030 vastly exceeds FMPA's excess
- Opportunity to expand ARP Membership over next 3 years, if desired
- Is ARP expansion desired?
- What considerations should be given if expansion efforts initiated?

Capacity Market Intelligence Suggests Large Increases

Fewer Bidders More Conservative With Excess MWs



ARP Has 55 MW – 105 MW of Excess Through 2030

High Growth (1.4%) & 120 MW Unplanned '28 Loss Shrinks Excess

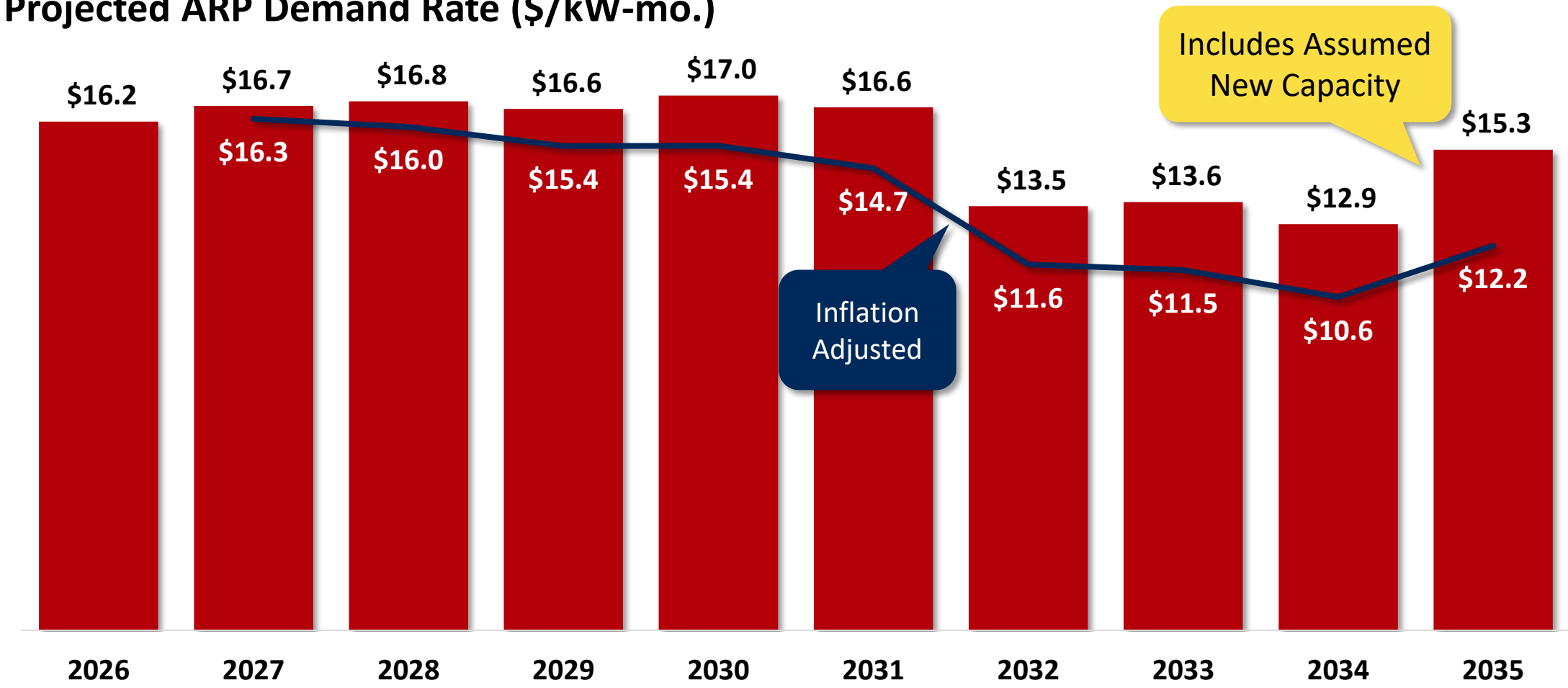
Year	Base Case Load w/Existing Assets	Base Case Load w/Upgrade Potential	High Growth & 120 MW Supply Loss
2025	167	167	154
2026	191	211	174
2027	145	169	164
2028	132	169	45
2029	89	140	34
2030	55	105	(8)
2032	35	105*	(24)
2035	(24)	68	(84)

*20 MW of additional upgrades between 2030 and 2032 assumed, which maintains excess.

ARP's Demand Rate Converging To Market Mid-2030s

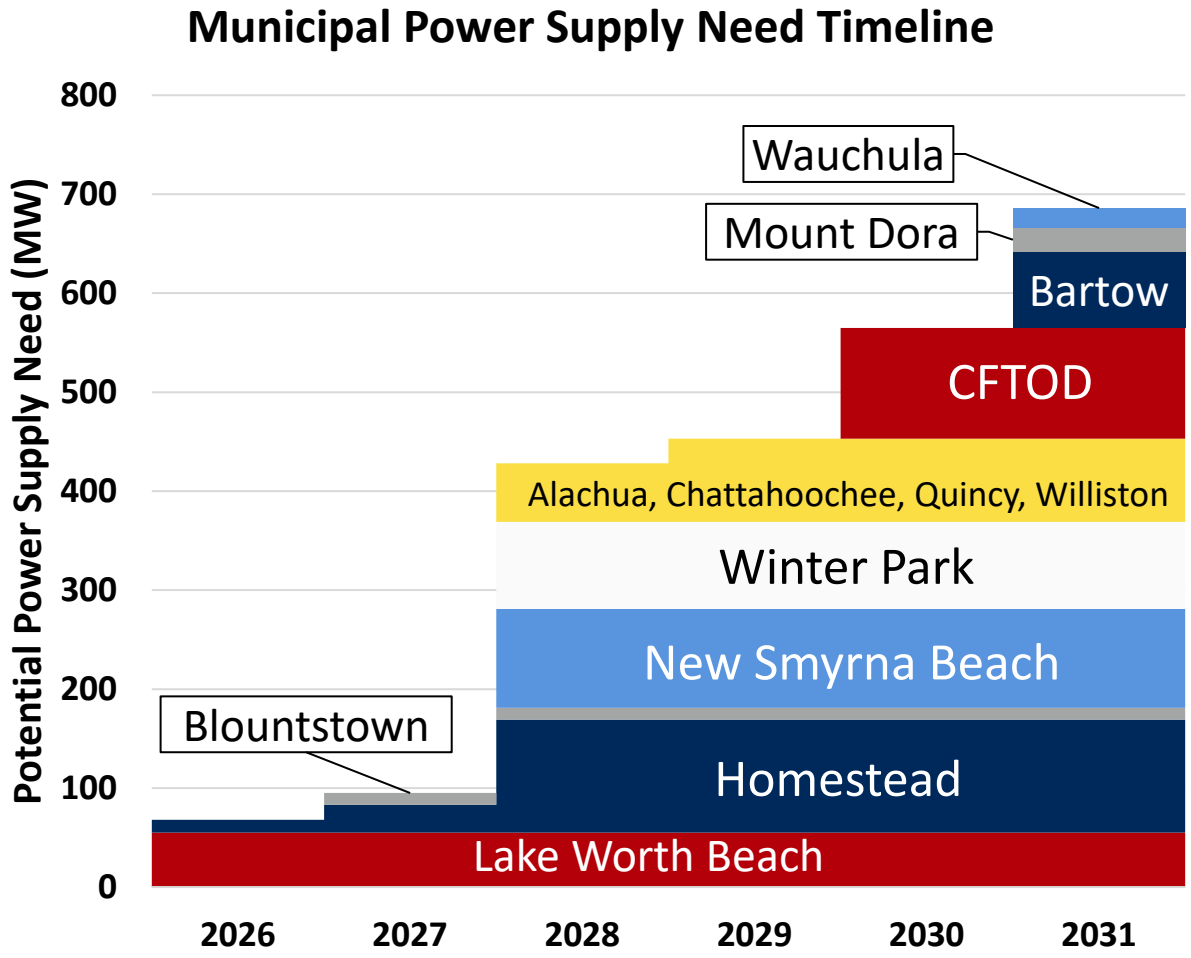
Resource Adequacy Investments Needed Statewide

Projected ARP Demand Rate ($/kW-mo.)



Municipals Seek 700 –1,000 MW Supply by 2031

ARP Has ~150MW of Excess to Manage Nearer-Term Needs



- Municipal short-term purchases begin to expire mid to late decade, 400-700 MW of need between 2028 and 2031
- Other municipals in market for capacity, 200-300 MW or more 2026 & beyond
  - Lakeland & JEA
- Other generators in market seasonally, 300-400 MW or more 2026 & beyond
  - Seminole, TECO
- Nationwide growth in demand increasing cost & extending timeline for new build
- Opportunity to sell excess capacity at higher values as market tightens

FMPA MUNICIPAL POWER

Dynamics Creating Opportunities to Expand ARP

Capacity At A Premium Statewide, Creating Risks for Members

- Market excess from 2005 – 2008 “bull cycle” finally worked off
- Data center driven demand making new units extremely high cost to build
- Only 2 “long” sellers in FL wholesale capacity market (FPL and FMPA)
  - Other bidders limiting terms or have other focused objectives
- Some Members desiring full requirements option
- Some Members looking for short-term stop-gap needs
- Some Members own substantial generation which could be rolled into ARP via a “TARP” to receive credit for capacity they own/operate.

Pros and Cons Of Membership Expansion

Pros

- Supports FL Munis
- Lowers ARP Member cost short term
- Likely lowers long-term cost of new Members
- Spreads risk over larger footprint
- Adds scale for larger asset additions
- Other?

Cons

- New Members “buy into” ARP assets of great value
- Could bring forward need for new asset
- Could increase mid-term cost for existing Members
- Other?

FMPA MUNICIPAL POWER

ARP Considerations For Potential Expansion

- Should ARP expansion candidates by given preference in capacity sales as bridge into ARP?
- Target year all members to pay same capacity prices, and if so, by when?
- Is there any buy-in for new members?
- When is new member a “new member” – 1st year of power deal or at year of full power price?
- Should a 30-year evergreen agreement be required for everyone?
- Each ARP Member agreement will need EC approval
- Other?

Next Steps

- Address questions from today's meeting at follow-up in December
- Potential for ARP Expansion Workshop in early 2026
- Provide FMPA Team with priorities and guidelines for upcoming bids/negotiations in Q1 2026.

AGENDA ITEM 9 – INFORMATION ITEMS

b. FMPA ARP Generation FY25 Results, FY26 Key Initiatives

Executive Committee
October 23, 2025

EC 9b - FMPA ARP Generation FY25 Results, FY26 Key Initiatives

Executive Committee

October 23, 2025

Strong FY25 ARP Generation & Engineering Performance

No Lost Time Accidents 3 Years Running, Under Budget, Solid Availability

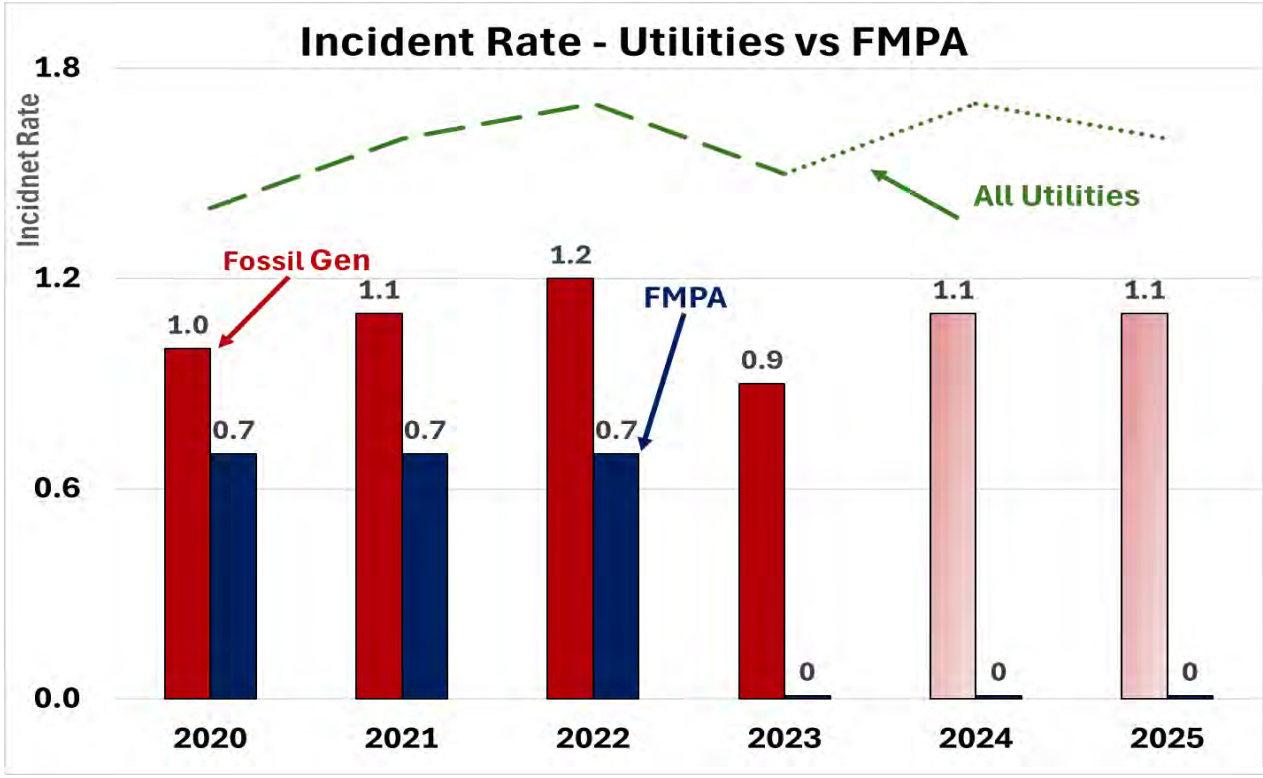
- No lost time incidents for 3 years; fleet outperforms industry benchmarks
- ARP fleet ~4% under overall $74M capex, O&M and labor budgets
- Baseload and intermediate generation availability 89.4%
  - 4.4% above industry average
- Stock Island >98% successful starts when needed
- First time in over a decade 90+% of budgeted capex projects completed
- Successful first full FY of SLEC & MEC, Preparation for integration of Bartow 1/1/26
- Acquisition and delivery of future Bartow LM6000 complete (from Belgium)

FMPA MUNICIPAL POWER

Exemplary Safety and Compliance Performance

ARP's Strong Track Record of Success Continued in FY25

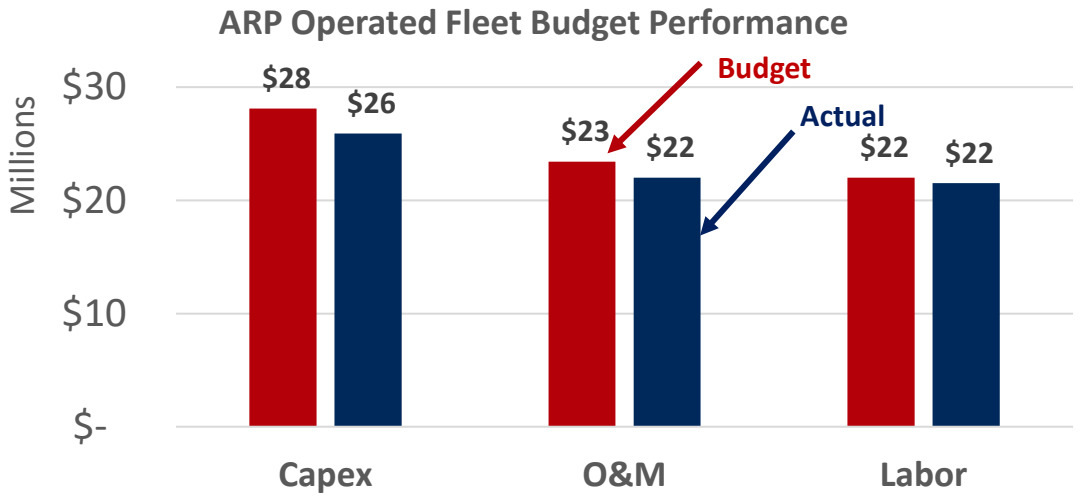
- 3-Years No Lost Time Accidents (LTA)
  - >330k work hours fleetwide in FY25
- Employee driven Safety Committee formed in FY25
  - Committee conducting peer assessments at all ARP sites
- No compliance violations in FY25
- NERC compliance audit set to begin in October

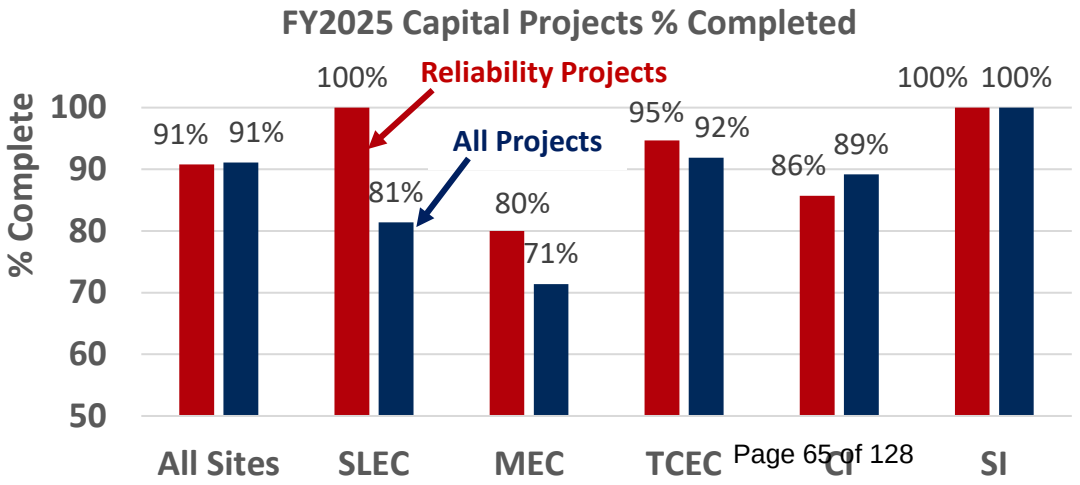


Strong Financial Results Contributes to ARP Rate Goals

Team Focused on Reliability Projects with High ROI, Short Payback

- ARP operated fleet ~4% under overall budget
  - Team shifted financial priorities across sites
  - >$12M long-lead POs already issued for FY26
- 92% of budgeted projects completed
  - $26M of long-term reliability projects complete
- Every site has contributed to resource sharing
  - CI loaned resource to MEC for >6 months
  - Plant SMEs utilized in outages and for projects
  - Engineer onsite workload increased substantially

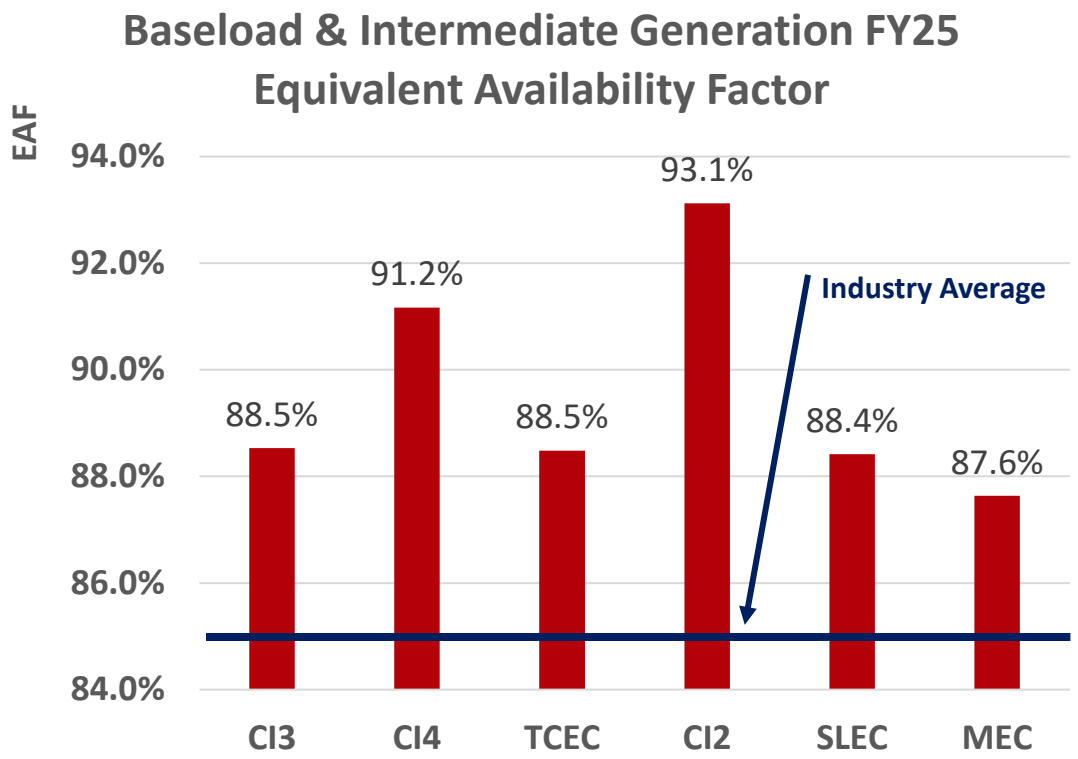




Several Milestones Achieved Around Operational Performance

Fleet Generation Production Roughly Equivalent to ARP Load

- Baseload gen EAF 4% above industry avg*
  - Over 10 years above industry average
- Intermediate EAF 5% above industry avg*
- Peaking EAF 2% above industry avg*
- Second time fleet produced >6M MWhs
  - Baseload generated >5M MWhs
- 2 outage-to-outage runs at TCEC, no trips
- 4th Year in row CI4 Surpassed 2M MWhs
- MEC no failed starts, record 26-day run
- 150% Increase in SI operating hours



* Per 2024 NERC GADS EAF reporting by natural gas unit size

FY26 Opportunities to Enhance Reliability & Expand Capacity

Markets Supporting Prudent Investments In Existing Assets

- 1898 IRP update indicates new gen >$3,000/kW
- Indicative used generation market >$2,000/kw

} FMPA Acquisitions <$150/kw

- 23MW potential fleetwide capacity initiatives for FY26
- Keys battery project go/no-go in Q2 2026
- Integrate Bartow on 1/1/2026
- Terminate participation in Stanton 1 on 1/1/2026
- Team assessing potential bid on New Smyrna Beach used Frame 5 generation equipment
  - Minimum bid on NSB gen auction $2.5M

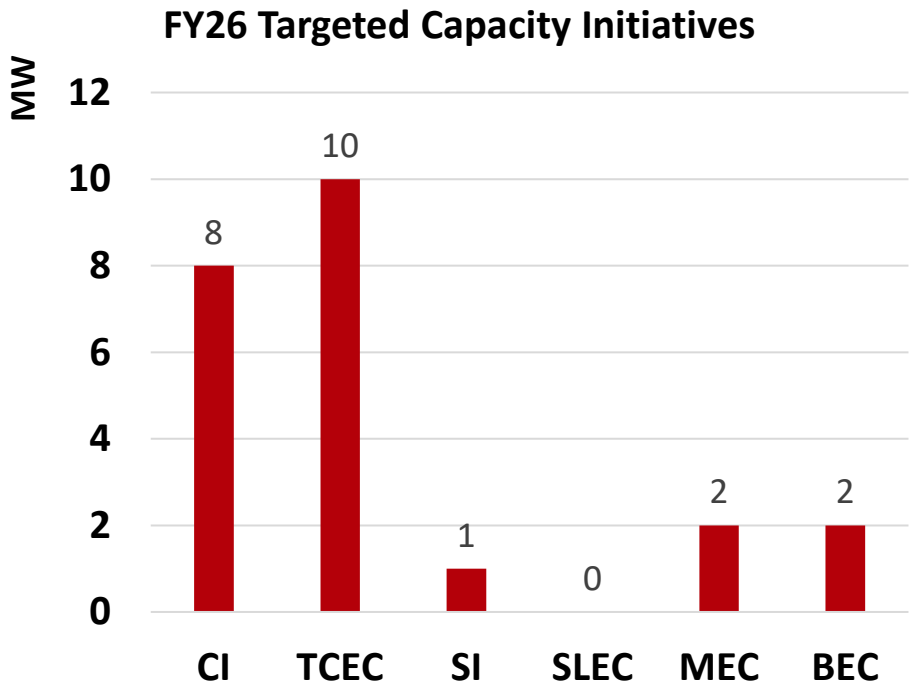
FMPA MUNICIPAL POWER

Reliable Capacity Growth Top Priority for FY26

All Sites Engaged To Find High Return Capacity Opportunities

- Recent capacity market prices increasing
- Staff evaluating capacity additions to fleet
  - Reviewing potential projects with total cost <$1,500/kw
  - Potential for >80MW enhancements before FY31
- TCEC receiving advanced gas path upgrade
- Working with Cane Island on potential authorization for use of “peak firing”
- Mulberry and Bartow will reduce station service with potential zero discharge removal

Goal to add 15MW Capacity in FY26
Potential for up to 23MW

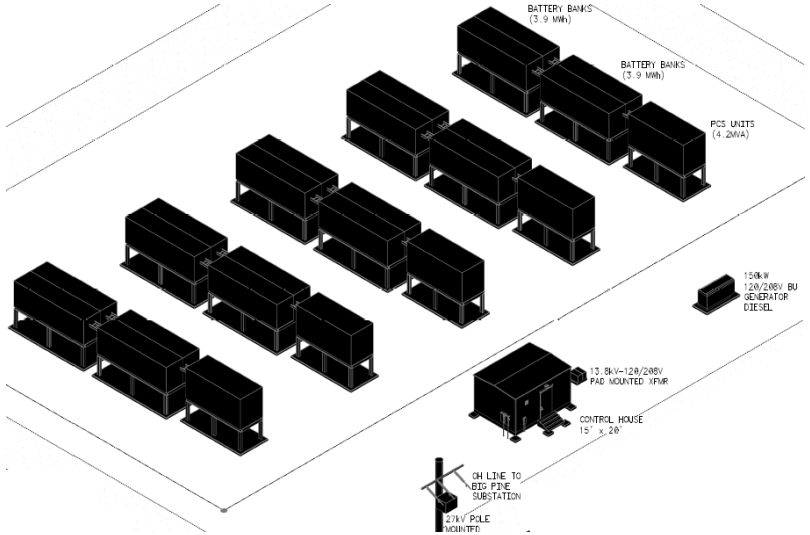


RFP Next Step Towards Go/No-go for Keys Battery

Economic Analysis To Be Updated With Current Pricing

- Goal of project: Enhance reliability & reduce costs
- Site selection complete;
  - Keys Energy offering land on Big Pine Key
- 30% design study complete
- Transmission study complete
- RFP release targeted for 12/15/25
- Pursuing potential synergies with Lake Worth Beach battery grant
- Go/No-go decision April 2026
- If go, target commissioning 2029

Rendering of Keys 15MW, 4 Hour Discharge BESS



FY 2025

Pre-Design

- S&L 30% Site Design for preferred site
- Injection Study

December 2025

Market Outreach

- RFP for BESS
- Data Gathering across range of structures

April 2026

Decision Gate

- Revisit Economics w/Firm Bids
- Update timeline

AGENDA ITEM 9 – INFORMATION ITEMS

c. FMPP PCI Software Maintenance and Support Agreement Renewal

Executive Committee
October 23, 2025

EC 9c – FMPP PCI Software Maintenance and Support Agreement Renewal

Executive Committee

October 23, 2025

PCI Products Used Across Several Pool Functions

Various Maintenance & Support Agreements Ending Soon

- PCI Energy Solutions provides industry standard software platforms
- FMPP has utilized PCI software and tools for many years
  - GenTrader – both short-term & long-term production modeling
  - GenPortal – generation data management system
  - CHP – custom developed and hosted settlement software
  - Ancillary Service modules – enables new settlement mechanisms
  - Forecasting services – load & solar forecasting that integrates with other tools
- Many agreements, change orders, and support arrangements
  - Looking to consolidate to a single agreement

Consolidation Will Simplify Continued Maintenance

Individual Agreement Extensions Would Be Needed Otherwise

- Change Order No. 10 combines all previous change orders
  - Covers maintenance, support, and hosting for all licensed products
  - Aligns support period to same 5 calendar year term
  - Fixes annual escalation rate for this and next renewal period
  - Includes ability to add new load area or solar facility forecasts
  - Includes development hours and training
- OUC the counterparty on agreement with PCI
  - Member payments allocated through Pool billing process annually

Information Only

Approval to be Requested at November EC Meeting

- Expenses included in FMPP budget, and in turn ARP budget
- FMPA cost up to $1.6M over 5 years (share of total $4.5M)
  - Limited to annual billing via Pool process, ~$300k - $350k per year
- OUC staff seeking approval from FMPP Committees & OUC Board

AGENDA ITEM 9 – INFORMATION ITEMS

d. Newberry 2nd Feed Update

Executive Committee
October 23, 2025

EC 9d - Newberry 2nd Feed Update

Executive Committee

October 23, 2025

Newberry Fastest Growing Municipal System In FL

Counties w/ Developable Land Growing – Alachua, Osceola, Lake, Polk, Volusia

ARP Members

Member	Actual Growth ('15-'24) FY	FY 2024 Actual NEL (GWh)
Newberry	3.3%	48
Kissimmee	2.4%	1,862
Bushnell[1]	1.9%	61
Ocala	1.0%	1,412
Leesburg	1.0%	522
Ft. Pierce	0.9%	607
Ft. Meade	0.7%	45
Green Cove Springs	0.4%	116
Keys	0.1%	788
Clewiston	0.0%	106
Jacksonville Beach	-0.1%	735
Starke	-0.5%	69
Havana	-1.0%	24

Other FMPA Members[2]

Utility	Sales Growth CY 2015-23
Alachua	2.6%
Bartow	1.7%
New Smyrna Beach	1.7%
Homestead	1.6%
Lakeland	1.4%
Orlando	1.2%
Lake Worth Beach	1.1%
Mount Dora	1.0%
Williston	0.8%
Jacksonville (JEA)	0.4%
Quincy	0.4%
Moore Haven	0.4%
Gainesville	0.3%
Tallahassee	0.1%
CFTOD	0.0%
Winter Park	-0.1%
Wauchula	-0.4%
Chattahoochee	-0.5%
Blountstown	-1.5%

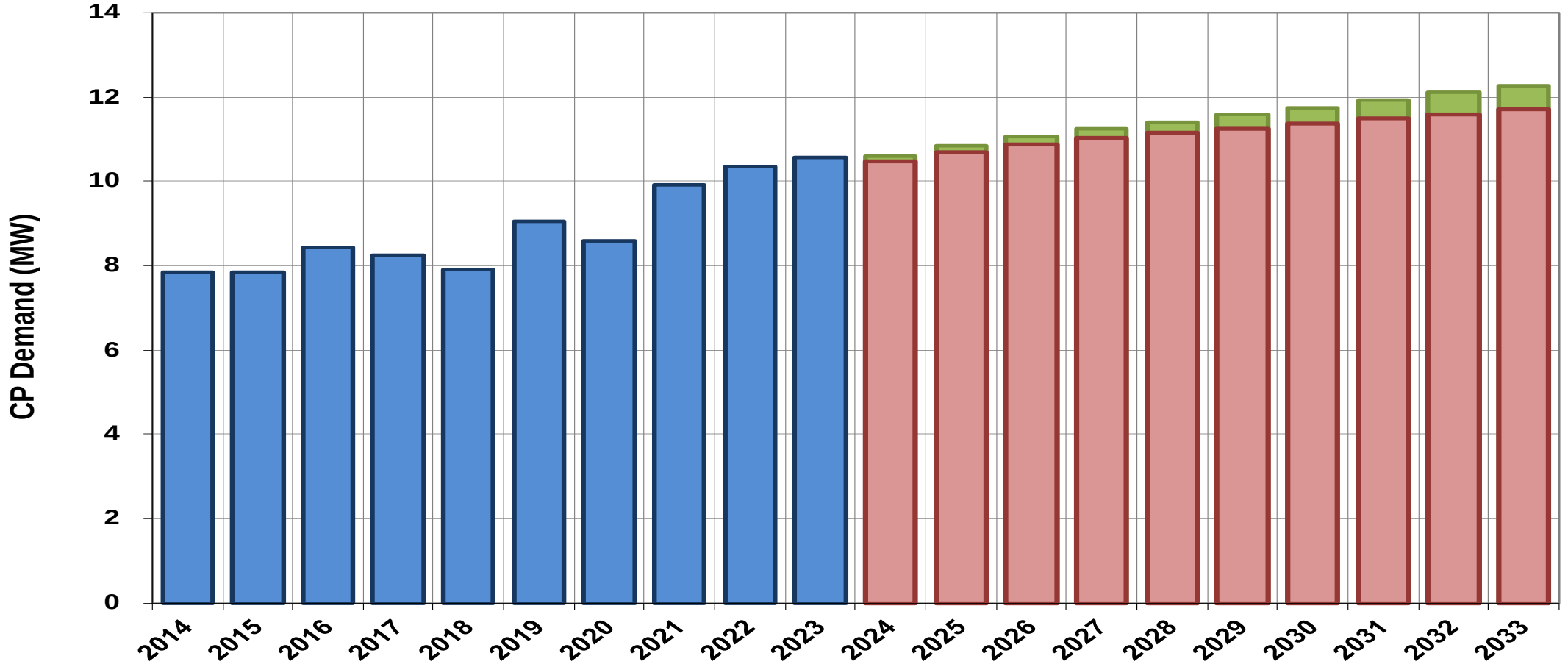
1 – Bushnell growth rate reflects weighted growth before and after SECO customer acquisition.

2 – For reference. Seminole grew (w/o Lee) at 2.2%, Duke Energy Florida grew at 0.7% and FPL w/Gulf grew at 0.7%.

CP Demand to Grow at 1.8% Per Yr. (2025-34)

Local Newberry "Non-Coincident" Peak Drives Delivery Needs

Projected Newberry Delivered Summer CP Demand



Recent Summer Substation Loading At The Edge

Coordinating With DEF On Short Term Mitigations

- July 28, 2025 – Newberry Substation experienced 14 MVA loading
- Effectively maximum rating of existing overall transformer bank
- City has made efforts to balance load across system to reduce likelihood of operating at/above emergency rating
- Duke coordinating with Newberry to investigate effectiveness of additional capacitor bank(s) for near term mitigation
- DEF, Newberry, FMPA aligned on need to pursue expedited 2nd feed

FMPA MUNICIPAL POWER

Delivery Request In Nov 2023 For Newberry Growth

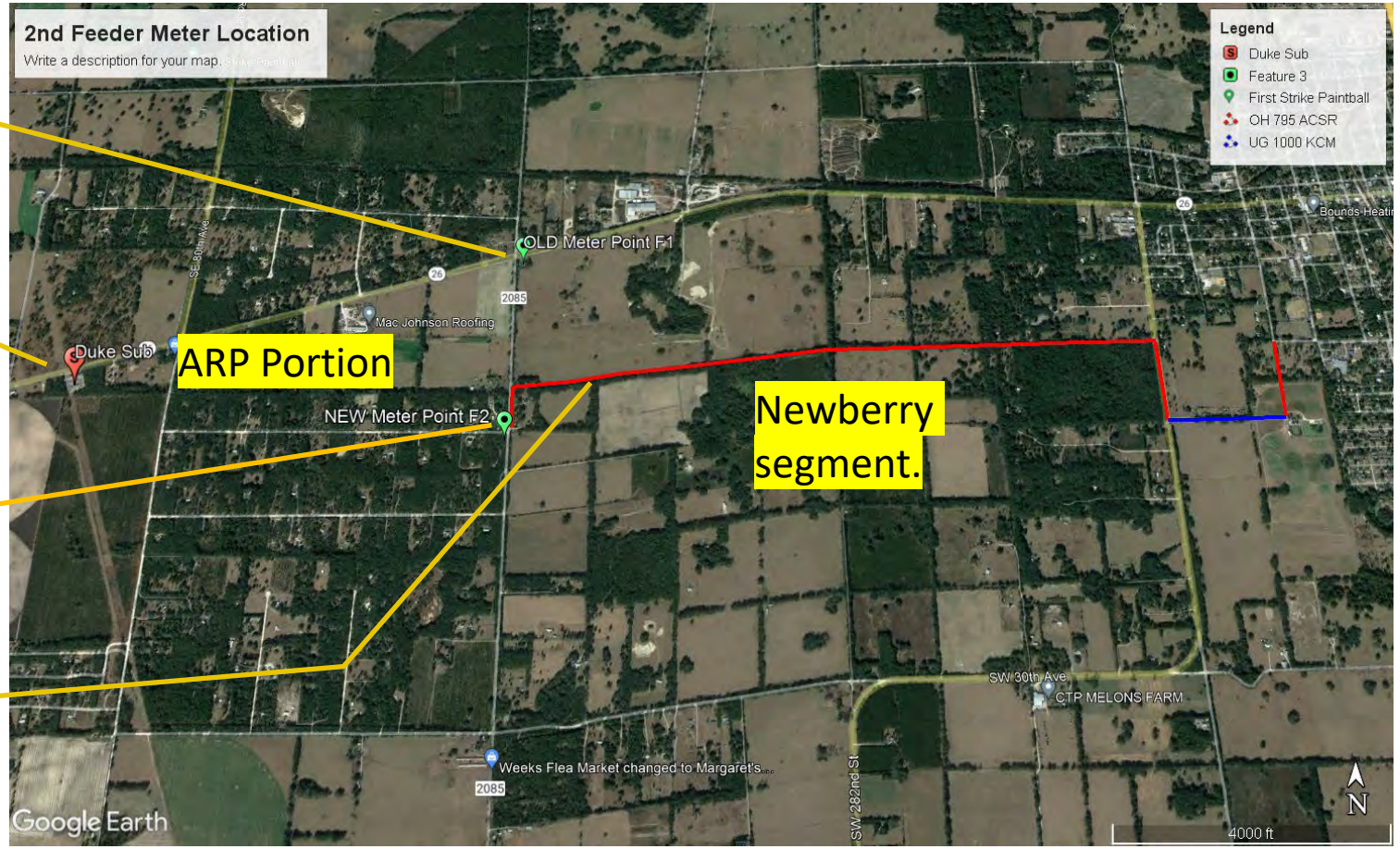
New Delivery Point South of Existing Meter Point Splits Load

Existing Meter Point 1.4 Miles from Sub

Duke's Newbery Substation

Requested 2nd Meter Point 1.5 Miles from Sub

Newberry Planned Feeder Loop



Duke Timing Depends On Signed NITS Agreement

~1.5 Miles of New Line Needed @ 13 kV Is ARP Responsibility

- ARP is responsible for costs to delivery point (DP)
  - Express line – Newberry only customer on this line – ARP pays for connection from DEF substation to the new 2nd metering point
  - Since no other DEF customers, cost cannot be socialized into the DEF NITS rate
- Duke will build, own and maintain line to DP after construction is completed
  - FMPA – ARP pays for construction
  - Possible maintenance costs adder to network transmission service costs – distinct O&M adder outside of NITS service
  - Path and design not finalized – Easements, territorial agreements and Rights of Way to be addressed
- Based on DP request supported by FMPA, Newberry requested in service date for DEF's segment (ARP's financial responsibility) of July 2026
- DEF requires NITS agreement executed to support further work

Key Provisions of Revised NITS Agreement

Costs For Detailed Design Would Inform NITS Revision

- DEF has provided Network Integration Transmission Service Agreement/Network Operating Agreement revisions to support 2nd Feed
- ~$1.3M initial estimated cost for DEF portion of express line includes overhead and underground conductor, surveying (real estate transactions), tree trimming, and flagging – **not final design**
  - EC could consider approving a cost cushion to support expedited revisions to this estimate
- DEF estimates 90 days to complete final design *after* FMPA executes NITS agreement
  - Changes also include cleanup related to Whistling Duck solar as a DNR, slightly reduced delivery point charges, and addition of a "Newberry #2" delivery point
- Estimated amount plus 10% due in full upon DEF invoice after completion of detailed design
- Direct assignment facilities charge likely includes O&M passthrough – DEF currently not fully clear on how direct O&M formula will function given time passed since last such effort – has committed to interfacing with internal SMEs on approach

Newberry Commitment to Construct Native Segment

MOU Supports Alignment With ARP For Next Steps

- Newberry has pursued grant funding sources to support construction of their native segment to complete the load split for long term reliability
- Pooled Loan program also an option to support long term financing of the segment
- System study ongoing with external consultant to further review preferred design and understand impacts on distribution system
- MOU with FMPA secures commitment from Newberry to construct their portion of the feed and to absorb the likely direct O&M pass-through
- Newberry has executed MOU; upon EC approval, FMPA can execute both the MOU and the updated NITs agreement with DEF to begin work on detailed design

Next Steps Require EC Approval of NITS/NOA w/DEF

Sequenced To Follow MOU Execution by Newberry and FMPA

- Information item expected to lead to action item in Nov/Dec for MOU and NITS agreement approval by EC
- MOU included in EC package as executed by Newberry
- NITS agreement edits proposed by DEF included in EC package
  - Staff has reviewed and found no areas of concern relative to DEF intent

AMENDED AND RESTATED

SERVICE AGREEMENT NO. 148

For

Network Integration Transmission Service

Between

Florida Municipal Power Agency (Transmission Customer)

And

Duke Energy Florida, LLC (Transmission Provider)

Amended And Restated Service Agreement For
Network Integration Transmission Service

1.0 This Amended and Restated Service Agreement, dated as of ~~September~~August 1, ~~2024~~2025, is entered into, by and between Duke Energy Florida, LLC (the Transmission Provider), and the Florida Municipal Power Agency ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff.

3.0 The Transmission Customer meets the creditworthiness standards of Attachment L of the Tariff, and thus the Transmission Provider waives the Application Deposit.

4.0 Service under this agreement shall commence on the later of (1) ~~September~~August 1, ~~2024~~2025, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission (the "Commencement Date"). Service under this Service Agreement shall continue until ~~September~~August 1, ~~2044~~2045 (the "Termination Date"), subject to successive automatic five (5)-year extensions thereafter (each a "Renewal Term"), unless notice of termination is provided at least one (1) year prior to the Termination Date or the end of the then-current Renewal Term, as applicable, and subject to Transmission Customer's reservation priority under Section 2.2 of the Tariff.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff and this Service Agreement. This Service Agreement shall govern if there is any conflict between the Tariff and this Service Agreement.

5.1 The Transmission Customer is responsible for replacing Real Power Losses associated with all transmission service in accordance with Section 28.5 of the Tariff. The Transmission Customer must identify the party responsible for supplying Real Power Losses before the transaction.

6.0 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:

Manager Tariff Administration
Duke Energy Florida, LLC
6565 38th Avenue North
St. Petersburg, FL 33710
Phone: (727)820-4818
TABS@Duke-Energy.com

Transmission Customer:

Assistant General Manager, Power Resources
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002
Phone: 407 355-7767

7.0 The Tariff, Specifications for Network Integration Transmission Service and the Network Operating Agreement, as may be amended from time to time, are incorporated herein and made a part hereof.

8.0 Service under this Service Agreement will be subject to some combination of the agreed-upon charges detailed below:

8.1 The Transmission Charge will be computed as follows:

Monthly Demand Charge = Formula Rate X Adjusted Monthly Network Load

Formula Rate = the Formula Rate determined pursuant to Schedules 10-A.1, 10-A.2 and 10-A.3 of the Tariff.

Adjusted Monthly Network Load = ((MNL) ÷ (1 - LF)) + BMG
MNL = Transmission Customer's Monthly Network Load (pursuant to Section 34.2 of the Tariff), expressed in kW.

LF = Loss Factor as applicable pursuant to 28.5 of the OATT

BMG = Behind Meter Generation (BMG) measured at the point of interconnection between the generator and the Transmission Customer's Member's distribution/transmission system and at the time coincident with the Transmission Provider's Monthly Transmission System Peak. BMG is the generation output from generators located behind the Transmission Customer's delivery points over which Transmission Customer has contractual rights for some degree of dispatch control expressed in kW. BMG generation is not intended to include generators that do not operate in parallel with the Transmission system such as, for example, emergency standby generators where load is switched from the transmission grid to be served

only by the back-up generator.

LF = Loss Factor (as applicable pursuant to Section 28.5 of the Tariff, which applies a transmission loss factor for deliveries at transmission voltages and a distribution loss factor for deliveries at distribution voltages).

8.2 System Impact and/or Facilities Study Charge(s): None.

~~8.3 Direct Assignment Facilities Charge: None.~~

8.3 Direct Assignment Facilities Charge: Transmission Provider shall construct and own a new nonintegrated transmission radial to serve Transmission Customer's load at the City of Newberry. Pursuant to Section (a)(ii) of Attachment U to the Joint OATT (DEF's Rate Treatment of New Transmission Radials), Transmission Provider will assess the Transmission Customer with a total lump-sum payment to recover the capital costs of such facility plus an O&M charge.

8.3.1 New Transmission Radial Line to Serve Transmission Customer's Load at City of Newberry:

8.3.1.1 The City of Newberry ("Newberry") is a network load under this Transmission Customer's NITSA.

8.3.1.2 Due to the natural growth in load at the City of Newberry Florida, estimated to be 3%, and a new 3 MW water treatment facility to be located in the City of Newberry, a second 13 kV radial transmission line is required to accommodate continuing network integration transmission service.

8.3.1.3 Parameters of the line are:

8.3.1.3.1 The second line will start from a new 13 k~~K~~V yard in Transmission Provider~~DEF~~'s Newberry Substation to the FMPA-Newberry second meter point on SE 90th Ave, 700 ft north of SE 71st St, on the bo~~a~~rder of Florida's Gilchrist and Alachua Counties. The line will consist of several segments of overhead and underground conductors. The preliminary plans are to build 3300 ft of underground conductors (1000 KCM ABC) and 6100 ft ~~795 ABC 336~~ N of overhead conductors (795 ABC 336). The estimated cost for construction of the line is approximately $1,300,000 dollars.

8.3.1.4 The Transmission Provider and Transmission Customer agree to the following:

8.3.1.4.1 As required by Attachment U to the Joint OATT, the Transmission Customer shall pay for all costs associated with the construction of the second 13 kV radial transmission line out of the Transmission Provider's Newberry Substation.

8.3.1.4.2 The Transmission Provider will design the 13 kV line from the line side of the associated 13 kV feeder breaker and provide an invoice to the Transmission Customer for the estimated cost of the project.

8.3.1.4.3 After the Transmission Customer pays such estimated costs, plus an additional 10%, to Transmission Provider, Transmission Provider shall commence construction.

8.3.1.4.4 If the actual costs of this project exceed the estimated costs, the Transmission Provider will provide an invoice to the Transmission Customer for the difference in costs which must be paid within 30 days. If the actual costs of the project are less than the estimated costs, the Transmission Provider will refund the difference to the Transmission Customer.

8.3.1.4.5 In the event that the Transmission Customer delays or terminates the request prior to completion of line construction, pursuant to Section 31.5 of the Joint OATT the Transmission Customer will pay Transmission Provider for all work already performed and also for any work needed to return the transmission system to safe, reliable, and compliant operating state.

8.3.1.4.6 The Transmission Provider will own, operate, and maintain the line after construction is completed. Pursuant to Attachment U to the Joint OATT, Transmission Provider shall assess a O&M charge to Transmission Customer to operate and maintain this line. This O&M ~~fee~~charge ~~and frequency of payment~~ will be based on Transmission Provider's actual costs to construct the new line and therefore will be determined after construction of the line. ~~and will be documents in a~~A future update of this NITSA will contain such charge.

8.4 Ancillary Services Charges:

8.4.1 Scheduling, System Control and Dispatch – Customer will be charged as specified in Schedule 1 of the Tariff.

Schedule 1 Monthly Rate * Adjusted Monthly Network Load (as defined above)

8.4.2 Reactive Supply and Voltage Control – Customer will be charged as specified in Schedule 2 of the Tariff.

Schedule 2 Monthly Rate * Adjusted Monthly Network Load (as defined above)

Although the Transmission Customer is required to take this ancillary service from the Transmission Provider, the Transmission Customer may reduce the charge for this service to the extent that the Transmission Customer can supply reactive power and voltage control to the Transmission Provider's Transmission System. The Transmission Customer's Network Load pursuant to Section B.2.1 of Schedule 2 of the Tariff shall be adjusted to reflect the Transmission Customer's generation resources interconnected with the Transmission Provider's System and other purchased reactive resources for which an operating agreement with the Transmission Provider is in place to provide reactive support as follows. The credited amount shall be adjusted when new resources are added.

S2M = Schedule 2 Multiplier.

COG (kW) = COG(b) + COG(p). COG (kW) represents the sum of the Transmission Customer's generation resources in Transmission Provider's System or purchased reactive resources in which the reactive output is under the control of the Transmission Provider.

COG is adjusted for the type of resource. Base Load (b) = 0.80 and Peaking (p) = 0.40

Base Load Units = Fossil Steam Units, Combined Cycle Steam Plants, Waste Recovery Steam and Renewable Fuel Steam Plans.
Peaking Units = Gas and Oil Fired Simple Cycle Units.

The Base Load Units and Peaking Units denoted below are agreed-upon sources of reactive power and voltage control for the purposes of Schedule 2. Other units may be added as appropriate during the term of this Service Agreement:

Base Load Units (for the calculation of COG(b)): None.

Peaking Units (for the calculation of COG(p)): None.

The following is an illustration of the calculation of COG (kW) that assumes

Transmission Customer has 20 MW of Base Load Units and 0 MW of Peaking Units. COG (kW) would be calculated as

COG(b) = (20 MW * .80)
COG(b) = 16 MW

COG(p) = (0 MW * .40)
COG(p) = 0 MW

Thus, the value of COG (kW) given the example above would be 16 MW.

The 0.80 and 0.40 percentage are intended to represent the percentage of time the plants are online since the VAR capability is not available to the Transmission Provider when the units are offline.

In order for a discounted rate to become effective for future resources not identified above, the Transmission Customer will need to provide a study to show that units are providing reactive support that would warrant a credit.

S2M = 1 – ((COG (kW))/((MNL) ~~/~~/ (1 – LF))

Adjusted charge under Schedule 2 = (S2M) * (Schedule 2 Rate) * ((MNL)/(1 – LF))

8.4.3 Regulation and Frequency Response – The Transmission Customer shall be exempt from charges for this ancillary service to the extent that Transmission Customer's Network Load is dynamically transferred into Transmission Customer's Control Area. Transmission Customer agrees to purchase Regulation and Frequency Response service (Schedule 3) from Transmission Provider for Transmission Customer's Network Load located in the DEF Control Area that is not dynamically transferred into Transmission Customer's Control Area.

8.4.4 Delivery Scheduling and Balancing Service – Customer agrees to purchase Delivery Scheduling and Balancing Service (Schedule 4) from Transmission Provider for the portion of Transmission Customer's Network Load that is located in the DEF Control Area and not dynamically transferred into Transmission Customer's Control Area.

In addition, Transmission Customer agrees to purchase Generator Imbalance Service (Schedule 13) either from Transmission Provider or make alternative comparable arrangements for non-dynamic scheduled resources (unit specific) located in the DEF Control Area if the Transmission Customer designates a resource of this type.

8.4.5 Spinning Reserve

The Transmission Customer self-provides spinning reserves for its load located within its Control Area. Customer agrees to purchase Spinning Reserve Service (Schedule 5) from Transmission Provider for that portion of the Transmission Customers load that is located in the Transmission Provider's Control Area and not dynamically transferred into Transmission Customer's Control Area.

Any schedule from a non-dynamic scheduled resource that exists within the DEF Control Area will be curtailed/adjusted for a loss/reduction in that unit's output. Alternatively, the Transmission Customer could elect to take Schedule 5 Spinning Reserve service, and in that case, the Transmission Provider will supply reserves for a loss/reduction in that unit's output.

8.4.6 Supplemental Reserve
The Transmission Customer self-provides supplemental reserves for its Network Load located within the Transmission Customer's Control Area. Transmission Customer agrees to purchase Supplemental Reserve Service (Schedule 6) from Transmission Provider for that portion of the Transmission Customer's load that is located in the Transmission Provider's Control Area that is not dynamically transferred into Transmission Customer's Control Area.

Any schedule from a non-dynamic scheduled resource that exists within the DEF Control Area will be curtailed/adjusted for a loss/reduction in that unit's output. Alternatively, the Transmission Customer could elect to take Schedule 6 Supplemental Reserve service, and in that case, the Transmission Provider will supply reserves for a loss/reduction in that unit's output.

8.4.7 Distribution Substation Service – Transmission Customer will be charged as specified by Schedule 11 of the Tariff.

Schedule 11 charge = Adjusted Monthly Network Load (d) x Schedule 11 rate.

Adjusted Monthly Network Load (d) = ((MNL(d) ÷ (1 – LF(d))) + BMG(d)

MNL(d) = The Customer Monthly Network Load at POD(s) at delivery voltages below 69 kV.

LF(d) = The distribution average loss factor from Section 15 of the Tariff.

BMG(d) = The Transmission Customer's generation located behind POD(s) at delivery voltages below 69 kV.

9.0 Nothing contained herein shall be construed as affecting in any way the Transmission Provider's right to unilaterally make application to the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, for any change in the Tariff or

this Service Agreement under Section 205 of the Federal Power Act, or other applicable statute, and any rules and regulations promulgated thereunder; or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder, including the right to oppose such Section 205 application or to seek changes to the Tariff or this Agreement under Section 206 of the Federal power Act.

10.0 The Transmission Customer will be responsible for Distribution Substation Service charges, Redispatch cost, Network Upgrade, and/or Direct Assignment Facilities cost as follows:

Distribution Substation Service for Newberry, Bushnell and any future delivery points at distribution level voltages per Section 8.4.7.

11.0 Point of Delivery Charges
Distribution Voltage:
Low Voltage (Socket Based meters installed on below 25 kV busses) - $~~365~~353 /mo.

Low Voltage (Switchboard Based meters installed on below 25kV busses) - $~~363~~352 /mo.

Transmission Voltage:
High Voltage (Socket Based meters located on 69kV and above busses) - $~~607~~683 /mo.

High Voltage (Switchboard Based meters located on 69 kV and above busses) - $~~650~~623 /mo.

12.0 Failure of either Party to enforce any provision of this Service Agreement will not be construed as a waiver of such provision, and will not affect the validity of the Service Agreement of the right of either Party subsequently to enforce any provision of the Service Agreement. Any waiver at any time by either Party of its rights with respect to this Service Agreement will not be considered a waiver with respect to any subsequent matter.

[Signatures on following page.]

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

Transmission Provider:

By: ~~/s/ Ben I. Harrison, Jr.~~
Name: Ben I. Harrison, Jr.
Title: VP, Grid Planning & Operations
Date: ~~9-23-2024~~

Transmission Customer:

By: ~~/s/ Jacob Williams~~
Name: Jacob A. Williams
Title: General Manager & CEO
Date: ~~09/20/2024~~

Specifications For Network Integration
Transmission Service

1.0 Term of Transaction: From ~~September~~August 1, ~~2024~~2025 (the "Commencement Date") to ~~September~~August 1, ~~2044~~2045 (the "Termination Date"), subject to successive automatic five (5)-year extensions thereafter (each a "Renewal Term"), unless notice of termination is provided at least one (1) year prior to the Termination Date or the end of the then-current Renewal Term, as applicable.

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates: ~~-~~The Transmission Customer's capacity and energy are provided by resources located in the Florida Municipal Power Pool (FMPP) Control Area. A current list of the Transmission Customer's resources shall be maintained on the Transmission Provider's OASIS.

3.0 Network Resources

(1) Transmission Customer Generation Owned or Leased:

Resource	Capacity	
Cane Island	530 MW	
Orlando Cogen/Sand Lake Energy Center	120 MW	
Mulberry Cogen	115 MW	
Orange Cogen	104 MW	Effective ~~01/01~~1/1/2026

(2) Transmission Customer Generation Purchased:

Source	Capacity	
OUC Share	131 MW	
Whistling Duck I Solar	51 MW	Effective 2/2/2026

Total Network Resources: (1) + (2) = 896 MW Effective until 1/1/2026

Total Network Resources: (1) + (2) = 1000 MW Effective 1/1/2026

Total Network Resources: (1) + (2) = 1051 MW Effective 2/1/2026

4.0 Network Load

~~City~~The Transmission Customer serves load of ~~Ocala 230 kV~~
~~City of Leesburg 69 kV~~
~~City~~the cities of Bushnell ~~13 kV~~
~~City of~~, Ft. Meade, Leesburg, Newberry ~~13 kV~~
~~Town~~, and Ocala, and the town of Havana ~~69 kV~~, whose network load on

an aggregated basis is estimated as set forth below.

~~City of Ft. Meade 69 kV~~

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Winter MW	373	378	381	382	385	387	392	393	396	398
Summer MW	437	442	444	448	451	455	458	463	467	471

The Transmission Customer's 10 year projected load connected to Transmission Provider's transmission system is provided annually to the Transmission Provider as part of ongoing joint planning modeling processes at the Florida Reliability Coordinating Council (FRCC).

5.0 NA

6.0 Designation of party(ies) subject to reciprocal service obligation: None.

7.0 Name(s) of any Intervening Systems providing transmission service: Orlando Utilities Commission provides transmission service for certain FMPA Network Resources. Florida Municipal Power Pool ("FMPP") provides certain ancillary services through the Transmission Provider's interfaces with the FMPP Control Area.

8.0 Party Responsible for Providing Real Power Losses: The Transmission Customer.

9.0 Transmission Credits: As of the execution of this Agreement, FMPA does not request credits for its transmission facilities. However, FMPA reserves the right to seek credits under Section 30.9 of the OATT for FMPA or FMPA member transmission facilities in the future – including, but not limited to, credits for facilities constructed prior to July 13, 2007.

10.0 Points of Delivery: See Exhibit 1.

EXHIBIT 1

POD	Delivery kV	Meter Location	Meter kV	Meter Comp (Y/N)	Amount of Charge
TOWN OF HAVANA #1	69	Customer's Sutter Creek Sub	13	Y	$~~365~~353/mo.
TOWN OF HAVANA #2	69	Customer's Sutter Creek Sub	13	Y	$~~365~~353/mo.
CITY OF NEWBERRY ~~#1~~	13	On the 13 kV Feeder	13	N	$~~365~~353/mo.
CITY OF NEWBERRY #2 (Effective 7/1/2026)	13	On the 13 kV Feeder	13	Y	$353/mo.
LEESBURG NORTH #1	69	Customer's Leesburg N. Sub	13	Y	$~~363~~352/mo.
LEESBURG NORTH #2	69	Customer's Leesburg N. Sub	13	Y	$~~363~~352/mo.
LEESBURG AIRPORT #1	69	Customer's Airport Sub	13	Y	$~~363~~352/mo.
LEESBURG AIRPORT #2	69	Customer's Airport Sub	13	Y	$~~363~~352/mo.
LEESBURG EAST #1	69	Customer's Leesburg E. Sub	13	Y	$~~363~~352/mo.
LEESBURG EAST #2	69	Customer's Leesburg E. Sub	13	Y	$~~363~~352/mo.
LEESBURG EAST #3	69	Customer's Leesburg E. Sub	13	Y	$~~363~~352/mo.
14TH STREET #1	69	Customer's Leesburg E. Sub	13	Y	$~~363~~352/mo.
14th STREET #2	69	Customer's Leesburg E. Sub	13	Y	$~~363~~352/mo.
PICCIOLA #1	69	Customer's Picciola Sub	13	Y	$~~363~~352/mo.
PICCIOLA #2	69	Customer's Picciola Sub	13	Y	$~~363~~352/mo.
CITY OF FORT MEADE #1	69	Customer's Fort Meade Sub	13	Y	$~~365~~353/mo.
CITY OF FORT MEADE #2	69	Customer's Fort Meade Sub	13	Y	$~~365~~353/mo.
DEARMIN #1	230	Customer's Dearmin Sub	230	N	$~~650~~623/mo.
DEARMIN #2	230	Customer's Dearmin Sub	230	N	$~~650~~623/mo.
SILVER SPRINGS N (ERGLE)	230	Seminole's Silver Spr. Sub	230	N	$~~607~~583/mo.
SILVER SPRINGS N (SHAW)	230	Seminole's Silver Sp N Sub	230	N	$~~607~~583/mo.
BUSHNELL #1	13	On the 13 kV Feeder	13	N	$~~363~~352/mo.
BUSHNELL #2	13	On the 13 kV Feeder	13	N	$~~363~~352/mo.
CITY OF OCALA AIRPORT	69	Customers Ocala Airport Sub	69	Y	$~~650~~623/mo.

Network Operating Agreement

The Transmission Provider and Florida Municipal Power Agency ("Transmission Customer" or "FMPA") agree that the provisions of this Network Operating Agreement ("NOA") and the Network Integration Transmission Service Agreement between the Parties dated ~~September~~August 1, ~~2024~~2025 ("NITSA") govern the Transmission Provider's provision of Network Integration Transmission Service to the Transmission Customer in accordance with the Transmission Provider's Open-Access Transmission Tariff ("Tariff"), as it may be amended from time to time. Unless specified herein, capitalized terms shall refer to terms defined in the Tariff.

1.0 Control Area Requirements

For the purposes of this NOA, the term "Control Area" herein shall be considered the same as the NERC definition of "Balancing Authority Area" and the terms may be used interchangeably. The Transmission Customer shall: (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation ("SERC") and the Florida Reliability Coordinating Council ("FRCC"); and/or (ii) satisfy its Control Area requirements, including all Ancillary Services, by contracting with the Transmission Provider; and/or (iii) satisfy its Control Area requirements, including all Ancillary Services, by contracting with another entity that can satisfy those requirements in a manner that is consistent with the Tariff and Good Utility Practice and satisfies NERC and SERC standards; provided, further, that the Transmission Provider and Transmission Customer may agree upon variations of the above-listed items in order to satisfy the latter's Control Area requirements. The Transmission Provider and the Transmission Customer shall each plan, construct, operate and maintain its facilities and system in accordance with Good Utility Practice, which

shall include, but not be limited to, all applicable guidelines of NERC, SERC, and FRCC, as they may be modified from time to time, and any generally accepted practices in the region that are consistently adhered to by the Transmission Provider.

2.0 Redispatch Procedures

(a) If the Transmission Provider determines that redispatching resources (including reductions in off-system purchases and sales) to relieve an existing or potential transmission constraint is required to ensure the reliable operation of the Transmission System, the Transmission Provider will redispatch the Transmission Provider's Network Resources and request the Network Customers, including the Transmission Customer, to redispatch their Network Resources, on a non-discriminatory least-cost basis, without regard to the ownership of such resources. The Transmission Provider will maintain a non-discriminatory least-cost redispatch protocol (as attached in Exhibit 1 to this NOA) and will apprise the Transmission Customer in writing of its redispatch practices and procedures as they may be modified from time to time pursuant to a Section 205 filing at the FERC.

(b) The Transmission Customer will submit verifiable cost data for its Network Resources, which represent the estimated cost to the Transmission Customer of changing the generation output of its Network Resources, to the Transmission Provider. This cost data will be used, along with similar data for the Transmission Provider's and other Network Customers' resources, as the basis for least-cost dispatch. The Transmission Provider's bulk power operations personnel will keep this data confidential, including not disclosing it to the Transmission Provider's or

other entities' marketing personnel or any person not entitled to same under the law. By January 1st of each year, the Transmission Customer shall submit an updated merit order list as described above to the Transmission Provider's Energy Control Center. The Transmission Provider will implement least-cost redispatch consistent with its existing contractual obligations and its current practices and procedures for its own resources in accordance with section 33.2 of the Tariff. The Transmission Customer shall respond within ten (10) minutes to requests for redispatch from the Transmission Provider's Energy Control Center such that the requested redispatch will occur as soon as practicable.

(c) The Transmission Customer may audit, at its own expense, particular redispatch events (including, but not limited to, the cause, necessity, method of redispatch, and resulting costs and cost allocation) during normal business hours following reasonable notice to the Transmission Provider. Either the Transmission Customer or the Transmission Provider may request an audit of the other Party's cost data (which data, in an audit initiated by the Transmission Customer, shall include the cost data of all Network Customers) and the auditing Party will be required to keep all cost data confidential.

(d) Once redispatch has been implemented, the Transmission Provider will book in a separate account the redispatch costs (i,e., the total production costs including sales and purchases with and without the redispatch during the redispatch period) incurred by the Transmission Provider and all Network Customers, including the Transmission Customer, based on the submitted cost data. The Transmission Provider and all Network Customers, including the Transmission Customer, will

each bear a proportional share of the total redispatch costs pursuant to section 33 of the Tariff. The redispatch charge or credit, as appropriate, will be reflected on the Transmission Customer's monthly bill.

3.0 Metering

(a) Unless otherwise agreed and except as provided in Section 3(b), the Transmission Provider will be responsible for the installation, operation, maintenance, repair and replacement of all metering equipment necessary to provide Network Integration Transmission Service. The charge for such equipment and service is included in the Point of Delivery charges set forth in the NITSA. Such metering equipment shall conform to Good Utility Practice and, if it is electrically located in the Transmission Provider’s Control Area, the standards and practices of the Transmission Provider's Control Area. Prior to installation of any such metering equipment by a Party or its agents, the Transmission Provider and the Transmission Customer shall review the metering equipment to ensure conformance with such standards or practices.

(b) Unless otherwise agreed, electric capacity and energy received by the Transmission Provider from the Transmission Customer will be measured by meters installed and maintained by the Transmission Customer at the Transmission Customer's Network Resources if such Network Resources are electrically located within the Transmission Provider’s Control Area. When measurement is made at any location other than a Point of Receipt, suitable adjustment for losses between the point of measurement and the Point of Receipt will be agreed upon in writing between the Parties hereto and will be applied to

all measurements so made. If not otherwise provided for herein or in the NITSA, metered receipts used in billing and accounting hereunder will in all cases include adjustment for such losses.

(c) Electric capacity and energy delivered to the Transmission Customer's Points of Delivery by the Transmission Provider will be measured by meters installed by the Transmission Provider at the Points of Delivery. When measurement is made at any location other than a Point of Delivery (e.g., at the low-side of the Transmission Customer-owned transformation facilities), suitable adjustment for losses between the point of measurement and the Point of Delivery will be agreed upon in writing between the Parties hereto and will be applied to all measurements so made. Metered receipts used in billings and accounting hereunder will in all cases include adjustments for such losses.

(d) Meters at the Transmission Customer’s Network Resources physically located within the Transmission Provider’s Control Area and at Network Load Points of Delivery will be tested at least biennially. Transmission Provider will not make changes to these meters, including software changes, without affording Transmission Customer reasonable notice of and an opportunity to witness such changes. In addition, each Party will, upon request of the other Party and at the other Party’s expense (except as provided below), test any of its meters at the Transmission Customer’s Network Resources within the Transmission Provider’s Control Area or at Network Load Points of Delivery which are used for determining the receipt or delivery of capacity and energy by the Transmission Provider. Representatives of the requesting Party will be afforded reasonable

notice of and an opportunity to witness such tests. In the event the test shows the meter to be inaccurate by more than ± two percent (2%), the non-requesting Party will make any necessary adjustments, repairs or replacements thereon and will bear the costs of the testing and corrective action.

(e) In the event any meter used to measure capacity and energy fails to register or is found to be inaccurate, appropriate billing adjustments, based on the best information available, will be agreed upon by the Parties hereto. Any meter tested and found to be not more than two percent (2%) above or below normal will be considered to be correct and accurate insofar as correction of billing prior to such determination is concerned. If, as a result of any test, a meter is found to register in excess of two percent (2%) either above or below normal, then the readings of such meter previously taken will be corrected according to the percentage of inaccuracy so found, but no correction will extend beyond ninety (90) days prior to the day on which inaccuracy is discovered by such test.

(f) Each Party will have the right to install, at its expense and with access to the other Party's current and potential transformers, suitable metering equipment at any Point(s) of Receipt or Delivery, as herein provided for the purpose of checking the meters installed by the other Party.

(g) Each Party will read the meters owned by it, except as may be mutually agreed, and will furnish to the other Party all meter readings and other information required for operations and for billing purposes under the NITSA and/or NOA. Such information will remain available to the other Party for at least three (3) years.

4.0 Control Area and Data Equipment

(a) Unless otherwise agreed, the Transmission Provider will be responsible for the installation, modification, operation, maintenance, repair and replacement of all data acquisition equipment, protection equipment, and any other associated equipment and software which may be required within the Transmission Provider’s Control Area by either Party for the Transmission Customer to operate in accordance with its choice under Section 1.0 of this NOA. The charge for such equipment and service shall be set forth in the NITSA. Such equipment and software shall conform to Good Utility Practice and to the written standards and practices of the Transmission Provider's Control Area as published by the Transmission Provider and made available to the Transmission Customer. Prior to installation of any control area and data equipment by Transmission Customer or its agents the Transmission Provider and the Transmission Customer shall review the equipment and software required by this section to ensure conformance with such standards or practices as consistently adhered to by the Transmission Provider and provided in writing to the Transmission Customer.

(b) The selection of real time telemetry and data to be received by the Transmission Provider's Energy Control Center from the Transmission Customer shall be determined by agreement of the Transmission Provider and the Transmission Customer, as deemed necessary for reliability, security, economics, and/or monitoring of system operations. This telemetry and data include, but are not limited to, loads, line flows, voltages, generator output, and breaker status at any of the Transmission Customer's transmission facilities within the Transmission

Customer's Control Area. To the extent telemetry is required that is not available on the Transmission Customer's transmission facilities within the Transmission Customer's Control Area, the Transmission 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 the Transmission Provider's Energy Control Center**.**

(c) Each Party shall be responsible for implementing any computer modifications or changes required to its own computer system(s) as necessary to implement this Section.

5.0 Operating Requirements

(a) The Transmission Customer shall comply with the Transmission Provider's power factor requirements set forth in Attachment V to the Tariff.

(b) The Transmission Provider power factor aggregation zones, which will be posted and maintained on the Transmission Provider's OASIS, are:

- Apopka
- Deland
- Jamestown
- Longwood
- Inverness
- Monticello
- Ocala Operations Center
- Buena Vista
- Lake Wales/Highland
- Southeast Orlando
- Clearwater
- Seven Springs
- St. Petersburg
- Walsingham
- Winter Garden

The Transmission Customer power factor aggregation zones, which, along with the power

factor aggregation zones of all Network Customers, will be posted and maintained on the Transmission Provider's OASIS, are:

- Ocala
- Havana
- Bushnell
- Newberry
- Leesburg
- Ft. Meade

(c) Insofar as practicable, the Transmission Provider and the Transmission Customer shall protect, operate, and maintain their respective systems so as to avoid or minimize the likelihood of disturbances which might cause impairment of service on the system(s) of the other. The Parties shall implement load shedding programs to maintain the reliability and integrity of the Transmission System, consistent with the standards of NERC and SERC, as provided in Section 33.6 of the Tariff. Load shedding shall include: (1) automatic load shedding by under frequency relay or (2) manual load shedding. Automatic load shedding devices will operate without notice. When manual load shedding is necessary, the Transmission Provider shall notify the Transmission Customer's dispatchers or schedulers of the required action, and the Transmission Customer shall comply within ten (10) minutes or as soon as practicable. The Transmission Provider shall implement load shedding on a non-discriminatory basis as between itself and the Transmission Customer.

(d) The Transmission Customer shall, at its own expense, provide, operate, and maintain in service under frequency load shedding equipment. The under frequency load shedding equipment shall enable the automatic disconnection of

its Network Load in a manner consistent with that followed by the Transmission Provider and as required by the FRCC.

The installation of under frequency relays to accomplish any load shedding in addition to that already installed shall be completed on a schedule agreed to by the Network Operating Committee. The Network Operating Committee may review the amount of load that would be disconnected automatically and make such adjustments and changes as necessary.

(e) The Transmission Provider and Transmission Customer will implement and maintain Network Operating Procedures, which shall be attached to this agreement as Exhibit 2, and automated processes to facilitate the Transmission Customer's utilization of Transmission Provider's Transmission System to deliver resources to its Network Load in accordance with Transmission Provider's OATT. The Network Operating Procedures shall be in accordance with applicable NERC, SERC requirements, Transmission Provider's Business Practices and are also intended to provide the Transmission Customer with the flexibility to self-provide ancillary services as permitted under the Tariff.

i. For purposes of the Network Operating Agreement and the Network Operating Procedures, Pool FMPA West (PFW) is the aggregate of Transmission Customer's Network Load that is connected to the Transmission Provider's Transmission System and pseudo-tied into the Transmission Customer's Control Area. PFW is the Point of Delivery for all dynamic transfers and scheduled deliveries from the Transmission Customer to the portion of its Network Load that is comprised of the City

of Ocala, the City of Leesburg, the City of Bushnell, the City of Ft. Meade, the City of Newberry, and the Town of Havana ("FMPA Dynamically Transferred Network Load").

ii. As of the Commencement Date, the Network Operating Procedures shall provide for Transmission Customer's use of pseudo-tie tags to forecast its use of resources located within Transmission Customer's native control area to serve PFW, as more fully described in the Network Operating Procedures. In the event that either party presents a more effective method of forecasting Transmission Customer's use of resources located within Transmission Customer's native control area to serve PFW without the use of pseudo-tie tags, then Transmission Provider and Transmission Customer shall negotiate in good faith whether it is appropriate to amend the Network Operating Procedures to adopt the new method.

6.0 Operational Information

The Transmission Customer shall provide via the Florida Transaction Management System ("FTMS"), or its successor, data needed for the safe and reliable operation of the Transmission Customer's Control Area and the Transmission Provider's Control Area and to implement the provisions of the Tariff, as set forth below. The Transmission Provider will treat this information as confidential and will not divulge it to its marketing personnel or otherwise.

(a) The Transmission Customer shall provide by December 31st of each year the Transmission Customer's Network Resource availability forecast (e.g., all planned resource outages, including off-line and on-line dates) for the following year.

Such forecast shall be made in accordance with Good Utility Practice. The Transmission Customer shall inform the Transmission Provider, in a timely manner, of any changes to the Transmission Customer's Network Resource availability forecast. In the event that the Transmission Provider determines that such forecast cannot be accommodated due to a transmission constraint on its Transmission System, and such constraint may jeopardize the security of its Transmission System or adversely affect the economic operation of either the Transmission Provider or the Transmission Customer, the provisions of Section 33.2 of the Tariff will be implemented.

(b) The Transmission Customer shall provide via FTMS at least thirty-six (36) hours advance notice of the Transmission Customer’s best forecast of any planned Network Resource outage(s) and other operating information that is reasonably deemed appropriate. In the event that such planned outages cannot be accommodated due to a transmission constraint on the Transmission Provider's Transmission System, the provisions of Section 33.2 of the Tariff will be implemented.

(c) Each Party shall notify and coordinate with as much advance notice as reasonably possible with the other Party prior to the beginning of any work by the other Party (or contractors or agents performing on its behalf) which may directly or indirectly have adverse effects on the reliability and security of the other Party’s system.

(d) The Transmission Customer is responsible for replacing Real Power Losses associated with all transmission service in accordance with Section 28.5 of the Tariff.

7.0 Network Planning

In order for the Transmission Provider to plan, on an ongoing basis, to meet the Transmission Customer's requirements for Network Integration Transmission Service, the Transmission Customer shall make available, by January 1st of each year, updated information (current year and 10-year projections) for Network Loads and Network Resources pursuant to Attachment N.

8.0 Character of Service

Power and energy delivered under the NITSA and this NOA shall be delivered as three-phase alternating current at a nominal frequency of sixty (60) Hertz, and at the nominal voltages at the Points of Delivery and Receipt.

9.0 Transfer of Power and Energy Through Other Systems

Since the Transmission Provider's Transmission System is, and will be, directly and indirectly connected with other electric systems, it is recognized that, because of the physical and electrical characteristics of the facilities involved, power delivered under the NITSA and this NOA may flow through such other systems. The Parties agree to advise other electric systems as deemed appropriate of such scheduled transfers and to attempt to maintain good relationships with affected third parties. If the Transmission Provider is charged by another electrical system for loop flow charges, then the Transmission Provider may seek recovery of these charges from the Transmission Customer based on

its cost responsibility pursuant to § 205 of the Federal Power Act, and the Transmission Customer retains its rights to oppose such filing.

10.0 Notice

Any Notice or request made to or by either Party regarding this NOA shall be made to the representative of the other Party as indicated in the NITSA.

11.0 Incorporation

The Tariff, the NITSA, and the attachments hereto, each as may be amended from time to time, are incorporated herein and made a part hereof.

12.0 Term

The term of this NOA shall be concurrent with the term of the NITSA between the Parties.

~~(The following pages are the signature pages)~~

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

Transmission Provider:

By: */s/ Ben I. Harrison, Jr.*

Name: Ben I. Harrison, Jr.

Title: VP, Grid Planning & Operations

Date: 9-23-2024

Transmission Customer:

By: */s/ Jacob Williams*

Name: Jacob A. Williams

Title: General Manager & CEO

Date: 09/20/2024

Network Operating Agreement

Exhibit 1

Least Cost Redispatch Protocol

The Transmission Provider's System Operations will determine the least cost (to the extent possible) reliability redispatch for the Transmission Customer and Transmission Provider and other Network Customers without regard to resource ownership. The Transmission Customer will be expected to perform the redispatch requested by the Transmission Provider until the constraint has been removed. The Transmission Provider's System Operations will determine the actual reliability redispatch cost and determine the cost responsibility of the Transmission Provider and other Network Customers, including the Transmission Customer, in accordance with the formula below. The purpose of this formula is to ensure a fair (i.e., proportionate based on Load Ratio Shares) allocation of the production costs attributable to redispatch.

Cost Allocation Methodology:

PC_{DEF} - Transmission Provider's and other Network Customers' (excluding Transmission Customer's) total production costs, including all sales and purchases, that would have been incurred but for the constraint redispatch during the period of the constraint redispatch.

PC_{TC} - Transmission Customer's total production costs, including sales and purchases, that would have been incurred but for the constraint redispatch during the period of the constraint redispatch.

PC_{DEF}' - Transmission Provider's and other Network Customers' (excluding Transmission Customer's) total production costs, including sales and purchases during the period of the constraint redispatch.

PC_{TC}' - Transmission Customer's total production costs, including sales and purchases, during the period of the constraint redispatch.

LRP_{TC} - The Transmission Customer's Load Ratio Share percentage.

PC - The total incremental production costs to relieve the constraint:

$PC = (PC_{DEF}' + PC_{TC}') - (PC_{DEF} + PC_{TC})$.

CR_{TC} - The cost responsibility of the Transmission Customer for the total incremental production costs to relieve the constraint:

$CR_{TC} = PC * LRP_{TC.}$

AC_{TC} - The incremental cost/saving incurred by the Transmission Customer to relieve the Constraint:

$AC_{TC} = (PC_{TC}' – PC_{TC})$.

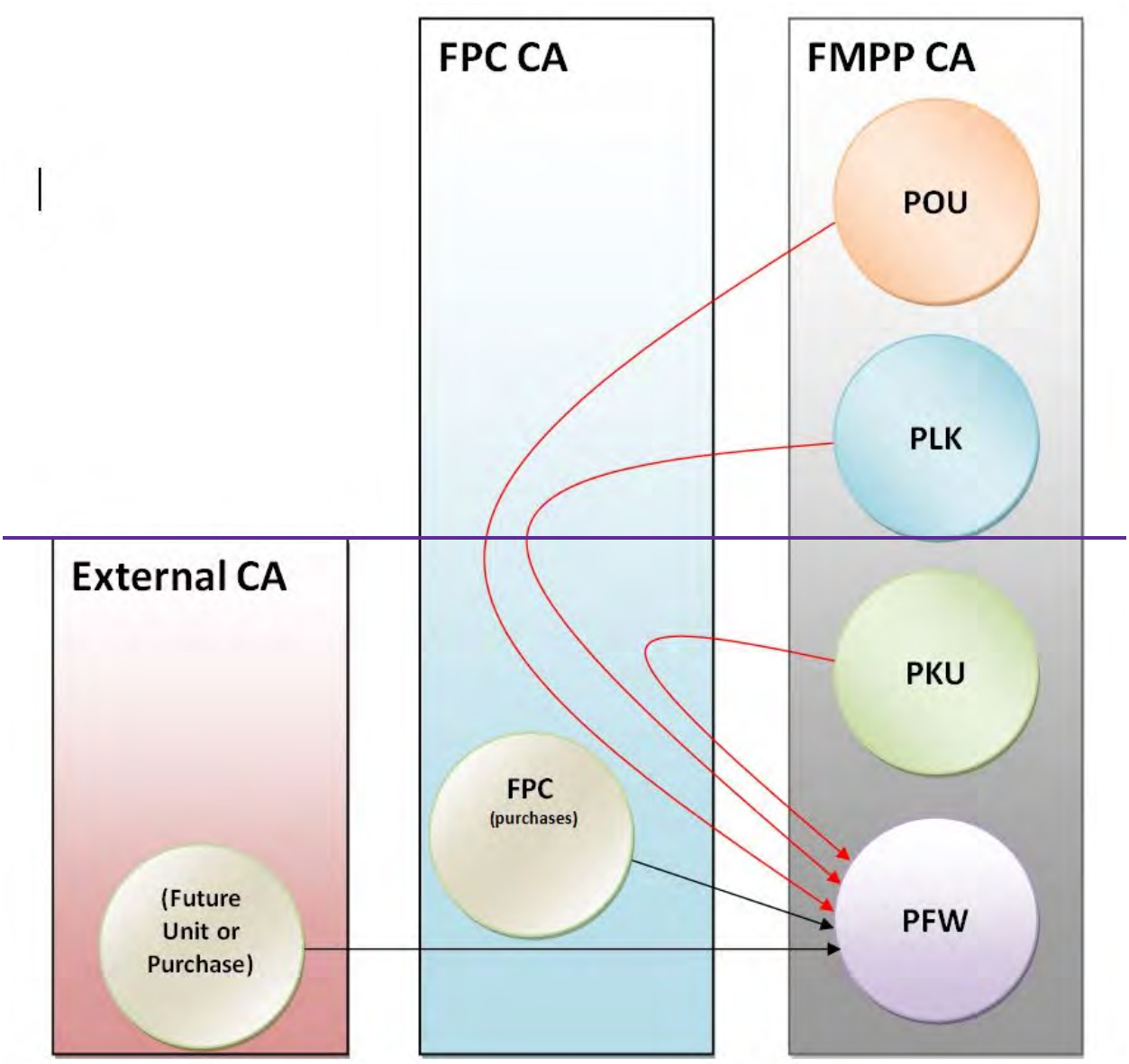
CC_{TC} - The charge or credit to the Transmission Customer:

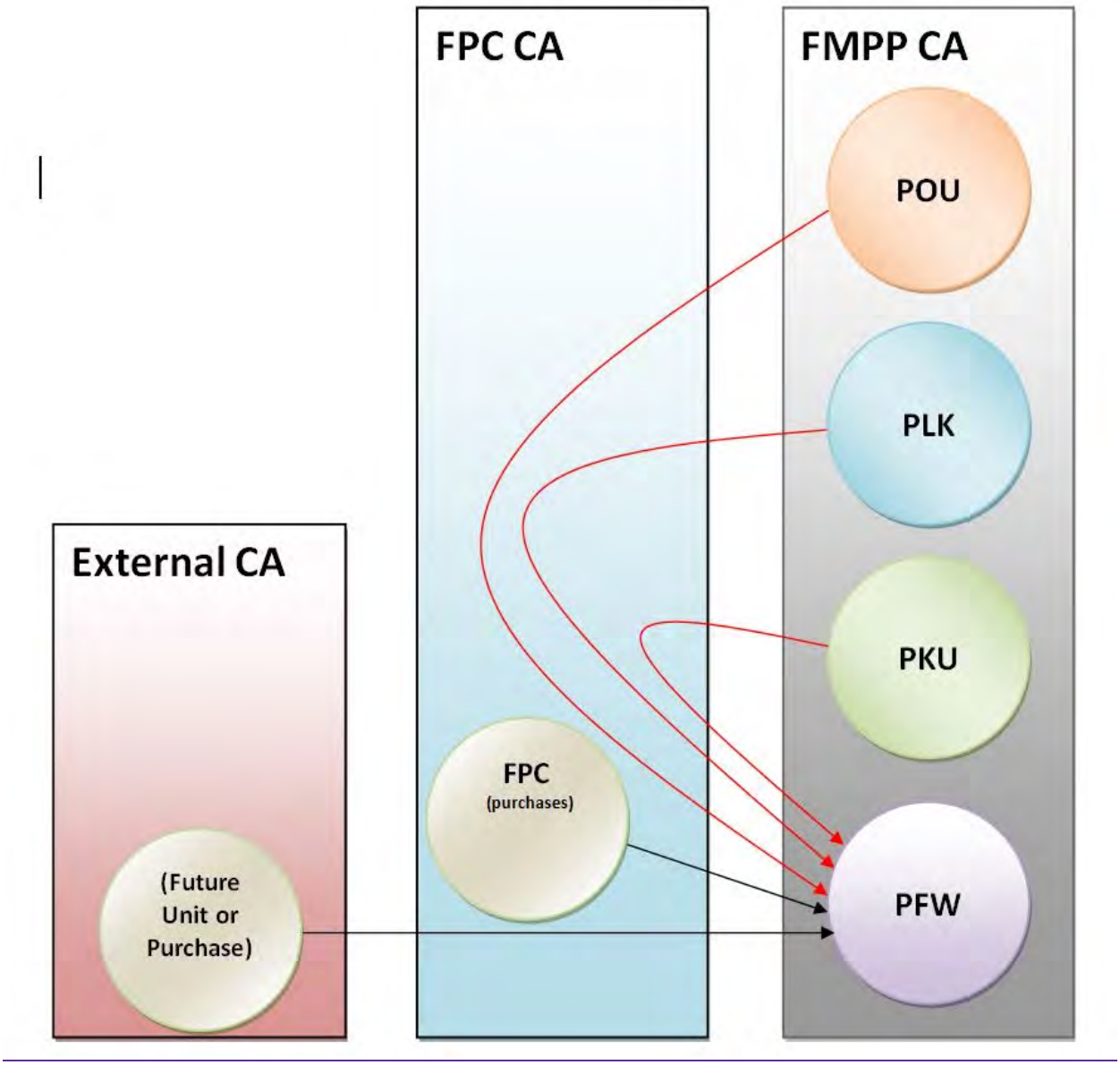
$CC_{TC} = AC_{TC} – CR_{TC.}$

Network Operating Agreement

Exhibit 2

NETWORK OPERATING PROCEDURES




FPC CA
FMPP CA
POU
PLK
PKU
PFW
External CA
(Future Unit or Purchase)
FPC
(purchases)

NETWORK OPERATING PROCEDURES

PART A - FMPA DYNAMICALLY TRANSFERRED NETWORK LOAD

1. The purpose of this part A of the Network Operating Procedures is to describe the process by which FMPA shall serve its Network Load that is located on the DEF's Transmission System and dynamically transferred into the FMPP Control Area ("FMPA Dynamically Transferred Network Load") through a pseudo-tie arrangement with DEF. As of the Commencement Date, FMPA's Dynamically Transferred Network Load consists of Pool FMPA West, as defined in section 5(e)i of the Network Operating Agreement. FMPA Network Resources to serve FMPA Network Load are those resources designated as such in DEF's OASIS. FMPA may make changes to Network Resources designated to serve FMPA Network Load using Network Integration Transmission Service (NITS) by submitting an OASIS request and DNR forms pursuant to DEF's OATT and OATT process. For purposes of these Network Operating Procedures, the term "Native FMPP Control Area" shall mean the resources and load of the FMPP members that are physically connected, under normal conditions, to the FMPP Control Area and not pseudo-tied to the FMPP Control Area. As of the Commencement Date, FMPP members include FMPA (All-Requirements Power Supply Project), OUC and Lakeland Electric.

2. FMPA will use NITS to transfer energy from resources located both within and external to the FMPP Control Area to serve FMPA Dynamically Transferred Network Load.

    a. FMPA will provide information to DEF on the forecasted use of its Network Resources located within the Native FMPP Control Area to serve FMPA Dynamically Transferred Network Load through the use of pseudo-tie tags. The path designations in DEF's OASIS (as indicated in Table A-1 below) will be used to create the pseudo-tie tags. Path designations are subject to change and addition as appropriate.

    b. FMPA may use non-designated resources located within the Native FMPP Control Area to serve FMPA Dynamically Transferred Network Load using secondary service pursuant to DEF's OATT. Secondary service will be reserved on the DEF OASIS, and FMPA will submit pseudo-tie tags when using the OASIS paths on DEF's OASIS that are indicated in Table A-1 below. Path designations are subject to change and addition as appropriate.

Table A-1: OASIS Path Designations for Resources Located within the Native FMPP Control Area

TRANSFER	OASIS	TAG	SCHEDULE
PLK – PFW	F/FPC/FMPP-FMPP/PLK-PFW	PSUEDO-TIE TAG #1	NO
POU –PFW	F/FPC/FMPP-FMPP/POU-PFW	PSUEDO-TIE TAG #2	NO
PKU –PFW	F/FPC/FMPP-FMPP/PKU-PFW	PSUEDO-TIE TAG #3	NO

c. Transactions from Network Resources external to the Native FMPP Control Area will be tagged and scheduled as normal tags using the path designations in DEF's OASIS (as indicated in Table A-2 below). Path designations are subject to change and addition as appropriate.

d. FMPA may use non-designated resources external to the Native FMPP Control Area to serve FMPA Dynamically Transferred Network Load using secondary service pursuant to DEF's OATT. Secondary service will be reserved on the DEF OASIS and will be tagged and scheduled as normal tags when using the OASIS paths on DEF's OASIS that are indicated in Table A-2 below. Path designations are subject to change and addition as appropriate.

Table A- 2: OASIS Path Designations for Resources External to the Native FMPP Control Area

TRANSFER	OASIS	TAG	SCHEDULE
"EXT BA" – PFW	F/FPC/"EXT BA"-FMPP/"EXT BA"-PFW	NORMAL TAG	YES
FPC – PFW	F/FPC/FPC-FMPP/FPC-PFW	NORMAL TAG	YES
Merchant –PFW	F/FPC/FPC-FMPP/"Merc"-PFW	NORMAL TAG	YES

e. FMPA will supply Real Power Losses to DEF. On a day-ahead basis, FMPA will calculate the amount of Real Power Losses to be supplied with a 24 hour energy profile based on a forecast of load for the following day, and will schedule and tag this transaction with DEF. Real Power Loss supply for Saturdays, Sundays, and NERC approved holidays, will be scheduled on the last business day of the week prior to the Saturday, Sunday or NERC approved holiday. On an hour-ahead basis, FMPA will adjust the Real Power Loss supply schedule as needed to account for day-ahead vs. hour-ahead forecast discrepancies. The Parties agree that any differences between scheduled losses and actual losses will be settled by applying Schedule 4 Energy Imbalance Service of DEF's OATT. FMPA and DEF may, by mutual agreement, develop and implement an alternative method for FMPA to supply Real Power Losses to DEF, including, without limitation, the use of a dynamic transfer of losses from FMPA to DEF.

3. To facilitate an understanding of FMPA's expected use of NITS, FMPA will forecast the use of resources located within the Native FMPP Control Area to serve FMPA Dynamically Transferred Network Load and provide such forecasts to DEF using pseudo-tie tags. In the event that the previous hour's actual hourly FMPA Network Load deviates from the sum of the hourly energy profiles indicated on FMPA's pseudo-tie tags and normal tags for the previous hour by the greater of +/- 10% or +/- 25 MW, FMPA will reevaluate its forecast and adjust pseudo-tie tags as appropriate for the next available scheduling hour and future hours. In the event that the hourly energy profile indicated on FMPA's pseudo-tie tags exceeds the actual hourly MW output of the resources associated with each corresponding Point of Receipt by the greater of 10% or 25 MW, FMPA will reevaluate its forecast and adjust pseudo-tie tags as appropriate for the next available scheduling hour and future hours. FMPA's obligations under this paragraph are subject to the following qualifications and conditions:

   a. Operation of resources located within the Native FMPP Control Area to serve FMPA Dynamically Transferred Network Load is accounted for as actual interchange and not scheduled interchange. FMPA shall use reasonable efforts to maintain the above metrics. The metrics shall not be used as a basis for assessing any charges or penalties under the OATT, or otherwise.

   b. The usage of resources located in the Native FMPP Control Area to serve FMPA Dynamically Transferred Network Load in amounts that differ from the pseudo-tie tags shall not be considered an unreserved use of Transmission Provider's transmission system.

   c. DEF and FMPA acknowledge and agree that FMPA's use of pseudo-tie tags to forecast its usage of its Network Resources does not affect or diminish FMPA's right

pursuant to DEF's OATT to firm transmission for FMPA's Network Resources to the full capacity that such Network Resources have been designated in DEF's OASIS.

4. FMPA shall use reasonable efforts to submit and make adjustments to FMPA's pseudo-tie tags and normal tags within the established DEF tagging and scheduling timetables as described in DEF Business Practices to maintain the metrics described in item 3 above as needed. For situations where a FMPA resource is suddenly lost and one or more of FMPA's pseudo-tie tags needs to be adjusted or a replacement created, FMPA shall use reasonable efforts to make the adjustment at the next available scheduling opportunity or no longer than 90 minutes from the time the FMPA resource is lost.

5. FMPA will provide the following information to DEF:

   FMPA will provide an economic dispatch order of its Network Resources with $/MWH to meet FMPA Network Load on an annual basis or when changes to the economic dispatch order occur.

MEMORANDUM OF UNDERSTANDING FOR A
SECOND POINT OF DELIVERY

This memorandum of understanding for a second point of delivery is dated as of [October __, 2025], between the CITY OF NEWBERRY, FLORIDA, a Florida municipality that owns and operates a retail electric distribution utility (the "**City**"), and the FLORIDA MUNICIPAL POWER AGENCY (ALL-REQUIREMENTS POWER SUPPLY PROJECT), a governmental legal entity created and existing pursuant to Florida law ("**FMPA**").

The City is a Project Participant in the Florida Municipal Power Agency's All-Requirements Power Supply Project (the "**Project**"). As a Project Participant, the City has entered into the All-Requirements Power Supply Project Contract with FMPA, entered into as of October 23, 2000, as amended by Amendment No. 1 to All-Requirements Power Supply Contract between Florida Municipal Power Agency and the City of Newberry, dated October 23, 2000, and further amended by Amendment No. 2 to All-Requirements Power Supply Project Contract between Florida Municipal Power Agency and City of Newberry, Florida, entered into December 17, 2018 (altogether, the "**Project Contract**").

Pursuant to the Project Contract, the City has a single Point of Delivery described as follows:

Delivery Point Identity and Location	Delivery Voltage
Intersection of SR 26 and SW 298 on FPC Pole No. B149423.	12 kV

This single Point of Delivery has now been apprised by the City and FMPA as reaching the limits of being suitable for reliable delivery of All-Requirements Services to the City, due to the growth of the City's capacity and energy needs within the foreseeable future. To address this situation, the City and FMPA have coordinated on certain study and other preliminary efforts to plan for and discuss with Duke Energy Florida, LLC ("**DEF**," successor in interest to Florida Power Corporation (referred to in the Project Contract as "FPC")) the coordinated design, construction, financing, and operation of a second Point of Delivery for the City (the "**Preliminary Discussions**").

Pursuant to those Preliminary Discussions, the City and FMPA now desire to set forth in greater detail what steps are required, and what cost responsibility each of the parties will bear, for a second Point of Delivery for the City.

The parties therefore agree as follows:

1. **Defined Terms**. Capitalized terms used in this memorandum of understanding, unless otherwise defined in this memorandum of understanding, have the meanings set forth in the Project Contract.

2. **Coordination among DEF, the City, and FMPA**. FMPA will use reasonable efforts to coordinate with DEF and the City to advance the Preliminary Discussions to a point where DEF is ready to make binding commitments, with understood cost parameters that are mutually agreeable to the City and FMPA, for the DEF work that is necessary to provide for the completion and operation of the second Point of Delivery for the City. The City will use reasonable efforts to coordinate with DEF and FMPA to provide for the same end. Further, the City and FMPA will use reasonable efforts to cooperate in the preparation of the necessary documents, and at the appropriate time seek all necessary governing body and other required approvals (including without limitation, for the City's seeking and obtaining needed financing) to provide for the completion and operation of the second Point of Delivery for the City, on a timeframe that is mutually agreeable between the parties, and reasonably achievable for DEF. Such documents shall include, at a minimum, required instruments between FMPA and DEF (as FMPA is the DEF transmission customer of DEF) to deliver capacity and energy from the Project to the City over the DEF transmission system, and an update to the Project Contract to memorialize the second Point of Delivery for the City, pursuant to section 5 of the Project Contract.

3. **Obligations for Second Point of Delivery; Cost Allocation**. (a) FMPA hereby agrees that FMPA, on behalf of the Project, will ultimately be responsible and liable for costs incurred to sell and deliver the City's All-Requirements Services on FMPA's side of the second Point of Delivery for the City, except for costs that the parties hereby agree will be allocated to the City or shared between the parties, as follows: all costs, if any, charged by DEF for operation and maintenance and other radial direct assignment costs that relate to FMPA's side of the second Point of Delivery for the radial feed to the City after construction is complete and that segment of line is put into service and energized, which shall be passed through to the City by FMPA based on charges from DEF, which as of the date hereof are yet to be known, but must be in accord with DEF's transmission tariff. Except as expressly provided in the previous sentence as a responsibility and liability of the FMPA, the City hereby agrees that it will be ultimately responsible and liable for all costs incurred for the second Point of Delivery and all necessary construction, improvement, expansion, extension, and other work on the Project Participant's System for the second Point of Delivery (which it hereby agrees to undertake and pursue pursuant to the terms of this memorandum of understanding), and the City shall make and pay for all connections between the Project Participant's System and the second Point of Delivery, and be responsible for all other costs that are otherwise allocated to, or made the responsibility of, the City in the Project Contract.

(b) FMPA will take due care and use reasonable efforts to keep the City informed of progress that it is making on achieving those actions and approvals necessary for it to accomplish FMPA's obligations hereunder as required to provide for the completion and operation of the second Point of Delivery for the City, including communicating to the City all DEF coordination needs with the City, as known to FMPA. The City hereby agrees it will take due care

and use reasonable efforts to keep FMPA informed of the progress that it is making on achieving those actions and approvals necessary for it to accomplish the City's obligations, on a schedule that is reasonable commensurate with DEF's schedule and FMPA's schedule for the second Point of Delivery for the City. If the City fails to maintain such a schedule, and that failure causes DEF or FMPA, or both, additional costs that are ultimately borne by FMPA, the City hereby agrees to reimburse FMPA for all such costs, which may be billed to the City, as a part of any of the bills rendered by FMPA, and owed by the City, for All-Requirements Services pursuant to the Project Contract.

(c) If after the date of this memorandum of understanding the City (1) decides to discontinue its pursuit of a second Point of Delivery or, (2) for whatever reason, is incapable or unwilling to proceed with its obligations hereunder to pursue the actions and approvals necessary to provide for the completion and operation of the second Point of Delivery for the City, including without limitation obtaining financing for the City's costs and expenses undertaken or to be undertaken hereunder, then all costs incurred by FMPA pursuant to this memorandum of understanding are hereby deemed by the parties to be the responsibility and liability of the City, including without limitation costs and expenses that FMPA incurs in unwinding or undoing contractual or other commitments made to DEF. Pursuant to the previous sentence, FMPA may bill the City for such costs on a bill rendered by FMPA, and owed by the City, for All-Requirements Services pursuant to the Project Contract.

4. **Effectiveness**. This memorandum of understanding will be effective and legally binding upon the parties upon approval of the governing bodies of both parties.

5. **Not an Amendment**. This memorandum of understanding is not an amendment to the Project Contract, and the Project Contract shall continue and be in full force and effect, pursuant to its terms, notwithstanding this memorandum of understanding.

6. **General Provisions**. (a) The descriptive headings in this memorandum of understanding are for convenience only and shall neither control nor affect the meaning or construction of any of the provisions hereof. No amendment to this memorandum of understanding (including any amendment to this section) shall have any effect, legal or otherwise, nor be construed to have any such effect, unless agreed to in writing by the parties.

(b) This instrument shall constitute the final complete expression of this memorandum of understanding between the parties relating to the subject matter hereof.

(c) Wherever possible, each provision of this memorandum of understanding is to be interpreted in such a manner as to be effective and valid under applicable law. Should any portion of this memorandum of understanding be declared invalid for any reason, such declaration shall have no effect upon the remaining portions of this memorandum of understanding. In the event any provision of this memorandum of understanding is held by any tribunal of competent jurisdiction to be contrary to applicable law, the remaining provisions of this memorandum of understanding remain in full force and effect.

(d) This memorandum of understanding reflects the negotiated agreement of the parties. Accordingly, this memorandum of understanding shall be construed as if the parties jointly prepared it, and no presumption against one party or the other shall govern the interpretation or construction of any of the provisions of this memorandum of understanding.

(e) The failure or delay of any party at any time to require performance by any other party of any provision of this memorandum of understanding, even if known, does not affect the continuing right of that party to require performance of that provision or to exercise any right, power, or remedy granted by this memorandum of understanding. The waiver by any party of a breach of any provision of this memorandum of understanding cannot be construed as a waiver of a continuing or succeeding breach of such provision, a waiver of the provision itself, or a waiver of any right, power, or remedy under this memorandum of understanding. No notice to or demand on a party in any circumstance shall, of itself, entitle the party receiving the notice or demand to any other or further notice or demand in similar or other circumstances.

(f) The validity and interpretation of this memorandum of understanding and the right and obligations of the parties hereunder shall be governed and construed in accordance with the laws of the State of Florida without regard for any conflicts of law provisions that might cause the law of other jurisdictions to apply. All controversies, claims or disputes arising out of or related to this memorandum of understanding or any agreement, instrument, or document contemplated hereby, shall be brought exclusively in the state or federal courts located in Florida, as appropriate.

(g) A default by any party under this memorandum of understanding shall entitle the other to all remedies available at law or in equity, except that the City hereby waives all rights to seek damages from FMPA for FMPA's failure, delay, or other defect or default in FMPA's performance hereunder (individually or collectively, an "**FMPA Default**") and, as such, the City's remedy for an FMPA Default is limited to equitable remedies, including without limitation, specific performance. In the event that any party is required to enforce this memorandum of understanding by court proceedings or otherwise, the prevailing party shall be entitled to recover all fees and costs incurred, including reasonable attorney's fees and costs (including allocations for in-house counsel), cost of investigation, trial, alternative dispute resolution, cost of settlement, and/or appellate proceedings.

(h) This memorandum of understanding may be executed in counterparts, including both counterparts that are executed on paper and counterparts that are in the form of electronic records and are executed electronically. An electronic signature means any electronic sound, symbol, or process attached to or logically associated with a record and executed and adopted by a party with the intent to sign such record, including e-mail electronic signatures (including electronically imaged signatures provided by DocuSign, Adobe Sign, or other technology). All executed counterparts shall constitute one agreement, and each counterpart shall be deemed an original. The parties hereby acknowledge and agree that electronic records and electronic signatures may be used in connection with the execution of this memorandum of

understanding and electronic signatures or signatures transmitted by electronic mail in so-called .pdf format shall be legal and binding and shall have the same full force and effect as if a paper original of this agreement had been delivered and signed using a handwritten signature.

The parties are signing this memorandum of understanding for a second point of delivery on the date stated in the introductory clause.

FLORIDA MUNICIPAL POWER AGENCY (ALL-REQUIREMENTS POWER SUPPLY PROJECT)

By: _____
Jacob A. Williams
General Manager and CEO

CITY OF NEWBERRY, FLORIDA

By: _____
Name: Jordan Marlowe
Title: City Manager

[Signature Page to Memorandum of Understanding for a Second Point of Delivery between the City of Newberry, Florida, and Florida Municipal Power Agency (All-Requirements Power Supply Project), dated as of [October __, 2025].]

AGENDA ITEM 10 – MEMBER COMMENTS

Executive Committee
October 23, 2025

AGENDA ITEM 11 – ADJOURNMENT

Executive Committee
October 23, 2025