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June 16, 2025

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20250011-EI - Petition for rate increase by Florida Power & Light Company

Dear Mr. Teitzman:

Please find enclosed for filing in the above referenced docket the **redacted** Direct Testimony and Exhibits of James Dauphinais.

If you have any questions or concerns, please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Walt Trierweiler
Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Florida Bar No.: 93590

CERTIFICATE OF SERVICE
DOCKET NO. 20250011-EI

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company. _______________________________/

Docket No. 20250011-EI

Filed: June 9, 2025

~~**CONFIDENTIAL PER DESIGNATION OF THE COMPANY**~~

DIRECT TESTIMONY

OF

JAMES R. DAUPHINAIS

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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LIST OF EXHIBITS

Exhibit	Title
Exhibit JRD-1	FPL Capacity Need under Traditional 20% PRM Resource Adequacy Criterion
Exhibit JRD-2	NERC EOP-011-4 – Emergency Operations Reliability Standard
Exhibit JRD-3	Relevant excerpts from NERC 2024 Long-Term Reliability Assessment
Exhibit JRD-4	Relevant excerpts from 2024-2034 SERC Annual Long-Term Reliability Assessment Report
Exhibit JRD-5	Estimated Stochastic LOLP Analysis Results for "TYP Portfolio + 1,400 MW of Storage" adjusted to reflect FPL's Proposed Pre-Summer 2027 Resource Additions
Exhibit JRD-6	Estimated Stochastic LOLP Analysis Results without FPL's 2026 and 2027 Proposed Solar Generation Additions
Exhibit JRD-7	Estimated Stochastic LOLP Analysis Results without FPL's 2027 Proposed Solar Generation Additions
Exhibit JRD-8	Excerpts from FPL 2025 Ten-Year Site Plan
Exhibit JRD-9	FPL Discovery Responses cited to by Mr. Dauphinais

DIRECT TESTIMONY

OF

James R. Dauphinais

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

DOCKET NO: 20250011-EI

I. INTRODUCTION

A. Background and Experience

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Florida Office of Public Counsel ("OPC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. In 1983, I graduated from Hartford State Technical College with an Associate's Degree in Electrical Engineering Technology. Subsequently, I completed undergraduate studies at the University of Hartford and was awarded a Bachelor's Degree in Electrical Engineering. I have also completed graduate level courses in the study of power system analysis, power system transients, and power system protection through the Engineering Outreach Program of the University of Idaho.

Q. PLEASE DESCRIBE YOUR EXPERIENCE.

A. I have over 40 years of experience in the electric utility industry, which began with the start of my employment as an Engineering Technician in the Transmission Planning Department of the Northeast Utilities Service Company ("NU," now "Eversource Energy") in 1984. In 1990, upon the completion of my undergraduate studies in electrical engineering, I was promoted to the position of Associate Engineer within the Transmission Planning Department. By 1996, I had been promoted to the position of Senior Engineer within the Transmission Planning Department.

In the employment of NU, I was responsible for conducting thermal, voltage, and stability analyses of the NU's electric transmission system to support planning and operating decisions. This involved the use of load flow, power system stability, and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions.

In 1997, I joined the firm of BAI. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science, and business. Since my employment with the firm, I have been involved with a wide variety of electric power and electric utility issues including, but not limited, to: ancillary service rates, avoided cost calculations, certification of public convenience and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates, and transmission line routing. I have provided expert testimony on all of the foregoing. This expert testimony has been provided to the Federal Energy Regulatory Commission ("FERC") and the utility regulatory bodies of 22 states or provinces, including the Florida Public Service Commission ("Commission" or "FPSC"). I provide further information on my education and background in Appendix A to my testimony.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. During my employment with NU, prior to the implementation of FERC Order Nos. 888 and 889, the transmission planning organization within whom I was employed was integrated with, and part of, the same functional organization as NU's generation planning organization. This integration led to significant involvement by transmission planning, including myself, in resource planning analyses (e.g., the analysis of the potential net benefit of retirement of existing generation resources) and resource planning in transmission planning analyses (e.g., whether to proceed with economic transmission upgrades). In addition, while employed at NU, I made significant usage of the General Electric Company Multi-Area Production Simulator ("MAPS") to analyze the generation production costs associated with various transmission operating and planning alternatives on the NU system.

Subsequently, during my employment with BAI since 1997, I have become further involved with resource planning issues, initially in support of my colleagues at BAI and later in a lead position. This work has included the review of electric utility resource plans, the review of proposed certificates of public convenience and necessity for new electric utility generation resources, the forecasting of future market prices, the forecasting of future utility rates, and the evaluation of long-term power supply options. I have conducted this work both for intervenors in regulatory proceedings and specific retail end-use customer clients of BAI who were evaluating their future power supply options. I have also been extensively involved in the development of Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") - administered power markets including, but not limited to, issues related to markets for energy, operating reserves and capacity.

Q. PLEASE IDENTIFY SOME OF THE CASES IN WHICH YOU PROVIDED TESTIMONY WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. In the past 20 years, I have provided testimony on resource planning and/or the prudency issues related to resource planning in Indiana Utility Regulatory Commission

("IURC") Cause No. 42643, Louisiana Public Service Commission ("LPSC") Docket No. U-30192, IURC Cause No. 43393, IURC Cause No. 43396, Colorado Public Utilities Commission ("CPUC") Docket Nos. 09A-324E and 09A-325E, IURC Cause No. 43956, IURC Cause No. 44012, New Mexico Public Regulatory Commission ("NMPRC") Case No. 13-00390-UT, NMPRC Case No. 15-00261-UT, NMPRC Case No. 17-00174-UT, NMPRC Case No. 19-00018-UT, NMPRC Case No. 19-00195-UT, NMPRC Case No. 21-00083-UT, NMPRC Case No. 23-00353-UT, Michigan Public Service Commission ("MPSC") Case No. U-21090, MPSC Case No. U-21193, FPSC Docket Nos. 20160186-EI and 20160170-EI (with respect to Scherer Unit 3 in the 2016 Gulf Power Company base rate case), FPSC Docket No. 20190061-EI (with respect to Florida Power & Light Company's SolarTogether Program and Tariff), and FPSC Docket No. 20240025-EI (with respect to proposed resource additions in the 2024 Duke Energy Florida, LLC base rate case).

In a number of these proceedings, I had extensive involvement in the review of the utility's Aurora®, EnCompass® or Strategist® resource planning analysis. In the case of EnCompass® and Strategist®, this has included either me personally running the modeling tool or having modeling runs performed under my direction and supervision by other members of the BAI team, based upon data provided by the subject utility.[1] As discussed in the Direct Testimony of Florida Power & Light Company

[1] Strategist®, which includes a module called Proview®, is a computer software tool produced by Ventyx (ABB) that allows resource planners to examine a very large number of alternative resource portfolios with the goal of identifying through an optimization algorithm the most cost-effective resource portfolio for an electric utility. It can also be used in a probabilistic mode to test the robustness (i.e., risk) of specific resource portfolios over a wide range of assumption variations. Strategist® is currently utilized, and has been utilized in the past, by many electric utilities to conduct their resource planning. Other commercial software tools that have some or all of the functionality of Strategist® include software tools such as System Optimizer®, PLEXOS®, Aurora® and EnCompass®. Of these, Aurora®, PLEXOS® and EnCompass® have become more commonly used in recent years due to their greater functionality and more robust solution technique.

("FPL" or "Company") Witness Andrew Whitley, FPL uses Aurora® to support its Integrated Resource Planning ("IRP") process.[2]

Q. DO YOU HAVE PREVIOUS EXPERIENCE WITH STOCHASTIC LOSS OF LOAD PROBABILITY ("LOLP") ANALYSIS THAT IS COMMONLY USED TO EVALUATE THE RESOURCE ADEQUACY OF ELECTRIC UTILITIES?

A. Yes. I have received past training with respect to SERVM® – a software modeling tool that was developed by Astrapé Consulting (now part of PowerGEM, LLC) to perform Stochastic LOLP analysis.[3] SERVM® is used by many utilities for LOLP analysis. In addition, I have had members of the BAI staff perform SERVM® runs under my direction and supervision for testimony I have presented before the NMPRC. Also, SERVM® is the primary modeling tool used by the Midcontinent Independent System Operator, Inc. ("MISO") for the capacity accreditation and Loss of Load Expectation ("LOLE") analysis it presents to the MISO Resource Adequacy Subcommittee and the MISO Loss of Load Expectation Working Group, both of which I regularly attend and monitor as a representative of large end-use customer groups located in Illinois, Indiana, Iowa, Louisiana, Michigan and Texas.

[2] FPL Witness Andrew Whitley Direct Testimony, p. 16. The term "Stochastic LOLP" refers specifically to the stochastic analysis presented by FPL.

[3] A stochastic analysis examines a very large number of cases where input assumptions are varied based on probability and the application of random number draws.

B. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present testimony with respect to the prudence, reasonableness, and cost effectiveness of FPL's already incurred and proposed investments for the following supply-side resource projects:

- FPL's estimated \$538 million investment in 7 currently under construction 74.5 MW 3-hour battery storage facilities, expected to be completed by the end of 2025 and collectively referred to by FPL as the 522 MW Northwest Florida ("NWFL") Battery Storage Project or "Gulf Battery Storage".[4]

- FPL's estimated \$6.5 billion investment in the following:
  - 12 proposed 74.5 MW_{AC} solar energy centers, totaling 894 MW and expected to be completed during 2026;
  - 11 proposed 74.5 MW 4-hour battery storage facilities; 1 proposed 400 MW 4-hour battery storage facility, and 1 proposed 200 MW 4-hour battery storage facility, collectively totaling 1,419.5 MW and expected to be completed during 2026;
  - 16 proposed 74.5 MW_{AC} solar energy centers, totaling 1,192 MW and expected to be completed during 2027; and

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[4] FPL Witness Andrew Whitley Exhibits AWW-5 through AWW-7; FPL Witness Tim Oliver Direct Testimony, p. 9; FPL Ten Year Site Plan 2025-2034, April 2025 ("FPL 2025 TYSP"), p. 163; and FPL Response to OPC's First Request for Production of Documents, No. 30, NEE BoD Decks, "Pimentel FPL BOD Business Review May 2024 v14F_Redacted.pdf" at Slides 27-39.

- 11 proposed 74.5 MW 4-hour battery storage facilities, totaling 819.5 MW and expected to be completed during 2027.[5]

Collectively, these projects represent the largest driver of the increase in FPL's rate base in its two proposed projected test years for this base rate proceeding (calendar years 2026 and 2027). FPL is attempting to predominately justify its proposed supply -side resource projects for 2026 and 2027 based on projected load growth and a large step increase in capacity need driven by the results of a Stochastic LOLP analysis that was performed for FPL by Energy and Environmental Economics, Inc. ("E3"). As a result, my testimony also addresses FPL's Stochastic LOLP analysis.

Beyond its proposed 2026 and 2027 supply-side resources, FPL in its Petition, testimony, and exhibits also discusses pursuing up to 1,490 MW_{AC} of additional solar energy centers and 596 MW of additional battery storage facilities in 2028 and pursuing up to 1,788 MW_{AC} of additional solar energy centers and 596 MW of additional battery storage facilities in 2029.[6] However, FPL is not at this time either requesting Commission approval for those proposed facilities or requesting cost recovery of the cost of those proposed facilities in its proposed base rates for 2026 and 2027.[7] Instead, FPL is requesting the Commission to approve a Solar and Battery Base Rate Adjustment ("SoBRA") Mechanism to allow FPL in future limited proceedings: to seek advance Commission approval of FPL-proposed 2028 and 2029 solar and battery facilities up to the aforementioned amounts, and to recover the costs of those facilities

[5] FPL Witness Andrew Whitley Direct Testimony, p. 22-28; FPL Witness Tim Oliver Direct Testimony, p. 12-20; Exhibit AWW-5; Exhibit 70-2; Exhibit 70-4; and FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx.," "Rev. Req. Detail" tab.
[6] FPL Witness Andrew Whitley Direct Testimony, p. 20, 28-30 and Exhibit AWW-6 and FPL Witness Tim Oliver Direct Testimony, p. 20-22.
[7] FPL Witness Andrew Whitley Direct Testimony, p. 30 and FPL Witness Tim Oliver Direct Testimony, p. 20-22.

through an adjustment to base rates once they are completed, provided certain criteria are met.[8]

Since FPL is not seeking approval or cost recovery for its proposed 2028 and 2029 solar energy centers and battery storage facilities in this proceeding, and since OPC recommends rejection of FPL's proposed SoBRA for 2028 and 2029 for the reasons discussed later in my testimony and in the direct testimony of OPC witness Schultz, I do not address the prudence, reasonableness, and cost effectiveness of FPL's proposed 2028 and 2029 SoBRA facilities. However, I do offer testimony on the cost-effectiveness criteria that should apply when evaluating new solar and battery facilities in the event the Commission approves a SoBRA for FPL despite OPC's direct testimony recommendation in this case.

Finally, the fact that I do not address any other particular issues in my testimony or am silent with respect to any portion of FPL's Petition or direct testimony in this proceeding should not be interpreted as an approval of any position taken by FPL.

Q. WHAT DID YOU REVIEW PRIOR TO PREPARING YOUR DIRECT TESTIMONY?

A. I reviewed FPL's petition in this proceeding along with the direct testimony and exhibits in this proceeding of FPL Witnesses Ina Laney, Tim Oliver, and Andrew Whitley. I have also reviewed FPL's responses to discovery in this proceeding regarding the issues of resource adequacy, resource planning, Investment Tax Credits ("ITCs"), Production Tax Credits ("PTCs"), FPL's 522 MW NWFL Battery Storage

[8] FPL Witness Tim Oliver Direct Testimony, p. 20-22.

Project, and FPL's 2026 and 2027 proposed solar energy centers and battery storage facilities. I also listened to, or reviewed the transcription of, the May 2025 depositions in this proceeding of FPL Witnesses Laney, Oliver, and Whitley. In addition, I listened to the May 29, 2025 deposition in this proceeding of Mr. Arne Olson, who is a Senior Partner at E3. As of the filing date of this testimony, neither Mr. Olson, nor anyone else from E3, is a witness in this proceeding on behalf of FPL. However, as discussed in the direct testimony of FPL Witness Whitley, E3 is the consultant that was engaged by FPL to assist FPL with resource adequacy issues, and E3, rather than FPL Witness Whitley, is the author of Mr. Whitley's Exhibit AWW-1.[9] I also reviewed the North American Electric Reliability Corporation ("NERC") Reliability Standards, NERC's most recent long-term reliability assessment, and SERC Reliability Corporation's ("SERC's") most recent long-term reliability assessment. Finally, I reviewed FPL's 2024 Ten-Year Site Plan ("2024 TYSP") and 2025 Ten-Year Site Plan ("2025 TYSP").

C. Summary of Conclusions and Recommendations

Q. BEFORE YOU SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS, DO YOU HAVE ANY CAVEATS YOU WOULD LIKE TO PUT ON THEM?

A. Yes. First, as I further discuss later in my testimony, the Stochastic LOLP analysis summarized in FPL Witness Whitley's Exhibit AWW-1 was not prepared by Mr. Whitley, who sponsored it, or anyone on the FPL team that reports to Mr. Whitley. It was prepared by E3, and FPL did not offer a witness from E3 to provide direct

[9] FPL Witness Andrew Whitley Direct Testimony, p. 14 and Exhibit AWW-1.

testimony on the analysis that E3 performed for FPL that is summarized in Exhibit AWW-1. In addition, during Mr. Whitley's deposition, it became apparent that neither he or anyone else on his team at FPL could likely perform the Stochastic LOLP analysis performed by E3 for FPL using E3's modeling tool, and they had no way to independently verify it.[10] While FPL ultimately offered Mr. Olson of E3 up for a May 29, 2025 deposition by the parties in this proceeding, that is not the same as having him provide direct testimony. Furthermore, in discovery it has been revealed that FPL has engaged E3 to potentially provide rebuttal testimony on its behalf.[11] For these reasons, there may be new information that comes to light later in this proceeding that could impact my conclusions and recommendations herein.

Second, FPL's economic analysis for its 2026 and 2027 proposed solar energy centers and battery storage facilities that was presented in FPL witness Whitley's direct testimony only examined the pursuit of those facilities on an "all or nothing basis." FPL did not provide economic analysis for the 2026 proposed facilities and 2027 facilities separately. Nor did FPL examine just adding all or part of the proposed 2026 and 2027 battery storage facilities without the addition of any of the proposed 2026 and 2027 solar energy centers. As a result, there is a potential for new information that comes to light later with respect to these alternatives that could impact my conclusions and recommendations herein.

Third, FPL's base case for its economic analysis for its 2026 and 2027 proposed solar energy centers and battery storage facilities was performed against a base case that cannot be realized due to lead time and supply chain limitations that FPL indicates

[10] FPL Witness Andrew Whitley May 7, 2025 Deposition Transcript, p. 33.
[11] FPL Response to FEL's Fourth Request for Production of Documents, No. 54, Exhibit C, p. 2.

limit the earliest date upon which it could bring new natural gas-fired generation online to late 2029 or 2030. Yet, FPL in its base case, also known as Case 4, assumed it could bring new combustion turbine generation online prior to the summers of 2028 and 2029. It did not provide an alternative base case that only adds battery storage facilities as necessary for resource adequacy prior to 2030. To examine such an alternative base case, Aurora® simulations would need to be performed of it. Neither BAI nor OPC have access to a license to Aurora® and, therefore, are unable to run such simulations. However, FPL would be able to run such simulations and may do so. Thus, there is also a potential for new information that comes to light later with respect to such an alternative base case that could impact my conclusions and recommendations herein. This said, as I discuss later in my testimony herein, there is evidence that FPL's current Aurora® modeling is unable to identify all of the costs FPL incurs for its existing and future solar generation investments such that any economic justification for new FPL solar generation investments should be rejected until such time FPL resolves the current modeling limitations FPL has with Aurora®.

Because new information in any of the above three areas may lead to one or more changes to my conclusions and recommendations within this testimony, it is my understanding that OPC reserves the right to file supplemental testimony to fully address the new information and the effects of that new information, if necessary.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. With the caveats I have given, my conclusions and recommendations can be summarized as follows:

- Under FPL's traditional *deterministic* 20% Planning Reserve Margin ("PRM") resource adequacy criterion, with no supply-side resource additions, FPL would have a need for additional capacity starting with Summer 2027.
- FPL has produced information in response to discovery that supports an immediate local reliability need for the Northwest Florida portion of its system for its 522 MW NWFL Battery Storage Project that is slated to fully enter service by the end of 2025.
- With the addition of the 522 MW NWFL Battery Energy Project, under FPL's traditional *deterministic* 20% PRM resource adequacy criterion, FPL will not have a need for additional capacity until Summer 2028.
- FPL in this proceeding is proposing to modify the way it applies its traditional *probabilistic* no more than 0.1 loss of firm load events days per year Loss of Load Probability ("LOLP") resource adequacy criterion by using a stochastic LOLP analysis that was prepared for FPL by E3.
- This change would require FPL to add the equivalent of up to 1,900 MW of combustion turbine generation additions for Summer 2027 above and beyond what its traditional *deterministic* 20% PRM resource adequacy criterion would require.

- FPL's Stochastic LOLP analysis in this proceeding appears to be overly conservative and potentially significantly overstating FPL's capacity need for Summer 2027 and beyond because:
  - The results imply that FPL is already significantly short of capacity, but there is no evidence supporting that is the case given FPL has not declared any North American Electric Reliability Corporation ("NERC") Energy Emergency Alerts ("EEAs") on its system since 2017, FPL has not needed to shed load anytime in the past ten years and FPL is not indicating that there is either currently a resource adequacy problem on its system or that FPL expects there to be one on its system in 2026.
  - FPL's Stochastic LOLP analysis results for 2027 are not consistent with the 2026-2028 Stochastic LOLP analysis results of NERC and SERC, which indicate that the SERC-Florida Peninsula and SERC-Southeast areas only have a Normal Risk of loss of load not an Elevated Risk or a High Risk of loss of load.
  - FPL's Stochastic LOLP analysis appears to be rushed because it did not commence until late-October 2024, was completed less than one month before FPL filed its case in this proceeding, did not examine FPL's current and projected 2026 stochastic LOLP, and was not supported with direct testimony from E3.

- At least one of the assumptions in FPL's Stochastic LOLP analysis was overly conservative.
- FPL did not in a timely manner provide all of the workpapers for its Stochastic LOLP analysis despite them being requested very early in the proceeding, limiting intervenor review of the reasonableness of the analysis.
- No FPL stakeholders, including the Commission Staff and OPC, were given an opportunity to provide any input, never mind meaningful input, with respect to the assumptions utilized in the analysis despite the fact FPL has an inherent incentive to grow its rate base to increase the returns to its shareholders.

- While I believe FPL's Stochastic LOLP analysis may be potentially significantly overstating FPL's capacity need for Summer 2027, due to high level of solar generation investment on the FPL system relative to its total load and due to clear operational challenges FPL is experiencing related to that investment, which it did not detect in advance with its traditional operational and planning modeling tools, I conceptually agree that FPL should begin to utilize stochastic LOLP analysis and my expectation is that FPL needs some level of additional capacity for Summer 2027 beyond that which is indicated by its traditional 20% PRM resource adequacy criterion, but not necessarily the equivalent of up to 1,900 MW of new combustion turbine generation resources.

- Because of this, I recommend that the capacity need identified by FPL's Stochastic LOLP analysis in this proceeding be limited in its application to FPL's 2026 and 2027 test years.
- In addition, for this reason, and the fact that FPL may have other resources available for 2028 such as Project Commodore, the reasons indicated in the direct testimony of OPC witness Bill Schultz, I recommend the Commission reject FPL's 2028 and 2029 SoBRA Mechanism proposals in this proceeding.
- I also recommend the Commission:
  - Require FPL to identify the current stochastic LOLP for its system as well as the expected stochastic LOLP for its system in 2026;
  - To the extent the LOLP value for either of those time periods is greater than 0.1 event days per year, require FPL to identify to the Commission whether there is an unreasonably high risk of a loss of load event on its system during those time periods, and, if so, identify all steps FPL is taking to minimize the likelihood of that risk being significantly greater than the normal risk that exists;
  - Require FPL to reconcile the 2027 results of its Stochastic LOLP analysis with the stochastic LOLP analysis results of the NERC 2024 Long-Term Reliability Assessment and the 2024-2034 SERC Annual Long-Term Reliability Assessment Report;
  - Require FPL, in future proceedings where it proposes to use stochastic LOLP analysis to justify resource additions to:

    - Provide all FPL stakeholders a reasonable opportunity, prior and during the analysis, to provide meaningful input with respect to the assumptions being utilized in the analysis;
    - Coordinate with the other utilities jurisdictional to the Commission to help ensure a consistent approach is used for stochastic LOLP analysis in Florida.
    - Have the analysis subject to review from an independent third-party not affiliated with either FPL or the contractor who performed the analysis on behalf of FPL; and
    - Provide direct testimony from an expert witness who either performed, or directly supervised the performance of, the analysis.
- FPL has not shown it has a need for all of its 2026 and 2027 proposed solar energy center and battery storage facility additions to meet its Stochastic LOLP analysis forecasted "perfect" capacity need for Summer 2027.
- FPL has not shown that the specific combination of 2026 and 2027 solar generation and battery storage resources it has proposed is the most cost-effective way to meet the "perfect" capacity need for 2027 that was identified by its Stochastic LOLP analysis in this proceeding.
- Due to the magnitude of the solar generation investment on FPL system, solar generation additions are no longer a good source of "perfect" capacity to meet FPL's resource adequacy needs versus other available resources such as battery storage facilities.

- Furthermore, FPL's current ability with its Aurora® modeling to account for all of the costs and challenges associated with further solar generation investment on its system is questionable.
- FPL's "perfect" capacity need for summer 2027 can be fully satisfied with FPL's 2026 and 2027 battery storage facilities alone – there is not a reliability need for FPL's proposed 2026 and 2027 solar energy center additions.
- As a result, for FPL's pursuit of its 2026 and 2027 proposed solar energy center additions to be found prudent, reasonable and cost effective, FPL needs to demonstrate there is a robust economic case for these resource additions to help ensure pursuit of them is consistent with providing reliable electric service at lowest reasonable cost.
- FPL has not performed such an economic analysis for its 2026 and 2027 proposed solar energy center additions and it is questionable whether its current Aurora® modeling could capture all of the costs associated with such additions at this time.
- For these reasons, while I do not oppose the Commission finding that FPL's pursuit of its 2026 and 2027 proposed battery storage facilities is prudent, reasonable and cost effective, I recommend that the Commission reject FPL's requested approval of its 2026 and 2027 proposed solar energy center additions and that the costs for those resource additions be removed from FPL's revenue requirement for the 2026 and 2027 projected test years in this proceeding.

- On an isolated basis, this would reduce FPL's non-fuel revenue requirement by $77.7 million in 2026 and by $153.6 million in 2027.
- Finally, if, despite my recommendation, the Commission approves a 2028 and 2029 SoBRA Mechanism for FPL in this proceeding, to the extent the SoBRA Mechanism involves pursuit of supply-side resource additions that are not substantially needed to meet a reliability need for the year they enter service (or in the immediately following six months), the portion of the additions that is in excess of what is needed to cost effectively meet the reliability should only be approved to the extent it is for the purpose of serving FPL's retail customers and has robust economic case associated with it as I have detailed in my testimony herein.

II. <u>TIMING AND AMOUNT OF FPL'S FIRM CAPACITY NEED</u>

A. Reviewing the Prudence, Reasonableness, and Cost-Effectiveness of Resource Additions

Q. PLEASE EXPLAIN HOW YOU REVIEWED THE PRUDENCE, REASONABLENESS AND COST-EFFECTIVENESS OF FPL'S ALREADY INCURRED AND PROJECTED INVESTMENTS FOR ITS 522 MW NWFL BATTERY STORAGE PROJECT AND ITS 2026 AND 2027 PROPOSED SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITY ADDITIONS.

A. I started by examining the timing of FPL's forecasted need for additional firm generation capacity and then examined FPL's forecasted economic performance for the investments.

Q. PLEASE EXPLAIN HOW THE TIMING OF FPL'S NEED FOR ADDITIONAL FIRM GENERATION CAPACITY DURING ITS PROJECTED TEST YEARS AFFECTS THE PRUDENCE, REASONABLENESS, AND COST-EFFECTIVENESS OF FPL'S PROPOSED INVESTMENTS IN THESE PROJECTS.

A. To the extent the firm generation capacity that would be provided by these projects is actually substantially needed immediately, or nearly immediately, following their entrance to service, there is a demonstrated reliability need for the firm capacity provided by them by the end of FPL's projected test years in this proceeding. Under that scenario, the pursuit of them would be consistent with providing reliable electric service at the lowest reasonable cost to FPL's customers provided the projects have a lower Cumulative Present Value Revenue Requirement ("CPVRR") within the expected life of the projects – for example, 35 years for new solar generation and 20 years for new battery storage – than other alternatives available to FPL that would provide a similar amount of firm generation capacity at a comparable level of risk.

However, if the firm generation capacity that would be provided by the projects is not substantially immediately needed, or nearly immediately needed, the pursuit of the projects in question by FPL with the timing that FPL has proposed would not necessarily be consistent with providing reliable electric service at lowest reasonable cost even if the investments are projected to provide a lower CPVRR for FPL. This is because there is not a reliability justification for the projects that makes them mandatory. Instead, they are elective. As elective projects, it would need to be demonstrated the projects are in fact for the purpose of serving FPL's customers (i.e., not for the purpose of FPL making off-system sales at wholesale). Furthermore, since projected cost savings would be the principal driver of pursuing these elective projects, it also needs to be demonstrated the projected CPVRR net benefit of the proposed projects, over alternatives to them that have an in-service date consistent with the timing of FPL's firm capacity need, is robust enough such that the investments are not speculative in nature and the balance of risk between FPL and its customers for the investments is reasonable.

Specifically, the economic analysis should exclude off-system sales margins (including any Production Tax Credits ("PTC") enabled by off-system sales), the CPVRR benefit to cost ratio for the investment over its book life should be robust (ideally 1.25 or higher, but at least 1.15), and a net CPVRR benefit from the investment be projected to be provided to customers no later than half-way through the life of the investment in question and no longer than 10 years after the investment enters service. The first criterion ensures the projects are being cost justified based on serving the load of FPL's customers rather than speculative off-system sales. The latter two criterion ensure the projects are essentially "no regrets" investments for FPL's customers.

Q. WHY IS IT IMPORTANT THAT FPL'S GENERATION OR RESOURCE INVESTMENTS THAT ARE ELECTIVE BE "NO REGRETS" INVESTMENTS FOR FPL'S CUSTOMERS?

A. It goes to the issues of the purpose of regulated electric service and the balance of risk between a utility and its customers. FPL's customers are not customers of FPL for the purpose of making speculative investments. They are customers of FPL for the purpose of receiving reliable electric service at the lowest reasonable cost. Hence, any elective investments FPL makes to provide that service needs to have a low risk and thus have "no regrets" associated with them. With respect to balancing risk, FPL is afforded an opportunity to earn its authorized return on the investments through its base rates whether or not the investments actually provide net savings for FPL's customers. Thus, to keep the balance of risk between FPL and its customers reasonable, the investments made by FPL once again must be of the "no regrets" nature.

Q. WHAT IS THE BASIS OF YOUR 1.25 AND 1.15 BENEFIT TO COST RATIO THRESHOLDS?

A. MISO requires a 20-year CPVRR Benefit to Cost Ratio of at least 1.25 for transmission projects pursued as Market Efficiency Projects ("MEP"). These are transmission projects that are solely being pursued for economic reasons.[12] PJM Interconnection, LLC ("PJM") uses the same threshold for economic-based transmission enhancements.[13] ERCOT uses a threshold benefit to cost ratio of 1.15 for such projects.

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[12] MISO Tariff Attachment FF-Transmission Expansion Planning Protocol Section II (B)(e).
[13] PJM Manual 14B: PJM Region Transmission Planning Process.

Q. WHY IS IT IMPORTANT FOR AN EARLY CPVRR BREAKEVEN YEAR TO BE MET IN ADDITION TO MEETING A MINIMUM BENEFIT TO COST RATIO?

A. It complements the minimum benefit to cost ratio by addressing the issue of there being less certainty about the future as you go out in time. There is much more risk with a net benefit actually being realized from a project that is not forecasted to provide a net benefit until many years from now versus one that has a forecast net benefit in just a few years.

B. Analysis of Capacity Need under FPL's Traditional 20% PRM Criterion

Q. PLEASE EXPLAIN HOW FPL HAS HISTORICALLY DETERMINED ITS FIRM CAPACITY NEED.

A. FPL indicates that it has been applying *deterministic* and *probabilistic* criteria to ensure it has sufficient firm capacity, and, thus, resource adequacy, to meet its forecasted load under its TYSPs. The primary *deterministic* criterion that FPL uses is to carry extra summer and winter firm capacity known as Planning Reserve Margin ("PRM") in an amount equal or greater than 20% of the forecasted firm summer and winter demand of its customers.[14] The 20% PRM criterion was part of a settlement agreement that was approved by the Commission in Order No. PSC-99-2507-S-EU issued in Docket No. 981890-EU.[15]

[14] FPL Witness Andrew Whitley Direct Testimony, p. 10.
[15] FPL Witness Andrew Whitley Direct Testimony, p. 10 and FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 16.

A secondary *deterministic* criterion that FPL uses is to ensure it carries enough firm capacity from generation resources alone to provide a PRM of least 10% of the forecasted firm summer and winter demand of its customers. FPL refers to this as a Generation-only Reliability Margin ("GRM") of 10%. This secondary *deterministic* criterion, which FPL indicates it first established in 2014, essentially limits the portion of its capacity need that can be met by Demand Side Management ("DSM").[16] FPL reports that to-date the GRM criterion has not required FPL to need more firm capacity than that is necessary to meet its PRM criterion.[17] Furthermore, FPL is not aware of the Commission ever issuing an order approving FPL's GRM criterion.[18]

The *probabilistic* criterion that FPL uses is to carry sufficient extra firm summer and winter capacity to ensure the forecasted LOLP (also known as Loss of Load Expectation ("LOLE")) for its firm load is no greater than one loss of firm load event day in 10 years, or no more than 0.1 loss of firm load event days per year.[19] FPL reports this LOLP criterion is commonly used throughout the entire electric utility industry.[20] While FPL indicates this LOLP criterion is also consistent with the NERC Reliability Standards, FPL also recognizes NERC only uses the metric for measurement purposes – FPL is not aware of any entity that requires the 0.1 event days per year LOLP criterion be met.[21] FPL also recognizes that being incrementally long or short of the firm capacity necessary to produce a 0.1 event days per year LOLP, it only respectively

[16] FPL Witness Andrew Whitley Direct Testimony, p. 10-11.
[17] FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 53.
[18] FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 52.

[19] FPL Witness Andrew Whitley Direct Testimony, p. 10-11.
[20] FPL Witness Andrew Whitley Direct Testimony, p. 11.
[21] FPL Witness Andrew Whitley Direct Testimony, p. 11 and FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 27.

means the LOLP is incrementally less than 0.1 days per year or incrementally greater than 0.1 event days per year.[22] In other words, resource adequacy does not "fall off a cliff" when a utility is incrementally short of the capacity necessary to produce a LOLP of 0.1 days per years or less. Instead, the utility's LOLP is only incrementally higher than 0.1 event days per year and that incremental difference may be imperceptible to customers. This is not to say capacity should not be added to achieve the target of a LOLP of 0.1 event days per year or less, but rather that customers do not "fall off a cliff" when the target is not met and, as a probabilistic criterion, the criterion is meant to be met on average over a number of years.

FPL also reports it has historically performed its LOLP analysis using a software package called the Tie Line Assistance and Generation Reliability ("TIGER") program.[23] TIGER has been used by others in Florida including the Florida Reliability Coordinating Council, Inc. ("FRCC").[24] Due to functionality limitations with the TIGER program, FPL reports it typically performs TIGER LOLP analysis by only examining the peak load hour of each day of the year rather than all of the hours of a year.[25] FPL is not aware of any time when FPL's TIGER LOLP analysis identified a need for firm capacity for FPL for summer or winter that was greater than the amount of firm capacity needed for FPL to meet its 20% PRM criterion.[26] As a result, historically, the 20% PRM has been providing FPL, as well as other utilities in Florida that use the 20% PRM criterion, an extra bit of resource adequacy margin above what

[22] FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 28-29.
[23] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 29.
[24] For example, *see* https://www.nerc.com/comm/PC/PAWG%20DL/FRCC.pdf.
[25] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 30-31.
[26] FPL Witness Andrew Whitley May 7, 2027 Deposition, Tr., p. 31.

would have been provided by just providing sufficient capacity to meet 0.1 event day per year LOLP based on TIGER LOLP analysis.[27]

Q. WHEN APPLYING ITS DETERMINISTIC 20% PRM CRITERION, DOES FPL CALCULATE THE FIRM CAPACITY FOR SOLAR GENERATION FACILITIES AND BATTERY STORAGE FACILITIES IN THE SAME MANNER AS IT DOES FOR ITS CONVENTIONAL GENERATION FACILITIES?

A. No. Since they are always available to provide their summer and winter rated capacity in all hours within the bounds of startup, shutdown and ramp rate constraints except when on outage, FPL determines the summer and winter firm capacity of its conventional generation facilities based on the summer and winter rated capability of those facilities. However, since solar generation output depends on the presence, level and angle of sunshine, and since battery storage facilities have limited energy available for discharge, FPL derates the summer and winter firm capacity for these resources from the rated capability for these resources. For solar generation, it has performed an analysis that accounts for the shifting of the time of its net peak[28] in summer as it has higher levels of solar generation penetration.[29] Specifically, FPL arrived at the following 2025 estimate of summer firm capacity as a percentage of nameplate capacity for new solar resources as a function of incremental solar generation added to its system starting in 2026.

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[27] I came to a similar conclusion with respect to Duke Energy Florida in my direct testimony in Docket No. 20240025-EI as Duke Energy Florida reported the same phenomenon.
[28] The net peak is the peak demand placed on FPL's non-solar resources after accounting for solar generation.
[29] FPL Response to FIPUG's First Set of Interrogatories, No. 8

TABLE JRD-1

Summer
Solar
Firm Capacity Value Percentages
Under
FPL 20% PRM Criterion

Solar Firmness	Additional Solar Up to MWs
12.62%	894
5.31%	2,086
5.31%	3,576
5.31%	5,364

Source: FPL Response to FIPUG's First Set of Interrogatories, No. 8

For winter, FPL uses a small percentage on the order of 2 to 3% of nameplate MW based on the low expected energy output of solar generation at the time of FPL's winter system peak.[30]

Q. CAN YOU EXPLAIN HOW THE ABOVE TABLE FOR SUMMER WORKS?

A. Yes. The first 894 MW of solar generation added in 2026 or later receives a summer firm capacity of 12.62% of nameplate. The next 1,192 MW of solar generation receives a summer firm capacity of 5.31% of nameplate. Then, the next 1,490 MW of solar generation receives a summer firm capacity of 5.31% of nameplate, and so on.

[30] FPL 2025 TYSP at 163-165 (Schedule 8) and [30] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 18-19.

Q. WHAT DOES FPL DO WITH RESPECT TO BATTERY STORAGE FACILITIES?

A. It develops similar incremental firm capacity value percentages for its 20% PRM criterion but based on the storage time need on its system versus the hourly storage rating of the battery storage facilities.[31] Table JRD-2 below summarizes these values for total battery storage capability on the FPL system up to 3,991 MW of installed battery storage capability. Note that 470 to 991 MW block involves 3-hour storage, while all of the storage above 991 MW are assumed to be 4-hour storage.

TABLE JRD-2

Summer
Battery Storage
Firm Capacity Value Percentages
Under
FPL 20% PRM Criterion

Storage Firmness	Total Storage Up to MWs
100%	469
67%	991
80%	1,491
73%	1,991
57%	2,491
53%	2,991
50%	3,991

Source: FPL's Response to OPC's First Request for Production of Documents, No. 15, Whitley Workpaper "2025 FCV Battery FCV Duration Calculation- 500 MW Increments-CONFIDENTIAL.xlsx" at "FCV" tab

[31] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 97-98.

For winter, FPL currently uses a battery storage firm capacity value percentage of 100% under its 20% PRM criterion.[32]

Q. PLEASE EXPLAIN HOW YOU SPECIFICALLY EXAMINED THE TIMING OF FPL'S NEED FOR ADDITIONAL FIRM CAPACITY.

A. I did so first based on FPL's 20% PRM resource adequacy criterion. Specifically, I performed an analysis for FPL's 2025 TYSP using the 20% PRM criterion and the firm capacity value percentages for solar energy center and battery storage facility additions that I have summarized above. Through 2031, FPL's 2025 TYSP is identical to FPL's resource plan presented in Column "(2)" of FPL witness Andrew Whitley's Exhibit AWW-7.[33] As such, FPL's 2025 TYSP includes FPL's 522 MW NWFL Battery Storage Project, FPL's proposed 2026 and 2027 solar energy center and battery storage facility proposals in this proceeding, and FPL's projected 2028 and 2029 SoBRA solar energy center and battery storage facility additions. In my analysis, using information FPL provided in response to Staff's Seventh Set of Interrogatories, No. 142 and Schedule 8 of FPL's 2025 TYSP, I created a modified version of Schedule 7.1 of FPL's 2025 TYSP that backs out the summer firm capacity indicated in Schedule 8 of FPL's 2025 TYSP that is associated with all of the supply-side resource additions in Schedule 7.1. I then also added a column that only adds FPL's 522 MW NWFL Battery Storage, the minor combined cycle capacity uprates included in FPL's 2025 TYSP, and FPL's

[32] FPL 2025 TYSP at 163-165 (Schedule 8) and FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 97-98.
[33] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 83-84.

projected 475 MW combustion turbine addition in 2032. These results are presented in my Exhibit JRD-1.

The results show that, under FPL's traditional 20% PRM resource adequacy criterion, with no resource additions, FPL would have a need for additional firm capacity starting in Summer 2027. The results also show this need for additional firm capacity under the 20% PRM criterion is pushed off to Summer 2028 with the addition of FPL's 522 MW NWFL Battery Storage Project by the end of 2025 and the pre-Summer 2027 completion of a projected 47 MW combined cycle capacity uprate.

Note, I have not performed a similar analysis for winter by constructing an alternate version of Schedule 7.2 of FPL's 2025 TYSP because Schedule 7.2 of FPL's 2025 TYSP shows FPL's reserve margins for winter are much higher (40% or more) versus those in the summer (typically just above 20%). As such, under FPL's 20% PRM criterion, summer drives FPL's general firm capacity need rather than winter.

Q. YOUR ANALYSIS INDICATES THE 522 MW NWFL BATTERY STORAGE PROJECT WOULD BE COMPLETED BY THE END OF 2025, BUT IS NOT NEEDED TO MEET FPL'S GENERAL FIRM CAPACITY NEED UNTIL THE SUMMER 2027. HAS FPL'S IDENTIFIED ANY OTHER RELIABILITY NEED FOR THE 522 MW NWFL BATTERY STORAGE PROJECT THAT WOULD REQUIRE THE PROJECT TO BE FULLY ONLINE PRIOR TO SUMMER 2026?

A. Yes, in response to discovery, FPL's has provided information that indicates there is a local reliability need in Northwest Florida starting this coming winter for the 522 MW

NWFL Battery Storage Project.[34] In the discovery response, FPL indicates that transmission constraints, which are not expected to relieved until January 2027, could cause the Northwest Florida portion of its system to be deficient in reserves if it had a repeat of the winter peak load it experienced in December 2022.[35] The 522 MW NWFL Battery Storage Project is the interim solution FPL identified to address the issue. Given there is an immediate local reliability need and it is very likely there is no other effective supply-side resource option to meet this need that could have as quickly been pursued, FPL's decision to pursue completion prior to Winter 2025 rather than prior to Summer 2027 appears to be prudent, reasonable and cost-effective.

Q. DO THE RESULTS OF YOUR ANALYSIS OF FPL'S CAPACITY NEED USING FPL'S TRADITIONAL 20% PRM RESOURCE ADEQUACY CRITERION SUPPORT A RELIABILITY NEED FOR FPL'S PROPOSED 2026 AND 2027 SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITY ADDITIONS?

A. No. As shown in my Exhibit JRD-1, under FPL's traditional 20% PRM resource adequacy criterion, after the addition of FPL's 522 MW NWFL Battery Storage Project, FPL does not need additional firm capacity until Summer 2028. This conclusion is further supported by the "Without Proposed 2026 and 2027 Solar and

[34] FPL Response to FEL's Eighth Set of Interrogatories, Nos. 82, 83 and 84 and FPL Response to OPC's First Request for Production of Documents, No. 43 at "Confidential – 2025 BESS – Northwest Florida Battery Storage May BOD Slides 1."

[35] FPL Response to OPC's First Request for Production of Documents, No. 43, "Development" folder at "Confidential – 2025 BESS – Northwest Florida Battery Storage May BOD Slides 1" at 3.

Battery Additions" column of witness Whitley's Exhibit AWW-5, that does not add any new firm capacity beyond the 522 MW NWFL Battery Storage Project until 2028.

C. Analysis of Capacity Need under FPL's Stochastic LOLP Analysis

Q. EARLIER, YOU INDICATED THAT YOU STARTED YOUR REVIEW OF FPL'S CAPACITY NEED BY PERFORMING AN ANALYSIS OF THAT NEED UNDER FPL'S TRADITIONAL 20% PRM RESOURCE ADEQUACY CRITERION. DID YOU PERFORM ADDITIONAL REVIEW AND ANALYSIS BEYOND THAT TRADITIONAL ANALYSIS?

A. Yes. FPL in this proceeding has proposed major changes to how it performs its analysis for its *probabilistic* LOLP resource adequacy criterion. This is the criterion under which capacity need is determined as the amount of capacity necessary to provide a targeted LOLE of no more than one loss of firm load event day in ten years (or no more than 0.1 loss of firm load event days per year). As I discussed earlier in my testimony, FPL has traditionally performed its LOLP analysis using TIGER with a focus on the peak load hour of each day and that TIGER analysis has not at any time in recent years required FPL to acquire more firm capacity than is necessary under its traditional 20% PRM resource adequacy criterion. FPL's specific proposal in this proceeding is to determine its capacity needs based on the results of a stochastic LOLP analysis performed by E3 on FPL's behalf using E3's proprietary Renewable Energy Capacity Planning Model ("RECAP") software package based on inputs and assumptions provided by FPL with no input from FPL's other stakeholders including, but not limited to, the Commission Staff and OPC. FPL's proposal, if adopted, would cause a very large 1,663 MW "perfect" capacity step increase in FPL's Summer 2027 capacity need versus FPL's capacity need for Summer 2027 under its traditional 20% PRM resource adequacy criterion. To my knowledge, FPL is the first utility within Florida to propose determining its capacity needs based on a stochastic LOLP analysis.

Q. WHAT IS "PERFECT" CAPACITY?

A. "Perfect" capacity is capacity that is available at all times to produce energy up to its stated MW amount of capacity during any hour of the year with no restrictions whatsoever. As such, it is firmer than what FPL deems firm capacity under its traditional 20% PRM resource adequacy criteria. Specifically, while 100% of the seasonal-rated capability of FPL's fossil and nuclear generating facilities counts as firm capacity under FPL's 20% PRM resource adequacy criterion, based on E3's Stochastic LOLP analysis, only approximately 89% of that amount on average is "perfect" capacity.[36] So, to cure a "perfect" capacity need of 1,663 MW with new combustion turbine generation additions, those combustion turbine generator additions might need to total as much as 1,869 MW of summer rated capability depending on their expected equivalent forced outage rate and other factors that restrict the availability of those combustion turbine generators to provide energy at their rated capability during all hours of the year.[37]

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[36] Exhibit AWW-1 at 21-26 under "Thermal + Kingfisher 1/2."
[37] 1,869 MW = 1,663 MW / 89%

Q. WHAT DIFFERENTIATES STOCHASTIC LOLP ANALYSIS PERFORMED WITH A SOFTWARE PACKAGE SUCH AS E3'S RECAP VERSUS THE LOLP ANALYSIS FPL HAS HISTORICALLY PERFORMED USING THE TIGER SOFTWARE PACKAGE?

A. There are a number of differences. First, FPL's TIGER analysis only examines the peak load hour of each day of the year, while a stochastic LOLP analysis examines all hours of the year.[38] While it has historically been an appropriate simplification to just examine the peak load hour of each day, it ceases to be so once a utility system has had a large enough penetration of renewable generation (especially solar generation) that it has caused the time of the utility system's greatest demand on its conventional fossil and nuclear generation resources (and other non-renewable resources) to significantly shift from the time of the utility system's peak system demand hour (typically in the mid-afternoon in the summer) to other hours (such as summer evening hours). This demand is often referred to as the utility system's net demand and typically calculated as the utility's demand in an hour less the portion of that demand that is being supplied by solar and/or wind generation in that hour. The utility's peak level of net demand is often referred to as the utility's net peak.

Another difference highlighted by FPL is that FPL's traditional LOLP analysis with TIGER modeled expected generation unavailability based upon historic forced outage rates, resulting in a cumulative probability matrix of potential unit outages, while stochastic LOLP analysis simulates random selection of plant outages, which is generally viewed as better reflecting the unpredictable nature of unavailable generation

[38] FPL Witness Andrew Whitley Direct Testimony, p. 10-12.

as observed in normal system operations.[39] Finally, FPL highlights the ability in stochastic LOLP analysis to produce a reliability assessment that captures the natural variability in solar generation energy production due to weather conditions – another factor that cannot be readily modeled in FPL's traditional TIGER LOLP analysis.[40]

Q. ARE THERE OTHER SOFTWARE PACKAGES BESIDES E3'S RECAP THAT CAN BE USED TO PERFORM STOCHASTIC LOLP ANALYSIS?

A. I am aware of two. The first is PowerGEM, LLC's SERVM® and the other is GE Vernova's Multi-Area Reliability Simulation ("MARS®") software package.

SERVM® is used by many electric utilities, ISOs, RTOs, and reliability organizations to perform stochastic LOLP analysis. Examples of these include, but are not limited to, DTE Electric Company, MISO, Public Service Company of New Mexico ("PNM") and SERC. As noted earlier in my testimony, I have experience with the use of SERVM® for stochastic LOLP analysis. I have limited knowledge of and no experience with MARS®.

Q. HOW DO YOU RESPOND TO FPL'S PROPOSAL TO USE STOCHASTIC LOLP ANALYSIS TO DETERMINE ITS CAPACITY NEED?

A. While I conceptually agree the use of stochastic LOLP analysis is the most appropriate approach for a utility system with high levels of renewable (especially solar) generation, I have serious concerns with respect to the specific stochastic LOLP analysis that was performed by E3 for FPL based on the inputs and assumptions

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[39] FPL Witness Andrew Whitley Direct Testimony, p. 13.
[40] FPL Witness Andrew Whitley Direct Testimony, p. 13-14.

provided by FPL. Specifically, I am concerned that the Stochastic LOLP analysis that was performed may be overly conservative and as a result may be significantly overstating the amount of additional capacity FPL needs by Summer 2027 above and beyond what its traditional 20% PRM resource adequacy criterion would require in order to achieve a LOLE target of 0.1 event days per year or less.

Q. PLEASE EXPLAIN WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. There are seven reasons. First, FPL's Stochastic LOLP analysis suggests FPL is currently significantly short of capacity given that it is indicating FPL needs nearly the equivalent of 1,900 MW of new fossil generation in 2027 above and beyond what it would need under its traditional 20% PRM criterion and would have a LOLE of 0.74 event days per year (the equivalent of 7.4 event days in ten years) in 2027[41] if that amount capacity (or the "perfect" capacity equivalent of it from other types of resources) is not added. If that were true, I would have expected to have started to see more frequent FPL declarations of North America Electric Reliability Corporation ("NERC") Energy Emergency Alerts ("EEAs") under NERC Reliability Standard EOP-011-4 over the last ten years.[42]

There are three levels of NERC EEAs:

- EEA Level 1: All available generation resources in use.
- EEA Level 2: (Non-firm) load management procedure in effect.
- EEA Level 3: Firm Load interruption is imminent or in progress.[43]

[41] Exhibit AWW-1, p. 21; FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (a).
[42] A copy of NERC Reliability Standard EOP-011-4 is provided in my Exhibit JRD-2.
[43] NERC Reliability Standard EOP-011-4 at 13-14.

Only the last of these three EEA levels involves the occurrence of a loss of firm load event. Furthermore, EEA Level 1 and EEA Level 2 are expected to occur with some level of frequency when an entity has significant demand responses and a LOLE close to 0.1 event days per year. This is because Demand Side Management ("DSM") is typically deployed during an EEA Level 1 or EEA Level 2 declaration.

The last time FPL had an EEA Level 1 declaration on its system, never mind a EEA Level 2 or EEA Level 2 declaration, was April 28, 2017 due to FPL's expected use of DSM over its peak load that day.[44] FPL has not made any EEA Level 2 or EEA Level 3 declaration on its system since at least January 1, 2016.[45] FPL indicates it came close to making a EEA Level 1 declaration in August 2024 when its system was impacted by hot weather.[46] This said, FPL has not identified any recent year trend in either its declaration or near declaration of NERC EEAs that would suggest FPL is not carrying sufficient capacity on its system and needs a big step in increase in its capacity supply (by 1,663 MW) versus the status quo method of determining its need for capacity.

Q. WHAT IS YOUR SECOND REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. FPL has not provided any evidence that there is either currently a resource adequacy problem on its system or that it expects one in 2026. When asked in discovery whether it had any reason to believe its current Stochastic LOLE or its expected Stochastic

[44] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (d).
[45] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (e) and (f).
[46] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (k).

LOLE for 2026 are in excess of 0.1 event days per year, FPL indicated it had not projected those values and "while no stochastic evaluations were performed, FPL consistently evaluates it system on operational basis."[47] Given FPL's response, FPL clearly does not believe it currently has a resource adequacy problem on its system or expects to have one in 2026. Yet, given the very large magnitude of additional capacity need FPL claims it has for 2027 based on its Stochastic LOLP analysis (above and beyond what would be needed under its traditional 20% PRM criterion) and the high stochastic LOLE of 0.74 event days per year that it has predicted for 2027 if that additional capacity is not added, I would expect FPL to be indicating that it currently has a stochastic LOLE in excess of 0.1 event days per year or at least expects a stochastic LOLE in excess of 0.1 events days per years in 2026. FPL has not done this. This leads me to further believe FPL's Stochastic LOLP analysis may be overly conservative.

Q. WHAT IS YOUR THIRD REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. Both NERC and SERC perform and report on long-term stochastic LOLP analysis of their own and neither is identifying any significant issue with Florida through 2028. Both have switched to reporting other stochastic LOLP measures than LOLE because LOLE does not provide any information with respect to the expected length or breadth of loss of load events and a LOLE result on one utility system may have a very different length and breadth than the same LOLE result on a different utility system.

[47] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 351 (a), (b), and (c).

Specifically, NERC and SERC are instead reporting Loss of Load Hours ("LOLH"), the expected number of hours per year of loss of firm load, and Expected Unserved Energy ("EUE"), the expected total amount of unserved firm energy per year measured in terms of MWh or, alternatively on a normalized basis, parts per million ("ppm") of total annual system energy consumption. Using these two metrics, NERC has defined the following three risk categories:

- **High Risk:** Annual LOLH exceed 2.4 hours per year for one or more years, annual normalized EUE exceeds 20 ppm, and/or resource adequacy target(s) of regulatory authority or market operator not met.
- **Elevated Risk:** Annual LOLH is between 0.1 and 2.4 hours per year for one or more years, annual normalized EUE is non-zero but less than 20 ppm, and/or plausible scenarios of above-normal demand and/or low-resource conditions associated with a one-per-decade event indicated risk of load loss.
- **Normal Risk:** Annual LOLH is below 0.1 hours per year for all years and annual normalized EUE is negligible or zero.[48]

While NERC in its 2024 Long-Term Reliability Assessment ("LTRA") identified several areas in the U.S. with either a High Risk or an Elevated Risk over the period of 2025 through 2029, SERC-Florida Peninsula and SERC-Southeast were not among them.[49] They were categorized as having a Normal Risk.[50] For 2028, SERC-Florida Peninsula had a stochastic LOLP analysis result of a LOLH of 0.02 hours per year and

[48] NERC 2024 Long-Term Reliability Assessment, December 2024 at 11-12. A copy of the relevant excerpts from the NERC 2024 Long-Term Reliability Assessment is provided in my Exhibit JRD-3.
[49] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 6.
[50] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 6.

an EUE of 0.06 PPM.[51] SERC-Southeast had a result of a LOLH of 0.00 hours per year and an EUE of 0.00 PPM.[52] SERC, in its 2024-2034 SERC Annual Long-Term Reliability Assessment Report shows the same stochastic LOLP analysis results, which SERC indicates were produced using SERVM®.[53] There is no evidence in the NERC and SERC reports of a need for a large step increase in capacity supply for FPL in Summer 2027 in order to maintain resource adequacy. If there was a problem that required such a large step increase in FPL's capacity supply by Summer 2027, I would have expected it to also manifest itself in terms of there being at least an Elevated Risk in SERC-Florida Peninsula or SERC-Southeast in the NERC and SERC reports, not a Normal Risk.

Q. WHAT IS YOUR FOURTH REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My fourth reason is that the FPL Stochastic LOLP analysis appears rushed. The FPL's Stochastic LOLP analysis appears to rushed because: (i) it didn't commence until late October 2024,[54] (ii) it was not completed until less than one month before FPL made its filing February 28, 2025 filing in this proceeding,[55] (iii) it did not examine either FPL's current stochastic LOLE or expected its stochastic LOLE for 2026,[56] (iv) it did not examine the stochastic LOLE for FPL's principal base case for evaluating its 2026

[51] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 103.
[52] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 107.
[53] 2024-2034 SERC Annual Long-Term Reliability Assessment Report at 16-17. A copy of the relevant excerpts from the 2024-2034 SERC Annual Long-Term Reliability Assessment Report is provided in my Exhibit JRD-4.
[54] May 29, 2025 Deposition of Arne Olson Tr., p. 32. (Errata pending).
[55] FPL Exhibit AWW-1 at 1 and FPL Response to OPC's Sixteenth Request for Production, No. 138 a. at "OPC POD 16-138-2025-01-27 FPL RA Check-In.pdf".
[56] FPL Response to OPC's Sixteenth Interrogatories, No. 351 (a), (b) and (c).

and 2027 proposed solar energy center and battery storage facility additions,[57] and (v) it was not supported with direct testimony on behalf of FPL by a witness from E3 who either performed the analysis or directly supervised its performance.[58] In my experience, there is a tendency, when performing a study on a rushed basis, to lean toward being conservative with respect to reliability when making assumptions. This increases the likelihood of the study being overly conservative. Furthermore, a rushed study is more likely to encounter errors – errors that could have contributed to an overly conservative result.

Q. WHAT IS YOUR FIFTH REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My fifth reason is that at least one of the assumptions that was made was overly conservative. Specifically, during the May 29, 2025 deposition of Mr. Olson, he confirmed that E3's modeling for FPL included an assumption that FPL is an electrical island.[59] This is, of course, not the case. Also, in my experience, it is not the most common practice, even for utilities that have only limited transmission access to other utility systems, to assume they are a complete electrical island. Furthermore, while Florida itself has limited transmission access to utility systems located outside of Florida, within Florida, there is a significant ability to call on neighbors. That ability

[57] FPL Response to OPC's Sixteenth Interrogatories, No. 351 (d) through (h); Staff's Third Interrogatories, No. 44 Corrected Supplemental; and Exhibit AWW-5.
[58] Instead, FPL witness Whitely sponsored the analysis as his Exhibit AWW-1 even though FPL did not perform the Stochastic LOLP analysis itself and witness Whitely did not directly supervise the performance of the Stochastic LOLP analysis by E3's personnel.
[59] May 29, 2025 Deposition of Arne Olson, Tr., p. 83-84 and 198-199. (Errata pending).

can and should be probabilistically modeled. To not model the ability at all is overly conservative.

Q. WHAT IS YOUR SIXTH REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My sixth reason is that not all of the workpapers for the Stochastic LOLP analysis were provided in a timely manner. Specifically, they were requested very early in this proceeding in OPC's First Request for Production of Documents No. 15, and FPL left the impression they had all been provided. However, during Mr. Olson's May 29, 2025 deposition, it became clear that several had not as of that time been provided including, but not limited to, the detailed workpapers for FPL's 2027 cases with and without 1,400 MW of additional battery storage added.[60] This limited intervenors' ability to independently review the assumptions and inputs used in FPL's Stochastic LOLP analysis, which is an essential part of ensuring that the results are not overly conservative.

Q. WHAT IS YOUR SEVENTH AND FINAL REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My last reason is that no FPL stakeholders, including the Commission Staff or OPC, were given an opportunity to provide any input, never mind meaningful input, with respect to the assumptions utilized in the analysis. FPL inherently has an incentive to

[60] May 29, 2025 Deposition of Arne Olson, Tr., p. 68 and 208-210. (Errata pending).

grow its rate base to increase the returns to its shareholders. As such, FPL cannot be relied upon alone to root out overly conservative assumptions. Review and meaningful input from other FPL stakeholders is needed to help ensure that occurs.

Q. WHILE YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE AND, AS A RESULT, OVERSTATING FPL'S CAPACITY NEED FOR RESOURCE ADEQUACY IN 2027, DO YOU BELIEVE SOME AMOUNT OF ADDITIONAL CAPACITY BEYOND THAT WHICH WOULD BE REQUIRED TO MEET FPL'S TRADITIONAL 20% PRM CRITERION MAY BE NECESSARY TO PROVIDE RESOURCE ADEQUACY IN 2027?

A. Yes. First, FPL is just under a 30,000 MW demand utility system, had 7,038 MW_{AC} of nameplate solar generation at the end of 2024, and currently in 2025 has a total of 7,932 MW_{AC} of such nameplate solar generation.[61] Thus, FPL has a high level of solar generation penetration that does require a move to stochastic LOLP analysis because at some point any historic conservatism that may have been inherent in its traditional 20% PRM criterion with respect to achieving a LOLE of 0.1 event days per year will eventually be washed away by the shift of FPL's greatest loss of load risk hours from the time of its system peak hour in the summer afternoon to summer evening hours due to FPL's heavy pursuit of solar generation. It is possible FPL has just reached that point such that its forecast load growth coupled with further pursuit of new solar generation will put FPL into a position that its traditional 20% PRM criterion will not

[61] FPL 2025 TYSP, p. 25, Exhibit AWW-5; FPL Witness Tim Oliver Direct Testimony, p. 5-6.

provide it with a LOLE of 0.1 event days per year or less in 2027. This said, this does not mean FPL necessarily needs 1,663 MW of additional "perfect' capacity for Summer 2027 to achieve a LOLE of 0.1 event days per year of less. As I have discussed, I am concerned FPL's stochastic LOLE analysis may be overly conservative and as a result significantly overstating the additional capacity FPL needs for Summer 2027 to achieve a LOLE of 0.1 event days per year of less.

Second, there is clear evidence that FPL is encountering challenges with the operation of its system related to its large investments in solar generation that FPL did not identify in advance from its Aurora® analysis. Specifically, E3 was not originally hired to provide a stochastic LOLP analysis to support proposed resource additions in this proceeding. E3's involvement with FPL instead has its origin in unexpected operational reserve problems that FPL encountered in Spring 2023 when lower than normal operational reserves were available during net system peak hours.[62]

FPL indicates these instances occurred during a period of higher than expected load and a high level of units on maintenance.[63] To address these problems, FPL had to scramble to react to lower reserves being available, had to postpone overhauls, and make short-term power purchases.[64] FPL later identified that its current generation overhaul planning process required modification to address solar energy generation decline in the late afternoon leading to a reduction in reserve margin during peak net demand.[65] It also at that time identified both short-term mitigations (reducing planned

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[62] FPL Response to OPC's Sixteenth Interrogatories, No. 350 (h).
[63] *Id.*
[64] FPL Response to OPC's Sixteenth Request for Production of Documents, No. 138 (b), "OPC POD 16-138 – Overhaul Scheduling with Increased Solar Penetration – 0928.pdf".
[65] *Id.*

overhauls, purchasing long-term firm power, dispatch of Manatee 1 and 2 and/or increase regular DSM use when short-term solution are limited) and long-term mitigations (install batteries on a more aggressive schedule, contract new conventional generation or pursue long-term Purchase Power Agreements ("PPAs").[66] FPL at that time also identified other operational issues with solar generation including: (i) reduced margin also limiting the ability to schedule maintenance; (ii) increased daily cycling of conventional generation; (iii) solar forecasting uncertainty; and (iv) solar power swings.[67] FPL continued to work on these issues into the early part of 2024 and this eventually led to FPL engaging E3 to assist it with the operational reserves issue.[68] To perform that work, E3 constructed more sophisticated production cost modeling of the FPL system for 2027 using PLEXOS ST® and identified that FPL may need better tools to address operating reserve needs in operations and planning.[69] It was E3's PLEXOS modeling work in 2024 that uncovered what E3 believed to be "red flags" with respect to FPL's resource adequacy in 2027.[70] This led to E3 being redirected to focus on a new 5th track of work, which was to perform a stochastic LOLP analysis for FPL, beginning in the fourth quarter of 2024.[71]

In summary, FPL is experiencing operational challenges on its system due to the level of FPL's solar generation investments that were not adequately detected by FPL's Aurora® and TIGER modeling and this may be symptomatic of FPL needing

[66] *Id.*
[67] *Id.*
[68] FPL Response to Staff's Third Interrogatories, No. 35.
[69] FPL Response to OPC's Sixteenth Request for Production of Documents, No. 138 (a), "OPC POD 16-138 – FP&L Exec Briefing 2025.01.06.pdf".
[70] *Id.*; May 29, 2025 Deposition of Arne Olson, Tr., p. 36-37. (Errata pending).
[71] FPL Response to Staff's Third Interrogatories, No. 35; May 29, 2025 Deposition of Arne Olson, Tr., p. 36-37 and 51. (Errata pending).

some level of additional capacity for Summer 2027 beyond that which would be necessary to meet FPL's traditional 20% PRM criterion.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO FPL'S STOCHASTIC LOLP ANALYSIS IN THIS PROCEEDING?

A. I recommend that the capacity need identified by FPL's Stochastic LOLP analysis in this proceeding be limited in its application to FPL's 2026 and 2027 test years. For this reason, the fact FPL may have access to other resource options for 2028 including Project Commodore, and the reasons discussed by OPC witness Schultz, I also recommend that FPL's proposed SoBRA for 2028 and 2029 should be rejected by the Commission. As I have discussed, FPL likely has some need for additional capacity beyond what is necessary to meet its traditional 20% PRM. However, as I have also discussed, it appears FPL's Stochastic LOLP analysis may be overly conservative and potentially significantly overstating the additional capacity FPL requires beyond its traditional 20% PRM criterion in order to assure resource adequacy. For this reason, in my opinion, the best course of action for the Commission to take is to limit the applicability of the capacity need identified by FPL's Stochastic LOLP analysis in this proceeding to FPL's 2026 and 2027 test years in the proceeding and to put conditions on FPL's future use of stochastic LOLP analysis to justify generation additions. Specifically, I recommend the Commission:

- Require FPL to identify the current Stochastic LOLP for its system as well as the expected Stochastic LOLP for its system in 2026;

- To the extent the LOLP value for either of those time periods is greater than 0.1 event days per year, require FPL to identify to the Commission whether there is an unreasonably high risk of a loss of load event on its system during those time periods, and, if so, identify all steps FPL is taking to minimize the likelihood of that risk being significantly greater than the normal risk that exists;
- Require FPL to reconcile the 2027 results of its Stochastic LOLP analysis with the stochastic LOLP analysis results of the NERC 2024 Long-Term Reliability Assessment and the 2024-2034 SERC Annual Long-Term Reliability Assessment Report;
- Require FPL, in future proceedings where it proposes to use stochastic LOLP analysis to justify generation additions to:
    - Provide all FPL stakeholders a reasonable opportunity, prior to and during the analysis, to provide meaningful input with respect to the assumptions being utilized in the analysis;
    - Coordinate with the other utilities jurisdictional to the Commission to help ensure a consistent approach is used for stochastic LOLP analysis in Florida.
    - Have the analysis subject to review from an independent third-party not affiliated with either FPL or the contractor who performed the analysis on behalf of FPL; and

- Provide direct testimony from an expert witness who either performed, or directly supervised the performance of, the analysis.

III. FPL'S 2026 AND 2027 SOLAR AND BATTERY ADDITIONS

Q. ASSUMING FPL DOES HAVE THE "PERFECT" CAPACITY NEED FOR 2027 THAT IT HAS IDENTIFIED IN ITS STOCHASTIC LOLP ANALYSIS IN THIS PROCEEDING, IS THAT SUFFICIENT ALONE TO SHOW THAT FPL HAS A RELIABILITY NEED FOR ITS 2026 AND 2027 PROPOSED SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITIES IN THEIR ENTIRETY?

A. No. First, the total nameplate capacity amounts of solar generation and battery storage proposed by FPL for 2026 and 2027 with in-service dates prior to Summer 2027 significantly exceed the amounts assumed in the Stochastic LOLP analysis case that FPL uses to justify the need for them from a reliability perspective ("TYP Portfolio + 1,400 of Storage," Exhibit AWW-1, page 22). Second, FPL has not provided any economic analysis showing the solar generation and battery storage additions in the amounts and proportions it has proposed for 2026 and 2027 are the most cost effective way to address the "perfect" capacity need for 2027 identified by FPL's Stochastic LOLP analysis. Furthermore, due to the large investment in solar generation that FPL has made to date on its system (7,932 MW_{AC} on nameplate basis), solar generation now only provides very limited "perfect" capacity (marginally, 17% of nameplate capacity per Exhibit AWW-1, page 22) versus other resource types such as battery storage (marginally, 76% of nameplate capacity per Exhibit AWW-1, page 22) such that solar generation is much less likely than in the past to be a cost-effective choice for meeting FPL's capacity needs. Third, the operational reserves problem FPL experienced in Spring 2023 continues to exist and challenge FPL and has also revealed that FPL's Aurora® modeling at this time is not likely able to capture all of the challenges and costs that would be associated with further investing in new solar generation. Finally, analysis I have performed, which corrects the expected in-service solar generation and battery storage resource levels for Summer and uses the cumulative "perfect" capacity curves for solar generation and battery storage developed in FPL's Stochastic LOLP analysis (including the interactions between the solar and battery curves),[72] shows that FPL's proposed 2026 and 2027 battery storage facility additions in this proceeding are alone capable of providing a stochastic LOLP analysis LOLE of 0.1 event days per year or less. FPL's proposed 2026 and 2027 solar energy center additions are not necessary for FPL to achieve a stochastic LOLP analysis LOLE of 0.1 event days per year or less for 2027.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE TOTAL NAMEPLATE CAPACITY AMOUNTS OF SOLAR GENERATION AND BATTERY STORAGE PROPOSED BY FPL FOR 2026 AND 2027 WITH IN-SERVICE DATES PRIOR TO SUMMER 2027 SIGNIFICANTLY EXCEED THE AMOUNTS ASSUMED IN THE STOCHASTIC LOLP ANALYSIS CASE THAT FPL USES TO JUSTIFY THE NEED FOR THEM FROM A RELIABILITY PERSPECTIVE.

[72] Exhibit AWW-1, p. 28.

A. For FPL's 2026 and 2027 proposed solar energy center and battery storage facility additions in this proceeding, FPL witness Laney in her revenue requirement workpapers shows a total of 1,490 MW_{AC} of the 2026 and 2027 solar resources and 1,867 MW of the 2026 and 2027 battery storage resources in service by April 2027.[73] When added to FPL's end-of-2025 utility solar total of 7,932 MW and battery storage total of 991 MW, this adds up to 9,422 MW of utility solar and 2,858 MW of battery storage. In contrast, the Stochastic LOLP analysis case that FPL uses to justify the need for them from a reliability perspective ("TYP Portfolio + 1,400 of Storage", Exhibit AWW-1 at page 22) only shows a total of 8,946 MW of utility solar and 2,391 MW of battery storage, which is lower by 476 MW of utility solar and 447 MW of battery storage.

To estimate how the additional 476 MW of utility solar generation and 447 MW of battery storage would change the Stochastic LOLP analysis results for the "TYP Portfolio + 1,400 of Storage" that are on page 22 of Exhibit AWW-1, I applied the cumulative "perfect" capacity curves for solar generation and battery storage developed in FPL's Stochastic LOLP analysis (including the interactions between the solar and battery curves) that are presented on page 28 of Exhibit AWW-1 and interpolated and extrapolated from the Stochastic LOLP analysis LOLE values for the two 2027 cases that were examined in Exhibit AWW-1.[74] The result of this estimate are shown in Exhibit JRD-5. As can be seen from that exhibit, with my revision to reflect pre-

[73] FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx", "Rev. Req. Detail" tab.
[74] Exhibit AWW-1, p. 20-22; FPL Response to OPC's First Request for Production of Documents, No. 15, Whitley folder, "2025-02-21 RA Study Workpapers.xlsx", "Loads, Capacity Short & LOLE" tab; and FPL Response to OPC's Sixteenth Interrogatories, No. 350 (a).

Summer 2027 in-service dates, I estimate that for 2027 FPL's 2026 and 2027 solar and battery storage additions would produce a "perfect" capacity surplus of 204 MW rather than a deficit of 273 MW and a stochastic LOLP analysis LOLE of 0.097 event days per year rather than one of 0.105 event days per year. As a result, not all of FPL's 2026 and 2027 proposed solar and battery storage additions in this proceeding are necessary for reliability.

Q. PLEASE FURTHER EXPLAIN YOUR CONCERN WITH RESPECT TO FPL NOT PROVIDING ANY ECONOMIC ANALYSIS SHOWING THE SOLAR GENERATION AND BATTERY STORAGE ADDITIONS IN THE AMOUNTS AND PROPORTIONS IT HAS PROPOSED FOR 2026 AND 2027 ARE THE MOST COST EFFECTIVE WAY TO ADDRESS THE "PERFECT" CAPACITY NEED FOR 2027 IDENTIFIED BY FPL'S STOCHASTIC LOLP ANALYSIS AND HOW THAT, WITH YOUR OTHER CONCERNS, LED YOU TO EXPLORING WHETHER JUST ADDING FPL'S 2026 AND 2027 PROPOSED BATTERY STORAGE ADDITIONS IS SUFFICIENT TO MEET FPL'S 2027 "PERFECT" CAPACITY NEED.

A. For FPL to demonstrate a proposed resource addition for reliability is prudent, reasonable and cost effective, it is not enough for FPL to demonstrate that the proposed resource addition will satisfy a reliability need such as resource adequacy. FPL must also show that the proposed resource addition is the most cost-effective way to address the reliability need.

In this proceeding, FPL did not use Aurora® to determine the most cost-effective way for it to make solar generation and battery storage additions in 2026 and 2027 to meet its capacity need in 2027. Instead, it performed the Aurora® analysis summarized in Exhibit AWW-5 that compared a case with its 2026 and 2027 proposed solar and battery storage additions to one that instead added new combustion turbine generation each year starting in 2028. While this provides insight with respect the cost effectiveness of FPL's 2026 and 2027 solar and battery storage versus a hypothetical scenario of pursuing new combustion turbines storage generation beginning in 2028, it provides absolutely no insight with respect to whether it would be most cost effective to meet FPL's 2027 capacity need with all solar generation, all battery storage, the combination of solar generation and battery storage that FPL proposed, or a different combination of solar generation and battery storage. Therefore, FPL has not shown its specific 2026 and 2027 proposed combination of solar generation and battery storage addition is the most cost-effective way to meet its 2027 capacity need.

This, combined with the concerns I also raised above with respect to solar generation additions no longer being a good source of "perfect" capacity for FPL, FPL's current Aurora® modeling not necessarily being able to properly capture all of the costs associated with further FPL solar generation additions, and FPL's 2026 and 2027 solar and generation additions providing more "perfect' capacity than necessary for 2027, led to me exploring whether FPL's "perfect" capacity need could be met without FPL's 2026 and 2027 proposed solar generation additions or at least without FPL's 2027 solar generation additions.

Q. PLEASE EXPLAIN HOW THIS EXPLORATION WAS PERFORMED AND HOW IT LED YOU TO CONCLUDE FPL'S 2026 AND 2027 PROPOSED SOLAR GENERATION ADDITIONS ARE NOT NECESSARY TO MEET FPL'S "PERFECT" CAPACITY NEED FOR 2027.

A. For both a case without FPL's 2026 and 2027 proposed solar generation additions and a case without just FPL's 2027 solar generation additions, I once again estimated stochastic LOLP analysis results by applying the cumulative "perfect" capacity curves for solar generation and battery storage developed in FPL's Stochastic LOLP analysis (including the interactions between the solar and battery curves) and interpolated and extrapolated from the Stochastic LOLP analysis LOLE values for the two 2027 cases that were examined in Exhibit AWW-1. The results for my case without FPL's 2026 and 2027 proposed solar generation additions is summarized in Exhibit JRD-6. The results for my case just without FPL's 2027 proposed solar generation additions is summarized in Exhibit JRD-7.

As shown in Exhibit JRD-6, for my case without FPL's 2026 and 2027 proposed solar generation additions, I estimate a "perfect' capacity deficit of only 89 MW and a stochastic LOLP analysis LOLE of 0.101 event days per year. This is sufficiently close to a LOLE of 0.1 events day per year or less to be considered resource adequate.

As shown in Exhibit JRD-7, for my case just without FPL's 2027 proposed solar generation additions, I estimate a "perfect' capacity surplus of 90 MW and a stochastic LOLP analysis LOLE of 0.098 event days per year. This is clearly a resource adequate result.

Based on these results, FPL's "perfect" capacity need for 2027 and Stochastic LOLP analysis LOLE target of 0.1 event day per year or less can be adequately met with FPL's 2026 and 2027 proposed battery storage facility additions alone. FPL's 2026 and 2027 proposed solar energy center additions are not necessary to meet this need and, thus, are not necessary for reliability. Therefore, as I discussed earlier in my testimony, demonstration of the prudence, reasonableness and cost effectiveness of FPL's 2026 and 2027 solar generation additions would require a demonstration that the economic case for those additions is robust and they are not being pursued for the purpose of making off-system sales. Specifically, with off-system sales excluded, they should provide a CPVRR breakeven within ten years of entering service and CPVRR benefit to cost ratio of at least 1.15 over their book life.

Q. HAS FPL PERFORMED ANY ECONOMIC ANALYSIS OF A CASE THAT INCLUDES ALL OF FPL'S 2026 AND 2027 PROPOSED SOLAR GENERATION AND BATTERY STORAGE ADDITIONS VERSUS A CASE THAT ONLY INCLUDES FPL'S 2026 AND 2027 PROPOSED BATTERY STORAGE ADDITIONS IN ORDER TO EVALUATE THE ROBUSTNESS OF THE ECONOMIC CASE FOR FPL'S 2026 AND 2027 PROPOSED SOLAR GENERATION ADDITIONS?

A. No, it has not provided one in either its direct testimony or its responses to discovery as of the filing date of this testimony. As a result, FPL has not shown pursuit of its proposed 2026 and 2027 solar energy center additions is prudent, reasonable, and cost-effective. Also, even if there was, for the reasons I discussed earlier in my testimony, it is questionable whether FPL's current Aurora® modeling would capture all of the costs associated with such additions at this time.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO FPL'S 2026 AND 2027 PROPOSED SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITY ADDITIONS IN THIS PROCEEDING?

A. Assuming the Commission allows FPL to use FPL's Stochastic LOLP analysis in this proceeding to determine FPL's capacity need for 2027, a reliability need for FPL's 2026 and 2027 battery storage facility additions has been demonstrated such that I do not oppose finding FPL's pursuit of them is prudent, reasonable and cost effective. However, with respect to FPL's 2026 and 2027 proposed solar energy centers in this proceeding, FPL has not demonstrated that these proposed solar energy center additions are necessary for reliability or demonstrated that they have a robust economic case associated with them. In addition, as I have discussed in detail in my testimony, it does not appear FPL's current Aurora® economic modeling fully considers all of the costs associated with FPL further pursuing solar generation additions on its system. For these reasons, I recommend the Commission reject FPL's requested approval of its 2026 and 2027 proposed solar energy centers additions and exclude the costs of these proposed facilities from FPL's 2026 and 2027 projected test years in this proceeding. Based on FPL Witness Ina Laney's workpapers, this adjustment in isolation would reduce the non-fuel portion of FPL's proposed revenue requirement by $77.7 million for 2026 and $153.6 million for 2027. OPC Witness Schultz's testimony encompasses the other accounting impacts of my recommendation.

Q. EARLIER IN YOUR TESTIMONY, YOU RECOMMENDED THAT THE COMMISSION REJECT FPL'S PROPOSED SOBRA MECHANISM IN THIS PROCEEDING FOR 2028 AND 2029. IF, DESPITE YOUR RECOMMENDATION, THE COMMISSION INSTEAD DECIDES TO APPROVE A SOBRA FOR FPL FOR 2028 AND 2029, DO YOU HAVE ANY RECOMMENDATIONS WITH RESPECT TO CONDITIONING SUCH APPROVAL?

A. Yes, to the extent the SoBRA involves the pursuit of supply-side resource additions that are not fully needed to meet a reliability need for the year they enter service (or in the immediately following six months), consistent with my earlier testimony herein, the portion of the additions that is excess of what is needed to cost effectively meet the reliability need should only be approved to the extent they are for the purpose of serving FPL's retail customers and have robust economic case associated with it. As I have discussed on my testimony, for the investment to have a robust economic case it should be demonstrated that it both has a CPVRR breakeven with ten years of entering service and a CPVRR benefit to cost ratio of 1.15 or greater by the end of the book life of the investment. As I also discussed in greater detail earlier in my testimony herein, the foregoing demonstrations are necessary to help ensure the investment is consistent with providing reliable electric service at lowest reasonable cost to FPL's customers and not a speculative investment.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Qualifications of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017, USA.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation, I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[75] as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system analysis, power system transients and power system

[75]In 2015, Northeast Utilities changed its name to Eversource Energy.

protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission ("NRC").

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000; Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000; Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and Midcontinent Independent System Operator, Inc. and Ameren Services Company Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta Utilities Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Connecticut Department of Public Utility Control, the Florida Public Service Commission, the Idaho Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service

Commission, the Montana Public Service Commission, the Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Wisconsin Public Service Commission, the Wyoming Public Service Commission, Federal District Court and various committees of the Illinois, Missouri and South Carolina state legislatures. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource adequacy, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several committees and working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group; Economic Planning Users Group; Loss of Load Expectation Working Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and Reliability Subcommittee. I am currently a member of the MISO Advisory Committee in the end-use customer sector on behalf of industrial customer groups in Illinois, Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky; and Phoenix, Arizona.

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FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20250011-EI

2025 Ten Year Site Plan
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak
Examination of Timing and Need for Firm Capacity Additions

Source: FPL 2025 Ten-Year Site Plan, Schedules 7.1 and 8; FPL Response to Staff's Seventh Interrogatories, No. 142, Attachment No. 1

(1)	(a1)	(a2)	(b1)	(b2)	(c)	(d)	(e)	(f)	(g)	(h1)	(h2)	(h3)	(i)	(j)	(2)
	Natural Gas														
August of Year	Firm Existing Combined Cycle Capacity MW	Firm New Combined Cycle Capacity MW	Firm Existing Combustion Turbine Capacity MW	Firm New Combustion Turbine Capacity MW	Firm Conventional Capacity MW	Firm Nuclear Capacity MW	Firm Coal Capacity MW	Firm Light Oil Capacity MW	Firm Perdido Capacity MW	Firm Existing Storage Capacity MW	Firm New NWFL Storage Capacity MW	Firm New Other Storage Capacity MW	Firm Existing Solar Capacity MW	Firm New Solar Capacity MW	Firm Installed Capacity 2025 TYSP MW
2025	20,204	0	2,933	0	961	3,502	215	203	3	469	0	0	3,482	0	31,971
2026	20,204	0	2,933	0	961	3,502	215	203	3	469	349	418	3,469	113	32,838
2027	20,204	47	2,933	0	961	3,502	215	203	3	469	349	1,429	3,457	198	33,970
2028	20,204	61	2,933	0	961	3,502	215	171	3	469	349	1,727	3,445	272	34,312
2029	20,204	61	2,933	0	961	3,502	215	171	3	469	349	1,974	3,433	362	34,637
2030	20,204	61	2,933	0	811	3,502	215	171	0	469	349	2,219	3,421	476	34,830
2031	20,204	61	2,933	0	811	3,502	215	171	0	469	349	2,463	3,409	593	35,180
2032	20,204	61	2,933	469	811	3,502	215	171	0	469	349	2,463	3,397	710	35,753
2033	20,204	61	2,933	469	811	3,502	215	171	0	469	349	2,887	3,385	826	36,282
2034	20,204	61	2,933	469	811	3,502	215	171	0	469	349	3,237	3,373	942	36,735

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated. It is equal to the sum of Col. (a1) through Col. (j).
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5)
Col. (6a) = Col.(6) - Col.(a2) - Col.(b2) - Col.(h2) - Col.(h3) - Col.(j)
Col. (6b) = Col.(6a) + Col.(a2) + Col.(b2) + Col.(h2)
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2024-on intended for use with the 2025 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(10a) = Col.(6a) - Col.(9)
Col.(10b) = Col.(6b) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(11a) = Col.(10a) / Col.(9)
Col.(11b) = Col.(10b) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13b) = Col.(10b) - Col.(12b)
Col.(14b) = Col.(13b) / Col.(9)
Col.(15b) = Col.(6b) - Col.(7) - Col.(12b)
Col.(16b) = Col.(15b) / Col.(7)

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20250011-EI

2025 Ten Year Site Plan
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak
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Source: FPL 2025 Ten-Year Site Plan, Schedules 7.1 and 8; FPL Response to Staff's Seventh Interrogatories, No. 142, Attachment No. 1

(1)	(2)	(3)	(4)	(5)	(6)	(6a)	(6b)	(7)	(8)	(9)	(10)	(11)	(10a)	(11a)	(10b)	(11b)	(12)	(13b)	(14b)	(15b)	(16b)
	Firm Installed Capacity	Firm Capacity	Firm Capacity	Firm	Total Firm Capacity Available	Total Firm Capacity Available	Total Firm Capacity Avl. Only CC, CT and	Total Peak		Firm Summer Peak	Total Reserve Margin Before Maintenance		Total Reserve Margin Before Maintenance		Total Reserve Margin Before Maint. Only CC, CT and		Scheduled	Total Reserve Margin After		Generation Only Reserve Margin After	
August of	2025 TYSP	Import	Export	QF	2025 TYSP	No Additions	NWFL Batt. Addtns.	Demand	DSM	Demand	2025 TYSP		No Additions		NWFL Batt. Additions		Maintenance	Maintenance		Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	% of Peak	MW	% of Peak	MW	MW	% of Peak	MW	% of Peak
2025	31,971	232	0	4	32,206	32,206	32,206	28,312	1,995	26,317	5,889	22.4	5,889	22.4	5,889	22.4	0	5,889	22.4	3,894	13.8
2026	32,838	231	0	4	33,073	32,194	32,543	28,664	2,016	26,648	6,425	24.1	5,546	20.8	5,895	22.1	0	5,895	22.1	3,879	13.5
2027	33,970	231	0	0	34,201	32,178	32,574	28,925	2,036	26,888	7,313	27.2	5,290	19.7	5,686	21.1	0	5,686	21.1	3,649	12.6
2028	34,312	231	0	0	34,543	32,134	32,544	29,333	2,056	27,277	7,266	26.6	4,857	17.8	5,267	19.3	0	5,267	19.3	3,211	10.9
2029	34,637	231	0	0	34,869	32,122	32,532	29,687	2,079	27,608	7,261	26.3	4,514	16.4	4,924	17.8	0	4,924	17.8	2,845	9.6
2030	34,830	231	0	0	35,061	31,957	32,367	29,982	2,106	27,877	7,184	25.8	4,080	14.6	4,490	16.1	0	4,490	16.1	2,384	8.0
2031	35,180	231	0	0	35,411	31,945	32,355	30,301	2,133	28,168	7,242	25.7	3,776	13.4	4,186	14.9	0	4,186	14.9	2,053	6.8
2032	35,753	191	0	0	35,944	31,892	32,771	30,823	2,161	28,662	7,282	25.4	3,230	11.3	4,109	14.3	0	4,109	14.3	1,948	6.3
2033	36,282	191	0	0	36,472	31,880	32,759	31,257	2,189	29,068	7,404	25.5	2,812	9.7	3,691	12.7	0	3,691	12.7	1,502	4.8
2034	36,735	121	0	0	36,856	31,799	32,678	31,677	2,217	29,460	7,396	25.1	2,339	7.9	3,218	10.9	0	3,218	10.9	1,000	3.2

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated. It is equal to the sum of Col. (a1) through Col. (j).
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5)
Col. (6a) = Col.(6) - Col.(a2) - Col.(b2) - Col.(h2) - Col.(h3) - Col.(j)
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Col.(16b) = Col.(15b) / Col.(7)

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

Attachment 1

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Docket No. 20250011-EI
Relevant excerpts from NERC 2024 Long-Term Reliability Assessment
Exhibit JRD-3, Page 1 of 19

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

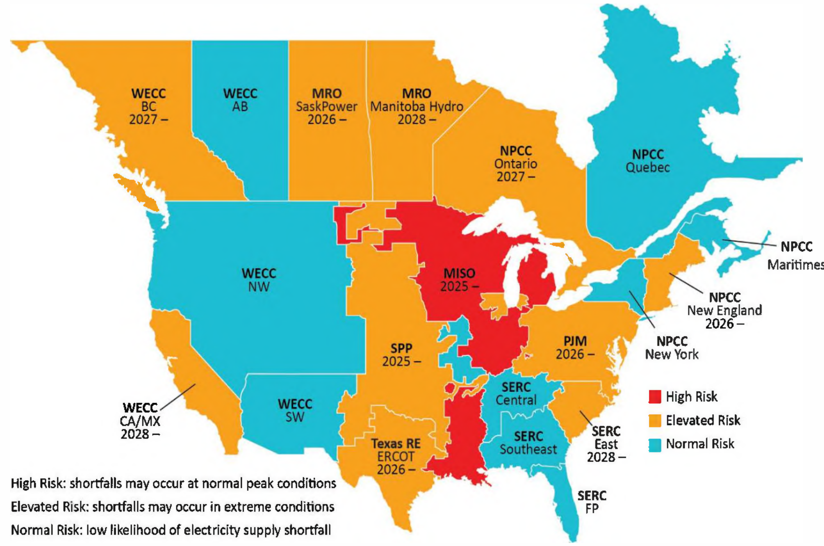


Figure 1: Risk Area Summary 2025–2029

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	High	2025 -	Resource additions are not keeping up with generator retirements and demand growth. Reserve margins fall below Reference Margin Levels (RML) in winter and summer.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in Figure 2. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

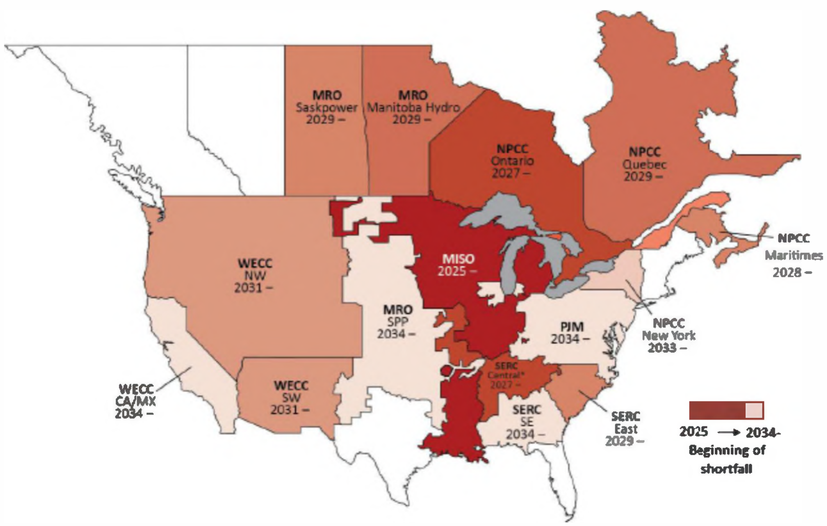


Figure 2: Projected Reserve Margin Shortfall Areas

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the Demand Trends and Implications and Transmission Development and Interregional Transfer Capability sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **__Integrated Resource Planners, market operators, and regulators__: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.
2. **__NERC and Regional Entities:__ Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.
3. **__Regulators and Policymakers:__ Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.
4. **__Regulators, electric industry, and gas industry member organizations:__ Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.
5. **__Regional transmission organizations, independent system operators, and FERC:__ Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

See the Demand Assumptions and Resource Categories for further details on these approaches. Assessment area dashboards (see Regional Assessments Dashboards) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** (see Figure 1) when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based

[8] See the NERC-National Academy of Engineering Workshop Report Evolving Planning Criteria for a Sustainable Power Grid.

on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

NERC assesses areas as normal risk when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

High-Risk Area Details

Most areas are projected to have electricity supply resources to meet demand forecasts associated with normal weather. However, the following areas (listed in order of appearance on the Regional Assessments Dashboards) do not meet resource adequacy criteria at some point during the next five years, indicating that the supply of electricity for these areas is likely to be insufficient and more firm resources are needed.

MISO

Additional coal-fired generator retirements and slower-than-anticipated resource additions since the *2023 LTRA* have caused a sharp decline in anticipated resources beginning next summer (2025). In addition, MISO's peak demand forecast has risen in 2026 and later, further lowering reserve margins compared to the *2023 LTRA*. PRMs in MISO for both summer and winter are projected to fall below the RML reserve margin requirements as new generation is insufficient to make up for generator retirements and load growth (Figure 3 and Figure 4). Delays to generator construction in MISO result in a 2.7 GW shortfall by 2029. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements as of July 2024 that can help meet resource adequacy needs if connection is completed.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.

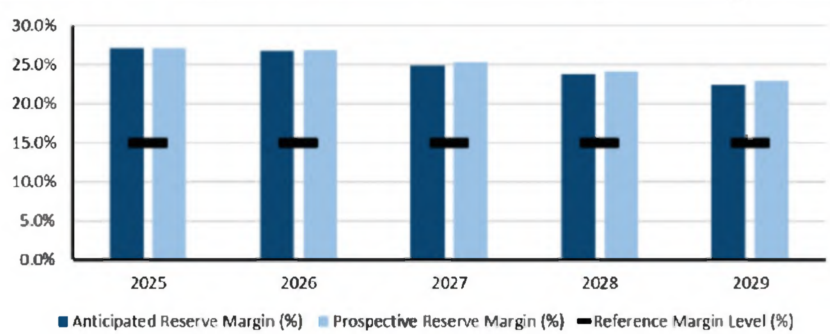
Docket No. 20250011-EI
Relevant excerpts from NERC 2024 Long-Term Reliability Assessment
Exhibit JRD-3, Page 12 of 19

SERC-Florida Peninsula

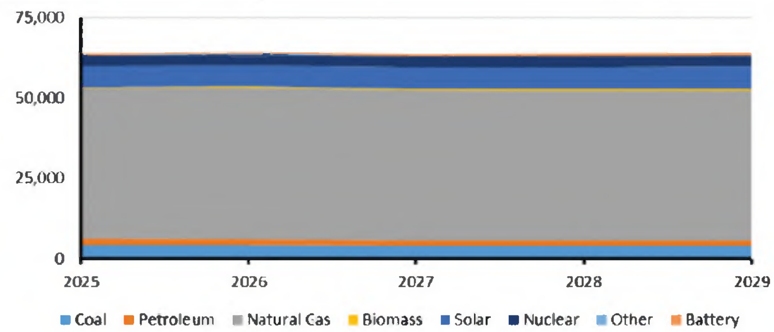
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745

* Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

SERC-Florida Peninsula Assessment

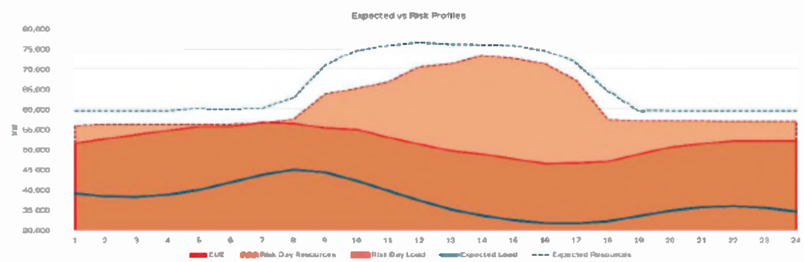
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

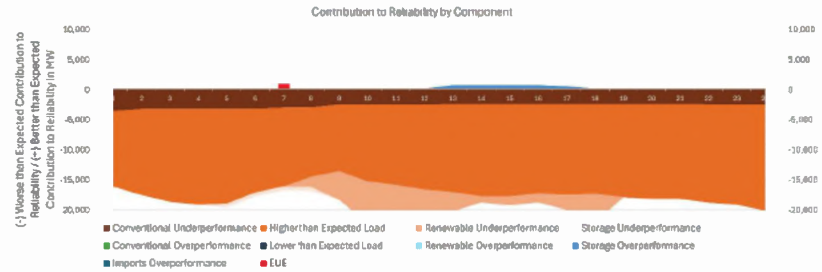
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	2.18	16.28
EUE (PPM)	0.00	0.01	0.06
LOLH (hours per year)	0.00	0.01	0.02
Operable On-Peak Margin	18.6%	19.2%	16.3

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Docket No. 20250011-EI
Relevant excerpts from NERC 2024 Long-Term Reliability Assessment
Exhibit JRD-3, Page 15 of 19

Generation
Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage
Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).
Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

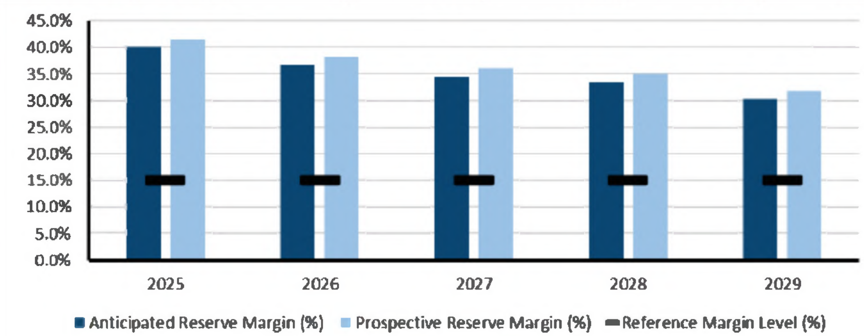
Transmission
The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

SERC-Southeast

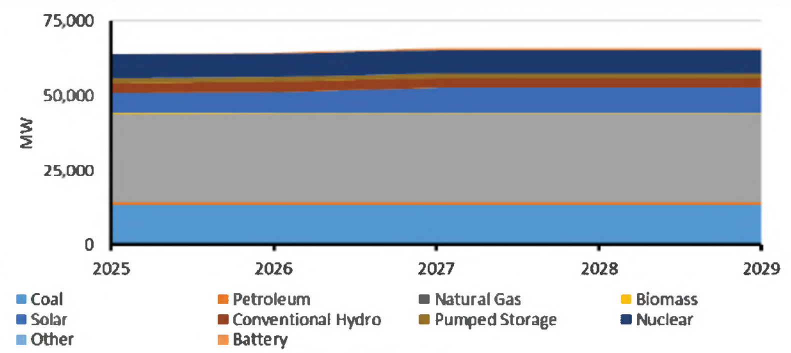
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
* Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per year)	0.00	0.00	0.00
Operable On-Peak Margin	30.8%	29.6%	25.6%

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

SERC Reliability Corporation

2024-2034 SERC ANNUAL LONG-TERM RELIABILITY ASSESSMENT REPORT

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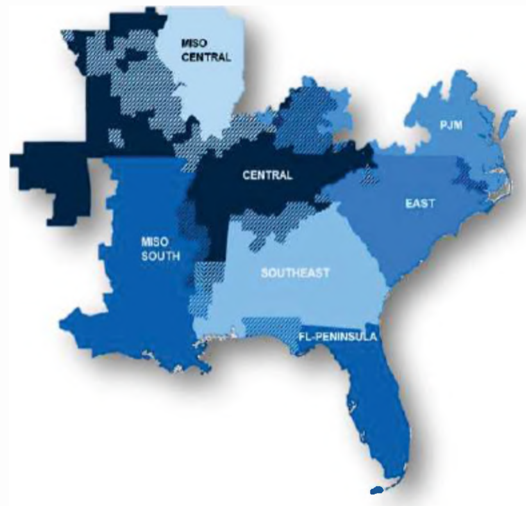
1 EXECUTIVE SUMMARY

1.1 INTRODUCTION

SERC Reliability Corporation's (SERC) mission is to ensure the effective and efficient reduction of risks to the reliability and security of the bulk power system (BPS). SERC is approved by the Federal Energy Regulatory Commission (FERC) as a North American Electric Reliability Corporation (NERC) Regional Entity with delegated authority to assess the reliability of the BPS. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central regions of the United States. The SERC region covers approximately 630,000 square miles and serves a population of more than 97 million. It includes all or portions of 16 states: Florida, Georgia, Alabama, Mississippi, Louisiana, Texas, Oklahoma, Arkansas, Missouri, Iowa, Illinois, Kentucky, Tennessee, Virginia, North Carolina, and South Carolina. Geographically, the SERC region is divided into seven subregions: SERC Central, SERC East, SERC FL-Peninsula, SERC Midcontinent Independent System Operator (MISO)-Central, SERC MISO-South, SERC PJM Interconnection, LLC (PJM), and SERC Southeast.

Figure 1: SERC Region



SERC's 2024-2034 Annual Long-Term Reliability Assessment (LTRA) Report is an independent assessment of the electric reliability of the SERC region under NERC's Rules of Procedure[1] and the NERC-SERC Delegation Agreement.[2] The report evaluates the resource and transmission adequacy to meet projected peak demand for the upcoming ten years across the SERC region.

For this assessment, SERC staff gathered, independently validated, and verified data from all SERC entities registered as applicable functions.[3] Additionally, to develop its assessment, SERC staff collaborated with industry experts through a stakeholder review process, independently ran studies, and analyzed the results. The conclusions highlighted throughout this report are based on SERC's independent assessments as to expected system adequacy and emerging risks over the next ten years.

This report provides valuable information to industry leaders, planners, operators, policymakers, and regulatory bodies across the SERC region to support the decision-making necessary to ensure the reliability of the BPS during the planning horizon. This report is a companion report to the NERC 2024 Long-Term Reliability Assessment (NERC LTRA). SERC recommends reviewing the NERC LTRA for a continent-wide view of the BPS.

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[1] North American Electric Reliability Corporation, Rules of Procedure (with Appendices), 11/28/2023, https://www.nerc.com/AboutNERC/RulesOfProcedure/NERC%20ROP%20effective%2020240627_with%20appendicies_signed.pdf.

[2] Amended and Restated Delegation Agreement Between North American Electric Reliability Corporation and SERC Reliability Corporation, 1/1/2021, https://www.nerc.com/AboutNERC/RDAs/Fully%20Executed%20SERC_RDA_2021_FERC_Revisions(CLEAN).pdf

[3] Applicable registered functions include but are not limited to Balancing Authority, Generator Owner, Generator Operator, Planning Coordinator, and Transmission Owner. SERC Reliability Corporation, Reliability Assessments, Data Collection (last visited Mar. 1, 2024), https://www.serc1.org/program-areas/reliability-assessments/reliability-assessments/data-collection.

1.2 PURPOSE

This assessment provides an overview of the reliability of the SERC region based on standard metrics of adequacy (as discussed in section six) and summarizes the results of SERC's independent engineering studies and analyses that it has performed throughout the year.[4] In this report, SERC identifies various trends related to electric generation, demand, and risks for the next ten-year period.

Figure 2: SERC Assessment Process

1.3 DEVELOPMENT PROCESS

SERC staff independently collect, verify, and validate the most relevant data on generation and transmission resources, planned outages, and demand projections on an hourly basis for the assessment period for this LTRA Report, which is from 2024 to 2034. SERC staff also evaluate and consider historical weather events, system outages, load levels in both peak and off-peak scenarios, as well as respective generating resource levels.

SERC staff use a standardized data collection and reporting process to promote data consistency. The collection of data began in the first quarter of 2024, with updates incorporated before publication.

After collecting and independently verifying and validating the data, SERC staff developed trends and dashboards, prepared models, and performed deterministic and probabilistic resource and transmission adequacy analyses. SERC staff also collaborated with the SERC Engineering Committee (EC), the SERC Reliability Review Subcommittee (RRS), and various SERC working groups to deepen context, ensure completeness, open dialogue, and leverage the vast expertise within these committees and working groups.

SERC also closely coordinated with NERC in the development of the NERC LTRA by preparing assessments for the SERC region that help inform the overall anticipated impact on BPS reliability in North America. Some information contained in this report also reflects updates within the SERC region since the release of the NERC LTRA and thus may not align exactly with the data in the NERC LTRA.

This report has four focus areas for each of the seven subregions: **Demand, Capacity Resources, Reserve Margins, and Transmission Adequacy**.

The future additions of generating resources considered in this report are classified as Tier 1, Tier 2, or Tier 3. Tier 1 generation projects are under construction and have met planning requirements. The Tier 2 and Tier 3 classifications reflect generating resources that are in the early stages of the interconnection request process and have not met the approved planning requirements. The definitions of the terms used throughout the document are provided in "Appendix B Data Concepts and Assumptions."

1.4 KEY OBSERVATIONS FOR THE ASSESSMENT PERIOD, 2024-2034

Through the independent assessment development process, SERC identified the following five key observations for the SERC region. The main body of this report provides additional details to support the key observations.

[4] Studies and analyses that SERC performs throughout the year include, but are not limited to, seasonal and long-term transmission system studies, seasonal load forecast analyses, and probabilistic analyses focused on resource adequacy on a seasonal and hourly basis. These studies use the system data pertaining to historical weather events, outage conditions, load levels in both peak and off-peak scenarios, as well as respective generating resource levels.

Key Observation 1: Reserve Margins Begin to Fall Below NERC's 15% Reference Margin During the Assessment Period for More than Half of SERC's Subregions.

Reserve margins measure the resources available after demand is met. They are expressed as a percentage, starting with the difference between the amount of projected on-peak capacity and the forecasted peak demand, and then dividing this difference by the forecasted peak demand. While the 2024 SERC Winter Reliability Assessment found that SERC and all its subregions met the 15% NERC reference margin for winter 2024/25, policymakers and other stakeholders should not take it for granted that SERC or any particular subregion will have reserves equal to or greater than the reference margin for any subsequent summer or winter. This SERC LTRA predicts that SERC MISO-Central's Anticipated Reserve Margin (ARM) will begin dropping below the reference margin in 2024-2026 and again in 2033 (summer only), SERC PJM's ARM will begin dropping in 2025 (winter) and in 2028 (summer), SERC MISO-South's ARM will begin dropping in 2028 (summer and winter), and SERC East's ARM will begin dropping in 2030 (summer and winter). The majority of these ARMs are currently predicted to remain below the reference margin once they fall below it. As compared to last year's SERC LTRA, which revealed only a single subregion's ARM (SERC Central) falling below the reference margin for a couple of years, this is a concerning trend. This observation is closely related to Key Observations 2 and 4, below (discussing rapidly rising demand and generation retirements).

Key Observation 2: Demand is Rising Rapidly.

SERC contains some of the areas in which demand is rising most rapidly, including the famous Data Center Alley in Loudon County, Virginia. Virginia is first among states in numbers of existing data centers as well as data centers announced or under construction. In terms of estimated power capacity by megawatt (MW) used by the data centers, Virginia's total is eight times as large as its nearest competitor, Texas. Other SERC states in the top ten for data centers include Georgia and Florida.[5] Of course, data centers are not the only reason for rising demand. Some SERC subregions are experiencing population or industrial growth. Increased electrification is also a factor. The 2024 SERC LTRA compound annual growth rate (CAGR) forecasts portend accelerated growth compared to just a couple of years ago. SERC PJM, which contains much of Virginia with its concentration of data centers, has more than doubled its CAGR from two years ago (2.17%) to 5.19% for the summer.[6] Other subregions have had similarly impressive growth. SERC Southeast[7] had a CAGR of 0.32% in the 2022 LTRA, while it now boasts CAGRs of 1.55% for winter and 1.81% for summer. SERC East had a CAGR of 0.69 in the 2022 SERC LTRA, but the 2024 SERC LTRA shows CAGRs of 1.47% for winter and 1.82% for summer.

Key Observation 3: Large Loads Pose Potential Challenges to BES Reliability.

In addition to the challenge that large loads pose simply by adding to the "load" column at a time when substantial amounts of conventional generation are retiring (see Key Observation 4), some large loads pose additional reliability challenges due to their particular characteristics. For example, NERC (and SERC) performed an "incident review" of a 2024 incident within SERC involving 1,500 MW of data center load that disconnected on the customer side due to customer controls. A lightning arrestor failed on a 230 kV transmission line, and, with multiple reclosing attempts, caused multiple faults over about a minute and a half period. Although the faults were properly cleared, the data center load disconnected and converted to using its onsite power. Most of the load—over 1,200 MW—did not return to the grid "for hours." Although in this particular case the system operators were able to handle the amount of load that disconnected without any larger disruptions to the grid, as NERC explained, "[t]his incident has highlighted potential reliability risks to the

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[5] *U.S. Data Centers and Power Demand*, ATERIO (Dec. 30, 2024), http://www.aterio.io/insights/us-data-centers.

[6] 2022-2031 SERC Annual Long-Term Reliability Assessment Report at 9.

[7] SERC Reliability Corporation, the Regional Entity, is sometimes confused with Southeastern Reliability Coordinator (abbreviated SeRC), one of the Reliability Coordinators within the SERC Southeast subregion. Despite the similarity of their acronyms, their functions are very dissimilar.

[Bulk Electric System] BES with respect to the voltage ride-through characteristics of large data center loads. Similar incidents have occurred in other Interconnections with cryptocurrency mining loads as well as oil/gas loads." The full incident review recently published by NERC has more details about the types of schemes employed by data centers and how they interact with the grid, among other helpful background on this incident that should serve as a wake-up call for any grid operators who are not already carefully examining these issues.[8]

Key Observation 4: Coal Retirements Continue; Replaced by Natural Gas, Solar, Battery Storage, and Wind.

Nearly **18 gigawatts (GW)** of coal are planned to retire during the assessment period, almost 30% of all SERC regional on-peak coal capacity. Winter on-peak capacity anticipated during the assessment period does not fully replace the coal retirements, with natural gas predominating at 6.6 GW, solar and energy storage both contributing over 3 GW, and wind nearly 2 GW. Summer anticipated capacity is a brighter story (pardon the pun): nearly 18 GW of solar capacity alone are projected to come online during the assessment period, plus another 8 GW of natural gas and 2.6 GW of energy storage. When coal is predominantly replaced by solar, grid operators must carefully evaluate whether the resources coming online can provide essential reliability services such as frequency response, balancing service, and voltage control, as well as blackstart capability.[9]

Key Observation 5: Important Transmission Additions Continue to Come Online; Interregional Transfer Capability Study Identifies Three SERC Subregions For "Prudent Additions."

SERC anticipates the addition of 3,468 transmission miles during the assessment years. The majority coming online between 2025 and 2029 (2,270 miles) are between 100 and 299 kV. The majority coming online between 2030 and 2034 (518 miles) are either between 100 and 199 kV or 400 and 599 kV. One hundred BES transformer additions are expected during the assessment period, the majority of which are between 200 and 299 kV, on the high side. Transmission serves important roles in, among other tasks, moving renewable resources from where they are best situated to the load centers where their energy is needed, supporting energy transfers between Balancing Authorities (BAs) (whether planned or emergency), and relieving congestion. Transmission projects can also replace aging infrastructure.

SERC facilitates the coordination of transmission expansion plans in the region through annual joint model-building efforts with SERC Transmission Planners (TPs) and Planning Coordinators (PCs). The coordination of transmission expansion plans with entities outside the region is achieved through annual participation in joint modeling efforts with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG).

SERC worked with NERC and industry on the Interregional Transfer Capability Study, or ITCS. This study, mandated by Congress as part of the Fiscal Responsibility Act of 2023, was required to be filed with FERC by December 2024. A key output of the ITCS was the identification of "prudent additions" to transfer capability for identified transmission planning regions. Three of SERC's subregions were among those identified for prudent additions, based on the 2023 resource mix and other study assumptions. The subregions identified for prudent additions, and the amount of transmission capacity that the ITCS recommended each subregion should add, are as follows: SERC East, 4,100 MW, SERC FL-Peninsula, 1,200 MW, and SERC MISO-South, 600 MW.[10]

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[8]NERC Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions (Jan. 8, 2025), 8 (quotation).

[9] Frequency response is the system's ability to stop and stabilize frequency deviations caused by the sudden loss of a generation resource or load. Grid frequency must be maintained in a "band" around 60 hertz. Balancing services are related to frequency response and are provided when system operators adjust the watts provided by generators over time. Voltage control is provided by generators providing reactive power (which has been analogized to blood pressure that allows the blood to flow, as reactive power allows real power to flow). Voltage control can also be adjusted on the load side by adjusting settings on transformers. Blackstart resources are those used to bring the grid back from a complete blackout or islanding event.

[10] https://www.nerc.com/pa/RAPA/Documents/ITCS_Report_Summary_Final.pdf

1.5 CONCLUSION

As in the 2023 SERC LTRA report, decarbonization continues to reduce coal capacity within the SERC region, with a record number of retirements during this assessment period (nearly 18 GW or 18,000 MW). Replacements tend to skew toward solar for the summer, with more natural gas (although still a substantial amount of solar) for the winter.[11] SERC MISO-Central is already below the reference margin for the summer of 2024, after being reevaluated with a different source of data than that used for last year's SERC LTRA. It is projected to be followed by SERC PJM beginning in 2025 (winter), SERC PJM (summer) and MISO-South (summer and winter) in 2028, and SERC Southeast in 2030 (summer and winter). Last year's SERC LTRA report only highlighted one potential shortfall (SERC Central), so this is a marked deterioration and a trend that bears watching, with careful responses from regulators and policymakers. Most critically, retirements and new resource construction must be coordinated, so that grid operators are not left trying to fill large resource deficits at or close to real time, when it is far too late. A key purpose of forward-looking reports like this is to sound the alarm early enough so that something can be done while there is still time to take meaningful action.

Grid operators will need to analyze the characteristics of the replacement generation and determine **whether essential reliability services (e.g., frequency response, balancing service, and voltage control) are still being provided**. They will also need to prepare for the additional ramping challenges posed by higher levels of renewable generation. Regulators and policymakers should pay close attention to whether proposed retirements shown in integrated resource plans will be replaced in time to meet projected load without falling below reference margins.

SERC looks forward to working with federal and state policy makers and regulators, SERC Registered Entities, and SERC's technical committees and working groups to continue to identify, understand, and address reliability and security concerns across the SERC region.

[11] The incremental generation used in this report is Tier 1 generation, the generation resources that are furthest along in the process and, therefore, the most likely to reach commercial operation. Substantial additional amounts of renewable generation are projected during the assessment period in Tiers 2 and 3, however, they are less certain to be built.

4 PROBABILISTIC ASSESSMENTS FOR RESOURCE ADEQUACY

Probabilistic analysis describes events in terms of how probable they are and requires knowledge of the performance characteristics of BPS components. These performance characteristics may include but are not limited to generator outage rates, resource realizations in terms of energy produced, load characteristics, transmission congestion and constraints, etc.[13] SERC performs its independent regional probabilistic analysis annually to evaluate the overall reliability, performance, and resource adequacy of the SERC region. SERC calculates the following resource adequacy metrics for each year of analysis:

- Loss Of Load Hours, hours/year (LOLH)
- Loss Of Load Expectation, days/year (LOLE)
- Expected Unserved Energy, MW-Hours (MWh) (EUE)
- Normalized Expected Unserved Energy (expected fraction of demand unserved during the analysis period, i.e., the ratio of EUE to total demand), ppm.

The 2024 SERC Probabilistic Assessment (ProbA) used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028. In the base cases, all 38 historical years of weather are assumed to be equally likely to occur.[14] This assessment complements other analyses by providing a regional probability-based system modeling approach. SERC's assessment looks broadly across its entire footprint and within each of its seven sub-regions.[15]

Key findings:

- The 2024 ProbA indicates some resource adequacy risk to the SERC region, with the results for the year 2028 showing slightly higher risk than the year 2026. The results are a probability-weighted average of a range of cases, including 38 years of historic weather-years, which are applied to load forecasts for the years 2026 and 2028. In addition, the model applies a range of economic load forecast errors from -4% to 4% and other assumptions as noted previously.
- In general, the risk for the study year 2028 is higher than the year 2026 due to a combination of increased load and lesser capacity available in early morning, winter hours with limited contribution from solar generation. The risk for January and summer of 2028 appears somewhat lower than 2026, which may seem inconsistent with the increasing load and generation retirements discussed elsewhere

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[13] North American Electric Reliability Corporation, Probabilistic Assessment Technical Guideline Document (August 2016).

[15] SERC uses Astrape SERVM software with 8760 hourly load and sequential Monte Carlo simulation. The model includes the entire SERC footprint including NERC Assessment Areas SERC Central, SERC East, SERC Southeast, and SERC FL-Peninsula. The rest of the SERC footprint is also modeled as SERC MISO-Central, SERC MISO-South, and SERC PJM. The model also includes interconnections to areas external to SERC such as Midwest Reliability Organization, ReliabilityFirst Corp., the rest of PJM, and Southwest Power Pool. The SERC ProbA simulates 190 load scenarios (38 weather-based load scenarios x 5 points of load factor error), each with 10 probabilistic based unit outage draws. The software runs 1900 simulations for each hour resulting in metrics that are an aggregate of simulations performed for each hour in the year and on an individual assessment area basis.

Impacts of weather-driven variations in load and VERs are modeled exogenously through a load modeling process which creates load profiles for all the weather years based on the historical relationship between load and temperature. The model assumes transfer limits between subregions in the model. The transfer capabilities modeled in the study are simultaneous and based on computer simulations of interconnected electric system operations under a specific set of assumed operating conditions using "AC" power flow technique.

in this report. These results stem largely from assumptions in the model about increased limits on imports based on power flow analysis, which were provided by the SERC Long-term Working Group.

Details for each subregion are provided below

- Similar to previous findings, SERC East shows relatively higher risk as compared to other SERC subregions. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The primary cases that contribute to this risk are when the economic load forecast error is 2-4% and for extreme cold weather conditions.
- The overall risk metrics from other SERC subregions are minimal to low; however, they show a potential risk in some cases during extreme summer evening hours or early morning winter hours when the contribution from solar generation is limited. In addition, SERC subregions show rapidly growing load and associated risk, particularly in SERC PJM.

Table 1: Probabilistic Analysis Results

Subregion	**Loss of Load Hours, LOLH (Hours)**		**Expected Unserved Energy, EUE (MW-Hours)**		**Normalized Expected Unserved Energy, NEUE (ppm)**	
	2026	**2028**	**2026**	**2028**	**2026**	**2028**
SERC Central	0.00	0.00	0.00	0.00	0.00	0.00
SERC East	0.09	0.17	143.35	207.26	0.60	0.81
SERC Southeast	0.00	0.00	0.00	0.00	0.00	0.00
SERC FL-Peninsula	0.01	0.02	2.18	15.75	0.01	0.06
SERC MISO-Central	0.01	0.00	0.00	0.00	0.00	0.00
SERC MISO-South	0.00	0.00	0.00	0.00	0.00	0.00
SERC PJM	0.00	0.00	0.00	2.77	0.00	0.00

The findings for each subregion are summarized below:

SERC Central:

The ProbA results for the SERC Central subregion show sufficient resources to meet demand for all hours of the year. Both the probability weighted, annual EUE and LOLH metrics are at 0.00 for the years 2026 and 2028.

SERC East:

SERC East, formerly a summer peaking subregion, now has roughly equivalent summer and winter peaks as the addition of solar PV generation shaves off summer peak demand and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas. For the year 2028, SERC East continues to show winter risk with 207.26 MWh of EUE and LOLH of 0.17. The expected duration of risk is still very short and occurs around 8:00 a.m. It is contributed to by the modeling impact of weather-years 1982 and

1985, which experienced extreme cold, combined with limited availability of imports, and cases with load forecast error of 2-4%.

SERC Southeast

The ProbA results for the SERC-Southeast subregion show sufficient resources to meet demand for all hours of the year. Both the EUE and LOLH metrics are at 0.00 for the years 2026 and 2028.

SERC FL-Peninsula

For study year 2026, the ProbA results for SERC FL-Peninsula show minimal to zero risk with 2.18 MWh of EUE and 0.0004 LOLH. The driver of the risk is mainly the weather year 1986, combined with the case with load forecast error of 4% and a certain draw of high forced outages. The risk occurs in late September, in evening hours around 7:00 p.m. when contribution from solar generation is also limited.

For study year 2028, the ProbA results show low risk, with 15.75 MWh of EUE and 0.02 LOLH. The driver of the risk is mainly weather year 1989, which was one of the worst winter freezes to hit Florida, combined with the case with load forecast error of 4%. The risk occurs in late December, morning hours around 7:00 a.m., when contribution from solar generation is limited, and when, due to the winter freeze event, imports from surrounding subregions were limited.

SERC MISO-Central

The ProbA results for the SERC MISO-Central subregion show sufficient resources to meet demand for all hours of the year. Both the probability weighted, annual EUE and LOLH metrics are at 0.00 for the years 2026 and 2028.

SERC MISO-South

The ProbA results for the SERC MISO-South subregion show sufficient resources to meet demand for all hours of the year. Both the probability weighted, annual EUE and LOLH metrics are at 0.00 for the years 2026 and 2028.

SERC PJM

The ProbA results for the SERC-PJM subregion show that probability weighted, annual EUE and LOLH metrics are at 0.00 for the years 2026 and 2.77 MWh and 0.00 hours respectively for the year 2028. The risk in the year 2028 appears in July and August, in summer evening hours around 8:00 p.m., when the contribution from solar generation is limited. The risk could be worse for extreme summer years.

The subregional aggregate EUE for SERC is shown in Figures 7 and 8 in a heat map format across hours of the day and months in the year. The heat map shows that for the SERC region, the risk tends to occur in winter morning hours and summer evening hours.

Figure 7: Heat map of EUE (MWh) for the study year 2026

Month of year 2026

Hour of day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	1.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	6.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	28.30	2.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	63.22	14.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	22.69	11.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	5.10	3.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.69	0.78	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.87	0.26	0.00	0.01	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.73	0.32	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.15	0.00	0.00	1.43	0.85	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.02	0.04	0.00	0.00	0.00
21	0.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 8: Heat map of EUE (MWh) for the study year 2028

Month of the year 2028

Hour of the day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.41
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.98
6	2.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.47
7	14.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.87
8	33.67	4.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.97
9	7.27	2.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.21
10	0.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.62
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.03
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	1.08	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.10	1.66	0.17	0.00	0.00	0.00	4.08
21	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00	4.76
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.99
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.14
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20250011-EI

Estimated Stochastic LOLP Analysis Results for "TYP Portfolio + 1,400 MW of Storage" Adjusted to Reflect FPL's Proposed Pre-Summer 2027 Resource Additions

	2027 - TYP Portfolio + 1,400 of Storage (Exhibit AWW-1, p. 22)			FPL's Proposed 2027 Portfolio with All Pre-Summer 2027 In-Service Resources Included (Estimated Results)	
	Nameplate Capacity (MW)	Cumulative Firm Capacity (MW)		Nameplate Capacity (MW)	Cumulative Firm Capacity (MW)
Utility Solar (Fixed + Tracking)	8,946			9,422	
Behind-the-meter (BTM) Solar	2,125			2,125	
Total Solar	11,071	3,096		11,547	3,325
Total Storage	2,391	1,904		2,858	2,151
Thermal + Kingfisher 1/2	28,281			28,281	
Demand Response (DR)	1,951			1,951	
Total Thermal, Kingfisher + DR	30,232	27,050		30,232	27,050
Portfolio ELCC *(E3 Methodology)*	43,694	32,049		44,637	32,526
Median Peak Demand (Grossed up for BTM PV & Net of Energy Efficiency)		29,708			29,708
PCAP Planning Reserve Margin (PRM)		8.8%			8.8%
Total Firm MW Requirement		32,322			32,322
Firm Capacity Surplus / (Shortfall)		(273)			204
Achieved Loss of Load Expectation (Days per Year)		0.105			0.097

Solar Cumulative ELCC, Firm MW

	(1) 0 GW Storage	(2) 2.3GW Storage	(3) Extrapolation of (1) and (2)
Solar Nameplate	0 MW of Storage	2,391 MW of Storage	2,858 MW of Storage
-	-	-	
1,000	420	640	683
4,000	1,335	1,655	1,718
7,000	1,840	2,424	2,538
10,177	2,174	2,986	3,145
11,071	2,237	3,096	3,264
12,433	2,330	3,259	3,440
14,746	2,447	3,443	3,637
17,046	2,548	3,594	3,799
31,761	2,915	4,011	4,225
36,000	2,973	4,062	4,274

Storage Cumulative ELCC, Firm MW

	(1) 0 GW Solar	(2) 11GW Solar	(3) Extrapolation of (1) and (2)
Storage Nameplate	0 MW of Solar	11,071 MW of Solar	11,547 MW of Solar
-	-	-	
250	173	227	230
1,000	630	915	927
1,841	1,051	1,564	1,586
2,391	1,286	1,904	1,930
3,211	1,587	2,288	2,318
3,807	1,792	2,553	2,586
4,403	2,013	2,772	2,805
7,383	3,266	3,827	3,851
9,000	3,810	4,296	4,317

Sources:

Exhibit AWW-1, p. 20, 22 and 28

FPL Response to OPC's First Request for Production of Documents, No. 15, Whitley folder, "2025-02-21 RA Study Workpapers.xlsx".

FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx", "Rev. Req. Detail" tab.

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20250011-EI

Estimated Stochastic LOLP Analysis Results without FPL's 2026 and 2027 Proposed Solar Generation Additions

	2027 - TYP Portfolio + 1,400 of Storage (Exhibit AWW-1, p. 22)			FPL's Proposed 2027 Portfolio without FPL's 2026 and 2027 Solar Additions (Estimated Results)	
	Nameplate Capacity (MW)	Cumulative Firm Capacity (MW)		Nameplate Capacity (MW)	Cumulative Firm Capacity (MW)
Utility Solar (Fixed + Tracking)	8,946			7,932	
Behind-the-meter (BTM) Solar	2,125			2,125	
Total Solar	11,071	3,096		10,057	3,122
Total Storage	2,391	1,904		2,858	2,061
Thermal + Kingfisher 1/2	28,281			28,281	
Demand Response (DR)	1,951			1,951	
Total Thermal, Kingfisher + DR	30,232	27,050		30,232	27,050
Portfolio ELCC *(E3 Methodology)*	43,694	32,049		43,147	32,233
Median Peak Demand (Grossed up for BTM PV & Net of Energy Efficiency)		29,708			29,708
PCAP Planning Reserve Margin (PRM)		8.8%			8.8%
Total Firm MW Requirement		32,322			32,322
Firm Capacity Surplus / (Shortfall)		(273)			(89)
Achieved Loss of Load Expectation (Days per Year)		0.105			0.101

Solar Cumulative ELCC, Firm MW

	(1) 0 GW Storage	(2) 2.3GW Storage	(3) Extrapolation of (1) and (2)
Solar Nameplate	**0 MW of Storage**	**2,391 MW of Storage**	**2,858 MW of Storage**
-	-	-	
1,000	**420**	640	683
4,000	**1,335**	**1,655**	1,718
7,000	**1,840**	2,424	2,538
10,177	**2,174**	2,986	3,145
11,071	**2,237**	3,096	**3,264**
12,433	**2,330**	3,259	3,440
14,746	**2,447**	3,443	3,637
17,046	**2,548**	3,594	3,799
31,761	**2,915**	4,011	4,225
36,000	**2,973**	4,062	4,274

Storage Cumulative ELCC, Firm MW

	(1) 0 GW Solar	(2) 11GW Solar	(3) Interpolation of (1) and (2)
Storage Nameplate	**0 MW of Solar**	**11,071 MW of Solar**	**10,057 MW of Solar**
-	-	-	
250	173	227	222
1,000	630	915	889
1,841	1,051	1,564	1,517
2,391	1,286	1,904	**1,847**
3,211	1,587	2,288	2,224
3,807	1,792	2,553	2,483
4,403	2,013	2,772	2,703
7,383	3,266	3,827	3,775
9,000	3,810	4,296	4,251

Sources:

Exhibit AWW-1, p. 20, 22 and 28

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FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx", "Rev. Req. Detail" tab.

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20250011-EI

Estimated Stochastic LOLP Analysis Results without FPL's 2027 Proposed Solar Generation Additions

	2027 - TYP Portfolio + 1,400 of Storage (Exhibit AWW-1, p. 22)		FPL's Proposed 2027 Portfolio without FPL's 2027 Solar Additions (Estimated Results)	
	Nameplate Capacity (MW)	Cumulative Firm Capacity (MW)	Nameplate Capacity (MW)	Cumulative Firm Capacity (MW)
Utility Solar (Fixed + Tracking)	8,946		8,826	
Behind-the-meter (BTM) Solar	2,125		2,125	
Total Solar	11,071	3,096	10,951	3,248
Total Storage	2,391	1,904	2,858	2,115
Thermal + Kingfisher 1/2	28,281		28,281	
Demand Response (DR)	1,951		1,951	
Total Thermal, Kingfisher + DR	30,232	27,050	30,232	27,050
Portfolio ELCC *(E3 Methodology)*	43,694	32,049	44,041	32,413
Median Peak Demand (Grossed up for BTM PV & Net of Energy Efficiency)		29,708		29,708
PCAP Planning Reserve Margin (PRM)		8.8%		8.8%
Total Firm MW Requirement		32,322		32,322
Firm Capacity Surplus / (Shortfall)		(273)		90
Achieved Loss of Load Expectation (Days per Year)		0.105		0.098

Solar Cumulative ELCC, Firm MW

	(1) 0 GW Storage	(2) 2.3GW Storage	(3) Extrapolation of (1) and (2)
Solar Nameplate	0 MW of Storage	2,391 MW of Storage	2,858 MW of Storage
-	-	-	
1,000	420	640	683
4,000	1,335	1,655	1,718
7,000	1,840	2,424	2,538
10,177	2,174	2,986	3,145
11,071	2,237	3,096	3,264
12,433	2,330	3,259	3,440
14,746	2,447	3,443	3,637
17,046	2,548	3,594	3,799
31,761	2,915	4,011	4,225
36,000	2,973	4,062	4,274

Storage Cumulative ELCC, Firm MW

	(1) 0 GW Solar	(2) 11GW Solar	(3) Interpolation of (1) and (2)
Storage Nameplate	0 MW of Solar	11,071 MW of Solar	10,951 MW of Solar
-	-	-	
250	173	227	227
1,000	630	915	912
1,841	1,051	1,564	1,558
2,391	1,286	1,904	1,897
3,211	1,587	2,288	2,280
3,807	1,792	2,553	2,545
4,403	2,013	2,772	2,764
7,383	3,266	3,827	3,821
9,000	3,810	4,296	4,290

Sources:

Exhibit AWW-1, p. 20, 22 and 28

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FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx", "Rev. Req. Detail" tab.

Ten Year Power Plant Site Plan
2025 – 2034

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FPL®

Ten Year Power Plant Site Plan

2025-2034

Submitted To:

Florida Public Service Commission

April 2025

I.A FPL System:

I.A.1 Description of Existing Resources

FPL's service area (including the former Gulf Power area now referred to as FPL NWFL) contains approximately 35,000 square miles. Currently, FPL serves more than 6 million customer accounts representing approximately 12 million people in 43 counties in peninsular and Northwest Florida. These customers are served by a variety of resources including FPL-owned fossil-fuel, renewable (solar), and nuclear generating units; non-utility owned generation; DSM; and purchased power.

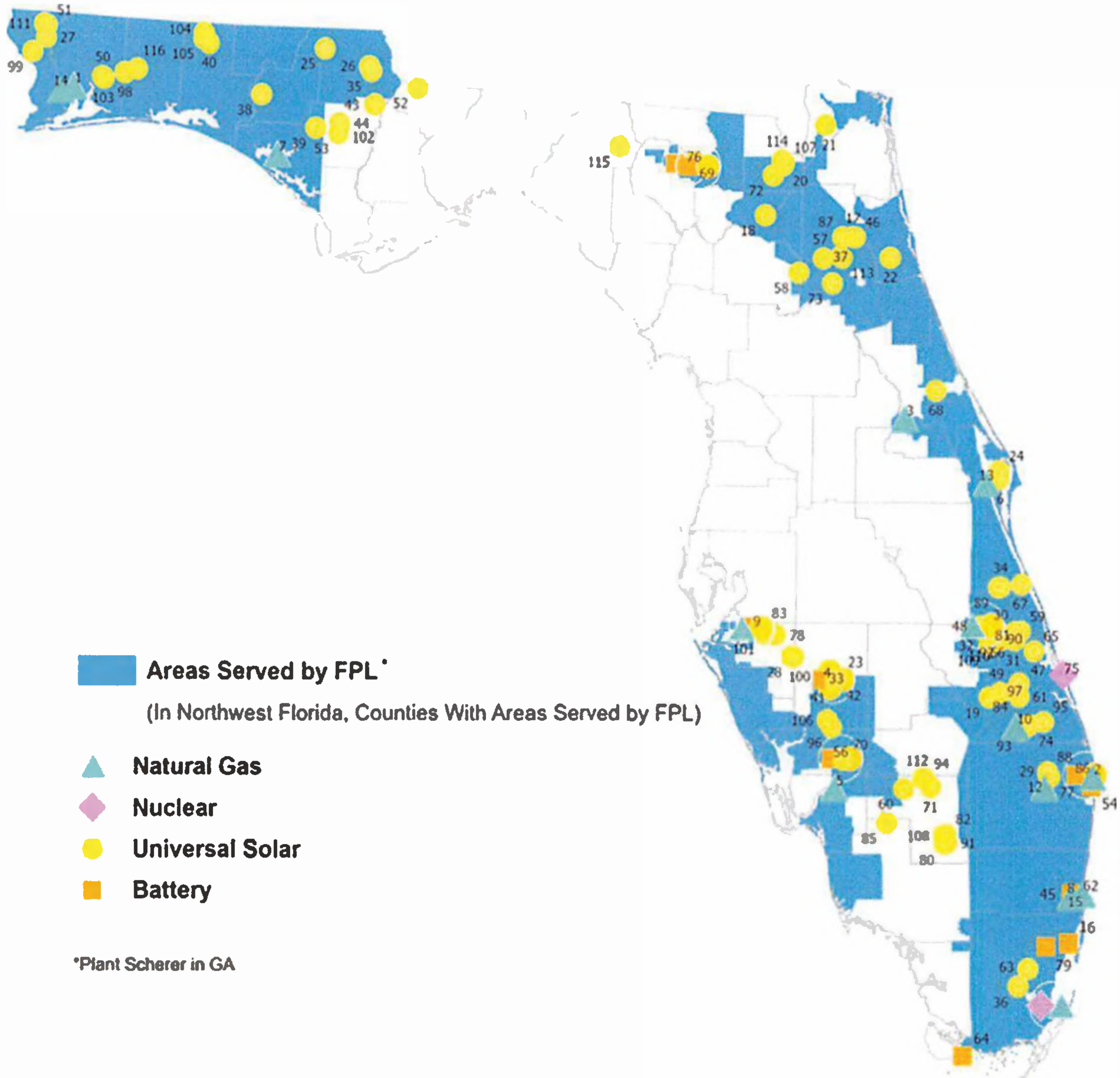
I.A.2 FPL - Owned Resources

As of December 31, 2024, FPL owned electric generating resources located at 116 sites distributed geographically throughout its service area and one site in Georgia (partial FPL ownership of one unit). These generating facilities consist of: four nuclear units, one coal steam-unit (the aforementioned partially owned unit in Georgia), 17 combined-cycle (CC) units, six fossil steam units, four gas turbines (GTs), 17 simple-cycle combustion turbines (CTs), two landfill gas units, three battery storage units, and 96 solar PV facilities. The locations of the 150 generating units that were in commercial operation on December 31, 2024, are shown on Figure I.A.2.1 and in Table I.A.2.1.

FPL's bulk transmission system, including both overhead and underground lines, is comprised of approximately 9,500 circuit miles of transmission lines. Integration of the generation, transmission, and distribution systems is achieved through FPL's 921 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.2.

FPL Generating Resources by Location



There are four small battery pilot projects shown on the map that are not listed in Table I.A.2: #26 – Florida Bay, #32 – Southwest, #36 – Wynwood, and #57 – FIU Microgrid. These sites are discussed in Chapter III.

Figure I.A.2.1: FPL's Generating Resources by Location (as of December 31, 2024)

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Page 1 of 4

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW 1/
	Nuclear				
75	St. Lucie 2/	St. Lucie County, FL	2	Nuclear	1,821
11	Turkey Point	Miami-Dade County, FL	2	Nuclear	1,681
	Total Nuclear:		4		3,502
	Coal Steam				
-	Scherer*	Monroe County, Ga	1	Coal	215
	Total Coal Steam:		1		215
	Combined-Cycle				
5	Fort Myers	Lee County, FL	1	Gas	1,822
9	Manatee	Manatee County, FL	1	Gas	1,246
3	Sanford	Volusia County, FL	2	Gas	2,418
7	Lansing Smith*	Bay County, FL	1	Gas	641
13	Cape Canaveral	Brevard County, FL	1	Gas/Oil	1,290
10	Martin	Martin County, FL	3	Gas/Oil	2,223
55	Okeechobee 3/	Okeechobee County, FL	1	Gas/Oil	1,720
62	Port Everglades	City of Hollywood, FL	1	Gas/Oil	1,237
2	Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,290
11	Turkey Point	Miami-Dade County, FL	1	Gas/Oil	1,292
12	West County	Palm Beach County, FL	3	Gas/Oil	3,771
45	Dania Beach Clean Energy Center	Broward County, FL	1	Gas/Oil	1,246
	Total Combined Cycle:		17		20,196
	Gas/Oil Steam				
9	Manatee 4/	Manatee County, FL	2	Gas/Oil	0
14	Gulf Clean Energy Center*	Escambia County, FL	4	Gas Steam	961
	Total Oil/Gas Steam:		6		961
	Gas Turbines(GT)				
5	Fort Myers (GT)	Lee County, FL	2	Oil	102
8	Lauderdale (GT)	Broward County, FL	2	Gas/Oil	69
	Total Gas Turbines/Diesels:		4		171
	Combustion Turbines				
8	Lauderdale	Broward County, FL	5	Gas/Oil	1,155
5	Fort Myers	Lee County, FL	4	Gas/Oil	852
1	Pea Ridge*	Santa Rosa County, FL	3	Gas	12
7	Lansing Smith*	Bay County, FL	1	Oil	32
14	Gulf Clean Energy Center*	Escambia County, FL	4	Gas	926
	Total Combustion Turbines:		17		2,977
	Land Fill Gas				
69	Perdido LFG*	Escambia County, FL	2	LFG	3
	Total LFG:		2		3

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

2/ Total capability of St. Lucie 1 is 981 Summer /1,003 Winter MW. FPL's share of St. Lucie 2 is 840 Summer /860 Winter MW.
FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

3/ As part of the Okeechobee Hydrogen Gas Pilot Program, a portion of the CO_2 generated from the unit is transferred to an electrolyzer where it is then converted into Hydrogen Gas.

4/ Manatee Units 1 & 2 are Winter Peaking ONLY units. They will only be manned and operated during an Extreme Winter event in which additional capacity is needed to meet load.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Map Key "-" is shown for units that are located outside the State of Florida and therefore do not appear on the Map in Figure I.A.2.1.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Page 2 of 4

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW 1/
	Battery Storage				
9	Manatee Battery Storage	Manatee County, FL	1	Storage	409
69	Sunshine Gateway Battery Storage	Columbia County, FL	1	Storage	30
76	Echo River Battery Storage	Suwannee County, FL	1	Storage	30
	Total Battery Storage:		3		469
	PV				
4	DeSoto Solar	DeSoto County, FL	1	Solar Energy	25
56	Babcock Ranch Solar	Charlotte County, FL	1	Solar Energy	74.5
41	Citrus Solar	DeSoto County, FL	1	Solar Energy	74.5
9	Manatee Solar	Manatee County, FL	1	Solar Energy	74.5
6	Space Coast Solar	Brevard County, FL	1	Solar Energy	10
65	Interstate Solar	St. Lucie County, FL	1	Solar Energy	74.5
63	Miami Dade Solar	Miami-Dade County, FL	1	Solar Energy	74.5
68	Pioneer Trail Solar	Volusia County, FL	1	Solar Energy	74.5
69	Sunshine Gateway Solar	Columbia County, FL	1	Solar Energy	74.5
58	Horizon Solar	Alachua County, FL	1	Solar Energy	74.5
42	Wildflower Solar	DeSoto County, FL	1	Solar Energy	74.5
66	Indian River Solar	Indian River County, FL	1	Solar Energy	74.5
57	Coral Farms Solar	Putnam County, FL	1	Solar Energy	74.5
60	Hammock Solar	Hendry County, FL	1	Solar Energy	74.5
67	Barefoot Bay Solar	Brevard County, FL	1	Solar Energy	74.5
59	Blue Cypress Solar	Indian River County, FL	1	Solar Energy	74.5
61	Loggerhead Solar	St. Lucie County, FL	1	Solar Energy	74.5
70	Babcock Preserve Solar	Charlotte County, FL	1	Solar Energy	74.5
71	Blue Heron Solar	Hendry County, FL	1	Solar Energy	74.5
23	Cattle Ranch Solar	DeSoto County, FL	1	Solar Energy	74.5
76	Echo River Solar	Suwannee County, FL	1	Solar Energy	74.5
20	Egret Solar	Baker County, FL	1	Solar Energy	74.5
77	Hibiscus Solar	Palm Beach County, FL	1	Solar Energy	74.5
19	Lakeside Solar	Okeechobee County, FL	1	Solar Energy	74.5
21	Nassau Solar	Nassau County, FL	1	Solar Energy	74.5
72	Northern Preserve Solar	Baker County, FL	1	Solar Energy	74.5
55	Okeechobee Solar	Okeechobee County, FL	1	Solar Energy	74.5
78	Southfork Solar	Manatee County, FL	1	Solar Energy	74.5
74	Sweetbay Solar	Martin County, FL	1	Solar Energy	74.5
22	Trailside Solar	St. Johns County, FL	1	Solar Energy	74.5
73	Twin Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
18	Union Springs Solar	Union County, FL	1	Solar Energy	74.5
17	Magnolia Springs Solar	Clay County, FL	1	Solar Energy	74.5
31	Pelican Solar	St. Lucie County, FL	1	Solar Energy	74.5
34	Palm Bay Solar	Brevard County, FL	1	Solar Energy	74.5
33	Rodeo Solar	DeSoto County, FL	1	Solar Energy	74.5
24	Discovery Solar	Brevard County, FL	1	Solar Energy	74.5
30	Orange Blossom Solar	Indian River County, FL	1	Solar Energy	74.5

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.
* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW 1/
	PV Continued				
29	Sabal Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
32	Fort Drum Solar	Okeechobee County, FL	1	Solar Energy	74.5
28	Willow Solar	Manatee County, FL	1	Solar Energy	74.5
82	Ghost Orchid Solar	Hendry County, FL	1	Solar Energy	74.5
80	Sawgrass Solar	Hendry County, FL	1	Solar Energy	74.5
84	Sundew Solar	St. Lucie County, FL	1	Solar Energy	74.5
85	Immokalee Solar	Collier County, FL	1	Solar Energy	74.5
81	Grove Solar	Indian River County, FL	1	Solar Energy	74.5
83	Elder Branch Solar	Manatee County, FL	1	Solar Energy	74.5
25	Blue Indigo Solar*	Jackson County, FL	1	Solar Energy	74.5
26	Blue Springs Solar*	Jackson County, FL	1	Solar Energy	74.5
27	Cotton Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
46	Anhinga Solar	Clay County, FL	1	Solar Energy	74.5
35	Apalachee Solar*	Jackson County, FL	1	Solar Energy	74.5
50	Blackwater Solar*	Santa Rosa County, FL	1	Solar Energy	74.5
49	Bluefield Preserve Solar	St. Lucie County, FL	1	Solar Energy	74.5
48	Cavendish Solar	Okeechobee County, FL	1	Solar Energy	74.5
40	Chautauqua Solar*	Walton County, FL	1	Solar Energy	74.5
43	Chipola Solar*	Calhoun County, FL	1	Solar Energy	74.5
38	Cypress Pond Solar*	Washington County, FL	1	Solar Energy	74.5
37	Etonia Creek Solar	Putnam County, FL	1	Solar Energy	74.5
36	Everglades Solar	Miami-Dade County, FL	1	Solar Energy	74.5
51	First City Solar*	Escambia County, FL	1	Solar Energy	74.5
44	Flowers Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
47	Pink Trail Solar	St. Lucie County, FL	1	Solar Energy	74.5
39	Saw Palmetto Solar*	Bay County, FL	1	Solar Energy	74.5
53	Shirer Branch Solar*	Calhoun County, FL	1	Solar Energy	74.5
52	Wild Azalea Solar*	Gadsden County, FL	1	Solar Energy	74.5
91	Beautyberry Solar	Hendry County, FL	1	Solar Energy	74.5
94	Caloosahatchee Solar	Hendry County, FL	1	Solar Energy	74.5
98	Canoe Solar*	Okaloosa County, FL	1	Solar Energy	74.5
89	Ibis Solar	Brevard County, FL	1	Solar Energy	74.5
93	Monarch Solar	Martin County, FL	1	Solar Energy	74.5
90	Orchard Solar	Indian River/St. Lucie County, FL	1	Solar Energy	74.5
97	Pineapple Solar	St. Lucie County, FL	1	Solar Energy	74.5
96	Prairie Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
88	Silver Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
87	Terrill Creek Solar	Clay County, FL	1	Solar Energy	74.5
92	Turnpike Solar	Indian River County, FL	1	Solar Energy	74.5
95	White Tail Solar	Martin County, FL	1	Solar Energy	74.5
103	Big Juniper Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
102	Fourmile Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
106	Hawthorne Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
107	Nature Trail Solar	Baker County, FL	1	Solar Energy	74.5

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Page 4 of 4

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1]
	PV [5] Continued				
104	Pecan Tree Solar*	Walton County, FL	1	Solar Energy	74.5
100	Sambucus Solar	Manatee County, FL	1	Solar Energy	74.5
99	Sparkleberry Solar*	Escambia County, FL	1	Solar Energy	74.5
101	Three Creeks Solar	Manatee County, FL	1	Solar Energy	74.5
105	Wild Quail Solar*	Walton County, FL	1	Solar Energy	74.5
108	Woodyard Solar	Hendry County, FL	1	Solar Energy	74.5
110	Buttonwood Solar	St. Lucie County, FL	1	Solar Energy	74.5
114	Cedar Trail Solar	Baker County, FL	1	Solar Energy	74.5
113	Georges Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
112	Hendry Isles Solar	Hendry County, FL	1	Solar Energy	74.5
109	Honeybell Solar	Okeechobee County, FL	1	Solar Energy	74.5
111	Mitchell Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
116	Kayak Solar*	Okaloosa County, FL	1	Solar Energy	74.5
115	Norton Creek Solar	Madison County, FL	1	Solar Energy	74.5
	Total Nameplate PV:		96		7,038
		Total Units:	150		35,531
		Nameplate System Generation as of December 31, 2024 =			35,531
		Firm System Generation as of December 31, 2024 =			31,691

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Schedule 3.1
History of Summer Peak Demand (MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2015	25,361	1,381	23,980	0	878	1,779	826	1,104	23,657
2016	26,044	1,443	24,601	0	882	1,809	836	1,119	24,326
2017	25,662	1,467	24,194	0	910	1,826	825	1,135	23,927
2018	25,411	1,418	23,993	0	866	1,839	866	1,149	23,679
2019	26,594	1,367	25,227	0	852	1,850	879	1,159	24,863
2020	26,400	1,595	24,805	0	845	1,861	887	1,175	24,668
2021	26,248	1,401	24,847	0	830	1,874	882	1,190	24,536
2022	26,429	1,572	24,857	0	827	1,886	871	1,201	24,731
2023	28,461	1,652	26,808	0	797	1,900	946	1,210	26,718
2024	28,266	1,731	26,535	0	863	1,917	961	1,221	26,442

Historical Values (2015 - 2024):

Col. (2) and Col. (3) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2025	28,312	1,728	26,584	0	937	21	1,025	12	26,317
2026	28,664	1,727	26,937	0	925	40	1,032	19	26,648
2027	28,925	1,723	27,202	0	913	59	1,038	26	26,888
2028	29,333	1,708	27,625	0	902	77	1,043	34	27,277
2029	29,687	1,606	28,081	0	896	95	1,047	41	27,608
2030	29,982	1,484	28,498	0	893	113	1,051	49	27,877
2031	30,301	1,315	28,987	0	891	131	1,055	57	28,168
2032	30,823	1,319	29,504	0	889	148	1,059	65	28,662
2033	31,257	1,323	29,934	0	888	166	1,063	73	29,068
2034	31,677	1,327	30,351	0	887	183	1,067	81	29,459

Projected Values (2025 - 2034):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent cumulative load management, incremental conservation, and load management.
All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.2
History of Winter Peak Demand (MW)

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2015	21,961	1,403	20,558	0	822	1204	551	522	20,588
2016	18,826	1,167	17,659	0	742	1232	570	528	17,514
2017	19,320	1,187	18,133	0	759	1238	577	541	17,984
2018	21,533	1,332	20,201	0	750	1244	588	547	20,194
2019	17,941	1,498	16,442	0	706	1248	613	557	16,621
2020	19,569	1,312	18,257	0	702	1253	614	568	18,253
2021	17,486	1,344	16,142	0	689	1256	619	580	16,178
2022	21,027	1,230	19,797	0	681	1258	628	584	19,718
2023	19,271	1,214	18,057	0	670	1263	631	589	17,970
2024	18,595	1,093	17,502	0	743	1,272	657	597	17,195

Historical Values (2015 - 2024):

Col. (2) and Col. (3) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.2
Forecast of Winter Peak Demand (MW)

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2025	23,042	1,375	21,667	0	778	12	717	7	21,527
2026	23,323	1,377	21,946	0	766	23	722	12	21,800
2027	23,648	1,380	22,268	0	754	35	727	17	22,116
2028	24,136	1,364	22,772	0	742	46	732	22	22,594
2029	24,603	1,313	23,290	0	731	57	735	27	23,053
2030	25,011	1,216	23,795	0	726	68	739	32	23,446
2031	25,384	1,140	24,244	0	721	79	742	37	23,804
2032	25,852	1,144	24,707	0	716	90	746	43	24,256
2033	26,245	1,149	25,096	0	712	102	749	48	24,634
2034	26,638	1,153	25,485	0	708	113	752	54	25,011

Projected Values (2025 - 2034):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent cumulative load management, incremental conservation, and load management.
All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Actual Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Actual Total Retail Sales (GWh)	(9) Load Factor(%)
2015	141,611	3,862	2,997	134,752	6,926	6,895	120,931	60.7%
2016	140,578	3,891	3,038	133,649	6,937	5,981	120,730	58.4%
2017	139,467	3,920	3,088	132,460	6,711	6,136	119,614	58.9%
2018	141,604	3,947	3,153	134,504	7,089	6,188	121,227	60.4%
2019	144,323	3,972	3,186	137,165	7,616	6,499	123,050	58.9%
2020	146,397	3,995	3,219	139,183	8,503	6,514	124,166	60.0%
2021	144,025	4,021	3,236	136,768	7,060	6,800	122,908	59.5%
2022	148,226	4,057	3,253	140,916	8,476	5,990	126,450	60.9%
2023	151,150	4,091	3,303	143,756	8,167	7,684	127,904	57.7%
2024	153,582	4,140	3,339	146,103	8,923	7,794	129,386	58.8%

Historical Values (2015 - 2024):

Col. (2) represents derived NEL not including conservation using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5)

Col. (3) & Col. (4) are annual (12-month) DSM values and represent total GWh reductions experienced each year.

Col. (8) is the Total Retail Sales calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and the greater of Col. (2) from Schedules 3.1 and 3.2 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Forecasted Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Net Energy For Load Adjusted for DSM GWh	Sales for Resale GWh	Utility Use & Losses GWh	Forecasted Total Billed Retail Energy Sales w/o DSM GWh	Load Factor(%)
2025	144,793	75	69	144,649	8,662	8,377	127,754	58.3%
2026	144,931	126	118	144,687	8,666	7,604	128,661	57.6%
2027	145,905	176	168	145,561	8,660	8,023	129,222	57.4%
2028	148,562	225	219	148,118	8,588	8,172	131,801	57.5%
2029	150,976	273	270	150,433	8,264	8,272	134,441	57.8%
2030	153,094	322	322	152,449	7,771	8,374	136,948	58.0%
2031	154,375	371	375	153,629	7,046	8,437	138,892	57.9%
2032	156,728	419	429	155,880	7,018	8,618	141,092	57.6%
2033	158,922	468	483	157,971	7,041	8,729	143,152	57.7%
2034	160,473	515	539	159,419	7,063	8,814	144,597	57.5%

Projected Values (2025 - 2034):

Col. (2) represents Forecasted NEL and does not include incremental conservation. It is the summation of Cols. (3) through (5).

Col. (3) & Col. (4) are forecasted values representing reduction on sales from incremental conservation

Col. (5) is forecasted NEL and includes incremental conservation as well company use and losses.

Col. (8) is Total Retail Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (10) from Schedule 3.1 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	% of Peak	Generation Only Reserve Margin After Maintenance MW	% of Peak
2025	31,971	232	0	4	32,206	28,312	1,995	26,317	5,889	22.4	0	5,889	22.4	3,894	13.8
2026	32,838	231	0	4	33,073	28,664	2,016	26,648	6,425	24.1	0	6,425	24.1	4,409	15.4
2027	33,970	231	0	0	34,201	28,925	2,036	26,888	7,313	27.2	0	7,313	27.2	5,276	18.2
2028	34,312	231	0	0	34,543	29,333	2,056	27,277	7,266	26.6	0	7,266	26.6	5,210	17.8
2029	34,637	231	0	0	34,869	29,687	2,079	27,608	7,261	26.3	0	7,261	26.3	5,182	17.5
2030	34,830	231	0	0	35,061	29,982	2,106	27,877	7,184	25.8	0	7,184	25.8	5,079	16.9
2031	35,180	231	0	0	35,411	30,301	2,133	28,168	7,242	25.7	0	7,242	25.7	5,109	16.9
2032	35,753	191	0	0	35,944	30,823	2,161	28,662	7,282	25.4	0	7,282	25.4	5,121	16.6
2033	36,282	191	0	0	36,472	31,257	2,189	29,068	7,404	25.5	0	7,404	25.5	5,215	16.7
2034	36,735	121	0	0	36,856	31,677	2,217	29,460	7,396	25.1	0	7,396	25.1	5,179	16.3

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2024-on intended for use with the 2025 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
2025	29,898	449	0	4	30,351	23,042	1,514	21,527	8,823	41.0	0	8,823	41.0	7,309	31.7
2026	30,451	219	0	4	30,674	23,323	1,523	21,800	8,874	40.7	0	8,874	40.7	7,350	31.5
2027	31,924	219	0	0	32,143	23,648	1,532	22,116	10,027	45.3	0	10,027	45.3	8,495	35.9
2028	33,046	219	0	0	33,265	24,136	1,542	22,594	10,672	47.2	0	10,672	47.2	9,130	37.8
2029	33,687	219	0	0	33,906	24,603	1,550	23,053	10,853	47.1	0	10,853	47.1	9,302	37.8
2030	33,887	219	0	0	34,106	25,011	1,565	23,446	10,660	45.5	0	10,660	45.5	9,095	36.4
2031	34,546	219	0	0	34,765	25,384	1,580	23,804	10,961	46.0	0	10,961	46.0	9,381	37.0
2032	35,680	219	0	0	35,899	25,852	1,595	24,256	11,643	48.0	0	11,643	48.0	10,048	38.9
2033	35,743	179	0	0	35,922	26,245	1,611	24,634	11,288	45.8	0	11,288	45.8	9,678	36.9
2034	37,000	179	0	0	37,179	26,638	1,627	25,011	12,168	48.6	0	12,168	48.6	10,541	39.6

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2024-on intended for use with the 2025 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 8 - Resource Plan

Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2/]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
FPL														
2025														
Martin Upgrade	4	Martin County	CC	NG	No	PL	No	-	1st Q 2025	Unknown	520,000	9	-	OP
Sanford Upgrade	5	Volusia County	CC	NG	No	PL	No	-	1st Q 2025	Unknown	1,252,000	26	10	OP
Turkey Point Upgrade	5	Miami-Dade County	CC	NG	FO_2	PL	TK		2nd Q 2025	Unknown	1,358,000	3	8	OP
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(11)	OT
											2025 Changes/Additions Total:	38	7	
2026														
Pea Ridge Retirement	1	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	5,000	-	(4)	P
Pea Ridge Retirement	2	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	5,000	-	(4)	P
Pea Ridge Retirement	3	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	5,000	-	(4)	P
Gulf Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	4th Q 2025	Unknown	521,500	522	349	P
Flatford Solar [3/]	1	Manatee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	5	3	P
Mare Branch Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	23	P
Price Creek Solar [3/]	1	Columbia County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	0	6	P
Swamp Cabbage Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	3	22	P
Big Brook Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	0	21	P
Mallard Solar [3/]	1	Brevard County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	4	P
Boardwalk Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	9	P
Goldenrod Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	4	P
North Orange Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	4	P
Sea Grape Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	2	4	P
Clover Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	4	P
Sand Pine Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	0	10	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2026	Unknown	1,419,500	1,420	997	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(12)	OT
											2026 Changes/Additions Total:	1,966	1,435	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A3.1, and I.A3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/]: FPL

Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Firm Net Capability [2/] Winter MW	(14) Firm Net Capability [2/] Summer MW	(15) Status
ADDITIONS/ CHANGES														
FPL														
2027														
Hendry Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
Tangelo Solar [3/]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
Wood Stork Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
Indrio Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
West County Upgrade	1	Palm Beach County	CC	NG	FO_2	PL	TK	-	1st Q 2027	Unknown	1,349,000	9	-	OP
West County Upgrade	2	Palm Beach County	CC	NG	FO_2	PL	TK	-	1st Q 2027	Unknown	1,349,000	9	-	OP
West County Upgrade	3	Palm Beach County	CC	NG	FO_2	PL	TK	-	1st Q 2027	Unknown	1,349,000	9	-	OP
Middle Lake Solar [3/]	1	Madison County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
Ambersweet Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
County Line Solar [3/]	1	Charlotte, DeSoto County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
Saddle Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
Manatee Upgrade	3	Manatee Country	CC	NG	No	PL	No	-	2nd Q 2027	Unknown	1,346,000	5	29	OP
Martin Upgrade	8	Martin County	CC	NG	FO_2	PL	TK	-	2nd Q 2027	Unknown	1,327,000	5	19	OP
Cocoplum Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Catfish Solar [3/]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Hardwood Hammock Solar [3/]	1	Walton County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Maple Trail Solar [3/]	1	Baker County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Pinecone Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Joshua Creek Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Spanish Moss Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Vernia Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2027	Unknown	819,500	820	432	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(12)	OT
											2027 Changes/Additions Total:	896	531	
2028														
Lansing Smith Retirement	3A	Broward County	CT	LO	--	TK	--	-	May-71	4th Q 2027	40,000	(40)	(32)	P
Manatee Upgrade	3	Manatee Country	CC	NG	No	PL	No		1st Q 2028	Unknown	1,346,000	3	14	OP
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	1,490,000	0	79	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2028	Unknown	596,000	596	298	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2028 Changes/Additions Total:	559	346	
2029														
Gulf Clean Energy Center Retirement	4	Escambia County	ST	NG	--	PL	--	-	Jun-61	4th Q 2029	75,000	(75)	(75)	P
Gulf Clean Energy Center Retirement	5	Escambia County	ST	NG	--	PL	--	-	Jun-61	4th Q 2029	75,000	(75)	(75)	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2029	Unknown	596,000	596	247	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	1,788,000	0	95	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2029 Changes/Additions Total:	446	179	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, LA3.1, and LA3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2/]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
FPL														
2030														
Perdido Retirement	1	Escambia County	IC	LFG	-	PL	-	-	Oct-10	4th Q 2029	1,500	(2)	(2)	P
Perdido Retirement	2	Escambia County	IC	LFG	-	PL	-	-	Oct-10	4th Q 2029	1,500	(2)	(2)	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2030	Unknown	596,000	596	244	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2030	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2030 Changes/Additions Total:	593	347	
2031														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2031	Unknown	596,000	596	244	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2031	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
											2031 Changes/Additions Total:	596	349	
2032														
2x0 Manatee CT	1	Manatee County	CT	NG	-	PL	-	-	1st Q 2032	Unknown	475,000	475	469	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2032	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
											2032 Changes/Additions Total:	475	574	
2033														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2033	Unknown	1,192,000	1,192	424	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2033	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
											2033 Changes/Additions Total:	1,192	528	
2034														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2034	Unknown	1,267,000	1,267	350	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2034	Unknown	2,235,000	0	119	P
Scherer Retirement	3	Monroe County, GA	FS	C	-	RR	-	-	Jan-87	4th Q 2034	215,000	(215)	(215)	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(15)	OT
											2034 Changes/Additions Total:	1,052	239	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A3.1, and I.A3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes hieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Florida Power & Light Company
Docket No. 20250011-EI
FEL's Eighth Set of Interrogatories
Interrogatory No. 82
Page 1 of 1

QUESTION:
Please explain whether there is any generation resource adequacy need for the 522 MW Battery NWFL in 2025 and please identify any documents supporting this response.

RESPONSE:
Yes, there is a resource adequacy need for the 522 MW NWFL Battery in 2025. This resource need is based on a need for winter peaking capacity in the NWFL region by December 2025.

Please see FPL's response to OPC's First Request for Production of Documents, No. 43 – specifically, the file titled "Confidential – 2025 BESS – Northwest Florida Battery Storage May BOD Slides 1" within the "Development" subfolder in the "POD 43 Confidential" folder.

Florida Power & Light Company
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FEL's Eighth Set of Interrogatories
Interrogatory No. 83
Page 1 of 1

QUESTION:
Please explain what the impact on the 2026 Test Year revenue requirement would be if FPL delayed the in-service date of the 522 MW Battery NWFL until 2026 and flowed-through the ITC in the year it entered service.

RESPONSE:
Delaying the in-service date of the 522 MW Battery NWFL until 2026 is not operationally feasible due to reliability considerations, so the response is not meaningful. The 522 MW Battery is needed by December 2025 to provide capacity to NWFL during winter operations and delaying the in-service date of the project would result in increased reliability risk to the NWFL region during the 2025/2026 winter months.

FPL provided the high-level estimated revenue requirement associated with the 2025 Battery Storage NWFL (522 MW) in FPL's response to OPC's First Request for Production of Documents, No. 15, under the "Laney" folder (file titled "SoBRA Revenue Requirements.xls."). The revenue requirement would be substantially similar if the 2025 battery storage was placed in service in 2026 during the same time of the year (*i.e.,* October). The Year 1 revenue requirement reduction will decline earlier in the year the battery storage enters service.

Florida Power & Light Company
Docket No. 20250011-EI
FEL's Eighth Set of Interrogatories
Interrogatory No. 84
Page 1 of 1

QUESTION:
Please explain the prudency of the 522 MW Battery NWFL project.

RESPONSE:
As stated in FPL's response to FEL's Eighth Set of Interrogatories, No. 82, there is a resource need for winter capacity in the NWFL area by December 2025. Of all the long-term options examined to meet this resource need, the battery project was identified as the most cost-effective option in terms of overall CPVRR.

Please also see FPL's response to OPC's First Request for Production of Documents, No. 43 – specifically, the file titled "Confidential – 2025 BESS – Northwest Florida Battery Storage May BOD Slides 1" within the "Development" subfolder in the "POD 43 Confidential" folder.

DECLARATION

I, Ina Laney, sponsor the answer to **Interrogatory No. 81** and co-sponsor the answers to **Interrogatory No. 83** from FEL's Eighth Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answers identified above, and that the facts stated therein are true.

Ina Laney

Ina Laney

Date: 5/28/2025

DECLARATION

I, Andrew Whitley, sponsor the answers to **Interrogatory Nos. 82 and 84** and co-sponsor the answer to **Interrogatory No. 83** from FEL's Eighth Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answers identified above, and that the facts stated therein are true.

Andrew Whitley

Date: 05/28/2025

Florida Power & Light Company
Docket No. 20250011-EI
FIPUG's First Set of Interrogatories
Interrogatory No. 8
Page 1 of 1

QUESTION:
Referring to page 31 of the direct testimony of Mr. Whitley:

a. Please explain the methodology used to assign firm capacity values to solar resources under the net peak load approach.

b. Please identify the firm value of capacity provided by FPL's proposed solar resources in each year for the period from 2026–2029.

RESPONSE:
a) The methodology that FPL uses to assign firm capacity values to solar resources under the net peak load approach is dependent upon several factors – solar site location, solar technology & design, and the total amount of solar that is operating on the FPL system. These factors contribute to assigning firm capacity values to each new solar facility.

These firm capacity values are described in terms of the percentage of the solar facility's nameplate (AC) rating that can be counted on as firm capacity at the Summer and Winter peak load hours. The Summer peak hour typically occurs in the 4 p.m. to 5 p.m. hour, and the Winter peak hour typically occurs in the 7 a.m. to 8 a.m. hour. Similarly, each new solar facility is assigned a specific firm capacity value based on the factors described above.

As more solar is added to the system, the net firm peak demand after accounting for solar production starts shifting further into the evening. Therefore, the firm capacity value for incremental solar additions decreases correspondingly with this shift. FPL uses this net peak load approach when calculating firm capacity for solar for its standard reserve margin calculation.

b) Please see Attachment No. 1 for the requested information.

Florida Power & Light Company
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Interrogatory No. 8
Attachment No. 1 of 1
Tab 1 of 1

FPL Solar Firm Capacity Value (FCV)					
Year	Solar Nameplate (MW)	Cumulative Solar Nameplate (MW)	Solar FCV (%)	Solar FCV (MW)	Cumulative Solar FCV (MW)
2026	894	894	12.62%	113	113
2027	1,192	2,086	5.31%	63	176
2028	1,490	3,576	5.31%	79	255
2029	1,788	5,364	5.31%	95	350

DECLARATION

I, Andrew Whitley, sponsor the answers to **Interrogatory Nos. 1-9, 15 and 22** and co-sponsor the answers to **Interrogatory Nos. 17 and 18** from FIPUG's First Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answers identified above, and that the facts stated therein are true.

Andrew Whitley

Date: 04/4/2025

Florida Power & Light Company
Docket No. 20250011-EI
OPC's Sixteenth Set of Interrogatories
Interrogatory No. 350
Page 1 of 4

QUESTION:
Resource Adequacy. Please refer to the Direct testimony of FPL witness Whitley at page 15; Exhibit AWW-1 at pages 20 through 22; and FPL's responses to Staff Interrogatory Nos. 35, 37 and 47.

a. For the portfolio shown on page 21 of Exhibit AWW-1, please provide the Achieved Loss of Load Expectation for 2027 in days per year in the same manner it was provided on page 20 of Exhibit AWW-1 for the portfolio shown on page 22 of Exhibit AWW-1. If the Achieved Loss of Load Expectation for 2027 in days per year for the portfolio shown on page 21 of Exhibit AWW-1 was not determined, please explain in detail why it was not determined given an Achieved Loss of Load Expectation was determined and provided on page 20 of Exhibit AWW-1 for all other portfolios shown pages 21 through 26 of Exhibit AWW-1.

b. Please confirm that FPL, being located with the FRCC rather than ReliabilityFirst, is not subject to NERC Reliability Standard BAL-502-RF-03.

c. Please confirm that FPL is subject to NERC Reliability Standard EOP-011-4.

d. Please identify the date, time, duration and cause of each NERC Energy Emergency Alert (EEA) 1 declaration on the FPL system since January 1, 2016.

e. Please identify the date, time, duration and cause of each NERC Energy Emergency Alert (EEA) 2 declaration on the FPL system since January 1, 2016.

f. Please identify the date, time and duration, and cause of each NERC Energy Emergency Alert (EEA) 3 declaration on the FPL system since January 1, 2016.

g. Please define the term "operational reserves" as that term is used by FPL in its response to Staff Interrogatory No. 35

h. Please provide a detailed description of the "operational reserve concerns" raised by the FPL's System Operations department that are noted in FPL's responses to Staff Interrogatory No. 35.

i. Please confirm that FPL is subject to NERC Reliability Standard BAL-001-2.

j. Please identify the date, time, duration and cause of each occurrence since January 1, 2016 when FPL was unable to comply with NERC Reliability Standard BAL-001-2.

k. Please identify the date, time, duration and cause of each occurrence since January 1, 2016 when FPL was unable carry, or was in danger of being unable to carry, sufficient regulating reserves to comply with NERC Reliability Standard BAL-001-2.

l. Please confirm that FPL is subject to NERC Reliability Standard BAL-002-3.

m. Please identify the date, time, duration and cause of each occurrence since January 1, 2016 when FPL was unable to comply with NERC Reliability Standard BAL-002-3.

n. Please identify the date, time, duration and cause of each occurrence since January 1, 2016 when FPL was unable carry, or was in danger of being unable to carry, sufficient contingency reserves to comply with NERC Reliability Standard BAL-002-3.

o. Please confirm that FPL is subject to NERC Reliability Standard BAL-003-2.

p. Please identify the date, time, duration and cause of each occurrence since January 1, 2016 when FPL was unable to comply, or in danger of being unable to comply, with NERC Reliability Standard BAL-003-2.

<u>RESPONSE</u>:

a. The achieved loss of load expectation for 2027 based on the case presented on page 21 of Exhibit AWW-1 would be 0.74 days per year.

b. Confirmed. North American Reliability Electric Corporation (NERC) Reliability Standard BAL-502-RF-03 is only applicable to the regional entity known as ReliabilityFirst, which is responsible for the reliability and security of the bulk electric system in the Great Lakes and Mid-Atlantic areas of the United States.

   For clarification, the North American bulk power system is made up of six Regional Entities under the authority of the NERC and the Federal Energy Regulatory Commission (FERC), of which FPL is located in the Southeastern Electric Reliability Corporation (SERC). The Florida Reliability Coordinating Council (FRCC) stopped being a regional entity in July 2019 but continues serving as the Reliability Coordinator (RC) and Planning Authority (PA) for the state of Florida.

c. Confirmed. NERC Reliability Standard EOP-011-4 is applicable to FPL.

d. FPL[1] declared one EEA-1 on April 28, 2017 from 12:43 to 17:00 the same day, due to the expected use of demand side management (DSM) over the peak based on the current load forecast, consistent with NERC Reliability Standard EOP-011-4.

[1] For the purposes of the response to these subparts, FPL is defined as peninsular Florida since the beginning of the specified timeframe of January 1, 2016. Northwest Florida (formerly Gulf Power) is included as part of this response as of July 13, 2022 when FPL assumed NERC functions Transmission Operator (TOP) and Balancing Authority (BA) from Southern Company.

e. FPL has not declared an EEA-2 within the time frame specified, consistent with NERC Reliability Standard EOP-011-4.

f. FPL has not declared an EEA-3 within the time frame specified, consistent with NERC Reliability Standard EOP-011-4.

g. Operating reserves in an electric utility system refers to the additional generating capacity that can be called upon on short notice to meet electric demand in the event of a sudden outage (*e.g.*, FPL's loss of its largest, single generating unit), if there is a supply disruption, or if demand is more than the forecast. FPL employs spinning operating reserves where the reserve capacity is the unloaded capacity on generators that are already online and can quickly increase output due to a sudden, unexpected event. Combustion turbines and batteries can also be used to contribute towards operating reserve capacity as they have quick-start capability.

h. The operational reserve concerns that were identified by FPL's System Operations refer to instances during the Spring of 2023 when lower than normal operational reserves were available during the system net peak. These instances occurred during a period of higher than expected peak load and high levels of units on maintenance. For further detail, please see the documents provided in FPL's response to OPC's 16th Request for Production of Documents, No. 138, sub-part (b).

i. Confirmed. NERC Reliability Standard BAL-001-2 is applicable to FPL.

j. FPL has not violated the requirements of NERC Reliability Standard BAL-001-2 during the specified time range.

k. FPL has not violated the requirements of NERC Reliability Standard BAL-001-2 during the specified time range. The purpose of NERC Reliability Standard BAL-001-2 is "*to control interconnection frequency within defined limits*" which is not directly related to carrying reserves. However, any instances in which FPL was unable to carry sufficient contingency reserve would result in the Company issuing an EEA declaration to the FRCC as part of NERC Reliability Standard EOP-011-4. Please refer to subparts d-f above for any EEA declarations that were issued by FPL within the specified time range.

   FPL does not track "in danger of being unable to carry" as it relates to NERC Reliability Standards, as only violations are required to be reported. The most recent instance in which FPL's contingency reserves approached a potential EEA-1 declaration was in August 2024, when the Company's service area was impacted by hot weather. In August 2023, FPL hit a new all-time consolidated system peak, which was nearly 8% higher than the previous consolidated peak. This significant increase in load further reinforced the importance of the Company having appropriate reserve margins for future heat/winter events.

l. Confirmed. NERC Reliability Standard BAL-002-3 is applicable to FPL.

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m. FPL has not violated the requirements of NERC Reliability Standard BAL-002-3 during the specified time range.

n. FPL has not violated the requirements of NERC Reliability Standard BAL-002-3 during the specified time range. The primary purpose of NERC Reliability Standard BAL-002-3 is "*to ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event*." FPL has not filed the CR Form 1 to document a Reportable Balancing Contingency Event within the specified time frame as required by this standard. Furthermore, any instances in which FPL was unable to carry sufficient contingency reserve would result in the Company issuing an EEA declaration to the FRCC as part of NERC Reliability Standard EOP-011-4. Please refer to FPL's response to subparts d-f above for any EEA declarations that were issued by FPL within the specified time range. Please refer to FPL's response to subpart k for "in danger of being unable to carry" as it relates to NERC Reliability Standards.

o. Confirmed. NERC Reliability Standard BAL-003-2 is applicable to FPL.

p. FPL has not violated the requirements of NERC Reliability Standard BAL-003-2 during the specified time range.

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Interrogatory No. 350
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Month	Hour	EUE	LOLP	LOLH
1	0	0	0	0
1	1	0	0	0
1	2	0	0	0
1	3	0	0	0
1	4	0	0	0
1	5	0	0	0
1	6	0	0	0
1	7	0	0	0
1	8	0	0	0
1	9	0	0	0
1	10	0	0	0
1	11	0	0	0
1	12	0	0	0
1	13	0	0	0
1	14	0	0	0
1	15	0	0	0
1	16	0	0	0
1	17	0	0	0
1	18	0	0	0
1	19	0	0	0
1	20	0	0	0
1	21	0	0	0
1	22	0	0	0
1	23	0	0	0
2	0	0	0	0
2	1	0	0	0
2	2	0	0	0
2	3	0	0	0
2	4	0	0	0
2	5	0	0	0
2	6	0	0	0
2	7	0	0	0
2	8	0	0	0
2	9	0	0	0
2	10	0	0	0
2	11	0	0	0
2	12	0	0	0
2	13	0	0	0
2	14	0	0	0
2	15	0	0	0
2	16	0	0	0
2	17	0	0	0
2	18	0	0	0
2	19	0	0	0
2	20	0	0	0
2	21	0	0	0
2	22	0	0	0
2	23	0	0	0
3	0	0	0	0
3	1	0	0	0
3	2	0	0	0
3	3	0	0	0
3	4	0	0	0
3	5	0	0	0
3	6	0	0	0
3	7	0	0	0
3	8	0	0	0
3	9	0	0	0
3	10	0	0	0
3	11	0	0	0
3	12	0	0	0
3	13	0	0	0
3	14	0	0	0
3	15	0	0	0
3	16	0	0	0
3	17	0	0	0
3	18	0	0	0
3	19	0	0	0
3	20	0	0	0
3	21	0	0	0
3	22	0	0	0
3	23	0	0	0
4	0	0	0	0
4	1	0	0	0
4	2	0	0	0
4	3	0	0	0
4	4	0	0	0
4	5	0	0	0
4	6	0	0	0
4	7	0	0	0
4	8	0	0	0
4	9	0	0	0
4	10	0	0	0
4	11	0	0	0
4	12	0	0	0
4	13	0	0	0
4	14	0	0	0
4	15	0	0	0
4	16	0	0	0
4	17	0	0	0
4	18	77 9285	0 00076	0 11364
4	19	0	0	0
4	20	0	0	0
4	21	0	0	0
4	22	0	0	0
4	23	0	0	0
5	0	0	0	0
5	1	0	0	0
5	2	0	0	0
5	3	0	0	0
5	4	0	0	0
5	5	0	0	0
5	6	0	0	0
5	7	0	0	0
5	8	0	0	0
5	9	0	0	0
5	10	0	0	0
5	11	0	0	0
5	12	0	0	0
5	13	0	0	0
5	14	0	0	0
5	15	0	0	0
5	16	0	0	0
5	17	0	0	0
5	18	0	0	0
5	19	0	0	0
5	20	0	0	0
5	21	0	0	0
5	22	0	0	0
5	23	0	0	0
6	0	0	0	0
6	1	0	0	0
6	2	0	0	0
6	3	0	0	0

Metric	Description	Units	Notes
EUE	Expected Unserved Energy	MWh	Averaged across all monte-carlo draws and weather years in that month, and hour For example, Month 7 and Hour 18 has, on average, 7 34 MWh lost across all simulated years in 2027
LOLP	Loss of load probability	% Probability	Averaged across all monte-carlo draws and weather years in that month, and hour For example, Month 7 and Hour 18 has, on average, 0 015% chance of loss load across all simulated years in 2027
LOLH	Loss of load hours	Hrs	Averaged across all monte-carlo draws and weather years in that month, and hour For example, Month 7 and Hour 18 has, on average, 0 02 hours lost across all simulated years in 2027

Month	Hour	EUE	LOLP	LOLH
7	18	7 340974	0 00015	0 02273

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Month	Hour	EUE	LOLP	LOLH
6	4	0	0	0
6	5	0	0	0
6	6	0	0	0
6	7	0	0	0
6	8	0	0	0
6	9	0	0	0
6	10	0	0	0
6	11	0	0	0
6	12	0	0	0
6	13	0	0	0
6	14	0	0	0
6	15	0	0	0
6	16	0	0	0
6	17	0	0	0
6	18	18 3603	0 00015	0 02273
6	19	34 2641	0 0003	0 04545
6	20	10 7771	0 00015	0 02273
6	21	0	0	0
6	22	0	0	0
6	23	0	0	0
7	0	0	0	0
7	1	0	0	0
7	2	0	0	0
7	3	0	0	0
7	4	0	0	0
7	5	0	0	0
7	6	0	0	0
7	7	0	0	0
7	8	0	0	0
7	9	0	0	0
7	10	0	0	0
7	11	0	0	0
7	12	0	0	0
7	13	0	0	0
7	14	0	0	0
7	15	0	0	0
7	16	0	0	0
7	17	0	0	0
7	18	7 34097	0 00015	0 02273
7	19	74 5837	0 00044	0 06818
7	20	53 3302	0 00015	0 02273
7	21	0	0	0
7	22	0	0	0
7	23	0	0	0
8	0	0	0	0
8	1	0	0	0
8	2	0	0	0
8	3	0	0	0
8	4	0	0	0
8	5	0	0	0
8	6	0	0	0
8	7	0	0	0
8	8	0	0	0
8	9	0	0	0
8	10	0	0	0
8	11	0	0	0
8	12	0	0	0
8	13	0	0	0
8	14	0	0	0
8	15	0	0	0
8	16	0	0	0
8	17	0	0	0
8	18	18 9331	0 00073	0 11364
8	19	17 1536	0 00029	0 04545
8	20	3 29388	0 00015	0 02273
8	21	0	0	0
8	22	0	0	0
8	23	0	0	0
9	0	0	0	0
9	1	0	0	0
9	2	0	0	0
9	3	0	0	0
9	4	0	0	0
9	5	0	0	0
9	6	0	0	0
9	7	0	0	0
9	8	0	0	0
9	9	0	0	0
9	10	0	0	0
9	11	0	0	0
9	12	0	0	0
9	13	0	0	0
9	14	0	0	0
9	15	0	0	0
9	16	0	0	0
9	17	27 1789	0 0003	0 04545
9	18	173 201	0 00167	0 25
9	19	103 642	0 00061	0 09091
9	20	35 1367	0 0003	0 04545
9	21	5 02901	0 00015	0 02273
9	22	30 1836	0 00015	0 02273
9	23	0	0	0
10	0	0	0	0
10	1	0	0	0
10	2	0	0	0
10	3	0	0	0
10	4	0	0	0
10	5	0	0	0
10	6	0	0	0
10	7	0	0	0
10	8	0	0	0
10	9	0	0	0
10	10	0	0	0
10	11	0	0	0
10	12	0	0	0
10	13	0	0	0
10	14	0	0	0
10	15	4 03994	0 00015	0 02273
10	16	0	0	0
10	17	51 2497	0 00059	0 09091
10	18	168 385	0 00147	0 22727
10	19	70 4846	0 00044	0 06818
10	20	0	0	0
10	21	0	0	0
10	22	0	0	0
10	23	0	0	0
11	0	0	0	0
11	1	0	0	0
11	2	0	0	0
11	3	0	0	0
11	4	0	0	0
11	5	0	0	0
11	6	0	0	0
11	7	0	0	0
11	8	0	0	0

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Month	Hour	EUE	LOLP	LOLH
11	9	0	0	0
11	10	0	0	0
11	11	0	0	0
11	12	0	0	0
11	13	0	0	0
11	14	0	0	0
11	15	0	0	0
11	16	0	0	0
11	17	0	0	0
11	18	0	0	0
11	19	0	0	0
11	20	0	0	0
11	21	0	0	0
11	22	0	0	0
11	23	0	0	0
12	0	0	0	0
12	1	0	0	0
12	2	0	0	0
12	3	0	0	0
12	4	0	0	0
12	5	0	0	0
12	6	0	0	0
12	7	0	0	0
12	8	0	0	0
12	9	0	0	0
12	10	0	0	0
12	11	0	0	0
12	12	0	0	0
12	13	0	0	0
12	14	0	0	0
12	15	0	0	0
12	16	0	0	0
12	17	0	0	0
12	18	0	0	0
12	19	0	0	0
12	20	0	0	0
12	21	0	0	0
12	22	0	0	0
12	23	0	0	0

<u>QUESTION</u>:
Resource Adequacy. Please refer to FPL May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44 including the corrected Attachment 1 to that response.

a. Please identify whether FPL has at any reason to believe that in 2024 the stochastic loss of load expectation for its system may have been greater than 0.1 days per year? To the extent it does, please identify in detail why it believes that in 2024 the stochastic loss of load expectation for its system may have been greater than 0.1 days per year.

b. Please identify whether FPL has any reason to believe that in the present calendar year (2025), the stochastic loss of load expectation for its system may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes that in 2025 the stochastic loss of load expectation for its system may be greater than 0.1 days per year.

c. If FPL believes that it in 2025 the stochastic loss of load expectation for its system may be greater than 0.1 days per year, but does not believe the stochastic loss of load expectation for its system in 2024 was greater than 0.1 days per year, please explain in detail what changed on its system between 2024 and 2025 that causes FPL to believe that in 2025 the stochastic loss of load expectation for its system may be greater than 0.1 days per year.

d. For the resource plan in Column 1 (Excel Row C) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2026 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

e. For the resource plan in Column 1 (Excel Row C) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2027 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

f. For the resource plan in Column 1 (Excel Row C) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2028 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

g. For the resource plan in Column 1 (Excel Row C) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2029 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

h. For the resource plan in Column 1 (Excel Row C) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2030 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

i. For the resource plan in Column 2 (Excel Row E) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2026 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

j. For the resource plan in Column 2 (Excel Row E) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2027 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

k. For the resource plan in Column 3 (Excel Row G) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2026 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

l. For the resource plan in Column 3 (Excel Row G) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2027 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

m. For the resource plan in Column 3 (Excel Row G) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2028 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

n. For the resource plan in Column 3 (Excel Row G) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2029 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

o. For the resource plan in Column 3 (Excel Row G) of Page 1 of 5 of the corrected version of Attachment 1 that was provided as part of FPL's May 8, 2025 corrected supplemental response to Staff Interrogatory No. 44, please identify whether FPL has any reason to believe that the stochastic loss of load expectation for calendar year 2030 for this resource plan may be greater than 0.1 days per year? To the extent it does, please identify in detail why it believes this.

RESPONSE:

a. FPL did not perform any projections of stochastic LOLP that covered the year 2024 and therefore cannot confirm what FPL's LOLE in 2024 was based on stochastic evaluations. FPL notes that while no stochastic evaluations were performed, FPL consistently evaluates its system on an operational basis.

b. FPL did not perform any projections of stochastic LOLP that covered the year 2025 and therefore cannot confirm what FPL's LOLE in 2025 was based on stochastic evaluations. FPL notes that while no stochastic evaluations were performed, FPL consistently evaluates its system on an operational basis.

c. Please see the response to sub-parts a. and b.

d. FPL has not performed a stochastic LOLP analysis of the resource plan in Column 1 and therefore cannot definitively say that this plan meets FPL's stochastic LOLP needs in any year. FPL notes that long-term this plan does not add solar resources and, while the plan therefore reduces future resource intermittency risk , the plan experiences none of the cost-effectiveness benefits of additional solar, thereby resulting in billions of dollars in CPVRR costs to customers relative to FPL's proposed plan.

e. Please see the response to subpart (d).

f. Please see the response to subpart (d).

g. Please see the response to subpart (d).

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h. Please see the response to subpart (d).

i. FPL did not perform any projections of stochastic LOLP that covered the year 2026 and therefore cannot confirm what FPL's LOLE in 2026 was based on stochastic evaluations. However, the resource plan in Column 2 adds battery storage facilities throughout 2026 that provide firm capacity that addresses potential loss of load scenarios throughout the year.

j. For Column 2, the LOLE for 2027 would not be above 0.1 days per year. This resource plan corresponds to the LOLE on page 22 of Exhibit AWW-1, before 819.5 MW of battery storage are added in 2027. The firm capacity from this additional storage would meet the firm capacity shortfall on page 22 of Exhibit AWW-1 and would result in an LOLE of less than 0.1 days per year.

k. FPL did not perform any projections of stochastic LOLE that covered the year 2026 and therefore cannot confirm what FPL's LOLE in 2026 was based on stochastic evaluations. However, the resource plan in Column 3 only adds solar in 2026 and does not add battery storage that would address LOLE shortfalls.

l. For Column 3, FPL projects that the LOLE for 2027, 2028, 2029, and 2030 would all be above the 0.1 days per year metric. Exhibit AWW-1, pages 22-25, shows LOLE values consistently above 0.1 days for each year assuming that all previous battery storage additions from Column 2 have been added. Column 3 does not have any battery storage added in those years, and therefore would have shortfalls in LOLE in each year.

m. Please see the response to subpart l.

n. Please see the response to subpart l.

o. Please see the response to subpart l.

DECLARATION

I, Eduardo De Varona, co-sponsor the answers to **Interrogatory Nos. 350 and 352** from OPC's Sixteenth Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answers identified above, and that the facts stated therein are true.

Eduardo De Varona

Date: 5-28-2025

DECLARATION

I, Andrew Whitley, sponsor the answer to **Interrogatory No. 351** and co-sponsor the answers to **Interrogatory Nos. 350 and 352** from OPC's Sixteenth Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answers identified above, and that the facts stated therein are true.

Andrew Whitley

Date: 05/29/2025

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Interrogatory No. 35
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QUESTION:
Provide a timeline of FPL's replacement of its LOLP planning methodology from the identification of a need to the selection of the SLOLP methodology. As part of this response, identify when FPL determined the need for a new resource planning model to replace its LOLP methodology, when FPL engaged with E3 and/or other vendor(s) to provide modeling services, when any studies (including the one summarized by AWW-1) were engaged, when the study results were provided to FPL, when any comparisons between the model(s) were conducted (if any), and when the SLOLP methodology was ultimately selected.

RESPONSE:
Throughout 2023 and into early 2024, FPL began examining its operational reserves and the ability of those reserves to address system reliability risks. In response to operational reserve concerns raised by the FPL's System Operations department, FPL added batteries to the resource plan in its 2024 TYSP to address these concerns. In 2024, FPL engaged E3 to provide an in-depth examination of FPL's operational reserves. While examining those issues, E3 and FPL discovered periods where resource adequacy gaps existed – *i.e.,* where load levels exceeded available generation. That discovery prompted an expansion of FPL's work with E3 to examine resource adequacy via enhanced LOLP tools, which have been utilized in other Independent System Operators and Regional Transmission Organizations with significant amounts of variable generation. This analysis was conducted throughout the 4th quarter of 2024, continuing into the 1st quarter of 2025. E3's stochastic LOLP modeling was ultimately used for this analysis as E3 already had access to and utilized FPL's assumptions from E3's initial examination of operational reserves.

DECLARATION

I, Andrew Whitley, sponsor the answers to **Interrogatory Nos. 32, 33, 34, 35, 36, 37, 38, 39, 40-52, 54, 55 and 56** and co-sponsor the answers to **Interrogatory Nos. 53 and 57** from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answers identified above, and that the facts stated therein are true.

Andrew Whitley

Date: 04/08/2025

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QUESTION:
Provide a resource plan for the period 2026 through 2035 using FPL's prior resource planning process, including the use of an econometric demand model and the TIGER program to determine probabilistic LOLP as described in the Utility's 2024 TYSP. As part of your response, provide the following information for each year of the period and a comparison of these values to the resource plan generated by FPL's new resource planning process using the SLOLP methodology:

a. Seasonal Peak Demand Forecasts (including the total peak demand net firm peak demand accounting for energy efficiency, demand response, curtailable load, and other factors);

b. Planning and Generation Only Reserve Margins;

c. LOLP and Expected Unserved Energy;

d. Resource Plans (including identifying each resource & capacity [non-firm and firm contributions] change); and

e. New resource financial information.

RESPONSE:
With this corrected response, FPL corrects the indication of column 1 of Attachment 1, Tab 1 (Excel file cell C12) to indicate that FPL has not performed an analysis to determine whether the resource plan demonstrated in column 1 would satisfy the 0.1 days-per-year loss of load probability standard as calculated through the stochastic methodology. This correction has no other impacts on the Attachment 1 that was previously provided with FPL's supplemental response to Staff's Third Set of Interrogatories, No. 44 served on May 2, 2025. A corrected Attachment 1 is provided with this response.

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Resource Plan Comparison

	(1)	(2)	(3)
Meets Standard 20% Reserve Margin:	Yes	Yes	Yes
Meets 0.1 Days Per Year LOLP Using Traditional Calculation:	Yes	Yes	Yes
Meets 0.1 Days Per Year LOLP Using Stochastic Calculation:	Unevaluated*	Yes	**No**

Common to all Plans Retirements / Additions	Year	Without Proposed 2026 and 2027 Solar And Battery Additions	Reserve Margin (%)	FPL Resource Plan with Rate Case Additions	Reserve Margin (%)	FPL Resource Plan - No Additions to Meet LOLP	Reserve Margin (%)
Pea Ridge (12 MW)	2025	894 MW Solar	22.4	894 MW Solar	22.4	894 MW Solar	22.4
---	2026	522 MW Battery NWFL	22.1	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1	522 MW Battery NWFL 894 MW Solar	23.1
Broward South (4 MW)	2027	---	21.1	1,192 MW Solar 819.5 MW Battery	27.2	1,192 MW Solar	22.3
Lansing Smith A (32 MW)	2028	1 x 2x0 CT (475 MW)	21.0	1,490 MW Solar 596 MW Battery	26.6	2,235 MW Solar	20.9
---	2029	1 x 2x0 CT (475 MW)	21.2	1,788 MW Solar 596 MW Battery	26.3	2,235 MW Solar 224 MW Battery	20.5
GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2030	1 x 2x0 CT (475 MW)	21.1	2,235 MW Solar 596 MW Battery	25.8	2,235 MW Solar 522 MW Battery	20.6
---	2031	1 x 2x0 CT (475 MW)	21.5	2,235 MW Solar 596 MW Battery	25.7	2,235 MW Solar 373 MW Battery	20.6
---	2032	1 x 2x0 CT (475 MW)	20.9	2,235 MW Solar 596 MW Battery	24.5	2,235 MW Solar 969 MW Battery	20.6
---	2033	1 x 2x0 CT (475 MW)	20.8	2,235 MW Solar 596 MW Battery	23.9	2,235 MW Solar 969 MW Battery	21.0
---	2034	1 x 2x0 CT (475 MW)	20.5	2,235 MW Solar 596 MW Battery	23.0	2,235 MW Solar 2,533 MW Battery	22.9

	(1)	(2)	(3)
CPVRR Costs =	**$108,841**	**$99,322**	**$98,776**
CPVRR Costs Difference from the Without Proposed Solar and Battery Additions Plan =	--	**($9,520)**	**($10,065)**
CPVRR Costs Difference from the FPL Plan with Rate Case Additions =			**($545)**

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071
Negative values indicate CPVRR savings to customers
Analysis assumes new CT capacity is available in 2028 to put plans on equal footing; realistically new CT installations would not be available until late 2029 or early 2030 at the earliest
Plans that do not add resources based on stochastic modeling have multiple years of reliabilty risk to customers

* FPL has not conducted a stochastic LOLP evaluation of this plan

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Case name:	**Without Proposed 2026 and 2027 Solar And Battery Additions**

			System Fixed Costs				System Variable Costs													
	Year	Annual Discount Factor 8.15%	Generation Capital Costs (Millions)	Fixed O&M & Capital Replacement Costs (Millions)	Transmission Interconnection Costs (Millions)	Total Fixed Costs (Millions)	System Net Fuel (Millions)	Startup Costs (Millions)	VOM Costs (Millions)	Emission Costs (Millions)	Total Variable Costs (Millions)	Total Annual Costs (Millions)	NPV Total Annual Cost (Millions)	NPV Cumulative Total Costs (Millions)	Year	Net Energy For Load (MWh)	Annual Rate ($/1,000 kWh)	Fixed Costs Component of Annual Rate ($/1,000 kWh)	Variable Costs Component of Annual Rate ($/1,000 kWh)
1	**2025**	1 000	165	6	4	**175**	2,325	261	76	1	**2,663**	2,838	2,838	2,838	**2025**	144,793,264	19 60	1 21	18 39
2	**2026**	0 925	259	7	5	**272**	2,594	268	63	1	**2,926**	3,198	2,957	5,794	**2026**	144,930,841	22 06	1 87	20 19
3	**2027**	0 855	241	7	5	**252**	3,154	303	69	1	**3,526**	3,778	3,230	9,025	**2027**	145,905,330	25 90	1 73	24 17
4	**2028**	0 791	299	8	11	**318**	3,276	302	86	1	**3,665**	3,983	3,149	12,173	**2028**	148,561,631	26 81	2 14	24 67
5	**2029**	0 731	358	29	17	**403**	3,584	326	95	1	**4,006**	4,409	3,223	15,396	**2029**	150,975,822	29 21	2 67	26 53
6	**2030**	0 676	419	16	23	**458**	3,886	331	102	1	**4,319**	4,778	3,229	18,625	**2030**	153,093,512	31 21	2 99	28 21
7	**2031**	0 625	483	20	29	**531**	3,770	349	116	1	**4,235**	4,767	2,979	21,604	**2031**	154,375,327	30 88	3 44	27 44
8	**2032**	0 578	549	41	35	**625**	4,071	363	142	1	**4,577**	5,201	3,006	24,610	**2032**	156,727,881	33 19	3 99	29 20
9	**2033**	0 534	613	32	41	**686**	4,541	392	276	1	**5,209**	5,895	3,150	27,760	**2033**	158,921,727	37 09	4 32	32 78
10	**2034**	0 494	679	37	47	**763**	4,765	411	475	1	**5,652**	6,415	3,169	30,929	**2034**	160,472,966	39 97	4 75	35 22
11	**2035**	0 457	1,052	64	75	**1,192**	5,090	493	671	1	**6,255**	7,446	3,401	34,330	**2035**	162,208,990	45 90	7 35	38 56
12	**2036**	0 422	1,023	59	73	**1,155**	5,397	521	613	154	**6,685**	7,841	3,312	37,642	**2036**	164,006,037	47 81	7 05	40 76
13	**2037**	0 391	990	62	71	**1,123**	5,551	550	639	319	**7,059**	8,182	3,195	40,838	**2037**	165,642,504	49 39	6 78	42 62
14	**2038**	0 361	1,111	79	79	**1,270**	5,750	574	662	494	**7,479**	8,748	3,159	43,997	**2038**	167,116,700	52 35	7 60	44 75
15	**2039**	0 334	1,223	90	88	**1,401**	5,982	597	686	680	**7,945**	9,346	3,121	47,118	**2039**	168,416,660	55 49	8 32	47 18
16	**2040**	0 309	1,186	105	85	**1,375**	6,332	631	708	873	**8,544**	9,919	3,062	50,180	**2040**	169,482,447	58 53	8 12	50 41
17	**2041**	0 285	1,302	125	94	**1,520**	6,661	651	732	1,013	**9,057**	10,577	3,020	53,200	**2041**	170,443,232	62 06	8 92	53 14
18	**2042**	0 264	1,261	118	91	**1,471**	6,860	689	751	1,160	**9,461**	10,931	2,885	56,085	**2042**	169,857,844	64 35	8 66	55 70
19	**2043**	0 244	1,221	136	88	**1,444**	7,185	715	774	1,341	**10,015**	11,459	2,797	58,882	**2043**	170,506,430	67 21	8 47	58 74
20	**2044**	0 226	1,350	151	97	**1,599**	7,389	738	795	1,543	**10,465**	12,064	2,723	61,605	**2044**	170,983,626	70 56	9 35	61 21
21	**2045**	0 209	1,304	166	94	**1,564**	7,769	770	820	1,788	**11,148**	12,711	2,653	64,257	**2045**	171,835,848	73 97	9 10	64 87
22	**2046**	0 193	1,248	156	91	**1,495**	8,479	813	845	2,006	**12,142**	13,638	2,631	66,889	**2046**	172,692,473	78 97	8 66	70 31
23	**2047**	0 178	1,395	202	102	**1,698**	9,025	843	874	2,254	**12,995**	14,693	2,621	69,510	**2047**	173,553,524	84 66	9 78	74 88
24	**2048**	0 165	1,354	171	99	**1,624**	9,583	889	900	2,527	**13,899**	15,523	2,561	72,071	**2048**	174,419,023	89 00	9 31	79 69
25	**2049**	0 153	1,312	228	95	**1,636**	10,176	927	934	2,844	**14,880**	16,516	2,519	74,590	**2049**	175,288,995	94 22	9 33	84 89
26	**2050**	0 141	1,475	275	107	**1,857**	10,861	974	963	3,193	**15,990**	17,848	2,517	77,107	**2050**	176,163,463	101 31	10 54	90 77
27	**2051**	0 130	1,431	278	104	**1,814**	10,931	985	993	3,288	**16,197**	18,010	2,349	79,456	**2051**	177,042,449	101 73	10 24	91 49
28	**2052**	0 121	1,601	286	117	**2,004**	11,209	1,009	1,044	3,460	**16,723**	18,726	2,258	81,714	**2052**	177,925,979	105 25	11 26	93 99
29	**2053**	0 111	1,993	387	147	**2,527**	11,884	1,035	1,151	3,820	**17,890**	20,417	2,276	83,990	**2053**	178,814,075	114 18	14 13	100 05
30	**2054**	0 103	1,936	386	142	**2,464**	12,061	1,077	1,206	3,982	**18,326**	20,789	2,143	86,134	**2054**	179,706,761	115 69	13 71	101 98
31	**2055**	0 095	2,110	420	155	**2,686**	12,078	1,091	1,236	4,080	**18,485**	21,171	2,018	88,152	**2055**	180,604,061	117 22	14 87	102 35
32	**2056**	0 088	2,531	438	187	**3,156**	12,595	1,135	1,331	4,402	**19,463**	22,619	1,994	90,145	**2056**	181,506,000	124 62	17 39	107 23
33	**2057**	0 081	2,460	465	181	**3,105**	12,663	1,157	1,374	4,544	**19,737**	22,843	1,862	92,007	**2057**	182,412,602	125 23	17 02	108 20
34	**2058**	0 075	2,386	467	175	**3,028**	12,736	1,179	1,419	4,690	**20,024**	23,052	1,737	93,744	**2058**	183,323,891	125 74	16 52	109 23
35	**2059**	0 070	2,578	519	190	**3,286**	12,734	1,213	1,459	4,801	**20,207**	23,493	1,637	95,381	**2059**	184,239,891	127 51	17 84	109 68
36	**2060**	0 064	2,470	489	183	**3,142**	12,799	1,250	1,506	4,951	**20,506**	23,648	1,524	96,905	**2060**	185,160,628	127 71	16 97	110 75
37	**2061**	0 060	2,380	515	176	**3,071**	12,799	1,278	1,547	5,070	**20,695**	23,766	1,416	98,320	**2061**	186,086,125	127 71	16 50	111 21
38	**2062**	0 055	2,597	532	192	**3,322**	12,917	1,314	1,606	5,242	**21,079**	24,401	1,344	99,664	**2062**	187,016,408	130 47	17 76	112 71
39	**2063**	0 051	2,819	520	208	**3,548**	13,225	1,340	1,690	5,534	**21,789**	25,337	1,290	100,955	**2063**	187,951,502	134 80	18 88	115 93
40	**2064**	0 047	3,043	541	224	**3,808**	13,347	1,388	1,761	5,751	**22,246**	26,055	1,227	102,182	**2064**	188,891,432	137 93	20 16	117 77
41	**2065**	0 044	2,955	661	217	**3,833**	13,382	1,419	1,818	5,912	**22,531**	26,363	1,148	103,330	**2065**	189,836,223	138 87	20 19	118 69
42	**2066**	0 040	2,865	609	209	**3,683**	13,408	1,452	1,870	6,073	**22,803**	26,486	1,066	104,396	**2066**	190,785,901	138 83	19 31	119 52
43	**2067**	0 037	3,112	675	227	**4,014**	13,432	1,488	1,927	6,237	**23,084**	27,098	1,009	105,405	**2067**	191,740,492	141 32	20 93	120 39
44	**2068**	0 034	3,007	767	219	**3,993**	13,463	1,543	1,988	6,410	**23,403**	27,396	943	106,348	**2068**	192,700,019	142 17	20 72	121 45
45	**2069**	0 032	3,255	769	238	**4,262**	13,482	1,555	2,042	6,581	**23,661**	27,923	889	107,237	**2069**	193,664,511	144 18	22 01	122 17
46	**2070**	0 029	3,143	806	230	**4,180**	13,509	1,609	2,105	6,761	**23,984**	28,164	829	108,066	**2070**	194,633,992	144 70	21 48	123 22
47	**2071**	0 027	3,031	924	222	**4,177**	13,542	1,649	2,172	6,948	**24,311**	28,489	775	108,841	**2071**	195,608,489	145 64	21 36	124 29
		Total NPV =	**$11,107**	**$1,297**	**$745**	**$13,150**	**$71,580**	**$6,855**	**$6,121**	**$11,137**	**$95,692**	**108,841**							

Florida Power & Light Company
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Case name:	**FPL Resource Plan with Rate Case Additions**

			System Fixed Costs				System Variable Costs												
	Year	Annual Discount Factor 8.15%	Generation Capital Costs (Millions)	Fixed O&M & Capital Replacement Costs (Millions)	Transmission Interconnection Costs (Millions)	Total Fixed Costs (Millions)	System Net Fuel (Millions)	Startup Costs (Millions)	VOM Costs (Millions)	Emission Costs (Millions)	Total Variable Costs (Millions)	Total Annual Costs (Millions)	NPV Total Annual Cost (Millions)	NPV Cumulative Total Costs (Millions)	Year	Net Energy For Load (MWh)	Annual Rate ($/1,000 kWh)	Fixed Costs Component of Annual Rate ($/1,000 kWh)	Variable Costs Component of Annual Rate ($/1,000 kWh)
1	**2025**	1 000	165	6	4	**175**	2,325	261	76	1	**2,663**	2,838	2,838	2,838	**2025**	144,793,264	19 60	1 21	18 39
2	**2026**	0 925	307	15	31	**353**	2,547	267	(19)	1	**2,796**	3,149	2,912	5,749	**2026**	144,930,841	21 73	2 43	19 29
3	**2027**	0 855	678	31	63	**771**	3,030	260	(117)	1	**3,173**	3,945	3,372	9,122	**2027**	145,905,330	27 04	5 29	21 75
4	**2028**	0 791	1,070	40	104	**1,215**	3,044	204	(258)	1	**2,991**	4,206	3,325	12,447	**2028**	148,561,631	28 31	8 18	20 13
5	**2029**	0 731	1,422	70	152	**1,644**	3,198	188	(451)	1	**2,935**	4,578	3,347	15,793	**2029**	150,975,822	30 33	10 89	19 44
6	**2030**	0 676	1,836	86	210	**2,133**	3,163	160	(705)	1	**2,618**	4,751	3,211	19,004	**2030**	153,093,512	31 03	13 93	17 10
7	**2031**	0 625	2,243	95	271	**2,608**	3,045	165	(984)	1	**2,227**	4,835	3,022	22,026	**2031**	154,375,327	31 32	16 89	14 43
8	**2032**	0 578	2,625	126	329	**3,080**	3,124	184	(1,232)	1	**2,076**	5,156	2,979	25,005	**2032**	156,727,881	32 90	19 65	13 25
9	**2033**	0 534	2,986	147	385	**3,518**	3,335	206	(1,402)	1	**2,139**	5,657	3,022	28,028	**2033**	158,921,727	35 59	22 13	13 46
10	**2034**	0 494	3,327	159	439	**3,926**	3,301	198	(1,543)	1	**1,956**	5,881	2,906	30,933	**2034**	160,472,966	36 65	24 46	12 19
11	**2035**	0 457	3,862	185	478	**4,524**	3,521	323	(1,529)	0	**2,315**	6,839	3,124	34,058	**2035**	162,208,990	42 16	27 89	14 27
12	**2036**	0 422	3,705	208	460	**4,373**	3,762	322	(1,522)	104	**2,666**	7,039	2,973	37,031	**2036**	164,006,037	42 92	26 66	16 26
13	**2037**	0 391	3,568	201	443	**4,213**	3,888	345	(1,383)	217	**3,067**	7,279	2,843	39,874	**2037**	165,642,504	43 94	25 43	18 51
14	**2038**	0 361	3,676	212	427	**4,315**	4,054	377	(1,204)	338	**3,564**	7,879	2,845	42,719	**2038**	167,116,700	47 15	25 82	21 33
15	**2039**	0 334	3,557	228	410	**4,196**	4,236	370	(977)	468	**4,097**	8,293	2,769	45,488	**2039**	168,416,660	49 24	24 91	24 33
16	**2040**	0 309	3,597	236	406	**4,238**	4,472	366	(690)	600	**4,747**	8,985	2,774	48,263	**2040**	169,482,447	53 02	25 00	28 01
17	**2041**	0 285	3,485	258	389	**4,132**	4,732	389	(378)	702	**5,445**	9,577	2,734	50,997	**2041**	170,443,232	56 19	24 24	31 95
18	**2042**	0 264	3,533	258	385	**4,176**	4,862	395	(69)	801	**5,988**	10,164	2,683	53,680	**2042**	169,857,844	59 84	24 58	35 26
19	**2043**	0 244	3,419	264	369	**4,053**	5,104	437	258	930	**6,730**	10,783	2,632	56,311	**2043**	170,506,430	63 24	23 77	39 47
20	**2044**	0 226	3,306	275	354	**3,935**	5,273	456	600	1,075	**7,403**	11,338	2,559	58,870	**2044**	170,983,626	66 31	23 01	43 30
21	**2045**	0 209	3,362	294	352	**4,008**	5,561	430	622	1,250	**7,863**	11,871	2,477	61,347	**2045**	171,835,848	69 08	23 32	45 76
22	**2046**	0 193	3,210	304	337	**3,851**	6,076	458	643	1,407	**8,584**	12,435	2,399	63,747	**2046**	172,692,473	72 01	22 30	49 71
23	**2047**	0 178	3,016	344	322	**3,682**	6,492	502	668	1,589	**9,253**	12,935	2,308	66,054	**2047**	173,553,524	74 53	21 22	53 31
24	**2048**	0 165	3,062	313	323	**3,699**	6,900	569	683	1,785	**9,936**	13,635	2,249	68,304	**2048**	174,419,023	78 17	21 21	56 97
25	**2049**	0 153	2,927	354	310	**3,591**	7,372	624	715	2,024	**10,734**	14,325	2,185	70,489	**2049**	175,288,995	81 72	20 49	61 24
26	**2050**	0 141	2,798	397	298	**3,493**	7,914	612	746	2,288	**11,560**	15,053	2,123	72,612	**2050**	176,163,463	85 45	19 83	65 62
27	**2051**	0 130	2,878	388	302	**3,568**	7,950	574	764	2,350	**11,639**	15,207	1,983	74,595	**2051**	177,042,449	85 89	20 15	65 74
28	**2052**	0 121	2,963	401	306	**3,671**	8,243	601	818	2,504	**12,165**	15,837	1,910	76,504	**2052**	177,925,979	89 01	20 63	68 37
29	**2053**	0 111	3,273	452	327	**4,053**	8,895	592	932	2,837	**13,256**	17,308	1,930	78,434	**2053**	178,814,075	96 80	22 66	74 13
30	**2054**	0 103	3,136	482	314	**3,932**	9,044	643	974	2,966	**13,627**	17,559	1,810	80,244	**2054**	179,706,761	97 71	21 88	75 83
31	**2055**	0 095	3,249	494	318	**4,062**	9,128	675	1,010	3,061	**13,874**	17,936	1,710	81,954	**2055**	180,604,061	99 31	22 49	76 82
32	**2056**	0 088	3,621	527	342	**4,491**	9,623	677	1,107	3,353	**14,759**	19,249	1,697	83,651	**2056**	181,506,000	106 05	24 74	81 31
33	**2057**	0 081	3,502	575	328	**4,405**	9,709	647	1,140	3,475	**14,971**	19,376	1,579	85,230	**2057**	182,412,602	106 22	24 15	82 07
34	**2058**	0 075	3,382	573	314	**4,268**	9,800	656	1,184	3,601	**15,240**	19,509	1,470	86,700	**2058**	183,323,891	106 42	23 28	83 13
35	**2059**	0 070	3,527	619	321	**4,467**	9,820	673	1,218	3,693	**15,405**	19,872	1,385	88,085	**2059**	184,239,891	107 86	24 25	83 61
36	**2060**	0 064	3,374	656	306	**4,336**	9,910	729	1,270	3,827	**15,736**	20,072	1,293	89,378	**2060**	185,160,628	108 40	23 42	84 99
37	**2061**	0 060	3,205	669	287	**4,161**	9,924	769	1,300	3,921	**15,914**	20,075	1,196	90,574	**2061**	186,086,125	107 88	22 36	85 52
38	**2062**	0 055	3,324	681	289	**4,295**	10,011	736	1,342	4,054	**16,143**	20,437	1,126	91,700	**2062**	187,016,408	109 28	22 96	86 32
39	**2063**	0 051	3,437	723	291	**4,451**	10,353	746	1,427	4,332	**16,858**	21,308	1,085	92,785	**2063**	187,951,502	113 37	23 68	89 69
40	**2064**	0 047	3,542	733	291	**4,566**	10,514	778	1,499	4,534	**17,327**	21,892	1,031	93,816	**2064**	188,891,432	115 90	24 17	91 73
41	**2065**	0 044	3,320	834	266	**4,420**	10,558	820	1,545	4,669	**17,593**	22,013	959	94,774	**2065**	189,836,223	115 96	23 29	92 67
42	**2066**	0 040	3,099	838	241	**4,179**	10,601	866	1,594	4,806	**17,867**	22,046	888	95,662	**2066**	190,785,901	115 55	21 90	93 65
43	**2067**	0 037	3,222	901	243	**4,366**	10,661	878	1,649	4,956	**18,144**	22,509	838	96,500	**2067**	191,740,492	117 39	22 77	94 63
44	**2068**	0 034	3,013	951	221	**4,185**	10,657	831	1,685	5,080	**18,252**	22,437	772	97,272	**2068**	192,700,019	116 43	21 72	94 72
45	**2069**	0 032	3,165	965	226	**4,356**	10,739	876	1,742	5,249	**18,606**	22,962	731	98,003	**2069**	193,664,511	118 57	22 49	96 07
46	**2070**	0 029	3,042	1,038	218	**4,297**	10,762	883	1,794	5,393	**18,832**	23,128	681	98,684	**2070**	194,633,992	118 83	22 08	96 75
47	**2071**	0 027	2,949	1,124	210	**4,283**	10,814	920	1,857	5,555	**19,146**	23,429	638	99,322	**2071**	195,608,489	119 77	21 90	97 88
		Total NPV =	**$29,907**	**$2,409**	**$3,344**	**$35,660**	**$55,482**	**$4,284**	**($4,325)**	**$8,220**	**$63,661**	**99,322**							

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Case name:	**FPL Resource Plan - No Additions to Meet LOLP**

			System Fixed Costs				System Variable Costs								
	Year	Annual Discount Factor 8.15%	Generation Capital Costs (Millions)	Fixed O&M & Capital Replacement Costs (Millions)	Transmission Interconnection Costs (Millions)	Total Fixed Costs (Millions)	System Net Fuel (Millions)	Startup Costs (Millions)	VOM Costs (Millions)	Emission Costs (Millions)	Total Variable Costs (Millions)	Total Annual Costs (Millions)	NPV Total Annual Cost (Millions)	NPV Cumulative Total Costs (Millions)	Year
1	**2025**	1.000	165	6	4	**175**	2,325	261	76	1	**2,663**	2,838	2,838	2,838	**2025**
2	**2026**	0.925	397	11	28	**436**	2,553	266	(9)	1	**2,811**	3,247	3,002	5,840	**2026**
3	**2027**	0.855	564	15	57	**636**	3,035	303	(113)	1	**3,226**	3,863	3,303	9,142	**2027**
4	**2028**	0.791	902	25	112	**1,038**	3,018	306	(299)	1	**3,026**	4,064	3,213	12,355	**2028**
5	**2029**	0.731	1,237	57	175	**1,469**	3,139	317	(552)	1	**2,904**	4,374	3,197	15,552	**2029**
6	**2030**	0.676	1,583	56	236	**1,875**	3,497	341	(820)	1	**3,019**	4,894	3,308	18,860	**2030**
7	**2031**	0.625	2,014	71	295	**2,380**	3,013	333	(1,100)	1	**2,248**	4,627	2,892	21,752	**2031**
8	**2032**	0.578	2,292	109	353	**2,754**	3,095	334	(1,357)	1	**2,073**	4,827	2,789	24,541	**2032**
9	**2033**	0.534	2,722	117	410	**3,248**	3,286	319	(1,545)	1	**2,061**	5,309	2,837	27,377	**2033**
10	**2034**	0.494	2,919	156	466	**3,541**	3,294	308	(1,680)	1	**1,922**	5,464	2,699	30,077	**2034**
11	**2035**	0.457	3,985	179	507	**4,670**	3,466	374	(1,683)	0	**2,158**	6,828	3,119		**2035**
12	**2036**	0.422	3,819	178	488	**4,485**	3,701	393	(1,680)	102	**2,516**	7,001	2,957		**2036**
13	**2037**	0.391	3,677	187	470	**4,334**	3,820	404	(1,542)	212	**2,894**	7,228	2,823		**2037**
14	**2038**	0.361	3,797	217	452	**4,466**	3,972	421	(1,274)	330	**3,450**	7,917	2,859		**2038**
15	**2039**	0.334	3,822	214	446	**4,483**	4,140	435	(993)	456	**4,039**	8,522	2,846		**2039**
16	**2040**	0.309	3,710	235	429	**4,374**	4,378	453	(703)	586	**4,714**	9,087	2,806		**2040**
17	**2041**	0.285	3,754	271	423	**4,448**	4,632	460	(391)	685	**5,386**	9,834	2,807		**2041**
18	**2042**	0.264	3,642	252	406	**4,300**	4,747	480	(82)	780	**5,926**	10,225	2,699		**2042**
19	**2043**	0.244	3,528	268	389	**4,185**	4,991	496	249	907	**6,643**	10,828	2,643		**2043**
20	**2044**	0.226	3,585	310	385	**4,280**	5,153	527	588	1,047	**7,315**	11,595	2,617		**2044**
21	**2045**	0.209	3,464	292	369	**4,126**	5,434	507	614	1,219	**7,774**	11,900	2,483		**2045**
22	**2046**	0.193	3,334	285	354	**3,973**	5,939	536	635	1,373	**8,482**	12,455	2,403		**2046**
23	**2047**	0.178	3,405	351	354	**4,110**	6,348	565	659	1,551	**9,123**	13,232	2,361		**2047**
24	**2048**	0.165	3,289	300	340	**3,929**	6,743	635	675	1,741	**9,794**	13,723	2,264		**2048**
25	**2049**	0.153	3,160	355	326	**3,842**	7,194	700	701	1,971	**10,565**	14,407	2,198		**2049**
26	**2050**	0.141	3,231	404	329	**3,964**	7,693	688	726	2,220	**11,328**	15,292	2,157		**2050**
27	**2051**	0.130	3,094	391	316	**3,800**	7,778	633	758	2,295	**11,464**	15,265	1,991	74,108	**2051**
28	**2052**	0.121	3,373	388	335	**4,096**	8,074	652	809	2,449	**11,984**	16,080	1,939	76,047	**2052**
29	**2053**	0.111	3,429	490	338	**4,257**	8,740	672	925	2,785	**13,122**	17,380	1,938	77,985	**2053**
30	**2054**	0.103	3,449	487	340	**4,277**	8,873	708	967	2,907	**13,456**	17,733	1,828	79,813	**2054**
31	**2055**	0.095	3,282	500	325	**4,107**	8,948	720	1,001	2,999	**13,668**	17,775	1,694	81,507	**2055**
32	**2056**	0.088	3,649	535	348	**4,533**	9,439	716	1,097	3,288	**14,540**	19,073	1,681	83,188	**2056**
33	**2057**	0.081	3,528	559	334	**4,421**	9,545	686	1,138	3,415	**14,784**	19,205	1,565	84,754	**2057**
34	**2058**	0.075	3,405	580	320	**4,304**	9,651	698	1,187	3,545	**15,081**	19,386	1,461	86,214	**2058**
35	**2059**	0.070	3,548	660	326	**4,534**	9,653	733	1,216	3,629	**15,231**	19,765	1,377	87,592	**2059**
36	**2060**	0.064	3,393	633	311	**4,337**	9,743	772	1,271	3,761	**15,547**	19,885	1,281	88,873	**2060**
37	**2061**	0.060	3,501	671	313	**4,485**	9,758	821	1,296	3,854	**15,730**	20,215	1,204	90,077	**2061**
38	**2062**	0.055	3,325	746	292	**4,363**	9,850	788	1,342	3,987	**15,967**	20,330	1,120	91,197	**2062**
39	**2063**	0.051	3,701	703	311	**4,715**	10,199	790	1,431	4,266	**16,686**	21,401	1,090	92,287	**2063**
40	**2064**	0.047	3,468	788	285	**4,541**	10,336	821	1,498	4,458	**17,113**	21,654	1,020	93,306	**2064**
41	**2065**	0.044	3,239	845	260	**4,344**	10,399	880	1,547	4,598	**17,423**	21,767	948	94,254	**2065**
42	**2066**	0.040	3,344	864	260	**4,468**	10,437	933	1,594	4,731	**17,694**	22,163	892	95,147	**2066**
43	**2067**	0.037	3,129	897	236	**4,262**	10,477	937	1,639	4,870	**17,922**	22,184	826	95,973	**2067**
44	**2068**	0.034	2,920	975	214	**4,108**	10,497	898	1,685	5,003	**18,083**	22,192	764	96,736	**2068**
45	**2069**	0.032	3,075	983	219	**4,277**	10,564	925	1,741	5,163	**18,393**	22,670	722	97,458	**2069**
46	**2070**	0.029	2,954	1,036	211	**4,201**	10,648	972	1,812	5,336	**18,768**	22,969	676	98,134	**2070**
47	**2071**	0.027	3,239	1,157	232	**4,629**	10,646	1,004	1,851	5,468	**18,969**	23,598	642	98,776	**2071**
		Total NPV =	**$29,703**	**$2,303**	**$3,560**	**$35,567**	**$54,911**	**$5,292**	**($5,045)**	**$8,052**	**$63,210**	**98,776**			

Net Energy For Load (MWh)	Annual Rate ($/1,000 kWh)
144,793,264	19.60
144,930,841	22.40
145,905,330	26.47
148,561,631	27.36
150,975,822	28.97
153,093,512	31.97
154,375,327	29.97
156,727,881	30.80
158,921,727	33.41
160,472,966	34.05
162,208,990	42.09
164,006,037	42.69
165,642,504	43.64
167,116,700	47.37
168,416,660	50.60
169,482,447	53.62
170,443,232	57.70
169,857,844	60.20
170,506,430	63.50
170,983,626	67.81
171,835,848	69.25
172,692,473	72.12
173,553,524	76.24
174,419,023	78.68
175,288,995	82.19
176,163,463	86.81
177,042,449	86.22
177,925,979	90.37
178,814,075	97.19
179,706,761	98.68
180,604,061	98.42
181,506,000	105.08
182,412,602	105.28
183,323,891	105.75
184,239,891	107.28
185,160,628	107.39
186,086,125	108.63
187,016,408	108.71
187,951,502	113.86
188,891,432	114.64
189,836,223	114.66
190,785,901	116.16
191,740,492	115.70
192,700,019	115.16
193,664,511	117.06
194,633,992	118.01
195,608,489	120.64

	Fixed Costs Component of Annual Rate ($/1,000 kWh)	Variable Costs Component of Annual Rate ($/1,000 kWh)
0.0	1.21	18.39
0.7	3.01	19.40
0.6	4.36	22.11
1.0	6.99	20.37
1.4	9.73	19.24
0.9	12.25	19.72
1.3	15.42	14.56
2.1	17.57	13.23
2.2	20.44	12.97
2.6	22.07	11.98
0.1	28.79	13.30
0.2	27.35	15.34
0.3	26.17	17.47
0.2	26.73	20.65
1.4	26.62	23.98
0.6	25.81	27.81
1.5	26.10	31.60
0.4	25.31	34.89
0.3	24.54	38.96
1.5	25.03	42.78
0.2	24.01	45.24
0.1	23.01	49.12
1.7	23.68	52.56
0.5	22.52	56.15
0.5	21.92	60.27
1.4	22.50	64.30
0.3	21.47	64.75
1.4	23.02	67.35
0.4	23.81	73.39
1.0	23.80	74.88
0.9	22.74	75.68
1.0	24.97	80.11
0.9	24.23	81.05
0.7	23.48	82.27
0.6	24.61	82.67
1.0	23.42	83.97
0.8	24.10	84.53
0.6	23.33	85.38
0.5	25.09	88.78
1.3	24.04	90.60
1.3	22.88	91.78
0.6	23.42	92.75
1.7	22.23	93.47
1.3	21.32	93.84
1.5	22.08	94.97
0.8	21.58	96.43
0.9	23.67	96.97

Differential - Staff minus Base

	Generation Capital Costs (Millions)	Fixed O&M & Capital Replacement Costs (Millions)	Transmission Interconnection Costs (Millions)	Total Fixed Costs (Millions)	System Net Fuel (Millions)	Startup Costs (Millions)	VOM Costs (Millions)	Emission Costs (Millions)	Total Variable Costs (Millions)	Total Annual Costs (Millions)	Annual Rate Differential ($/1,000 kWh)
2025	0	0	0	**0**	0	0	0	0	**0**	0	**$0.00**
2026	90	5	3	**83**	6	(0)	10	0	**15**	98	**$0.67**
2027	114	16	5	**-135**	6	43	4	0	**53**	82	**($0.56)**
2028	169	16	8	**-177**	(26)	102	(41)	0	**35**	142	**($0.95)**
2029	185	13	23	**-175**	(59)	130	(101)	0	**-30**	205	**($1.36)**
2030	253	30	26	**-257**	334	181	(114)	0	**401**	144	**$0.94**
2031	229	24	25	**-228**	(32)	168	(116)	0	**21**	208	**($1.35)**
2032	333	17	24	**-326**	(29)	150	(124)	0	**-3**	330	**($2.10)**
2033	264	30	24	**-269**	(49)	114	(143)	0	**-78**	348	**($2.19)**
2034	408	3	27	**-384**	(7)	110	(137)	0	**-34**	-418	**($2.60)**
2035	123	6	29	**146**	(55)	51	(153)	0	**-157**	11	**($0.07)**
2036	114	30	28	**112**	(62)	71	(157)	(2)	**-150**	38	**($0.23)**
2037	109	14	27	**121**	(68)	59	(159)	(4)	**-173**	51	**($0.31)**
2038	121	5	26	**151**	(81)	44	(69)	(8)	**-114**	37	**$0.22**
2039	265	14	36	**287**	(95)	65	(16)	(12)	**-58**	229	**$1.36**
2040	113	0	23	**136**	(95)	88	(13)	(14)	**-34**	102	**$0.60**
2041	269	13	34	**316**	(100)	71	(13)	(16)	**-59**	257	**$1.51**
2042	109	5	20	**124**	(115)	85	(13)	(21)	**-63**	61	**$0.36**
2043	110	3	19	**132**	(113)	58	(9)	(23)	**-87**	45	**$0.26**
2044	280	34	32	**345**	(121)	71	(12)	(27)	**-88**	257	**$1.50**
2045	102	2	17	**118**	(127)	77	(8)	(31)	**-89**	29	**$0.17**
2046	124	19	17	**122**	(137)	78	(9)	(34)	**-102**	20	**$0.12**
2047	390	6	31	**428**	(144)	62	(10)	(38)	**-130**	298	**$1.71**
2048	227	13	16	**230**	(157)	66	(8)	(44)	**-142**	88	**$0.51**
2049	234	1	16	**251**	(178)	76	(14)	(53)	**-169**	82	**$0.47**
2050	433	8	30	**471**	(221)	77	(20)	(68)	**-232**	239	**$1.35**
2051	216	3	14	**233**	(173)	59	(6)	(55)	**-175**	58	**$0.33**
2052	410	14	29	**425**	(169)	51	(9)	(55)	**-181**	243	**$1.37**
2053	156	38	11	**204**	(156)	81	(6)	(52)	**-133**	71	**$0.40**
2054	313	5	26	**345**	(171)	66	(7)	(59)	**-171**	174	**$0.97**
2055	33	5	7	**46**	(180)	46	(9)	(63)	**-206**	160	**($0.89)**
2056	28	8	6	**42**	(183)	39	(9)	(65)	**-218**	176	**($0.97)**
2057	25	16	6	**15**	(164)	39	(3)	(60)	**-187**	172	**($0.94)**
2058	23	7	6	**36**	(149)	42	4	(56)	**-159**	123	**($0.67)**
2059	21	41	5	**67**	(168)	60	(2)	(64)	**-174**	107	**($0.58)**
2060	19	22	5	**1**	(167)	43	1	(66)	**-189**	188	**($1.01)**
2061	296	3	26	**324**	(166)	52	(4)	(67)	**-185**	140	**$0.75**
2062	1	65	3	**68**	(161)	51	0	(66)	**-175**	107	**($0.57)**
2063	264	20	21	**265**	(154)	44	4	(66)	**-172**	93	**$0.49**
2064	74	55	6	**-25**	(178)	43	(1)	(77)	**-213**	238	**($1.26)**
2065	81	11	6	**-76**	(159)	59	2	(71)	**-170**	246	**($1.30)**
2066	245	26	19	**290**	(165)	68	(0)	(75)	**-173**	117	**$0.61**
2067	93	4	7	**-104**	(185)	59	(10)	(86)	**-221**	325	**($1.70)**
2068	93	23	7	**-77**	(160)	67	1	(77)	**-169**	245	**($1.27)**
2069	90	18	7	**-79**	(175)	48	(0)	(86)	**-213**	292	**($1.51)**
2070	88	1	7	**-96**	(115)	90	18	(57)	**-64**	160	**($0.82)**
2071	290	34	22	**346**	(168)	84	(6)	(87)	**-177**	169	**$0.86**

Florida Power & Light Company
Docket No. 20250011-EI
Staff's Third Set of Interrogatories
Interrogatory No. 44 Supplemental
Attachment No. 1 of 1
Tab 5 of 5

Comparison of the Resource Plans: Comparison of Bill Impacts (assuming 1,000 kWh Usage)

1) Projection of Incremental Customer Bill Impacts:

	Without Proposed 2026 and 2027 Solar And Battery Additions			**FPL Resource Plan with Rate Case Additions**			**FPL Resource Plan - No Additions to Meet LOLP**		
Year	Projected Incremental Fixed Cost Rate Impact ($/1,000 kWh)	Projected Total Variable Cost Rate Impact ($/1,000 kWh)	Projected Incremental Customer Bill Impact ($/1,000 kWh)	Projected Incremental Fixed Cost Rate Impact ($/1,000 kWh)	Projected Total Variable Cost Rate Impact ($/1,000 kWh)	Projected Incremental Customer Bill Impact ($/1,000 kWh)	Projected Incremental Fixed Cost Rate Impact ($/1,000 kWh)	Projected Total Variable Cost Rate Impact ($/1,000 kWh)	Projected Incremental Customer Bill Impact ($/1,000 kWh)
2025	1.208	18.389	$19.60	1.208	18.389	$19.60	1.208	18.389	$19.60
2026	1.875	20.189	$22.06	2.435	19.294	$21.73	3.007	19.395	$22.40
2027	1.730	24.167	$25.90	5.287	21.748	$27.04	4.362	22.113	$26.47
2028	2.138	24.672	$26.81	8.177	20.134	$28.31	6.988	20.369	$27.36
2029	2.672	26.533	$29.21	10.888	19.438	$30.33	9.731	19.237	$28.97
2030	2.993	28.214	$31.21	13.931	17.099	$31.03	12.250	19.720	$31.97
2031	3.443	27.436	$30.88	16.895	14.425	$31.32	15.415	14.560	$29.97
2032	3.987	29.201	$33.19	19.652	13.246	$32.90	17.569	13.226	$30.80
2033	4.315	32.778	$37.09	22.134	13.460	$35.59	20.440	12.966	$33.41
2034	4.752	35.221	$39.97	24.463	12.188	$36.65	22.068	11.978	$34.05

2) Projection of Incremental Customer Bill Differentials:

	Bill Differentials From Without Proposed 2026 and 2027 Solar And Battery Additions	
Year	**FPL Resource Plan with Rate Case Additions**	**FPL Resource Plan - No Additions to Meet LOLP**
2025	$0.00	$0.00
2026	($0.33)	$0.34
2027	$1.14	$0.58
2028	$1.50	$0.55
2029	$1.12	($0.24)
2030	($0.18)	$0.76
2031	$0.44	($0.90)
2032	($0.29)	($2.39)
2033	($1.50)	($3.69)
2034	($3.32)	($5.93)

Bill Differential - Rate Case Additions Vs. No Additions to Meet LOLP
$0.00
$0.67
($0.56)
($0.95)
($1.36)
$0.94
($1.35)
($2.10)
($2.19)
($2.60)

DECLARATION

I, Andrew Whitley, sponsor the corrected supplemental answer to **Interrogatory No. 44** from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 20250011, and the response is true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration, and the interrogatory answer identified above, and that the facts stated therein are true.

____
Andrew Whitley

Date: 05/08/2025

Florida Power & Light Company
Docket No. 20250011-EI
FEL's Fourth Request for Production
Request No. 54
Page 1 of 1

QUESTION:
Please refer to confidential document with bates stamp FPL 034918 (produced in response to FEL production of documents request number 24), with referenced attachments at the bottom of the page. Please provide the referenced attachments.

RESPONSE:
Please see confidential responsive documents provided.

The documents responsive to FEL's Fourth Request for Production of Documents No. 54, Bates Nos. 040739-040804, are confidential in their entirety.

Energy+Environmental Economics
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Solar Integration Study and Resource Planning Review Phase 2

E3 Proposal for FPL

February 7, 2025

Summary

Over the past several months, Energy and Environmental Economics (E3) has provided Florida Power and Light Company (FPL) modeling and advisory services related to integrated resource planning (IRP) (Track 1), operations (Tracks 2-4), and resource adequacy (Track 5) related primarily to higher expected penetrations of solar and battery resources. This document outlines potential additional work scopes that E3 and FPL have identified to provide additional value to FPL.

1. Track 6: Rate Case Filing Testimony Support

E3's initial scope did not anticipate support of FPL's rate case filing. However, E3 has accelerated model development and conducted additional model runs that were only needed to support FPL's rate case filing. In addition, FPL has E3 to provide data to support the filing, to review FPL testimony, and to advise on case strategy.

TASK 1. CONDUCT PLEXOS AND RECAP MODEL RUNS TO PROVIDE DATA FOR POTENTIAL INCLUSION IN FPL'S RATE CASE FILING

+ Conduct additional PLEXOS and RECAP model runs at different levels of modeling granularity and for additional quantities of solar and batteries.

+ Summarize outputs in tabular and graphical format for inclusion in rate case filing.

+ Prepare work papers.

TASK 2. REVIEW FPL RATE CASE TESTIMONY AND ADVISE FPL ON REGULATORY STRATEGY

+ Review FPL testimony, provide proposed redline edits, and discuss case strategy with FPL regulatory team.

TASK 3. PARTICIPATE IN FPL RATE CASE FILING

+ Prepare responses to intervenor data requests.
+ Review intervenor testimony and prepare questions for cross-examination.
+ Prepare rebuttal testimony.
+ Prepare for and participate in oral cross-examination.
+ Review draft opening and final briefs and provide comments.

2. Track 7: Additional Planning and Operational Studies

E3 recommends additional planning and operational studies to evaluate the impact of significant additional quantities of solar expected to be added to the FPL system – a cumulative quantity of 21 GW by 2035, up from 9 GW in the 2027 test year. E3 recommends developing a future test year, e.g., 2035 and conducting resource adequacy and operational reliability studies similar to those already conducted for the 2027 test year. A side-by-side comparison of 2027 and 2035 will provide valuable information to FPL about how the primary planning and operational challenges will evolve over time.

TASK 4. DEVELOP 2035 RECAP CASE

+ Update load shapes to reflect any changes expected by 2035 (e.g., more electric vehicles, data center loads).
+ Calculate PCAP PRM and determine total resource need.
+ Develop load & resource tables to compare to FPL's 20% ICAP PRM tables.

- Calculate marginal ELCC values for additional solar and battery quantities beyond the 2035 penetrations.
- Calculate marginal ELCC surface reflecting interactive effects for use in capacity expansion modeling.
- Pull graphics of most extreme weather events to build intuition about system performance and how each resource contributes to keeping the lights on.
- Evaluate both summer and wintertime events to develop a complete picture of reliability events with significant amounts of solar with high summertime production.

TASK 5. DEVELOP 2035 RESERVE CASE

- Recalculate operating reserve quantities given much higher solar penetrations.
- Use of RESERVE model is recommended to capture non-linearities in reserve needs (e.g., random errors scale with the square root of the sum of squares rather than linearly).
- Attend and present at FRCC meeting as appropriate.

TASK 6. DEVELOP MULTI-STAGE 2035 PLEXOS CASE

- Use RECAP and RESERVE studies to ensure the 2035 PLEXOS case has sufficient effective capacity and operating reserves to serve all load reliably.
- Develop a 2-stage PLEXOS model where the first, day-ahead stage commits generators based on load and solar forecasts, maintaining headroom and footroom needed to cover load and renewable generation variability and forecast errors as well as contingency reserves. The second stage would represent real-time operations and would enforce the commitment schedule from the first stage for units that cannot be committed in real-time (i.e. CCGT steam turbines). The second stage would use real-time load and solar generation profiles and would hold regulation and/or fast frequency response reserves to manage variations of load and solar within the real-time dispatch interval. E3 will work with the FPL to develop day-ahead commitment strategies and to determine an appropriate granularity for the second stage, i.e., hourly, 15-minute or 5-minute.

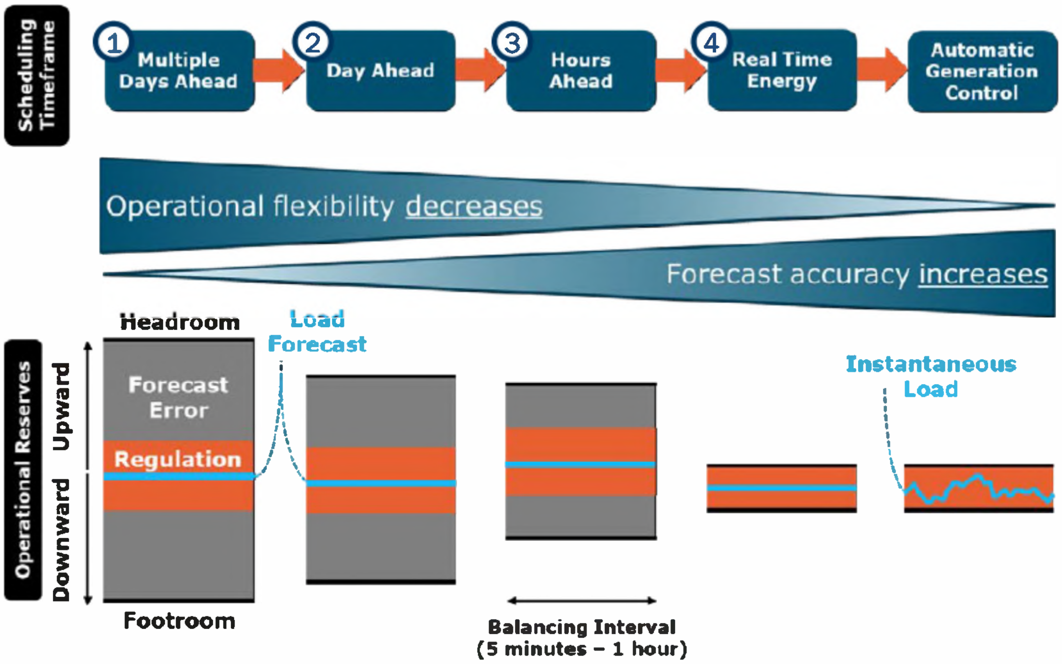

Figure 1 Illustration of multi-stage models

+ Calculate production costs under alternative reserve coverage thresholds to evaluate cost/reliability tradeoffs.

+ Calculate "flexibility value" for batteries and flexible thermal generation and "flexibility penalty" for solar (aka "integration costs").

+ Develop a Flexible Solar case and calculate the incremental value of allowing solar to provide upward and downward operating reserves.

+ Pull graphics of representative operating days to build intuition about the most challenging operating conditions.

    - Springtime high solar day
    - Summertime high load day
    - Summertime variable cloud cover day
    - Autumn high maintenance outage day
    - Wintertime needle peak cold day

+ Develop tables and graphics to show utilization of energy storage resources.
  - Charging times and which resources are on the margin
  - Discharge times and which resources are on the margin to evaluate cost savings
  - Provision of ancillary services on average throughout the year, by season, and on specific representative days
+ Develop metrics about storage state of charge on average throughout the year and on representative days.
+ Prepare additional operational outputs including:
  - **Reserve shortfall events:** The number of intervals in the test year in which FPL is unable to supply the needed reserve quantities while meeting all energy load. Reserve shortfalls will be counted separately in the upward and downward direction.
  - **Solar curtailment:** Solar curtailment will likely be necessary due to inflexibility; increasing flexibility will reduce solar curtailment and increase fuel savings.
  - **Effective solar LCOE:** Each solar portfolio (Main and Alternatives) will have differing amounts of solar curtailment and capital costs. E3 will calculate the LCOE of each solar portfolio based on solar actually delivered to the system to enable a cost-comparison of each portfolio.
  - **Thermal starts:** number of starts for each resource in the thermal fleet.
  - **Thermal ramps:** number of hours for each resource where it ramps at its maximum rate.
  - **Hours at Pmin:** number of hours for each resource where its generation is at its minimum stable level.
  - **Ancillary Service Shadow Prices:** the ancillary service shadow prices during each hour should provide interesting information about the extent to which additions of solar generation are making it more difficult to meet the system's reserve requirements.
+ Pull additional simulation data as needed to inform operational strategies.

3. Track 8: Resource Planning Model Development and Capability Building

- Work with FPL to develop strategy and process flow for a strategic integrated system plan to inform FPL's 10-year Site Plan.
- Develop process to incorporate transmission constraints and upgrade opportunities into resource planning workflow.
- Discuss with FPL whether and how to incorporate distribution and customer program planning into ISP process.
- Develop PLEXOS LT model for optimal capacity expansion.
- Link PLEXOS LT and ST models and train FPL staff to operate the models.
- Work side by side with FPL staff during first run-through of new strategic ISP process.
- Work with FPL to develop a formalized evaluation process for internal and external resource options.

4. Budget and Timeline

E3 proposes to complete the tasks described above on a time-and-materials basis subject to a not-to-exceed budget ceiling as indicated. Any additional out-of-pocket expenses such as travel costs would be passed through at cost with no markup.

Task	Timeline	Budget
Track 6: Rate Case Filing Testimony Support – March Filing	3/1/2025	[redacted]
Ongoing Rate Case Filing Testimony Support	12/31/2025	
Track 7: Additional Planning and Operational Studies	6/30/2025	
RESERVE updates	*4/30/2025*	
RECAP updates	*5/31/2025*	
PLEXOS updates	*6/30/2025*	
Track 8: Resource Planning Model Development and Capability Building	12/31/2025	
Model licenses		
Total Budget (USD)		[redacted]

Potential Future Tasks

5. Develop Pilot RESERVE Tool for FPL Control Center

TASK 7. DEVELOP RESERVE TOOL SUITABLE FOR USE IN REAL-TIME OPERATIONS

- Start with planning-level RESERVE tool described above and configure a tool for use by FPL system operators.
- The tool would calculate the quantity of upward and downward operational reserves needed to meet a designated threshold of net load over- and under-forecasts, e.g., 97.5% of under-forecasts and 97.5% of over-forecasts (95% coverage in combination) over a given timesteps.
- Timesteps would be developed through consultation with FPL and could include:
  - 24 hourly timesteps, calculated at the day-ahead preschedule time period.
  - 5 hourly timesteps, calculated each hour for the next five hours on a rolling basis.
  - 24 five-minute timesteps, calculated each five minutes on a rolling basis.

TASK 8. TRANSFER RESERVE MODEL TO FPL AND MONITOR REAL-TIME TESTING

- E3 would craft a functional and convenient interface in Excel or other easily accessible applications. The interface would include fields to fill in all necessary short-term performance information and near-term forecast. It would serve as a bridge between the client and the underlying Python script.
- Along with the interface, E3 will deliver a pre-trained RESERVE model as its back-end. The model would be tuned based on mutual discussion with FPL on project completion. The model and its pre-tuned parameters would arrive in a prepackaged format based on TensorFlow. The underlying RESERVE source code will also be provided to allow FPL to further customize and raise in-house capability in reserve determination.
- Three intensive user training sessions focusing on understanding the trained reserve model, and to a lesser extent the training of a new reserve model with new data. E3 would also hold practice sessions for operations room staff members, focused on the hands-on application of the reserve interface.

+ FPL staff would use the tool on a trial basis for 12 months. E3 would monitor the trial, communicating regularly with FPL operating staff and making real-time updates as needed to ensure that the tool is maximally useful.

+ E3 would work with FPL staff to develop data to quantify the tool's impact on FPL operations.

+ E3 will work with FPL to review the performance of the RESERVE Model over the course of the deployment period.

TASK 9. QUARTERLY RETRAIN OF RESERVE MODEL

+ E3 will perform four quarterly re-trainings of the FPL RESERVE model. The re-training aims to capture any emerging patterns as FPL expands its renewable generation portfolio.

+ E3 will also provide technical support for any questions that come up regarding RESERVE's deployment.

+ To ensure a relatively smooth retraining experience, E3 suggests the first few re-trainings to happen off-site, with FPL providing updated performance data for load and renewable forecast.

6. Review FPL's Maintenance Outage Scheduling Practices and Provide Recommendations for Improvements

TASK 10. REVIEW FPL'S CURRENT PRACTICES FOR MAINTENANCE SCHEDULING.

+ E3 will work with FPL to understand its current practices regarding scheduling of maintenance outages on thermal generators.
  - What is FPL's current approach?
  - What data is currently considered, and what additional data is available on a 3-week ahead time period that might be relevant to the determination of acceptable maintenance practices?
  - What challenges is FPL facing related to maintenance scheduling?
  - Does FPL consider the impact to operational reserve sufficiency in determining maintenance schedules?
  - How does higher solar penetration affect FPL's maintenance scheduling?
  - How does solar forecast uncertainty and solar variability factor into maintenance scheduling?
  - How do FPL's practices compare to jurisdictions with higher solar penetration such as Hawaii, CAISO, AEMO?
+ Develop recommendations for improvements to FPL's procedures to ensure that all relevant data is considered in determining maintenance schedules.

Florida Power & Light Company
Docket No. 20250011-EI
OPC's First Request for Production
Request No. 30
Page 1 of 1

QUESTION:
Board Minutes. Please provide a copy of all FPL and NextEra Energy("NEE") Board of Directors Meeting minutes and board committee minutes and presentations to the FPL and NEE boards in 2022, 2023, 2024 and 2025 to date.

RESPONSE:
The attachments to FPL's response to OPC's First Request for Production of Documents, No. 30 are designated as Highly Sensitive Information, as that term is used in the Confidentiality Agreement in use in this proceeding. These attachments will be made available for inspection at the offices of Shutts & Bowen LLP, located at 215 South Monroe Street, Suite 804, Tallahassee, Florida 32301, provided the reviewing party has executed the Confidentiality Agreement and remains in compliance with the requirements of the Confidentiality Agreement associated with the review of Highly Sensitive Information.

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Florida Power & Light Company
Docket No. 20250011-EI
OPC's First Request for Production
Request No. 43
Page 1 of 1

QUESTION:
Plant. Please provide all documents identified in response to OPC's First Set of Interrogatories, No. 48.

RESPONSE:
Please see the confidential and non-confidential responsive documents provided.

Certain documents responsive to OPC's First Request for Production, No. 43 are designated as Highly Sensitive as that term is used in the Confidentiality Agreements in use in this proceeding. The Highly Sensitive responsive documents will be made available for inspection at the offices of Shutts & Bowen LLP, located at 215 South Monroe Street, Suite 804, Tallahassee, Florida 32301, provided the reviewing party has executed the Confidentiality Agreement and remains in compliance with the requirements of the Confidentiality Agreement associated with the review of Highly Sensitive Information.

Additionally, please see the workpapers of FPL witness Oliver provided in FPL's response to OPC's First Request for Production of Documents, No. 15 and FPL's EV Annual Report provided at the following link:

https://www.floridapsc.com/pscfiles/library/filings/2025/00576-2025/00576-2025.pdf

Please also see FPL's Petition for approval of solar base rate adjustment effective January 31, 2025 at the following link:

https://www.floridapsc.com/pscfiles/library/filings/2024/01600-2024/01600-2024.pdf

The documents responsive to OPC's First Request for Production of Documents No. 43, Bates Nos. 031954-032029, 032191-032268, and 032306-032530, are confidential in their entirety.

Northwest Florida Battery Storage Executive Summary

FPL is seeking the approval of the Board of Directors to develop, construct and operate seven energy storage sites in Northwest Florida (NWFL) collectively known as NWFL Battery Storage. The project consists of ~520 MW of 3-hour batteries located at operating FPL solar plants with an expected commercial operations date (COD) of December 1,
1 2025. The total capital expenditure is expected to be [redacted]

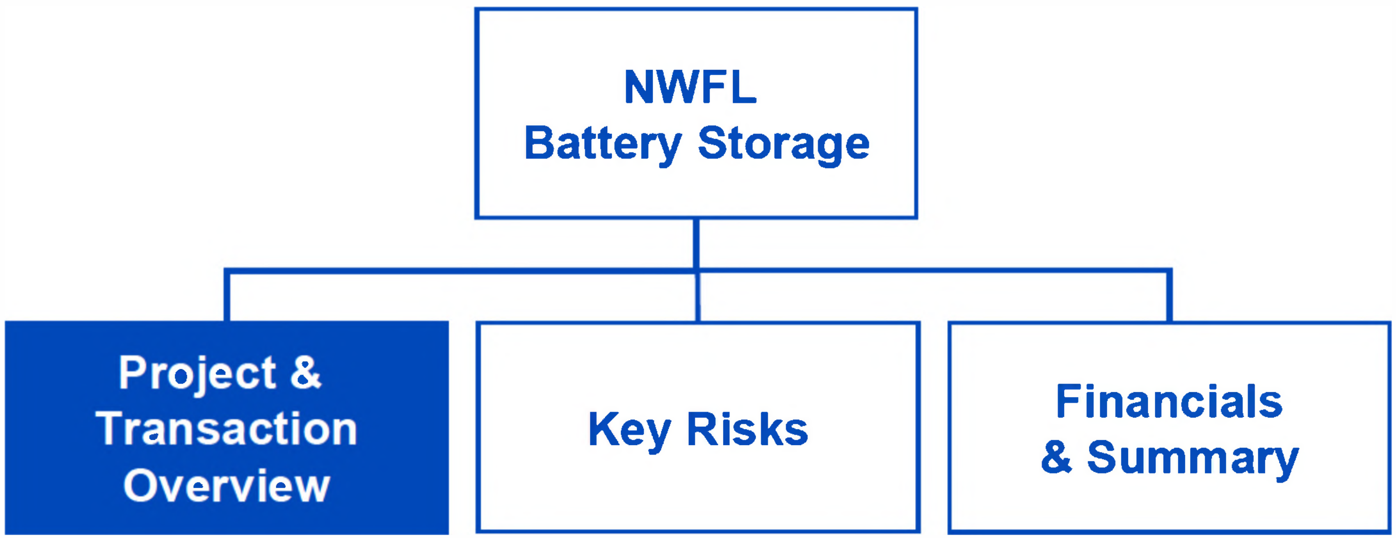
The sites are in Calhoun, Okaloosa and Santa Rosa counties in Florida. 100% of the land required was previously secured for existing solar plants. All pre-construction permitting is expected to be completed by August 2024. The new batteries will interconnect into the FPL transmission system via existing solar substations.

Under normal winter (P50 load) conditions there are sufficient reserves in NWFL but, factoring in potential forced outages or peak winter load, shortfalls may occur starting in 2025.

The proposed project addresses the NWFL reliability need and provides additional firm capacity to the FPL system. The FPL Ten-Year Site Plan (TYSP) shows 520 MW of battery storage placed in service beginning in December 2025.

A key risk for the project is potential permitting delays, interconnection studies and long lead material deliveries that would result in FPL securing PPAs to ensure winter reserve margin adequacy in lieu of the NWFL Battery Storage Project.

FPL requests Board of Directors approval to develop, construct and operate NWFL Battery Storage



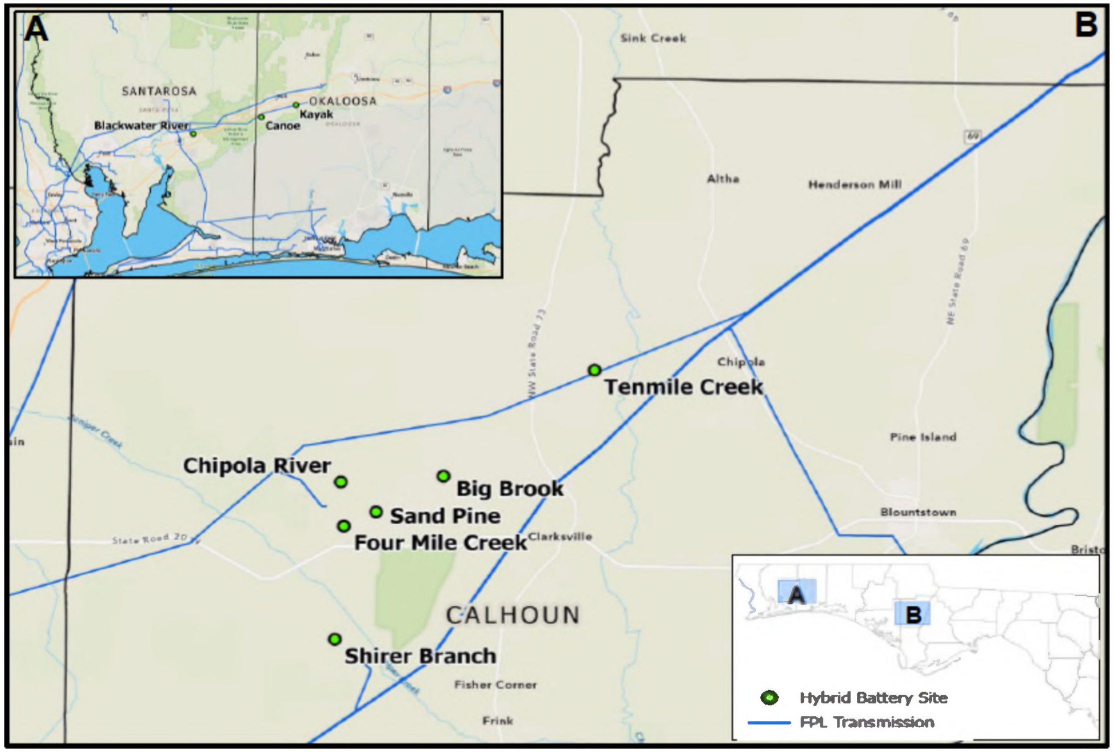
Additional winter capacity is required in NWFL area starting in 2024 due to growth in the area and potential for severe winter temperatures

FPL NWFL Winter Reserves

- **Power flow studies show limited transfer capability on the North Florida Resiliency Connection (NFRC) transmission line during high-load winter conditions**
  - Constraint alleviated when Duke Energy Florida (DEF) completes upgrades on affected lines, currently expected by January 2027
- **Under winter conditions similar to those experienced in December 2022, NWFL would be deficient in reserves from December 2024 through February 2025**
  - Winter reserve shortfall in NWFL is not based on projections of extreme winter peak loads, but rather the actual NWFL peak load experienced in December 2022 (i.e., 2,892 MW)
  - Assumes all NWFL resources are operating at full capacity
- **Recommendation is to add battery storage in December 2025 and add Power Purchase Agreements (PPAs) to meet interim needs in 2024/2025**
  - In interim, prudent PPA expenditures are recovered through Capacity Clause (capacity and transmission) and Fuel Clause (energy)

NWFL Battery Storage is located across three counties in the Florida Panhandle – Calhoun, Santa Rosa and Okaloosa

Proposed Battery Locations(1)



1) FPL is pursuing permits on nine potential sites shown on map to mitigate permitting risk but will construct seven under this project

Battery Storage will enhance reliability in NWFL and mitigate capacity shortfall under severe winter conditions

Project Overview

- **NWFL Battery Storage consists of seven 74.5 MW, 3-hour duration battery storage sites added onto existing solar sites in Northwest Florida**
- **Sites selected by considering:**
  - Sites with sufficient remaining space to accommodate battery storage
  - Existing solar substations with surplus interconnection capacity to mitigate interconnection queue study risk and transformer lead times
- **Expected COD: December 1, 2025**
- **Project qualifies for 30% ITC, but no ITC kickers**

1 • [redacted]
2
  - GE Flex 1571 inverters will be contracted by end of June 2024
  - Bidding for EPC contractor occurring in summer 2024

3 • **Total capital cost** [redacted]

A B C

1 **Battery procurement is long-lead schedule item and NEE has secured sufficient capacity from** [redacted]

Procurement Opportunity Summary

2 - **1.7 GWh of batteries contracted at** [redacted]
  - Batteries priced at current cost curve
3 - [redacted]
- **Battery storage system includes all major components (cells, modules, rack assembly, control panel, management system)**
4 - All components manufactured in [redacted]
- **Equipment delivery to project sites aligned with Engineering and Construction timeline**
  - Batteries will arrive in U.S. several months in advance and stored off-site prior to final delivery to project sites
- **Aligned with FPL's strategy to diversify battery storage supply chain by moving away from Chinese suppliers**

This battery procurement supports proposed 2025 NWFL Battery project and materials can be reallocated to other locations if necessary

FPL requests Board of Directors approval to develop, construct and operate NWFL Battery Storage

NWFL Battery Storage

- Project & Transaction Overview
- **Key Risks**
- Financials & Summary

Delays in permitting or material could postpone COD and necessitate third party PPA(s) to provide appropriate reserve margin

Key Risks: Potential Schedule Delays

- **Sites have not yet secured certain permits without which construction cannot proceed**
  - County permitting requires modifications to existing solar permits
  - Florida Department of Environmental Protection (FDEP) environmental and stormwater permit modifications in progress with half the sites approved as of May 1, 2024
- **Surplus interconnection studies are pending and will be conducted in summer 2024**
- **Procurement lead times for major material, including battery modules and inverters, are limited**
- **Bidding process for construction effort is pending and will occur during summer of 2024**

Missed COD for NWFL Battery Storage would require FPL to extend third party PPA(s) to provide required winter reserve margin capacity

FPL is engaged with local and state officials to expedite permitting, and has a process to accelerate construction and commissioning schedules if needed

A B

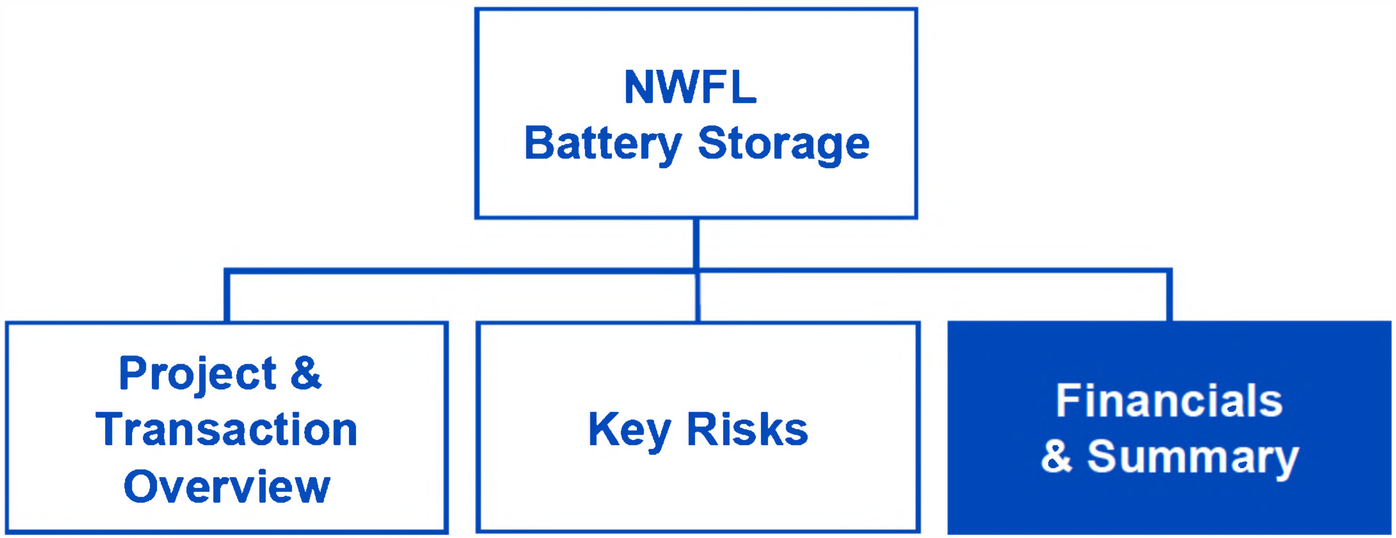
Mitigants: Potential Schedule Delays

- **Teams are working with relevant authorities to obtain outstanding permits in timely manner**
  - Florida Department of Environmental Protection expeditiously reviewing permit modifications; county permits on-track for August 2024 approval
- **Early coordination with Power Delivery team on surplus interconnection indicates that negative impacts are unlikely**
  - To be confirmed in July-August via formal request and study process

1 - **[redacted] batteries were secured in January 2024 and ISC is closely coordinating with supplier on delivery timeline**
  - Inverters will be contracted by June 2024 to meet construction schedule
  - Evaluating storage locations to support early deliveries to further mitigate schedule risk
- **If the development / procurement process delays start of construction beyond October 2024, EPC acceleration payments can recover commissioning schedule**

2 - 6-week mobilization delay would require [redacted] in acceleration payments to recover sched[redacted]

FPL requests Board of Directors approval to develop, construct and operate NWFL Battery Storage



A B C

1 [redacted]

NWFL Battery Storage – Preliminary Cost Estimate

	Category	Cost ($ MM)	$/kWh
2	Battery Materials	[redacted]	
3	Balance of Plant		
4	Development		
5	Land & Easements		
6	Transmission		
7	AFUDC		
8	Total		

Criteria	Design Assumption
COD	12/1/2025
Year-1 MWh	1,564.5
Cycles / Year	20

- **Major material pricing has been locked in**
  - 9 – [redacted] battery order placed in April 2024
  - 10 – [redacted] nverters to be secured in June 2024
- **Project is eligible to earn AFUDC, similar to grouping of FPL solar sites**

1) Assumes $0.5 MM for each separate site; development leverages existing site work and studies

NWFL Battery Storage allows FPL to meet potential winter reserve margin shortfall without third party PPAs, while enhancing system reliability

Investment Rationale

- **NWFL Battery Storage is the lowest cost option to meet system needs during severe winter weather event in NWFL**
  - Third party PPAs would be more costly
  - NWFL Battery Storage provides additional reserve margin and system reliability benefits (i.e., voltage support, avoided solar curtailment, etc.)
- **NWFL Battery Storage leverages existing FPL solar assets in the region and minimizes schedule risk for late 2025 COD**
  - Connecting to operating solar sites substations with available capacity
  - Majority of sites in economically disadvantaged counties that will benefit from increased tax base
- **Timely battery procurement allows FPL to benefit from favorable market pricing**
  - Additional value in diversification of supply chain

Approval Request

- **FPL requests Board of Directors approval to complete the development, construction and operation of NWFL Battery Storage**

FPL – Resource Adequacy Study

Final Data Checks

Jan 13, 2025

Adrian Au, Associate Director
Ritvik Jain, Senior Consultant
Les Armstrong, Associate
Arne Olson, Senior Partner

Energy+Environmental Economics

Agenda

RA Check-In (1/16)

1. **Portfolio Nameplate Capacity**
    1. BTM Solar Forecast
2. **Load Variability**
    1. Evening fall off
3. **Solar Benchmarking**
    1. Month-hour
    2. bubble
4. **Thermal Benchmarking**
    1. Partial Outages

Game Plan

Sun	Mon	Tue	Wed	Thu	Fri	Sat
	27 *Today*	28 *Check In* *Continue Data Updates*	29	30 *Check In* *Finish all Data Updates*	31	1
2	3 *E3 sends draft results*	4 *Check In* *FPL provide feedback*	5	6 *Check In* *FPL provide feedback*	7	8
9	10 *E3 sends draft results*	11 *Check In* *FPL provide feedback*	12	13 *Check In* Finalize Results for Testimony	14	15

Action items

+ **FPL to Send Tuesday Times to Margo to set up with team**

Deliverables: Three (3) L&R Tables for 2027-2029 + One (1) L&R with existing L&R accounting method

LOLP-Derived Methodology

		2027		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + KF1/2	28,150	25,316	88%
2	Utility Solar	8,946	1,728	19%
3	Storage	***2,391***	1,246	52%
4	Demand Response (DR)	1,883	982	52%
5	Portfolio Effect/Peak to Net Load Shift		1,811	
6	**Portfolio ELCC** *(E3 Methodology)*	41,370	31,083	
7	Median Peak Demand	28,925		
8	Median Peak Demand less DR	Not used		
9	PCAP Planning Reserve Margin (PRM)	8.8%		
10	Total Firm MW Requirement	31,457		
11	Firm Capacity Surplus / Shortfall	*-374*		

- All resources are accredited using a Last-in ELCC methodology
- Demand response is dispatched by the LOLP model
- 8.8% represents the reserve margin needed to achieve a 0.1 LOLE target, if all resources were perfectly available
- Shortfall is directly calculated through LOLP model

Final Data Updates / Benchmarking / Checks + Coordination

Data	FPL Contact	E3 Contact	Status	Improve Reliability?
Add BTM Solar Capacity Forecast	Andy W. / Mike Cashman	Adrian / Ritvik	**Action needed:** Need FPL's Forecast	Yes
Add the Peak Impacts to Peak Load Forecast	Andy W	Adrian / Ritvik	**Action Needed:** Need E3's update	N/A
Benchmark Utility / BTM Solar Profile	N/A	Adrian / Ritvik	FPL to sign off after this meeting	N/A
Check Load Variability	Mike C. / Rafael	Adrian	FPL to sign off after this meeting	N/A
Check Thermal Operating Characteristics	Bernardo	Adrian / Les	FPL to sign off after this meeting	N/A
Check Thermal Nameplate Capacity	Andy W	Adrian / Les	FPL to sign off after this meeting	N/A

Portfolio Nameplate Checks

Nameplate Double Check

- **Thermal To dos:**
  - Change Retirement of GCEC 4 (CRIST4) from 2024 > 2029 end of year
  - Figure out gap where 28,067 MW vs 28,010 MW in 2027
  - Question: Do we want to adjust hot summer vs cold winter?
    - Hot summer – April-Oct
    - Cold Winter – Nov – Mar
- **Solar to do – None**
- **Storage to do – None**
- **DR to do**
  - Refine seasonal availability (currently only using summer availability)

2027-2029 Nameplate Capacity Summer (Without MT1+2)

Resource Type	2027	2028	2029	Notes / Source
Thermal (Summer)	28,011 MW	27,971 MW	27,701 MW	Unit Generator Inputs AURORA.xlsx Nameplate used for L&R table. Output depends on season
Solar	8,946 MW	10,138 MW	11,628 MW	2020-2029 Solar Sites.xlsx
Storage	2,391 MW	3,491 MW	4,391 MW	Unit Generator Inputs AURORA.xlsx
Demand Response	1,951 MW	1,945 MW	1,943 MW	DSM 2025-2039 MW by Month - RB Edits.xlsx

Andy, please check to see if these numbers match yours in your testimony

2027-2029 Nameplate Capacity Winter (With MT1+2)

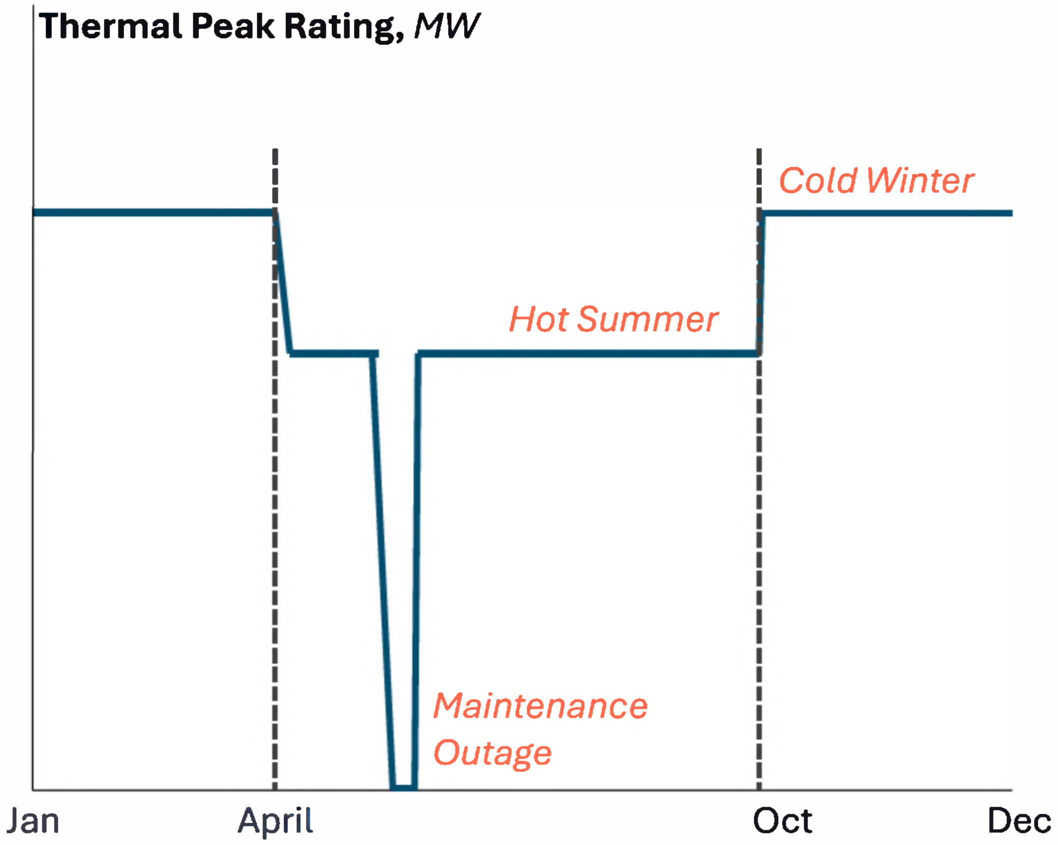
Resource Type	2027	2028	2029	Notes / Source
Thermal (Winter)	29,601 MW	29,561 MW	27,756 MW	Unit Generator Inputs AURORA.xlsx Nameplate used for L&R table. Output depends on season
Solar	8,946 MW	10,138 MW	11,628 MW	2020-2029 Solar Sites.xlsx
Storage	2,391 MW	3,491 MW	4,391 MW	Unit Generator Inputs AURORA.xlsx
Demand Response	1,951 MW	1,945 MW	1,943 MW	DSM 2025-2039 MW by Month - RB Edits.xlsx

Andy, please check to see if these numbers match yours in your testimony

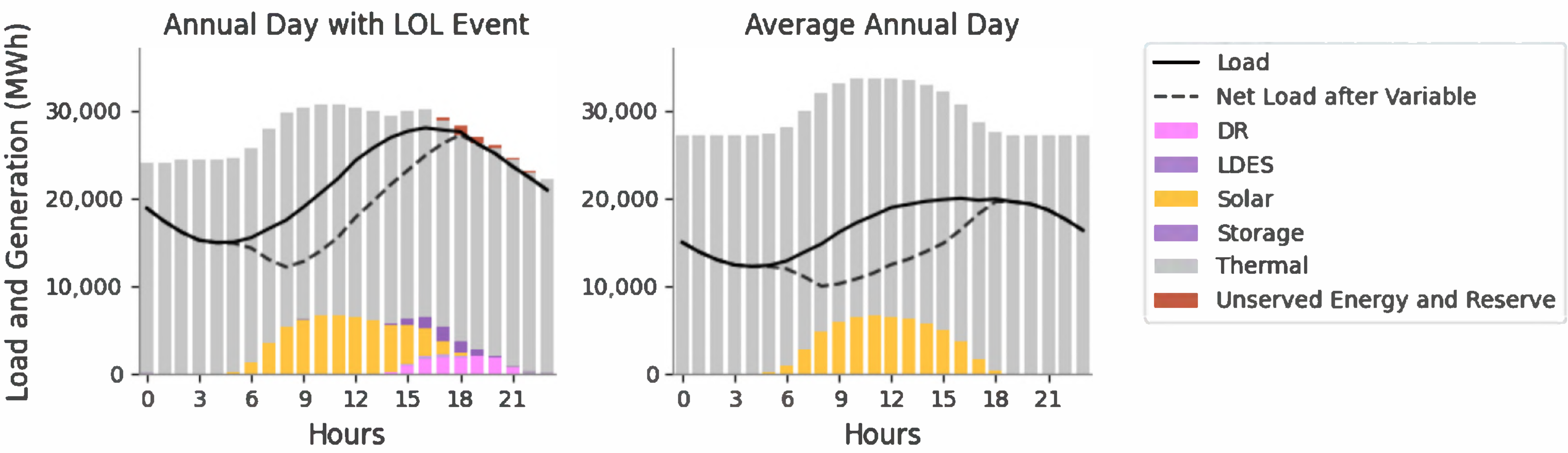
Thermal representation: seasonal derates and outages

- **Summer = Apr – Oct**
- **Winter = Nov - Mar**
- **Hot Summer Peak Rating**
- **Cold Winter Peak Rating**

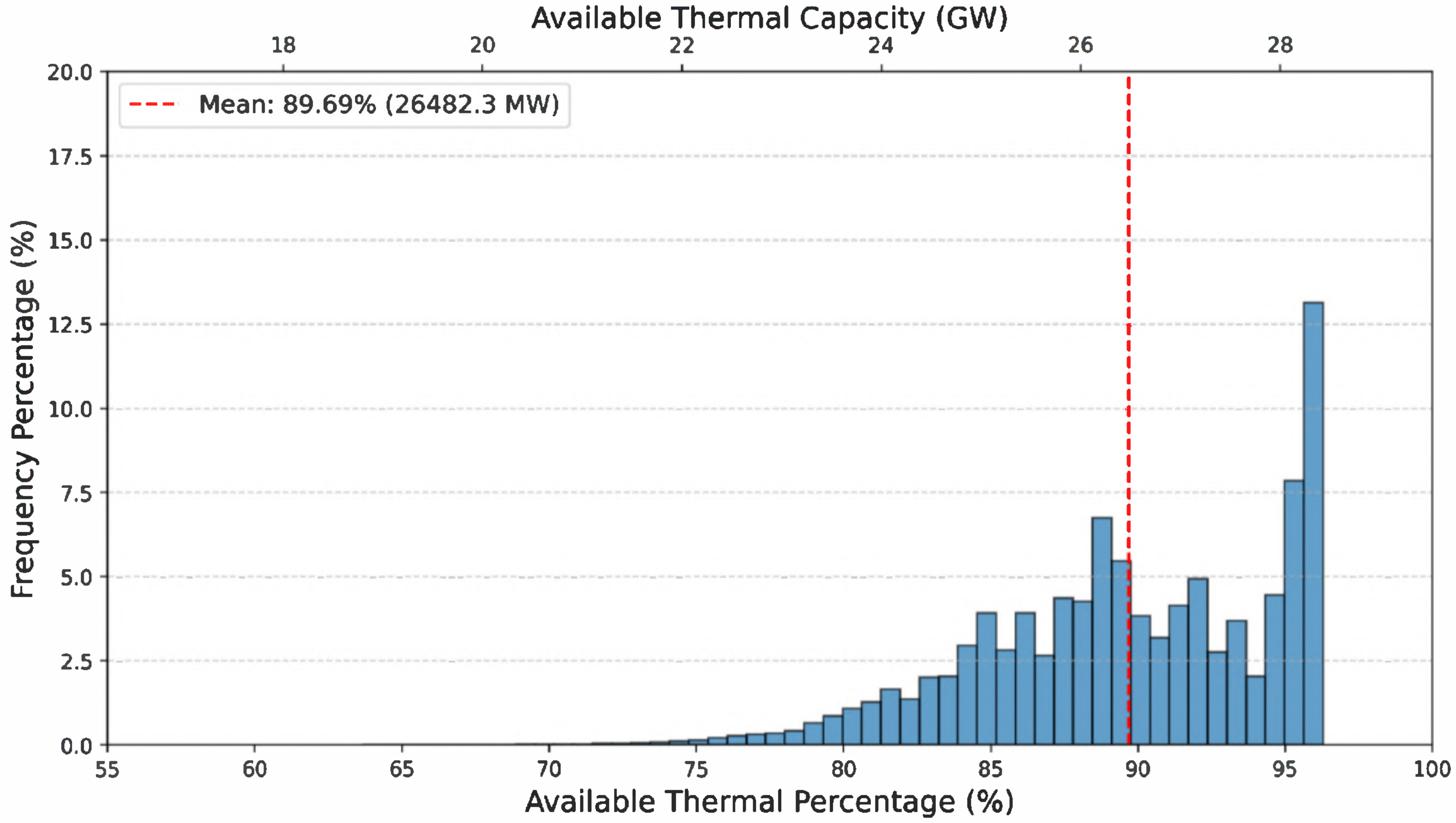
- **Do we want to break up the season more?**
  - Option 1: 4 seasons
    - Winter = Cold Winter
    - Spring = Winter
    - Summer = Hot Summer
    - Fall = Summer



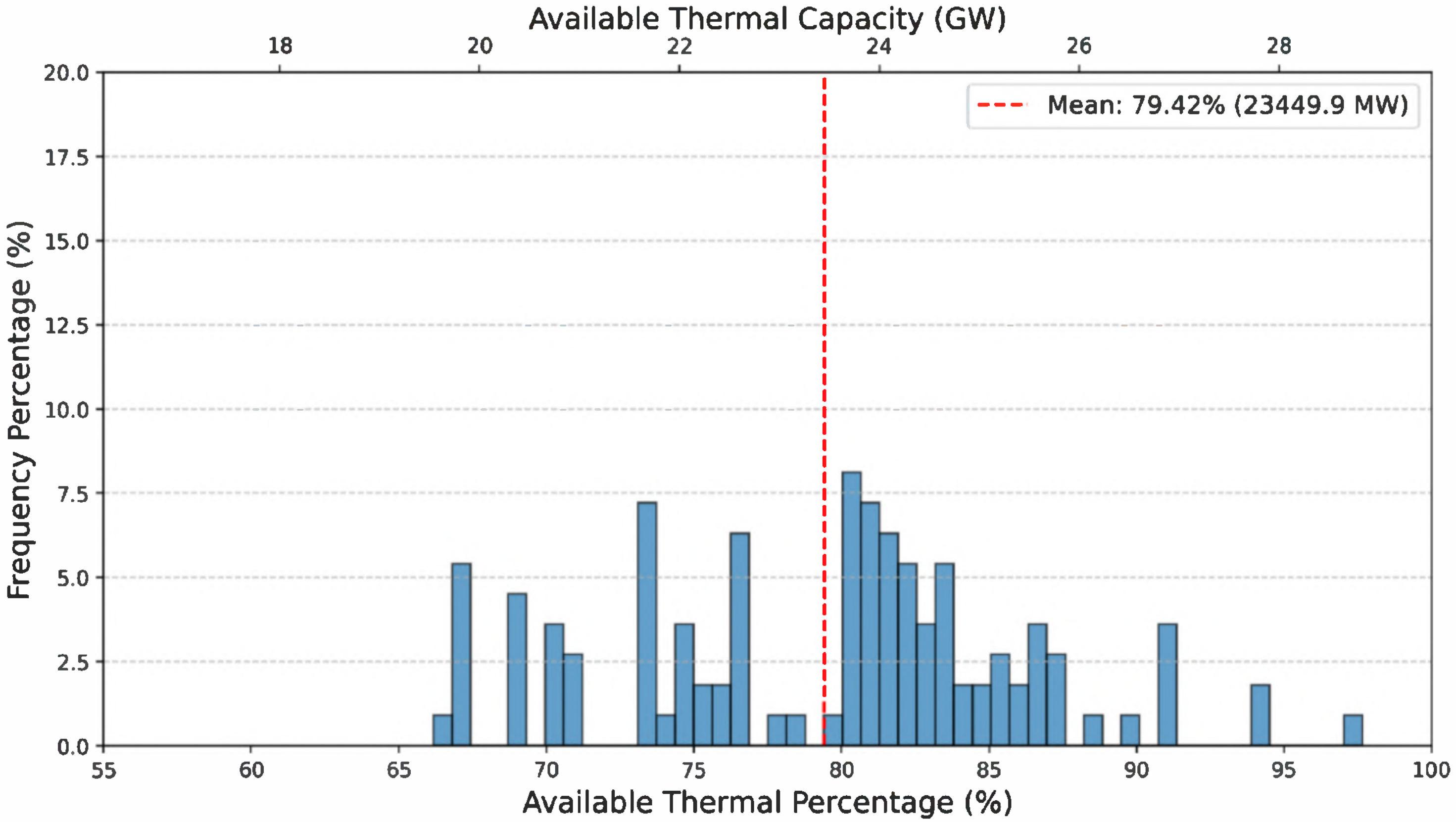
Average Summer vs LOL Days



The distribution of available capacity ranges from 70% to 95% of thermal nameplate, avg around ~90%



During Loss of load events, average thermal capacity is ~11.86% lower than summer average (3,502 MW)



Thermal representation: outage characterization

+ **Thermal Nameplate Capacity: 29,526 MW**
  - Summer Nameplate = 27,936 MW (No Manatee 1+2)
+ **Summer (April – Oct)**
  - Hours in Summer: 1,129,920
  - Daily max load mean: 22,800 MW
+ **LOL Events**
  - LOL hours count: 111
  - Load mean: 27,029 MW
  - Available Thermal Capacity mean: 23,450 MW
+ **Loss of load events occur on average when thermal capacity is ~10.45% lower than summer average (3,085 MW)**

Load Profile Check

Solar Benchmarking

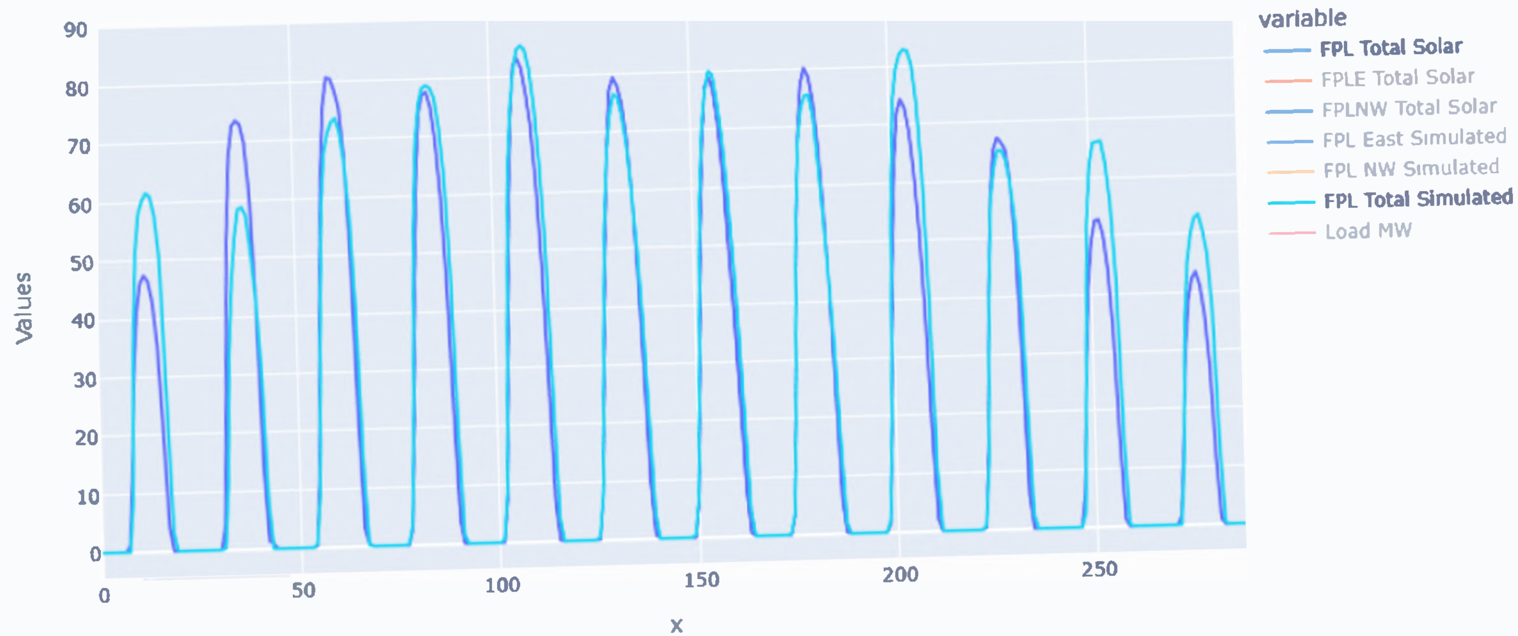
Energy+Environmental Economics

Energy+Environmental Economics

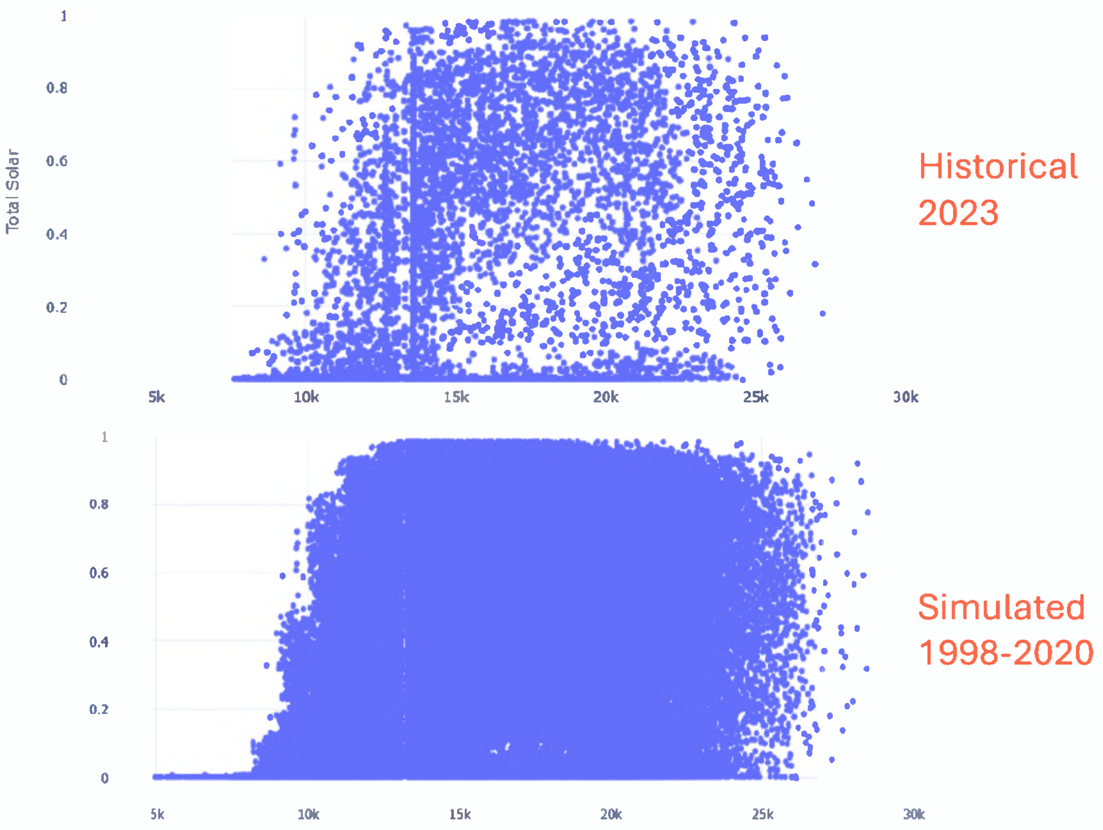
Solar Benchmarking Checks

- **Profiles provided by FPL consist of CST/CDT as well as EST/EDT time zones in hour beginning format – as informed by FPL.**
  - For all of the solar sites, corresponding region is described in the data template provided by FPL
- **Using these definitions E3 mapped solar profiles to time zones based on regions and then converted all profiles to Eastern Standard Time, Hour Beginning.**
  - E3 additionally created FPL East and FPL NW average solar profiles to represent solar sites that did not have a profile
- **E3 further benchmarked all of these profiles with Historical actuals used by the RESERVE team, this included sunrise, sunset times, daylight shift and overall shapes**
- **E3's check list**
  - Timezone alignment
  - Sunrise/Sunset Checks
  - Simulated vs Historical Solar Checks
  - Solar vs Load Correlation Checks
- **For historical solar, are these mainly Fixed Tilt or Tracking solar resources?**

Month hour Shapes



Simulated Solar vs Load Correlation generally follows historical trend



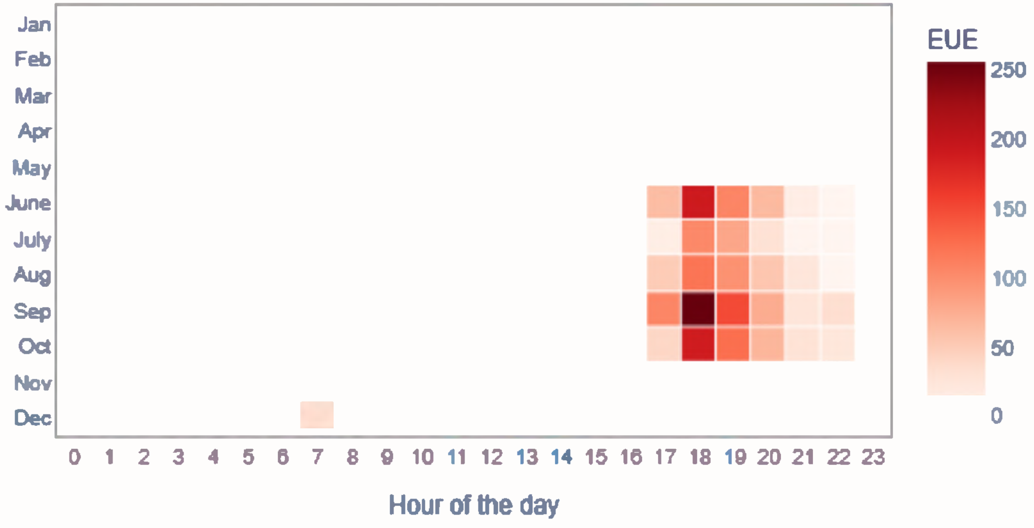
Final deliverables

Heat Map + resource portfolio bars

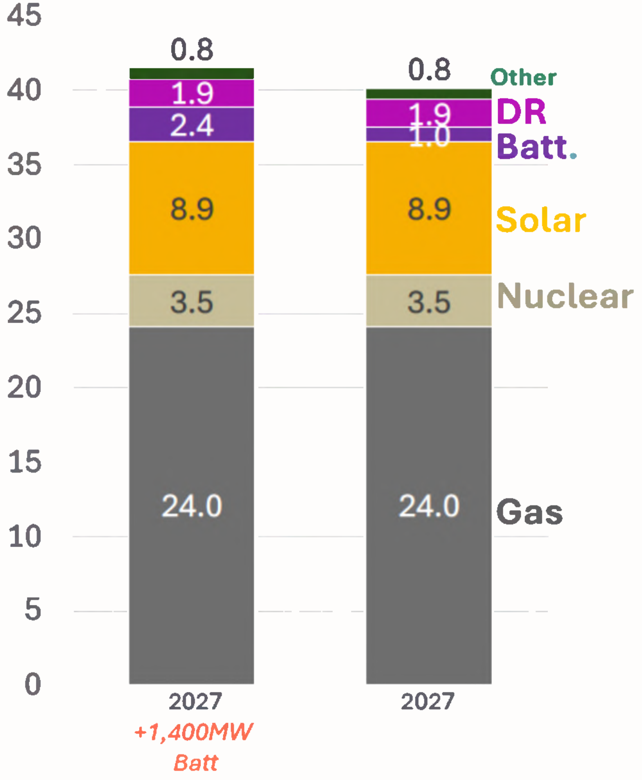
+ Observations

- Summer loss of load dominates, but winter challenges do exist
- Loss of load is driven by (1) high loads in the late summer evenings, (2) multi-thermal outage events, and (3) lack of charge in storage.

2027 Month-Hour Average Unserved Energy, *(MWh)*



2027 Portfolios,
Nameplate MW



2027 TYP

	LOLP-Derived Methodology	2027		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + KF1/2	28,150	25,316	88%
2	Utility Solar	8,946	1,728	19%
3	Storage	*2,391*	1,246	52%
4	Demand Response (DR)	1,883	982	52%
5	Portfolio Effect/Peak to Net Load Shift		1,811	
6	**Portfolio ELCC** *(E3 Methodology)*	41,370	31,083	
7	Median Peak Demand	28,925		
8	Median Peak Demand less DR	Not used		
9	PCAP Planning Reserve Margin (PRM)	8.8%		
10	Total Firm MW Requirement	31,457		
11	Firm Capacity Surplus / Shortfall	*-374*		

- **All resources are accredited using a Last-in ELCC methodology**
- **Demand response is dispatched by the LOLP model**
- **8.8% represents the reserve margin needed to achieve a 0.1 LOLE target, if all resources were perfectly available**
- **Shortfall is directly calculated through LOLP model**

2027 PLEXOS

LOLP-Derived Methodology

		2027		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + KF1/2	28,150	25,316	88%
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- **Shortfall is directly calculated through LOLP model**

2028 PLEXOS

LOLP-Derived Methodology		2028		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + KF1/2	28,150	25,316	88%
2	Utility Solar	8,946	1,728	19%
3	Storage	***2,391***	1,246	52%
4	Demand Response (DR)	1,883	982	52%
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- **8.8% represents the reserve margin needed to achieve a 0.1 LOLE target, if all resources were perfectly available**
- **Shortfall is directly calculated through LOLP model**

2029 PLEXOS

	LOLP-Derived Methodology	2029		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + KF1/2	28,150	25,316	88%
2	Utility Solar	8,946	1,728	19%
3	Storage	*2,391*	1,246	52%
4	Demand Response (DR)	1,883	982	52%
5	Portfolio Effect/Peak to Net Load Shift		1,811	
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7	Median Peak Demand	28,925		
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10	Total Firm MW Requirement	31,457		
11	Firm Capacity Surplus / Shortfall	*-374*		

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- **8.8% represents the reserve margin needed to achieve a 0.1 LOLE target, if all resources were perfectly available**
- **Shortfall is directly calculated through LOLP model**

Florida Power & Light Solar & Storage Study

Project Update

Confidential Draft

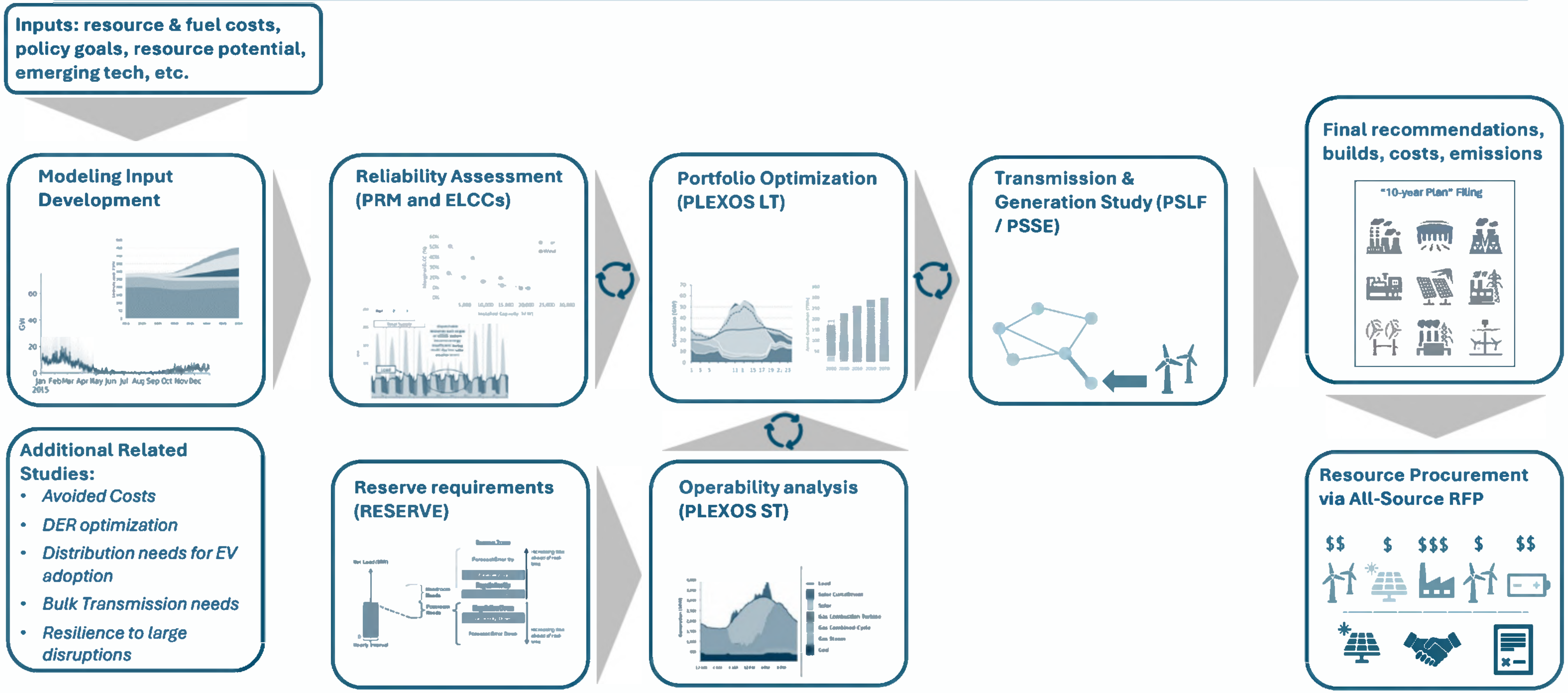
01/06/2025

Energy+Environmental Economics

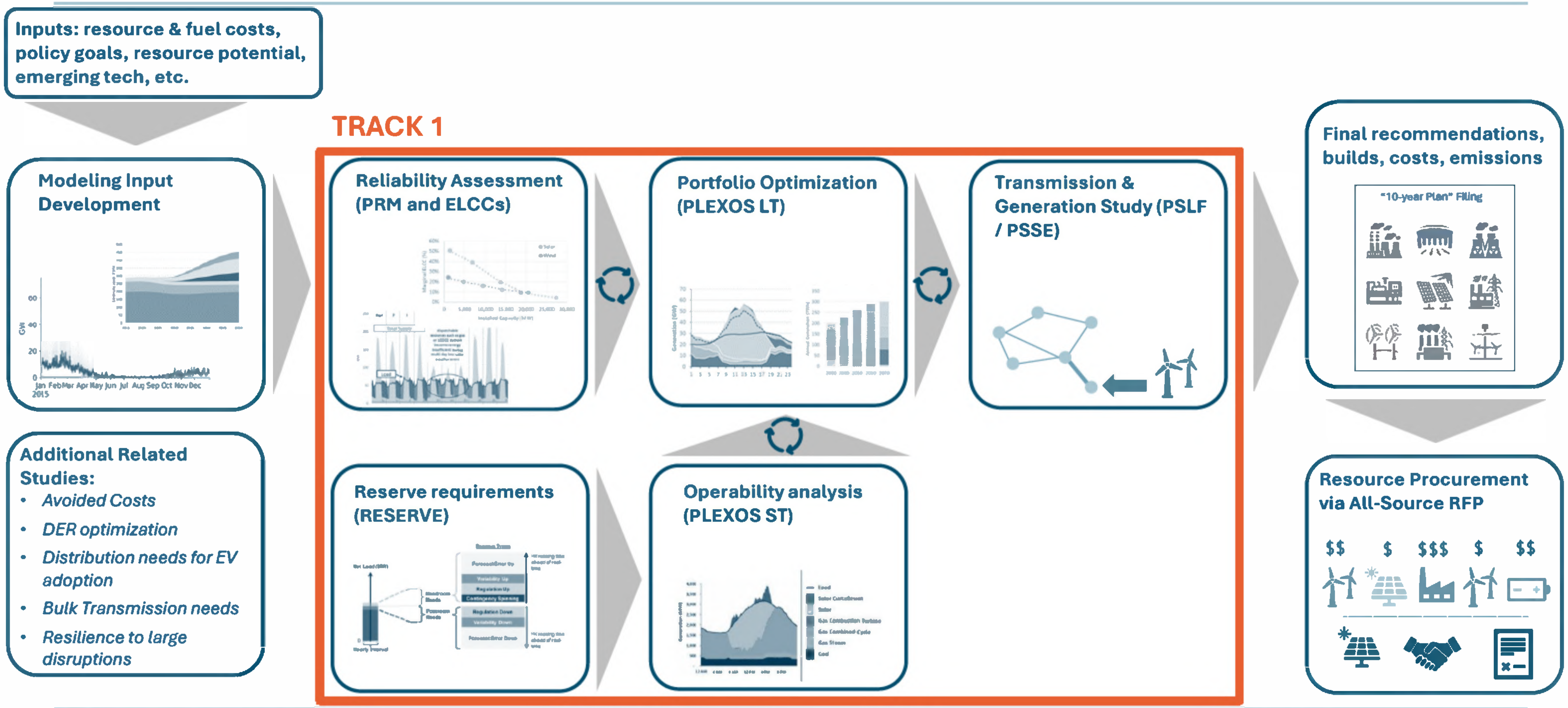
Agenda

+ Schedule Update
+ PLEXOS Results Update (Track 4)
+ Update on Tracks 1-3
+ Track 5 Overview and Updates
+ Schedule for E3 Site Visit (1/21-22)

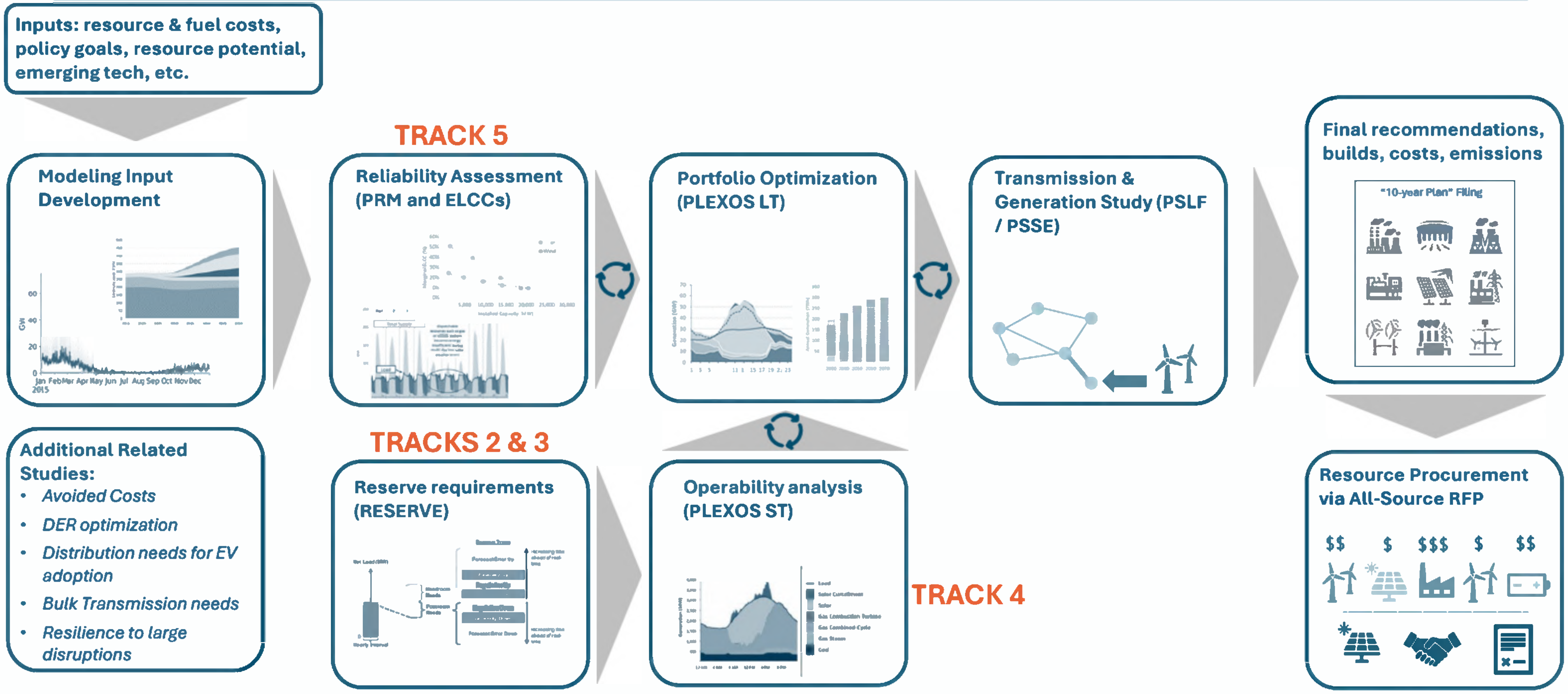
Typical Resource Planning Analysis Workflow



Typical Resource Planning Analysis Workflow



Typical Resource Planning Analysis Workflow



Project Schedule / Deliverables (Updated 12/17)

Track	Schedule by Milestone	Deliverables
1. Integrated Resource Plan Review	• ~~**12/18:** 2 Mtgs with AW wrap-up fact-finding re Operational Flexibility and Portfolio Selection~~ • **1/8:** Draft ppt • **1/24:** Final ppt	**PPT Report** that summarizes FPL's current practices and approach to Operational Flexiblity, Resource Adequacy, and Portfolio Selection; compares FPL's approach to industry best-practices; makes recommendations for improvements based on emerging industry best practices
2. Review FPL's Operating Reserve Practices	• ~~**Dec. 9th:** Mtg with CC to confirm our understanding of FPL practices / present high-level recommendations~~ • **EOY:** Strawman proposal for comprehensive reserve improvement plan, and define reserve products specification to be quantified in Track 3 • **Week of Jan. 13th:** Finalize comprehensive operational reserves improvement, deliver PPT report.	**PPT Report** that summarizes FPL's current practices and approach to Operating Reserves; compares FPL's approach to industry best-practices; makes recommendations for additional reserve products and improvements to current practices based on emerging industry best practices
3. Develop Planning-Level Machine Learning Operating Reserve Quantification Tool	• ~~**Week of 12/16:** Confirm data availability from FPL, with additional data transferred before EOY~~ • **Week of 1/13:** Draft results for some of the reserve products, showcasing the dynamics, economics, and reliability of the new reserve. • **Week of 1/27:** If feeding track 3 results into track 4&5, finalize and deliver relevant reserves. • **End of Feb:** Final Calculations, analysis, and presentation on all specified Reserve Products. • **End of Mar:** Finish knowledge transfer on the usage of E3 developed reserve quantification tool, for planning and potentially operations purpose.	**PPT Report** describing an updated, comprehensive reserve product strategy and specifications for FPL's consideration, and a methodology for calculating hourly operating reserve product needs for any future resource portfolio as a function of load and solar penetration for use in production simulation and capacity expansion modeling
4. Detailed Operations and Solar Integration Cost Study	• ~~**12/9:** Share PLEXOS ST Results (v3)~~ • ~~**Week of 12/16:** rerun cases and share PLEXOS ST Results (v4) if needed~~ • **EOY:** PLEXOS ST modeling complete • **1/10:** Draft ppt • **1/24:** Final ppt	**PPT Report** summarizing PLEXOS ST methodology, assumptions, inputs and results for inclusion in rate case
5. Loss-of-Load and Effective Load-Carrying Capability Study	• ~~**12/12:** Summarize data received and finalize initial inputs~~ • ~~**12/19:** Share preliminary results~~ • **1/15:** Draft results/ppt for rate case • **1/29:** Final results/ppt for rate case	**PPT Report** summarizing the RA study methodology, FPL's 2027 system reliability characteristics, the PRM needed to meet 0.1 LOLE, and the incremental ELCC of short-duration batteries.

Tracks 4

Operations & Production Simulation

Energy+Environmental Economics

Methodology for 2027 “missing” operational reserve value study

Run 1:
- No additional batteries
- No operational reserves

Run 2:
- +1,400 MW batteries
- No operational reserves

Calculate battery operational value without operational reserves (mimics Aurora): Production cost difference between Run 2 and 1

The difference in battery operational value with and without operational reserves is the value that isn’t quantified in Aurora
= (4 - 3) - (2 - 1)

FPL to include missing value ($/kW-yr) in support for accelerating battery deployment

Run 3:
- No additional batteries
- Operational reserves modeled

Run 4:
- +1,400 MW batteries
- Operational reserves modeled

Calculate battery operational value with operational reserves (reflects real-world operations): Production cost difference between Run 4 and 3

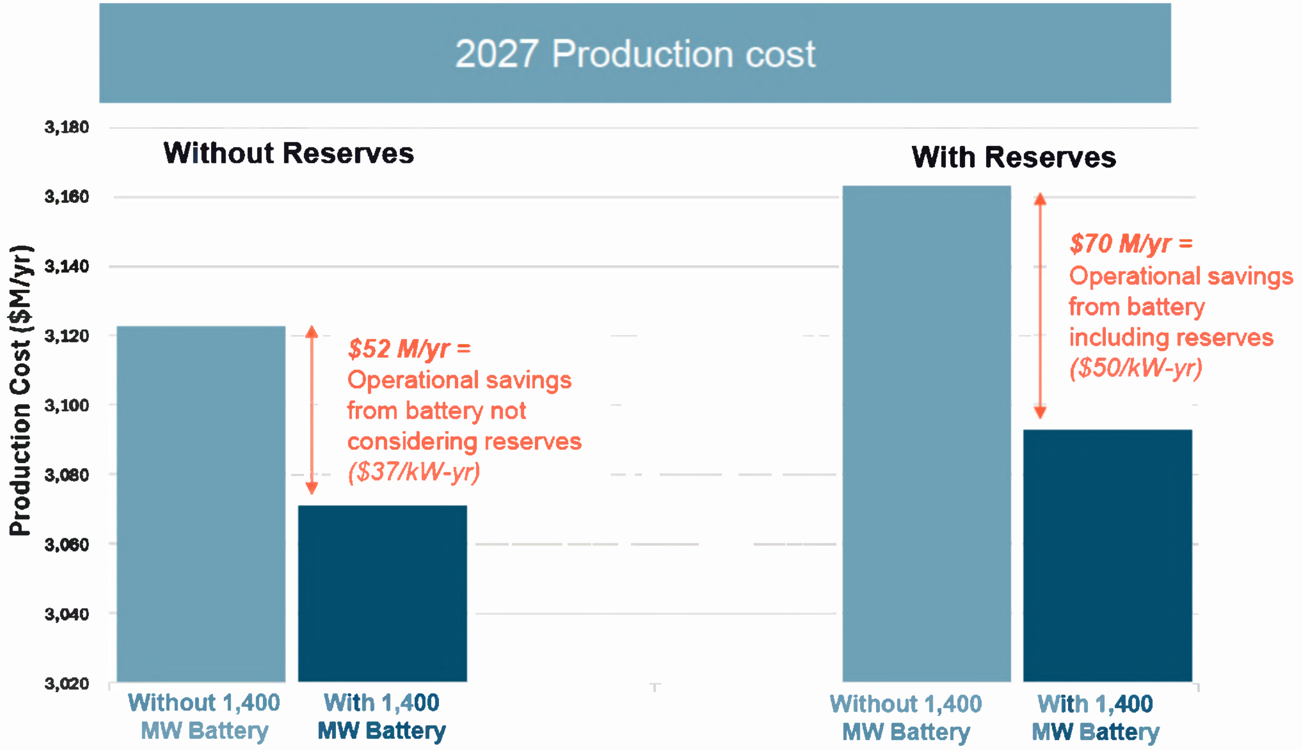
Production cost (PLEXOS) modeling progress

- **Main updates since 11/21/2024 results:**
  - Added cold/warm/hot starts and transition times for CCGTs
  - Updated start cost ($/start) and running cost ($/hour online) values to latest data recommended by FPL
  - Updated heat rates to FPL data
  - Other misc. updates
- **FPL (Bernardo) has reviewed dispatch results**
- **What remains to be done:**
  - Add wind resources
  - Minor Ft Myers CCGT update
  - Potentially: include reserve requirements from reserve modeling (Track 3)

The start cost and start time updates had the largest impact on results of any of the updates listed

- **Deliverable: Slide deck of modeling inputs, methodology, and results**

Annual Battery Reserve Value: Results update



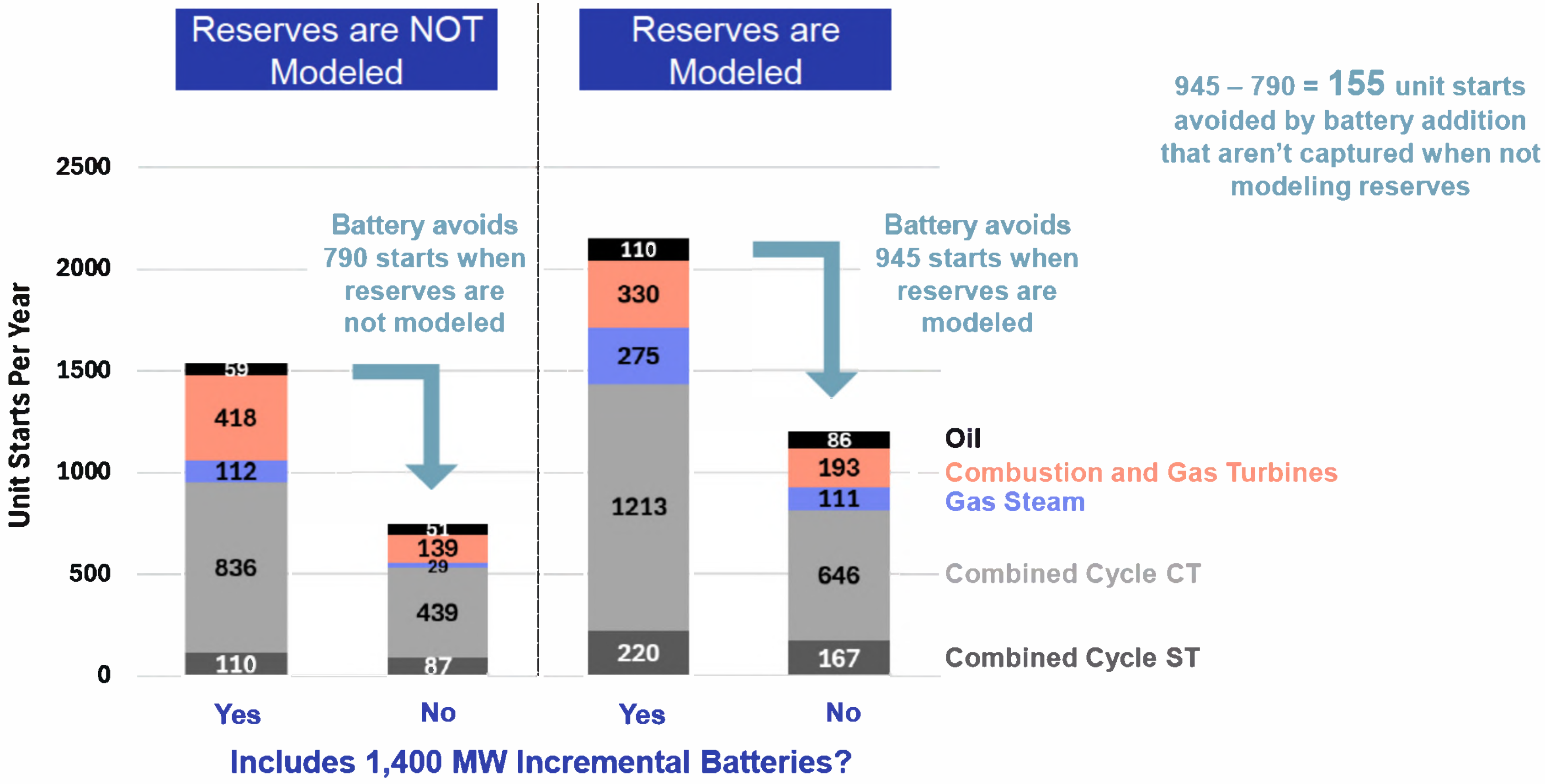
$70 M/yr - $52 M/yr =
$18 M/yr = "Missing" value of 1,400 MW of incremental batteries providing reserves
= $13/kW-yr

The battery reserve value has increased by $10 M/yr since the previous (11/21) results: previous results had $8 M/yr of battery reserve value

Cost breakdown (Appendix)

Reserves Modeled?	1,400 MW Battery Included?	Total Production Cost ($M/Yr)	Fuel Cost ($M/yr)	Maintenance Cost: VO&M and Running Cost ($M/yr)	Start & Start Fuel Cost ($M/yr)
No	No	3,123	3,060	16	46
No	Yes	3,071	3,031	16	24
Yes	No	3,163	3,080	18	65
Yes	Yes	3,093	3,041	17	36

Number of starts



Tracks 2 & 3

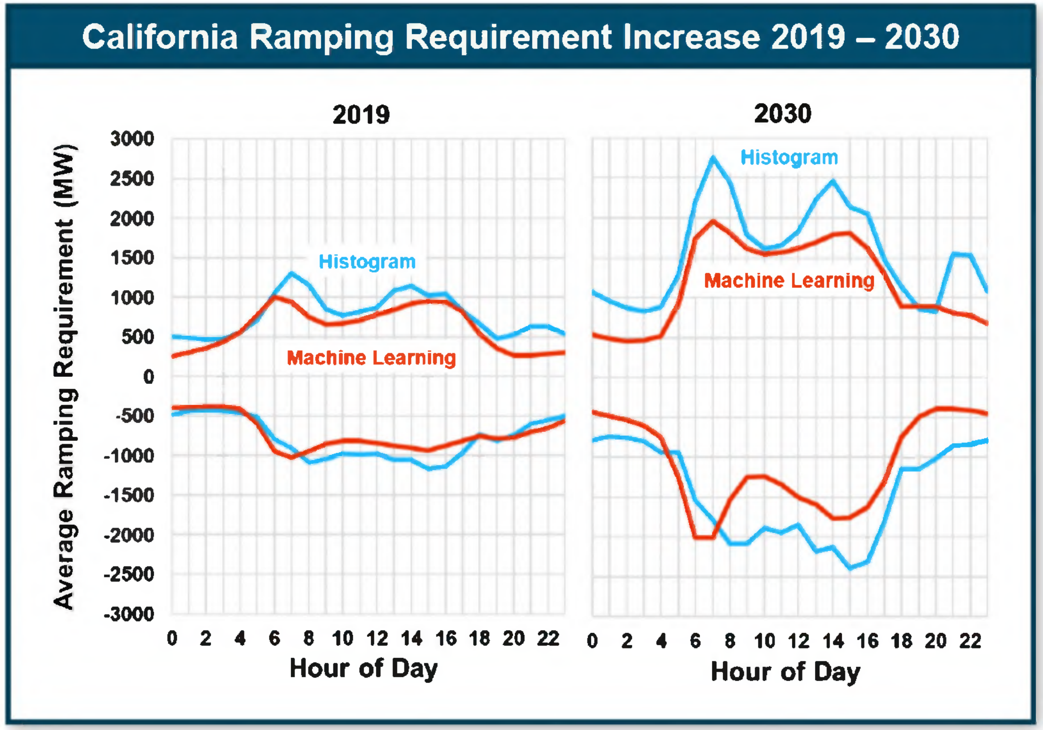
Operating Reserves Study

Energy+Environmental Economics

Need for grid services will grow with higher penetrations of wind and solar generation

+ Grid operators have always balanced variability and uncertainty in demand and supply using ancillary services
+ The need for grid services will grow as wind and solar increase due to increased variability and forecast errors
+ The need for grid services will also become more dynamic as grid conditions change with the weather

FPL may need better tools to address dynamic operating reserve needs in operations and planning



Source: E3, Predicting Reserve Needs Using Machine Learning, project partially funded with grant from ARPA-E

Track 2: Review of FPL operating reserve practices

+ Current Status:

- Finished three major rounds of interviews, along with smaller focus group meetings.
- Deep dive on day-ahead commitment and real-time operations, including the PCE interface.
- Developing draft PPT report that provides comprehensive recommendations

+ Next Steps

- Align with FPL on strawman proposal for regulating, contingency, and ramping reserves
  - Focus on aligning on temporal cadence, categorization, and substitutability.
- Finish report and visualization
  - Suggest method of calculation
- Explore implementation with PCE

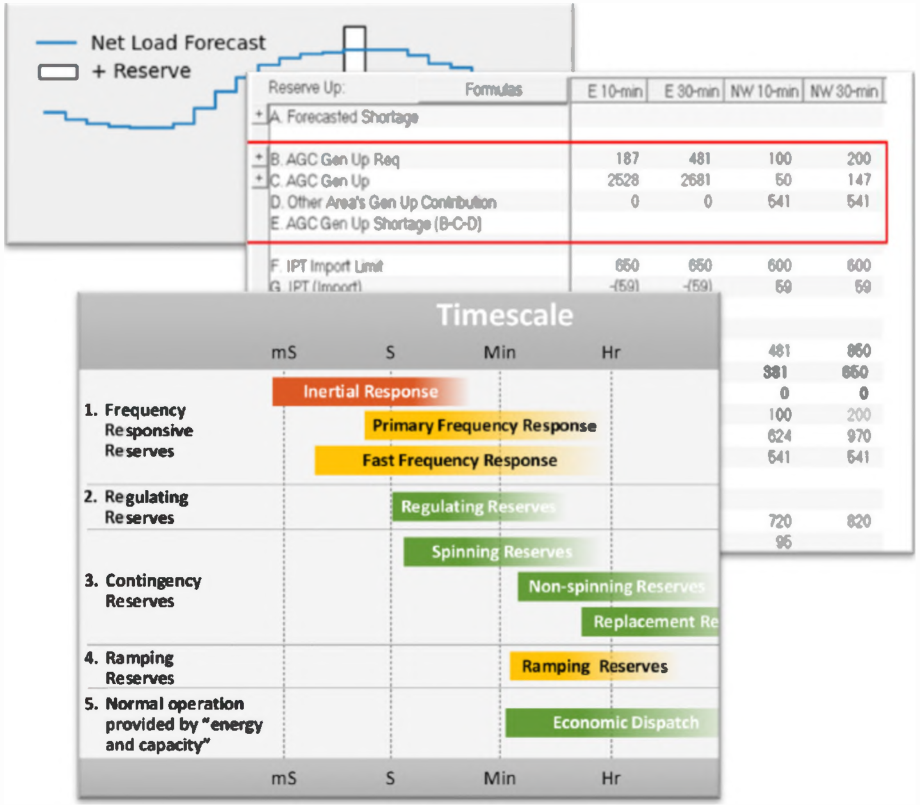


Fig 10.1 Power Grid Operational Reserves Procedure by Timescale

Track 3: Develop machine learning tool for calculating dynamic uncertainty reserves in planning studies

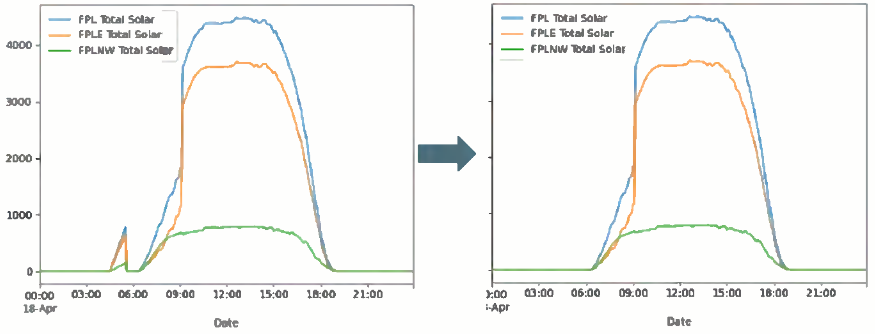
+ Current Status:

- Completed data collection and cleaning: solar and load actuals and forecasts for roughly 2023-2024
  - – Limited iteration on data due to time constraints.
  - – Some additional clarity and spatial disaggregation would be great.
- Input other parameters into the RESERVE model UI, and created model skeleton based on Track 2 straw man proposal

+ Next Steps:

- Use machine learning to quantify day-ahead forecast error induced reserve for test year
- Evaluate combined effect of forecast error + variability
- Develop method for projecting reserve needs into the future as solar penetration grows

Snapshot of some data cleaning for solar actuals



Snapshot of Neural Network Params

Parameters	Value	Notes
num neurons	100	Structural parameter of the ANN network
activation type	relu	Structural parameter of the ANN network
num cv folds	10	number of cross validation folds
batch size	64	size of each mini-batch in the SGD
max epochs	1000	Maximum number of epochs in training. In each epoch, each training
training_verbosity	2	The higher this number is, the less amount of information will be filtere
optimizer choice	adam	Optimizer choice. Default to ADAM, a popular choice that have 1st an
early stop min delta	0.1	if the difference/decrease in loss is less than min_delta, the model is
early stop patience	50	For number of patience epochs, observe if the model has improved m
early stop verbosity	1	0: no output, 1: some output, 2: full output

Track 5

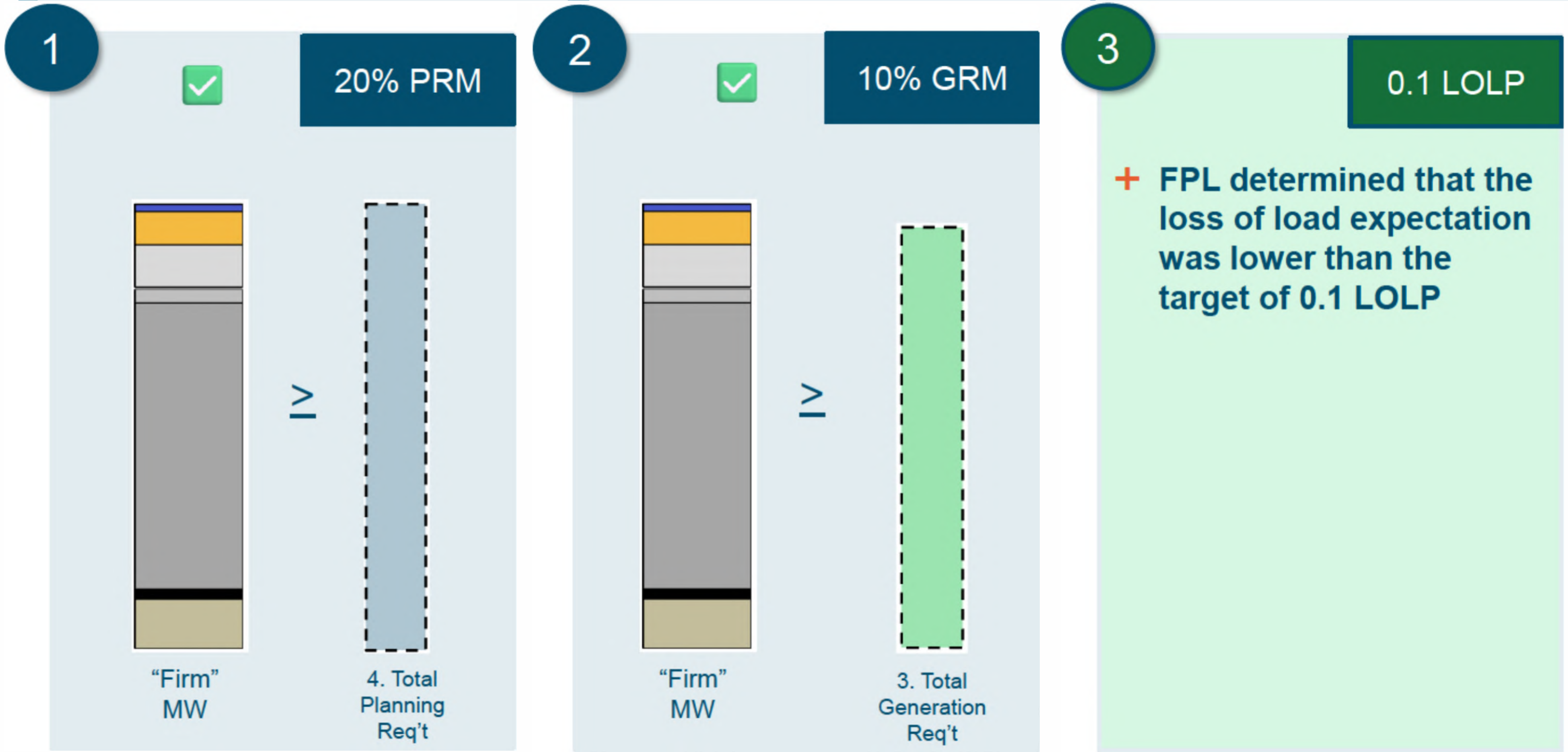
Resource Adequacy Study

Motivation for a Resource Adequacy Study

- **Florida has a commission-mandated 20% planning reserve margin (“PRM”) requirement**
  - Currently, FPL does not utilize probabilistic analysis, such as an effective load carry capability study (“ELCC”) to derive accredited capacity for each resource type
  - Method of calculating the 20% is not set in stone
- **Using FP&L's current accredited capacity methodologies, E3 understands FPL can meet its PRM requirement through the end of the decade even without the additional 1,400 MW of battery energy storage**
- **However, preliminary results from E3’s operational study raises RED FLAGS as to whether FPL’s system is resource adequate in the 2027 test year**
  - As a result, E3 has begun conducting a detailed resource adequacy study using a custom loss-of-load probability model (RECAP)

Current FPL RA Practices

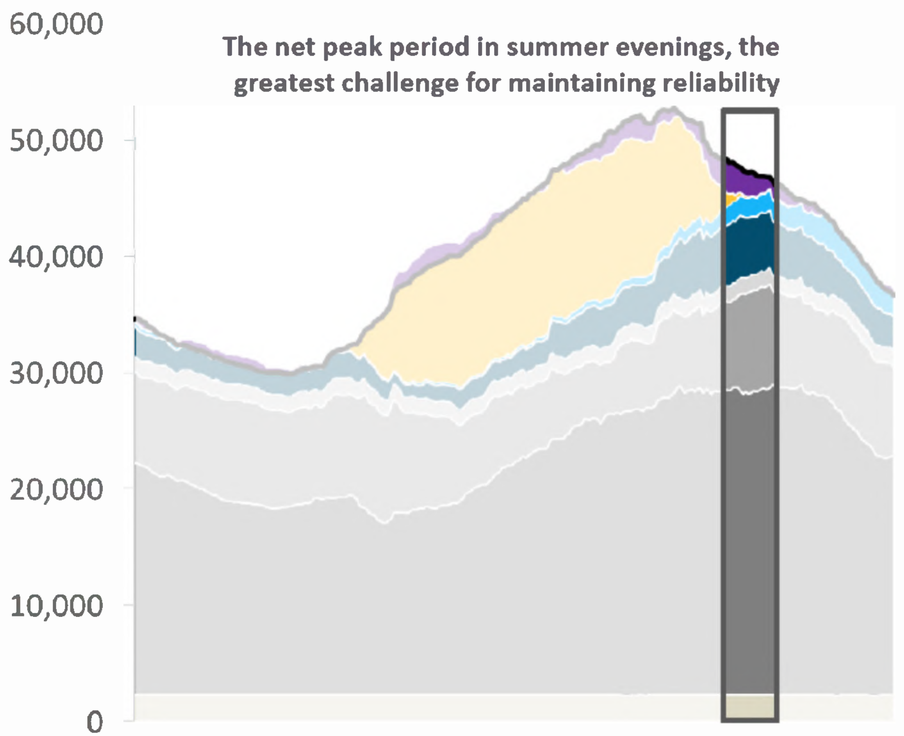
Uses 3 different criteria to ensure reliability, E3's RA study focuses on (3)



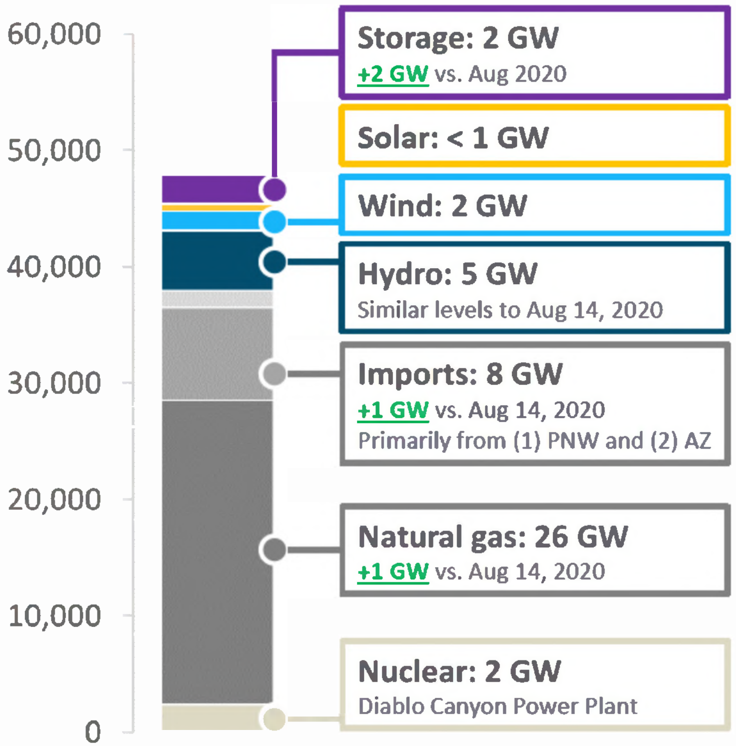
+ FPL determined that the loss of load expectation was lower than the target of 0.1 LOLP

Resource adequacy needs are shifting from the *gross* peak load hour to the *net* peak load hour

CAISO System Operations on September 6, 2022
(MW)



Generation During Hour of Highest Net Load
(MW)

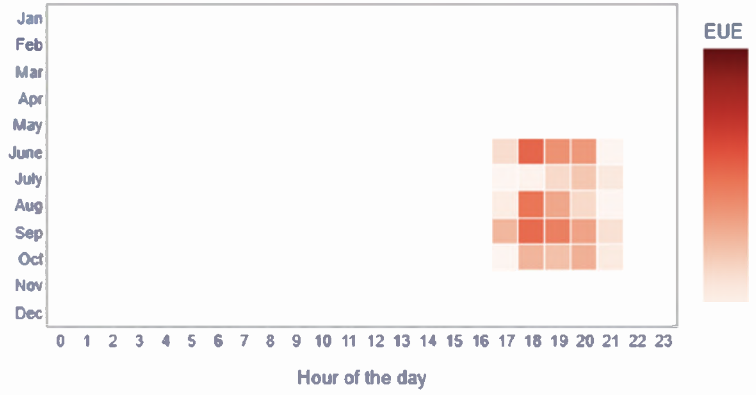


E3's RA study will quantify FPL's current RA position as well as reliability contribution from existing and new resources

+ By Jan 21, E3's RA study will evaluate:

- FPL's **Target PRM** to meet a reliable system as defined by a 0.1 LOLE standard
- FPL's current **achieved PRM**, i.e., its current capacity position
- The existing **portfolio capacity value**
- **Incremental solar & battery capacity value** contribution
- FPL's **timing of system risk** and how it may evolve with new resources

2027 Month-Hour Expected Unserved Energy, *(MWh)*



The RA study will answer these key questions about FPL's system

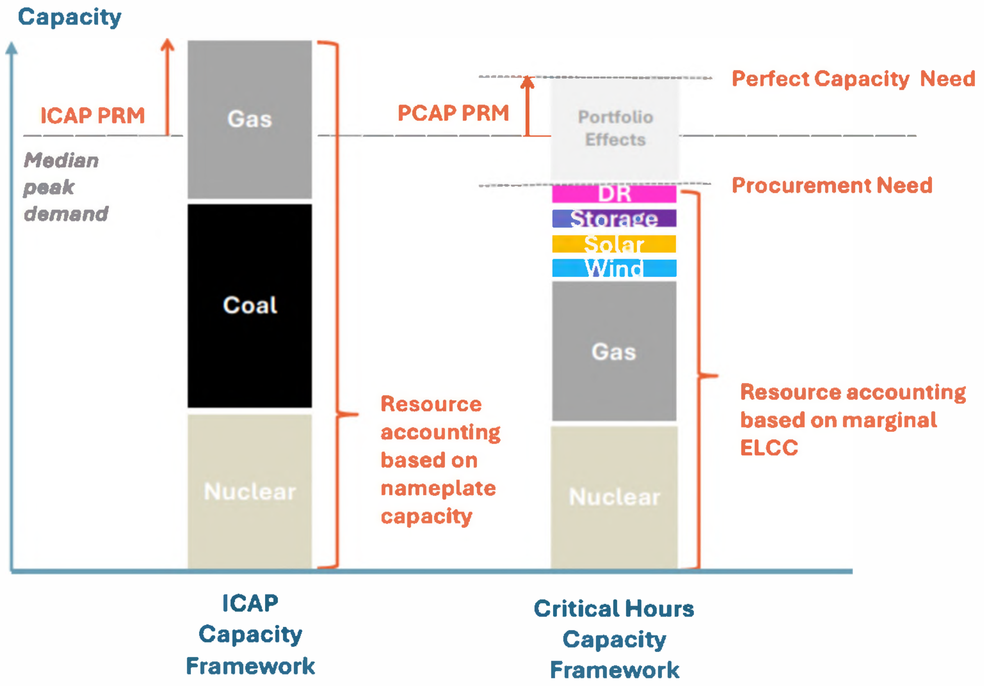
1. Does FPL currently have sufficient resources to be "reliable"?
2. How do current resources contribute to reliability?
3. In the event of an outage, what do reliability challenges look like for the FPL system?
4. How do new batteries contribute to reliability?

Preliminary results thus far are confirming the importance of deeper investigation on resource adequacy

+ **E3 has a working model and is producing draft results**
+ **LOLE is coming in very close to the 0.1 days/yr. standard for 2027 test year**
+ **2027 system includes the new 1400 MW of batteries**
+ **Next steps:**
  - Refine key inputs for the following:
    - Thermal outage characteristics
    - Battery dispatch constraints
  - Test resource adequacy without the batteries to determine whether system meets LOLE target
  - Develop load-resource table for side-by-side comparison with FPL's current methods
  - Calculate ELCC values for batteries, solar, and combinations
  - Examine the impact of transmission limitations between NW and E regions
  - Examine impacts for scheduled maintenance

Adapting the PRM for higher solar & battery penetration

+ **PRM defined based on need for Perfect Capacity (PCAP)**
  - Covers annual peak load variation and operating reserves only; forced outages addressed in resource accreditation
+ **Individual resources accredited based on ELCC or Perfect Capacity Equivalent**
  - Large differences in availability during peak
  - Significant interactions among resources
  - ELCC values are dynamic based on resource mix
+ **Use *marginal* ELCCs for future planning & procurement**
  - Accurately captures reliability impact of changes to FPL's portfolio
  - Reflects both diminishing returns and portfolio effects



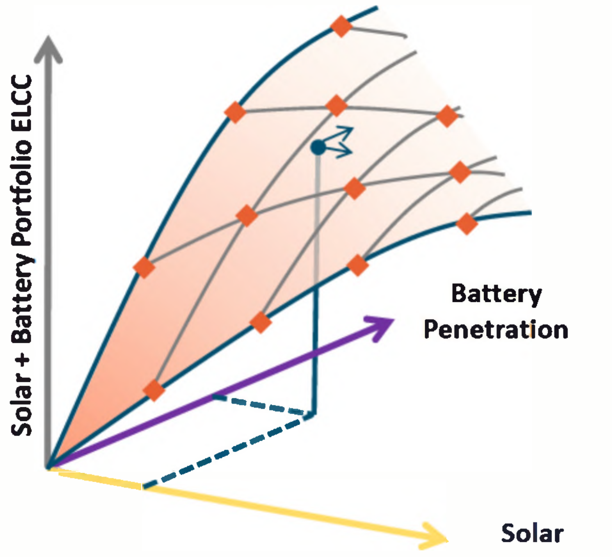
$$Portfolio\ ELCC = f(G_1, G_2, \ldots, G_n)$$

Use a multi-dimensional ELCC surface to explore future capacity contributions of solar & batteries at different penetrations

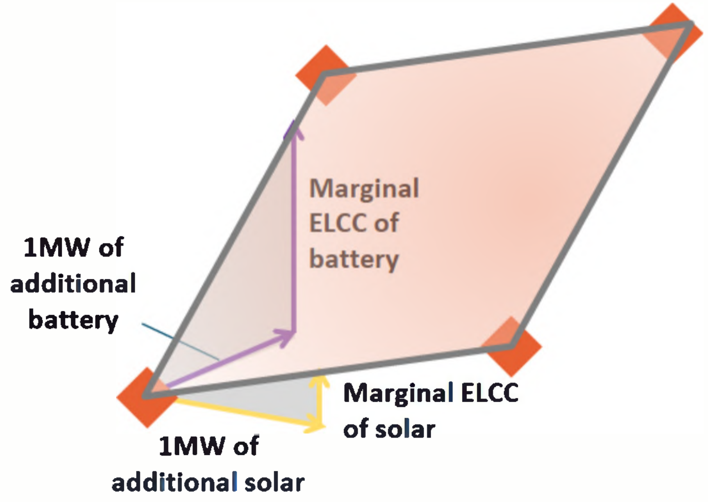
- ELCC surface captures both diminishing returns and diversity benefits between resources
- Used in capacity expansion modeling to constrain future portfolios to ensure adequacy

The height of the orange dots gives the total solar + storage portfolio ELCC

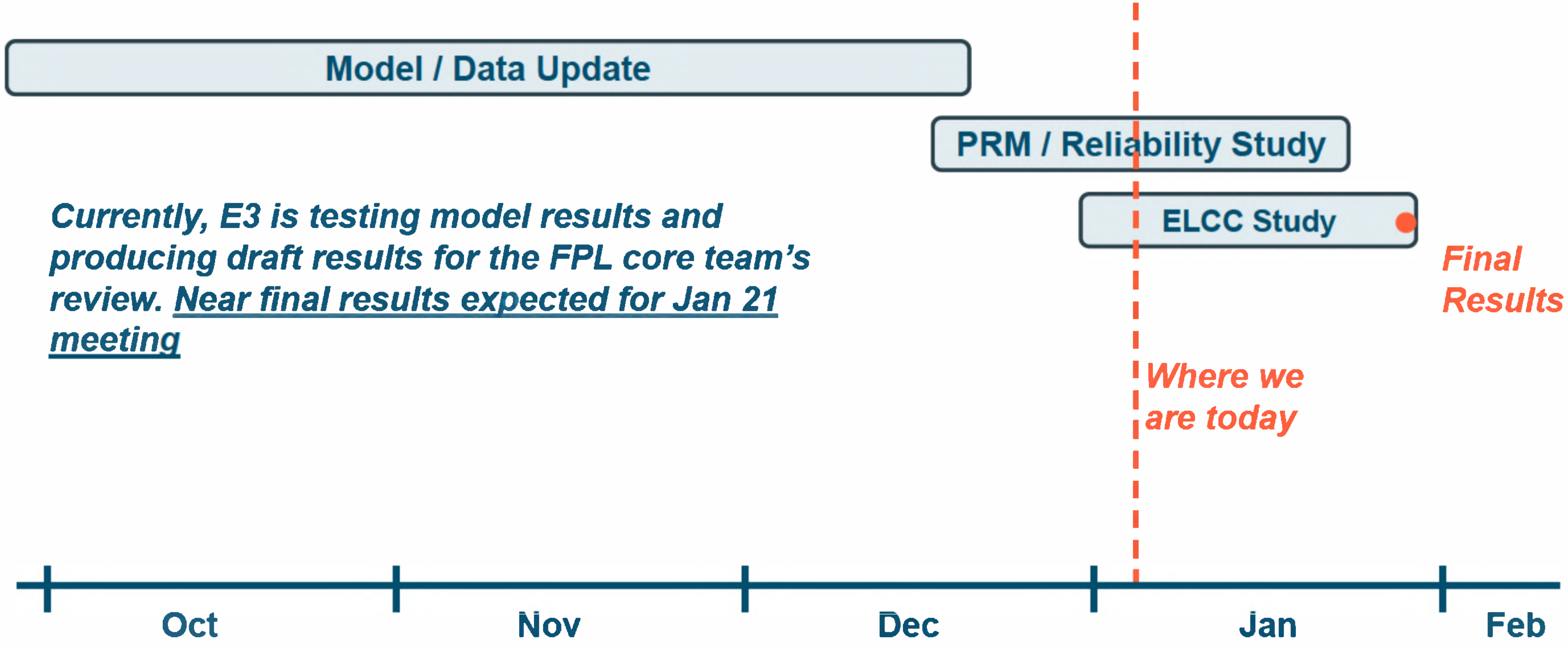
The slope between each point gives the marginal capacity value of solar and storage at a given capacity



For any plane on the surface:



What is E3's RA study's current progress?



Currently, E3 is testing model results and producing draft results for the FPL core team's review. Near final results expected for Jan 21 meeting

FPL Site Visit Schedule

Energy+Environmental Economics

Schedule for Upcoming Site Visit (January 21-22)

Tuesday 1/21 (@ LFO)

- 9:30 – 10:30am: Control center tour and operations overview
- 10:30 – 11:30am: Debrief on work to date
  - Goals of reserve study
  - CAISO example - spend some time on a challenging day
- 11:30am – 1:00pm: Lunch
- 1:00 – 3:00pm: Tracks 3 & 4 discussion w/ focus on next steps

Wednesday 1/22 (@ Juno Beach HQ)

- 9:00 – 10:00am: Meeting with Andy W's team on Track 1
- 10:00 – 10:45am: Executive presentation on high-level findings
- 11:00am – 12:00pm: Meeting with Scott B and team on plan for rate case
- 12:00 – 1:30pm: Lunch with Elena's team
- 1:45 – 2:45pm: Team meeting with E3
  - Discussion on resource adequacy findings and whether/how to implement recommendations to calculation of PRM

FPL

Overhaul Scheduling with Increased Solar

James French
Ernie Gonzalez

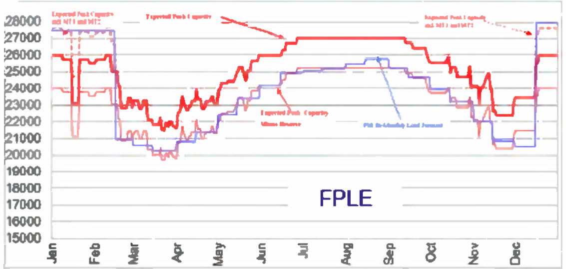
System Operations has identified deficiencies in the current Overhaul planning process that has led to a reduction in reserve margin for upcoming Overhaul seasons.

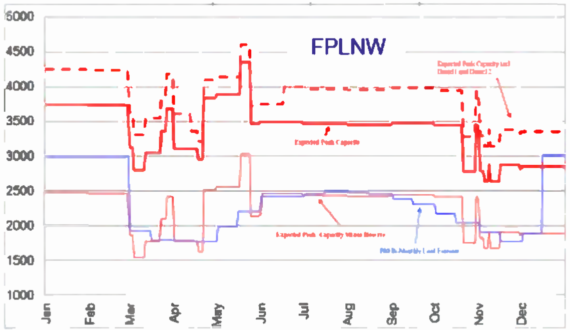
Executive Summary

- **As more solar is installed, system generation capacity is most limited one to two hours following the time of Peak Load.**
- **Current Overhaul planning process requires modification to address solar generation decline in the late afternoon leading to a reduction in reserve margin during Peak Net Demand.**
- **Reduction in margin leads to less room for planned Overhauls using current margin assumptions.**
  - Short term mitigations (1-3 years): Reduce planned overhauls, purchase long term firm power, plan to dispatch Manatee 1 and/or 2, or increase risk of regular DSM use when short term solutions are limited.
  - Long term mitigations (3+ years): Install batteries on a more aggressive schedule, construct new conventional plants, or pursue long term PPA contracts

Current Situation – What assumptions go into the Overhaul planning process?

- **Seasonal P80 Peak Load forecast for both areas provided by RAP**
  - P95+ for Extreme Cold Weather Dec 15 to Feb 15
- **Solar at Peak Load Assumptions:**
  - 0% Solar Dec 15th - Mar 1st
  - 27% Solar Mar 1st - Mar 11th
  - 54% Solar Mar 12st - Nov 4th
  - 27% Solar Nov 4th - Dec 15th
- **1810 MW margin is added to address potential unit unavailability:**
  - PGD Daily Uncertainty: 820 MW
  - SL Nuclear Outage: 990 MW
- **Do not rely on transfers between FPLE and FPLNW**
- **Do not rely on DSM for Overhaul planning**





FPL 045751
20250011-EI

What does a high load day in the Spring (P80 Peak Load) look like?

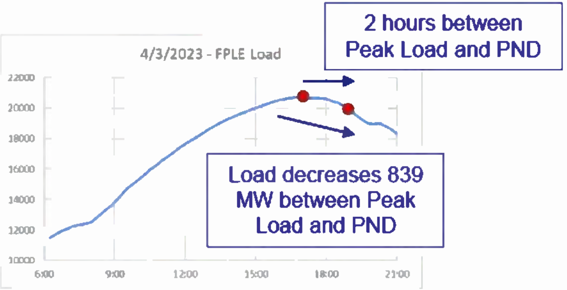
Example Day: April 3rd, 2023

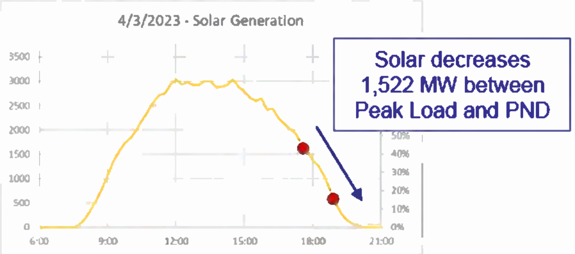
- **FPLE P80 Peak Load Forecast:**
  - Load: 20,809 MW
  - Solar: 2141 MW
  - FPLE Overhaul plan was built with 1810 MW of margin assuming a Net Demand of **18,668** MW
- **5pm FPLE Peak Load:**
  - Load: 20,754 MW
  - Solar: 2,015 MW
- **7pm FPLE PND:**
  - Load: 19,915 MW
  - Solar: 493 MW
  - PND: **19,422** MW

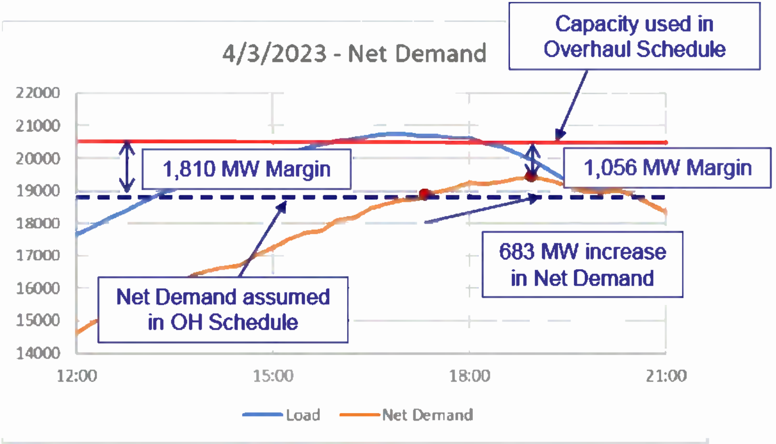
FPL 045752
20250011-EI

Even though April 3rd Peak Load matched the Overhaul plan, reserves at PND were 754 MW *lower* than OH Plan forecast

4/3/2023 – Peak Net Demand (FPLE)







1,810 MW of planned reserve margin at Peak Load was reduced to 1,056 MW at Peak Net Demand

FPL 045753
20250011-EI

FPL

Actual response to low reserve margins seen in first week of April 2023

What happens when our margin is challenged?

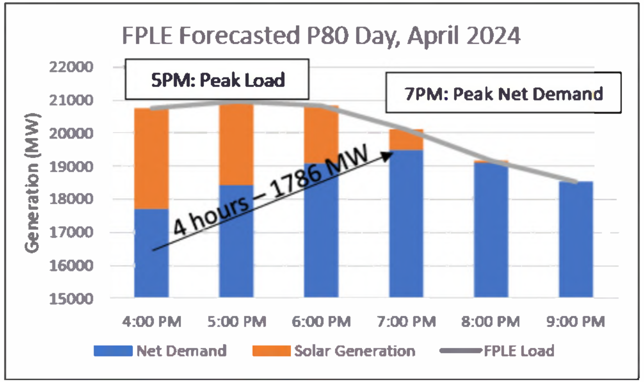
- **FPLE hit near-P80 Peak Load levels for the week of 4/2 through 4/8**
  - Planned 1810 MW of generation reserves at time of Peak Load
  - Reserves were reduced by 600 MW at PND
  - Further reduction of 600 MWs due to late Overhauls at Sanford #5
- **Mitigations to restore reserves to adequate levels at PND:**
  - FM2 B-CT Overhaul was postponed
  - OK1 C-CT unplanned sky-vent use during block OH
  - Short term Non-Firm Power purchases

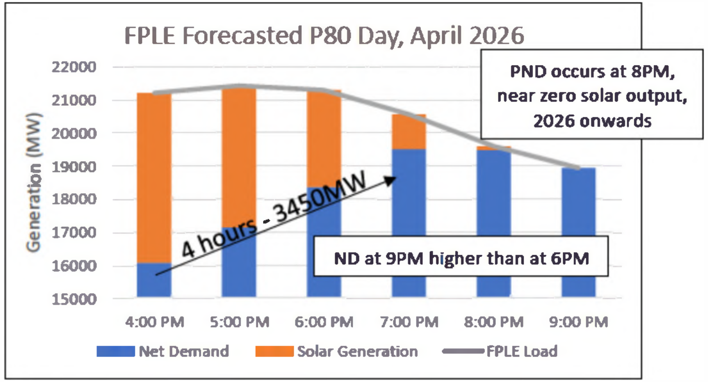
System Operations, PGD, and EMT scrambled to react to lower reserves during PND and units being late from OHs

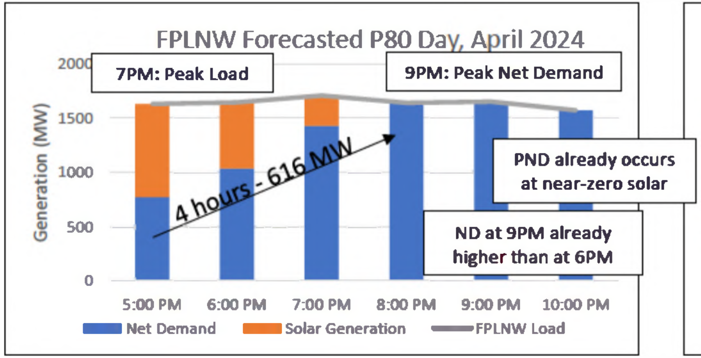
Other high load days during the Spring 2023 Outage Season where reserves were lowered during PND

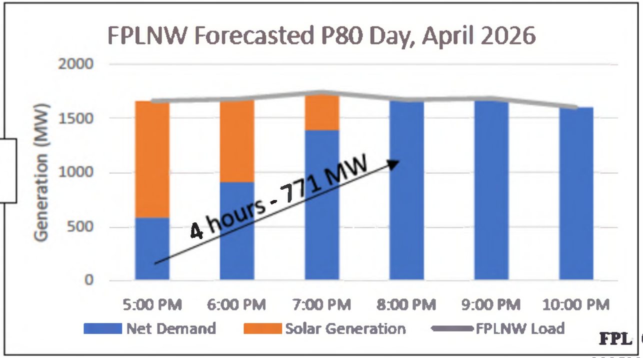
Date	Time of Peak	Peak Load	P80 Load	OH / Actual Load Delta	Time of PND	Peak Net Demand	Overhaul ND	OH / Actual ND Delta	Reduction in Generation Reserves at PND (MW)
25-Mar	17:00	19929	20273	-344	18:45	18181	18132	49	393
26-Mar	17:00	20590	20273	317	18:30	18967	18132	835	518
27-Mar	17:30	21249	20273	976	18:45	19611	18132	1479	503
28-Mar	17:00	20605	20273	332	17:00	19216	18132	1084	752
2-Apr	17:00	20055	20809	-754	18:45	18670	18668	2	757
3-Apr	17:00	20754	20809	-55	19:00	19422	18668	754	809
4-Apr	17:00	21562	20809	753	18:45	20040	18668	1372	619
5-Apr	17:00	20795	20809	-14	18:30	19204	18668	536	550
6-Apr	17:00	20886	20809	77	18:30	19202	18668	534	457
7-Apr	17:00	20466	20809	-343	18:30	18638	18668	-30	313
8-Apr	16:45	20121	20809	-688	18:15	18750	18668	82	770
15-Apr	16:15	21230	20809	421	19:00	19264	18668	596	175
16-Apr	16:30	21163	21381	-218	17:15	19360	19240	120	339
27-Apr	16:30	20866	21381	-515	18:30	19571	19240	331	846
28-Apr	17:00	20501	21381	-880	18:00	19092	19240	-148	732
29-Apr	15:15	20794	21381	-587	15:30	19683	19240	443	1030

FPL 045755
20250011-EI


FPLE Forecasted P80 Day, April 2024
5PM: Peak Load
7PM: Peak Net Demand
4 hours – 1786 MW
Generation (MW)
22000
21000
20000
19000
18000
17000
16000
15000
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM
Net Demand
Solar Generation
FPLE Load


FPLE Forecasted P80 Day, April 2026
PND occurs at 8PM, near zero solar output, 2026 onwards
4 hours - 3450MW
ND at 9PM higher than at 6PM
Generation (MW)
22000
21000
20000
19000
18000
17000
16000
15000
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM
Net Demand
Solar Generation
FPLE Load


FPLNW Forecasted P80 Day, April 2024
7PM: Peak Load
9PM: Peak Net Demand
4 hours - 616 MW
PND already occurs at near-zero solar
ND at 9PM already higher than at 6PM
Generation (MW)
2000
1500
1000
500
0
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM
10:00 PM
Net Demand
Solar Generation
FPLNW Load

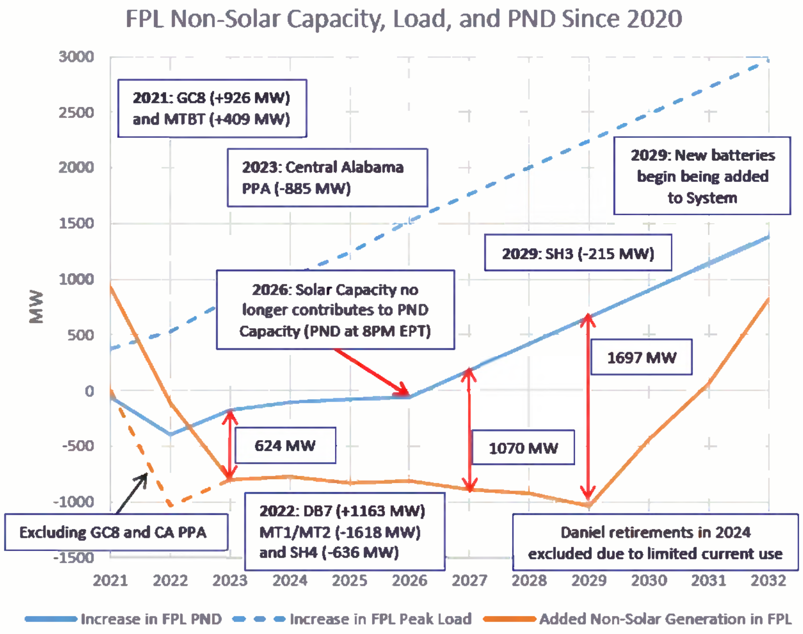

FPLNW Forecasted P80 Day, April 2026
4 hours - 771 MW
Generation (MW)
2000
1500
1000
500
0
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM
10:00 PM
Net Demand
Solar Generation
FPLNW Load

Converting the seasonal P80 Net Demand forecast to a PND forecast reduces room for planned Overhauls and Maintenance Outages

Possible Short-Term Countermeasures (2024-2026)

1. Reduce number and/or length of planned Overhauls
2. Pre-planned firm power purchases during periods of insufficient reserves
3. Dispatch Manatee 1 and/or 2 within 48 hours for duration of insuffient reserves
4. Include the use of DSM in normal operations to mitigate periods of insufficient reserves
   - DSM forecast must be adjusted lower for lower load at PND
   - Non-Firm power purchases and/or delaying planned Overhauls can restore margins to acceptable levels if possible

How has PND and Non-Solar Capacity Changed Since 2020?



- PND grows much slower than peak load until 2026 due to new solar constructions
- 624 MW difference in non-solar generation growth vs. PND growth is reflected in availability to schedule Overhauls
- Difference remains mostly constant until 2026, but grows significantly afterwards until batteries are added to the system
- FPLE issues seen in 2022 were mitigated by unplanned reliance on DB7 commissioning, tagged generation from GC8 Peakers before July 22nd, and excess FPLNW generation July 22nd onwards (IPT)

FPL.

Responding to the results of the PND Analysis

Possible Long-Term Countermeasures (2026+)

1. **Install more dispatchable generation**
   – Construct batteries on a more aggressive schedule
      -- 4-hour batteries needed to bridge gap between 6 and 10PM
      -- Batteries currently needed in FPLNW to replace margin lost from Central Alabama PPA expiration
      -- Batteries will be needed in FPLE starting in 2026 to keep up with forecasted load increases at 8PM
   – Construct new conventional plants
      -- Peakers address other operational issues with increased solar capacity and unit cycling discussed on next slide
2. **Long-term PPA contracts (FPLE or FPLNW)**

Other Operational Issues with Solar

- **Reduced Margin will also limit ability to schedule Maintenance Outages**
- **Ramping Capabilities and Solar Curtailments**
  - Increased daily cycling of conventional units
  - Missed RFCs will result in additional cycling and/or solar curtailments
- **Solar Forecasting Uncertainty**
  - A less accurate solar forecast will lead to increased daily cycling, increased solar curtailment, and decreased availability for scheduled maintenance outages
- **Solar power swings**
  - 200-500 MW deviations in 5-10 minutes in FPLE have been seen