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June 9, 2025

Mr. Adam Teitzman
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 Direct Testimony and Exhibits of Tony Georgis on behalf of the Florida Retail Federation. This filing is being made via the Florida Public Service Commission's Web Based Electronic Filing portal.

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

Sincerely,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony and Exhibits of Tony Georgis has been furnished by electronic mail to the following parties on this 9th day of June, 2025:

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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**
	)	

DIRECT TESTIMONY OF TONY GEORGIS

ON BEHALF OF THE FLORIDA RETAIL FEDERATION

JUNE 9, 2025

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT EMPLOYMENT POSITION.

A. My name is Tony M. Georgis. I am the Managing Director of the Energy Practice of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Blvd, Suite 450, Lakewood, Colorado 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Florida Retail Federation. The Florida Retail Federation is an established association of more than 8,000 members in Florida. Many of the FRF's members are retail electric customers of Florida Power & Light Company ("FPL"), including the territories previously served by Gulf Power Company, and these members purchase electricity from pursuant to various FPL rate schedules that are subject to Commission review and approval.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I have a Master of Business Administration degree from Texas A&M University, with a specialization in finance. Also, I earned a Bachelor of Science in Mechanical Engineering from Texas A&M University. In addition to my undergraduate and graduate degrees, I am a registered Professional Engineer in the state of Colorado.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I am the Managing Director of NewGen's Energy Practice. I have more than 25 years of experience in engineering and economic analyses for the energy, water, and waste resources industries. My work includes various assignments for private industry, local governments, and utilities, including sustainability strategy, strategic planning, financial and economic analyses, cost of service and rate studies, energy efficiency, and market research. I have been extensively involved in the development of unbundled cost of service ("COS") and pricing models during my career. A summary of my qualifications is provided within Exhibit TMG-1 to this testimony.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony before the Florida Public Service Commission, ("Commission") in the prior Florida Power & Light Company ("FPL") base rate case, Docket No. 20210015-EI, and in Duke Energy Florida, LLC's most recent base rate case, Docket No. 20240025-EI. I have also submitted testimony to the Public Utility Commission of Texas, California Public Utility Commission, the Indiana Utility Regulatory Commission, as shown in my resume and record of testimony included as Exhibit TMG-1.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My testimony addresses several key aspects of FPL's filing in this docket and makes the following basic findings and recommendations:

1. **Resource plan and capital spending**.

   - There are serious deficiencies in FPL's resource plan that underlies its proposed capital investments in the test years. FPL has been over-aggressive in adding solar photovoltaic ("PV") resources to its system in recent years.
   - These solar PV additions are shifting the hour in which system peaks are expected to a time of day where solar is an ineffectual, generally unavailable resource. This has created operational and reliability concerns that are magnified by the material growth FPL expects in new customer accounts, most of which are weather sensitive residential loads that will add to peak demands.
   - Securing reliable, firm, dispatchable capacity resources to serve the growing net peak demand that has become the driver of FPL's resource and operational planning through at least the end of this decade.[1]
   - Although FPL now proposes to scale back its previously planned solar investments in the test years, I recommend that FPL further curtail its solar PV investments in the test years and recommend against solar-based SOBRA base rate increases for 2028 and 2029.

[1] *See* Exh. AWW-1, page 17 of 30 (Florida Power & Light Resource Adequacy Study prepared by Energy + Environmental Economics (E3)).

2. **Cost of service study ("COSS")**. Significant revisions are required to the FPL COSS. These fall into the following categories:

- FPL failed to update the COSS for expected test year peak system conditions.
- FPL's COSS contains significant errors in the classification of costs and derivation of cost allocators. These result in more than $150 million in costs being incorrectly classified as energy-related rather than demand-related. I explain the nature of these errors and the corrections required to the COSS.
- Based on system conditions, and following basic cost causation principles, FPL should allocate its demand-related production and battery energy storage costs using a four coincident peak ("4CP") method and should not adopt the twelve coincident peak and 25% average demand ("12CP and 25% AD") method that FPL has proposed in this case.
- FPL's COSS systematically over-allocates utility production and transmission costs to non-firm interruptible service commercial and industrial customers by treating them as firm customers. The Commercial Demand Reduction ("CDR") and Commercial/Industrial Load Control ("CILC") credit offset that FPL incorporates in its COSS is not valued correctly and is inconsistent with how the FPL system and its customers have realized the benefits of these programs in the past.

3. **Revenue allocation**.

- The COSS errors distort FPL's cost of service results, which in turn materially skew the utility's proposed revenue allocation of increases among customer classes.

- Because the application of judgements and approximations are part of any cost of service analysis, it is appropriate to place a tolerance band around the system average return so that all customer classes falling within than band receive a system average increase. FPL should, but does not, apply this step in its proposal.
- The principle of gradualism means placing reasonable limits on base rate increases to avoid rate shock. FPL's application of gradualism uses total revenues, rather than base rate revenues, to measure the impact on customer classes. Total revenues include costs recovered in FPL's various cost recovery mechanisms that are not in issue in this case and should not be considered when assessing the impact of the base rate increases.
- Overall, I conclude that, due to the material errors in the FPL COSS, its results cannot be relied upon for imposing above system average increases on the general service demand, curtailable, and interruptible service classes. Also, FPL should apply a tolerance band of +/-15% when assigning revenue increases and measure gradualism impacts based on the proposed change in base rate revenues. I recommend that any base rate increases that the Commission approves for FPL be assigned among rate classes on an equal percentage basis tied to the approved system average increase for the 2026 and 2027 rate increases, if any, just as FPL proposes to apply its base rate increases for the years 2028 and 2029 for its "SOBRA" investments.

4. **CDR and CILC interruptible credit**.

- The basic value of load management programs such as the CILC/CDR programs is the amount of generation capacity and associated costs that have been avoided by the non-firm service option. Over several decades, CILC/CDR participants, which currently offer roughly 1,000 MWs of reliable emergency capacity, have allowed FPL to avoid the construction of hundreds of MWs of capacity.
- FPL's proposed 29% reduction to the CILC and CDR credits is not justified. I explain that the current credits are undervalued.
- The system benefits and value of these programs are heightened through the term of this proposed rate plan given the very limited capacity resource alternatives that are available to FPL.
- I recommend that FPL increase the CILC/CDR credit by 10% (i.e., from \$8.76/kW-month to \$9.63/kW-month) through the year 2030, or such longer time as FPL requires to add 1,000 Megawatts ("MW") of dispatchable fast ramping generation with reliable production for longer than six continuous hours.

5. **TAM and a four year base rate plan.**

- Given the deficiencies in the FPL filing, the Commission should reject FPL's highly contingent commitment to a four-year rate plan.
- Considering the substantial organic revenue growth projected from new customer accounts, the uncertainty associated with potential large load additions (i.e., data centers) within the rate plan, as well as the considerable

impact that recent and potential federal actions likely will have on FPL's resource planning and investment decisions, I recommend that the Commission proceed with caution and render a decision only regarding revenues and rates for the test years of 2026 and 2027, the years for which it has filed MRFs. Such a limited determination renders FPL's proposed Tax Adjustment Mechanism ("TAM") unnecessary.

Finally, while my testimony is limited in scope to the above matters, it should not be inferred that FRF endorses any other aspect of the FPL rate request.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following exhibits:

TMG-1	Resume and Record of Testimony of Tony Georgis
TMG-2	CDR and CILC Embedded Cost Value
TMG-3	Compiled Data Request Responses of Florida Power & Light Company
TMG-4	Excerpts from Florida Power and Light Company's 2024 and 2025 Ten Year Site Plans
TMG-5	Excerpts from National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual

III. FPL FILING OVERVIEW

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE FPL BASE RATE FILING.

A. FPL has proposed a series of significant base rate increases over the four years from 2026 through 2029. These are comprised of a proposed increase of roughly $1.55 billion (15.6%) in 2026, a $930 million increase in 2027 (a cumulative increase of

24.8%), and Solar and Battery Base Rate Adjustments ("SOBRAs") that are estimated to increase base rates by an additional $296 million in 2028 and $266 million in 2029.[2] The rate proposal will provide a cumulative increase in revenues to FPL of roughly $9.8 billion compared to current base rates.[3]

In its testimony, FPL points to a number of significant drivers to the proposed 2026 revenue increase, with the largest element being nearly $14 billion in rate base additions during the period 2024 to 2026 which increases the revenue requirement by an estimated $1.84 billion by itself.[4] A major element of the new and planned capital additions concern FPL's continued investment in utility scale solar PV power plants, but FPL effectively concedes that it has been overly aggressive in its solar PV additions.[5]

FPL remains a summer peaking utility,[6] but the utility's existing and planned solar PV power plant additions for the test years amplify the challenges in serving this summer peak as increasing solar production shifts the "net peak" (i.e., the peak net of solar output) from late afternoon to early evening. Currently, the FPL system peak typically

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[2] *See* Direct Testimony of Liz Fuentes on Behalf of Florida Power & Light Company at 6:5-8, 8:9-12, FPL Exh. IL-13, page 1 of 1 (Tax Adjustment Mechanism Amount) (showing a 2028 and 2029 SoBRA revenue requirement of $296 million and $266 million, respectively).

[3] Additional revenue requirements as follows: $1.545 billion in 2026-2029, $927 million in 2027-2029, $296 million in 2028-2029, and $266 million in 2029.

[4] *See* Direct Testimony of Ina Laney on Behalf of Florida Power & Light Company at 27:1, 14-19 ("Laney Direct").

[5] *See* Direct Testimony of Andrew Whitley on Behalf of Florida Power & Light Company at 20:10-15 (discussing the "greater than 50% reduction in planned solar for 2026 and 2027 as compared to FPL's 2024 TYSP" and the "similar decelerations of solar deployment" in 2028-2029) ("Whitley Direct").

[6] *See, e.g.*, FPL MFR Schedule E-11, Att. No. 2 of 3, Page 1 of 40.

occurs at 4 to 5 PM; however, FPL estimates that the solar PV additions are driving the system net peak to 8 to 9 PM by the 2027 test year.[7] Since the sun is setting or has set completely by that time in the summer, the reliable capacity value ("firm capacity") of all of its solar PV production declines to *de minimis* levels (roughly 5% of nameplate rating) in that net peak hour, and reliable capacity to serve that load must come from other sources.[8]

FPL seems to have grasped the severity of the operational and system reliability challenges that its solar additions have created. Between its 2024 and 2025 Ten Year Site Plan ("TYSP") filings, FPL reduced its planned solar PV investments for the test years by half and accelerated the battery energy storage investments it now claims are needed for reliability.[9]

FPL claims that the combination of solar PV energy production and battery capacity is its most cost-effective resource option, but FPL subsequently conceded that the battery energy storage additions essentially are its only feasible near-term capacity option over at least the next five years.[10] In effect, FPL backed itself into a resource planning corner, and has created a system "duck curve" that both shifts the peak later in the day in the summer and requires fast response firm or dispatchable capacity to meet system

[7] Whitley Direct at 32:4-7 (discussing the shift in the 2026 test year); Exh. AWW-1, Page 30 of 30.

[8] Exh. TMG-3 at page 2 of 29 (FPL's Response to FIPUG Int. No. 8, Att. 1 of 1.)

[9] Whitley Direct at 20:16-22:15.

[10] Exh. TMG-3 at page 25 of 29 (FPL's Corrected Supplemental Response to Staff Int. No. 44, Att. 1).

peak ramping needs comparable to what California's clean energy mandates have created in that state.

This system net peak shift with the attendant increased need for fast response generation resources is driving several other material issues that directly affect this rate case. These include:

- The capital cost of both FPL's new solar additions and the accelerated installation of battery energy storage as capacity, as well as how FPL proposes to apply the solar and battery tax credits to the annual revenue requirements;
- FPL's proposal to adjust production related cost allocation to increase reliance on energy consumption rather than contribution to system peak demand;[11]
- Overstated performance and heat rate improvements of FPL's generation fleet;[12] and
- Commitment to a four-year rate plan without certainty in rates for the proposed term.[13]

To moderate the immediate rate impact of its decisions, FPL proposes to apply $983 million in clean energy tax credits in the 2026 test year ($385 million in solar production tax credits and $660 million in battery investment tax credits).[14] Notably, FPL proposes to apply the battery investment tax credits ("ITCs") as a one-time tax

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[11] Whitley Direct at 31:1-32:14

[12] *See* Direct Testimony of Thomas Broad on Behalf of Florida Power & Light Company at 7:13-8:13 ("Broad Direct"); Exh. TB-5, page 1 of 1 (showing FPL's claimed generating efficiency improvements include the addition of solar resources).

[13] *See generally* Direct Testimony of Scott R. Bores on Behalf of Florida Power & Light Company at 53:9-63:20 (discussing the elements of the four year plan by FPL) ("Bores Direct").

[14] Laney Direct at 36:5-7.

event.[15] This accounting treatment provides a first year moderation in base rate revenue requirements, but it also creates an immediate and dramatic increase in subsequent year revenue requirements to reflect the full rate impact of the battery investments. FPL states that it plans additional battery storage investments in the 2027 test year, so the one-time battery ITCs for that year mitigate the revenue impact of the expired 2026 credits, but the now-cascading revenue requirement effect to be borne by FPL consumers from the energy storage investments simply shifts another year. Also, as of this date, the continued availability of federal tax credits for solar and energy storage is very much up in the air.[16] The expiration of those credits would both undercut the claimed economic cost effectiveness of FPL's resource investment plan and essentially guarantee additional base rate increases after the test years.

Next, while FPL's solar PV investments are creating capacity and operational issues on the system, the utility points only to the energy benefits of its solar investments as the reason for allocating all of its production related costs and plant on a more energy-oriented basis. This more energy oriented allocation is seen in the proposed 12CP and 25% AD production allocation method. However, in 2024, FPL solar production amounted to only 8.5% of its total generation output and in the 2026 test year it is forecasted to comprise only about 13.6% of annual production.[17] Hence the increase in solar investment and its comparatively small impact on system energy production does

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[15] *Id.* at 43:4-20.

[16] The budget bill recently passed by the House of Representatives would terminate or phase out most clean energy production and investment tax credits after 2028.

[17] Exh. TMG-4, pages 25-26 of 40 (2025 FPL TYSP, Schedule 6.2 (Actual Energy Sources % by Fuel Type) & Schedule 6.2 (Forecasted Energy Sources % by Fuel Type)).

not justify a shift in how all production costs are allocated. In fact, I explain why the changing FPL system profile and characteristics should lead to a greater focus on FPL's net peak load growth that is magnifying the need for existing reliable and dispatchable firm capacity through at least the year 2030.

FPL also claims a significant improvement in the heat rate efficiency of its generation fleet by adding its solar energy production to the output of its fossil units.[18] This is misleading. Generation heat rates as a measure of production efficiency for fossil fuel power generation are typically measured in British thermal unit/kilowatt-hour ("Btu/kWh"), but this metric is not applicable to solar PV power plant efficiency since it does not burn fuel.

The pertinent FPL resource planning issue concerns the system consequences, both operationally and in the need for reliable capacity back-up, associated with the variable and intermittent solar PV energy generation that is not dispatchable and cannot be counted upon to meet the system peak demands at a time when that peak load growth is expected to grow as more and more customer accounts that are weather sensitive are added to the FPL system. These unavoidable solar PV limitations, particularly during the summer evening net peaks, are driving FPL's generation capacity operational decisions, infrastructure investments, reliability issues, and resource planning actions needed to reliably serve its net peak demands and firm load during those periods.

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[18] *See* Broad Direct at 7:13-8:13; Exh. TB-5, page 1 of 1 (showing FPL's claimed generating efficiency improvements include the addition of solar resources).

Finally, FPL has filed a contingent four-year rate plan which does not ensure there will be stability or certainty in the rates as eventually approved by the Commission. FPL describes its filing as a four-year rate plan which would not require any additional base rate changes in that period; however, the utility states that it will not commit to the four-year plan unless essentially every facet of its as-filed proposal is approved by the Commission.[19] In particular, FPL ties its commitment to the four-year rate plan to a variety of special rate treatments and conditions, specifically including an Tax Adjustment Mechanism ("TAM") proposal through which FPL would accelerate (or delay) reflecting certain deferred tax liabilities in rates in order to manage its reported earnings within the allowed return on equity ("ROE") range established by the Commission throughout the rate plan term.

IV. FPL RESOURCE PLANNING AND CAPITAL SPENDING

Q. PLEASE DESCRIBE FPL'S RESOURCE PLANNING AND ITS IMPACT ON THE PROPOSED RATE INCREASES.

A. The largest driver of the proposed 2026 base rate increase concerns $1.8 billion in revenue requirement increases associated with capital initiatives that increase rate base by $13.6 billion from 2024 levels.[20] This is heavily tied to:

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[19] Bores Dep. at 205:7-209:21.

[20] Laney Direct at 27:1, 14-19.

- Aggressive investment in large scale solar PV projects since 2021 (7,932 MW according to FPL witness Tim Oliver) as well as initial investments in battery-based energy storage,[21]
- Continued investment in solar PV in the test years of 2026 and 2027 combined with $2 billion in investment in 1,419 MW of battery energy storage,[22] and
- Additional infrastructure and upgrades needed to service a significant projected growth in new customer accounts.[23]

However, FPL's testimony and its most recent TYSP reveal that the utility's over-aggressive solar PV investments have and will continue to create material operational concerns and near term capacity needs tied to the shifting net peak demand, or "duck curve" performance inevitably associated with significant amounts of solar PV on electric utility systems.[24] As a result, since it filed its 2024 TYSP, for the period 2025-29 FPL has cancelled 4,172 MWs in previously planned solar additions (equivalent to 56 projects rated at 74.5 MWs) and added 2,530 MWs of battery energy storage.[25] Also, even though it is reducing its near-term solar installations, FPL still estimates that the remaining existing and planned additions will push its net peak to 8-9 PM by 2027. At

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[21] Direct Testimony of Tim Oliver on Behalf of Florida Power & Light Company at 5:11-13.

[22] Laney Direct at 29:4-5.

[23] *Id.* at 7:12-14, 34:15-21.

[24] Whitley Direct at 31:9-12.

[25] *Cf* Exh. TMG-4, page 40 of 40 (FPL 2024 Ten Year Site Plan at Table ES-1) (showing projected solar resource additions of 10,430 MW and projected battery additions of 1,422 MW between 2025-2029), *and* Exh. TMG-4, page 10 of 40 (FPL 2025 Ten Year Site Plans at Table ES-1) (showing projected solar resource additions of 6,258 MW and projected battery additions of 3,952.5 MW between 2025-2029). Note that in 2030, FPL plans to resume the prior level of planned annual solar PV additions. *See id.*

8-9 PM, solar contributes little or no energy or capacity to serve firm load. This circumstance in turn forces FPL to accelerate its battery energy storage expansion.[26]

Q. PLEASE FURTHER EXPLAIN THE INCREASED PENETRATION OF SOLAR PV AND RELATED IMPACTS TO THE FPL SYSTEM SUCH AS THE "DUCK CURVE."

A. Solar PV energy production is non-dispatchable and effectively provides energy aligned with the sunrise and sunset. In general, solar PV production begins in late morning, peaks at midday when available sunlight is at its peak unless storms or cloud cover impair output, and declines in the late afternoon as the sun sets. Solar PV energy placed on the system reduces the power generation required from conventional thermal or other dispatchable generation throughout the middle of the day. However, as the sun sets, the system load continues to ramp up and may increase at a dramatic rate during summer peak periods. FPL thus requires large amounts of dispatchable generation over a short period of time. This net load minus solar profile that the utility must follow with reliable capacity resources begins to resemble the profile or shape of a duck. This issue is now affecting generation operational decisions and FPL resource investments needed for reliability.

Q. WHAT IS THE IMPACT TO FPL'S SYSTEM AND ITS RESOURCE PLANS AS IT ADDS MORE SOLAR PV?

A. As FPL adds more and more solar, these operational concerns are magnified, and it must have more reliable and dispatchable generation available (operating reserves) to compensate for the inherent variability in solar production as well as the daily drop-off

[26] Whitley Direct at 20: 10-12

of solar production which drives the increased for more rapid response and dispatchable.

Furthermore, FPL remains a summer peaking utility,[27] but, as noted, as more solar production is added, the reliability value of the solar PV generation assets declines precipitously because the net peak shifts to the late evening when little to no solar PV energy or capacity is available. This is readily apparent in FPL's 2025 TYSP. Schedule 1 in the TYSP shows the reliable "firm capacity" associated with each of its existing generating resources.[28] For example, FPL attributes a summer firm capacity value of 39.77 MW to its Blue Cypress 74.5 MW facility added in 2018 (53.3% of its nameplate rating), and a 30.08 MW summer rating to its Beautyberry facility added in January 2024 (40.3% of its nameplate rating).[29] Schedule 8 to the 2025 TYSP, which shows FPL's planned and prospective resource additions and changes, attaches only a 4 MW summer firm capacity rating to all of its 74.5 MW solar projects (just 5.4% of the nameplate rating).[30]

As a practical matter, this means that, by 2027, FPL expects that all of its solar PV output, not just the incremental additions, will have negligible value in serving the system net peak in the critical summer peaking months and ramping periods.

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[27] *See, e.g.*, FPL MFR Schedule E-11, Att. No. 2 of 3, Page 1 of 40.

[28] FPL defines "firm capacity" as the amount of capacity that it can reasonably rely upon from a unit at the time of its summer and winter peaks. Exh. TMG-4, page 12-14 of 40 (FPL 2025 TYSP).

[29] Exh. TMG-4, pages 15-22 of 40 (2025 FPL TYSP, Schedule 1 (FPL Existing Generating Facilities as of December 31, 2024)).

[30] Exh. TMG-4 2025, pages 28-30 of 40 (FPL TYSP Schedule 8 (Planned and Prospective Generating Facility Additions and Changes)); *see also* Exh. TMG-3, page 2 of 29 (FPL Response to FIPUG Int. No. 8, Att.1).

Q. HOW DOES FPL ADDRESS THE RELIABILITY ISSUES OF SOLAR PV AND PEAK SHIFTING DURING THE TEST YEAR AND RATE PLAN (2026–2029)?

A. FPL's core resource planning through the proposed years of the rate plan (i.e., 2026-2029) concerns adding sufficient other generation capacity to reliably meet system needs and the loss of load probability ("LOLP") planning standard of 0.1 days per year threshold.[31] In other words, FPL wants its customers to pay for adding both solar energy production and reliable generating capacity.

FPL witness Whitley claims that the combination of solar additions backed up by 4-hour duration battery storage is the company's most effective resource option,[32] but FPL admits it could not add additional gas-fired combustion turbines until late 2029 or early 2030 "at the earliest."[33] In short, for the next five years at least, FPL has limited reliable capacity resource choices other than storage batteries to meet the need for firm capacity during the evening hours to meet the shifting net peak system demands.

Q. WHAT DO YOU RECOMMEND?

A. It is apparent that the planned solar additions during the test years and into 2028-29 are not needed for system reliability. In fact, they will likely amplify FPL's existing and expected operational and reliability challenges. As noted, FPL has proposed to reduce its near-term solar additions significantly to mitigate those concerns.[34] I recommend

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[31] *See* Whitley Direct at 15:1-12; *see generally* Exh. AWW-1.

[32] Whitley Direct at 20:1-20.

[33] *See* Exh. TMG-3 at page 25 of 29 (FPL Corrected Supplemental Response to Staff 3rd Interrogatory No. 44, Att. 1).

[34] *See supra* n.25.

that FPL suspend further solar additions in the test years altogether and focus instead on addressing demonstrated reliable capacity needs.

In that regard, it is important to note that FPL's existing CDR/CILC program offers more than 1,000 MWs of proven emergency capacity resource in the form of quick response customer load reductions and on-site standby generation that are dispersed throughout the FPL service territory. This resource and its value are discussed in more detail later in my testimony.

V. COST OF SERVICE STUDY ERRORS

Q. WHAT ERRORS OR ISSUES DID YOU IDENTIFY IN FPL'S COSS AND MFRS?

A. I identified four categories of errors which require adjustments in FPL's COSS:

1) The COSS should reflect the changing system peak conditions expected for the test years;
2) The classification of costs for most of the production and battery storage operating expense accounts must be corrected because fixed costs have been allocated to energy that are demand-related;
3) The allocation of demand costs to the customer classes in the COSS should reflect the summer and 4CP peaking method rather than the 12CP and 25% AD allocation method that FPL proposes to apply in this case; and
4) FPL's COSS systematically over-allocates utility production and transmission costs to non-firm interruptible service commercial and industrial customers by treating them as firm customers. The Commercial Demand Reduction ("CDR") and

Commercial/Industrial Load Control ("CILC") credit offset that FPL incorporates in its COSS is not valued correctly and is inconsistent with how the FPL system and its customers have realized the benefits of these programs in the past.

A. Cost of Service Study Functionalization Issues

Q. PLEASE DESCRIBE FPL'S COSS AND ITS USE.

A. FPL's COSS appears in Minimum Filing Requirement ("MFR") Sch. E-1 and was provided in Excel format in discovery.[35] In its model, FPL initially developed the FPL system-wide revenue requirement which includes, but is not limited to, FERC operating and maintenance expense accounts, taxes, other expenses, depreciation expenses, and rate base associated with providing electric service to customers.[36] FPL then takes each individual expense or rate base-related account and directly assigns or allocates the costs to the customer classes.[37]

Q. WHAT ARE THE INDUSTRY STANDARD STEPS IN DEVELOPING A COST OF SERVICE STUDY AND FOR ESTIMATING THE COST TO SERVE EACH CUSTOMER CLASS?

A. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual defines the industry standard for the key components and steps in a COS study. The NARUC Manual states after the test year revenue requirement is developed; the next three steps include:[38]

1. Functionalization

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[35] *See* Exh. TMG-3, page 4 of 29 (FPL Response to FIPUG Int. No. 11).

[36] *Id.*

[37] *Id.*

[38] Exh. TMG-5 at page 3 of 10 (NARUC Electric Utility Cost Allocation Manual).

2. Classification

3. Allocation of costs to customer classes

Step 1 includes translating the system-wide Test Year revenue requirement to functionalized costs (e.g., production, transmission, distribution, and customer related components). Within each of those functions, those costs are then typically classified as demand-, energy-, or customer-related costs. The final step takes the classified costs and aims to allocate them to the customer classes based on the customer class's unique characteristics or impacts to the utility system. This final step develops the total cost of service, or revenue requirement, for each customer class that would be recovered by retail rates.

Q. DID FPL'S COSS AND MFRS INCLUDE THIS LEVEL OF DETAIL AND EACH STEP?

A. No. The COS model provided by FPL does not provide a fully functionalized system revenue requirement or functionalized revenue requirement for each customer class. For example, the test year revenue requirement for FPL in 2026 is $9.6 billion.[39] Functionalizing the costs would provide or translate that $9.6 billion into the production, transmission, distribution, and customer components that sum or total the 2026 test year revenue requirement. In addition to the system total revenue requirement, functionalizing costs would provide the same functional revenue requirement for each customer class.

[39] FPL MFR Schedule E-1, Att. 4, Equalized Base Revenue Requirements.

Q. PLEASE EXPLAIN HOW FPL'S COSS MODEL DOES NOT PROVIDE FUNCTIONALIZED COSTS.

A. Rather than functionalizing costs, then classifying, and allocating to customer classes as described above, FPL's COS model directly allocates the individual expense and rate base accounts to the customer classes by classifying the costs in each account and allocating those dollars directly to the customer class. This skips the first step of functionalizing costs prior to classifying the costs and allocating them to customer classes. While FPL's accounts are organized in production, transmission, distribution, and customer related accounts, there are other accounts that include shared administrative and general expenses and general plant which are not specific to an individual electric utility function.

The NARUC Manual states that shared expenses or accounts are to be functionalized by allocating them to the major cost functions (e.g., production, transmission, distribution, and customer).[40] These shared costs must be allocated to each function to develop the full system and customer class functionalized revenue requirement or COS. By simply providing the individual FERC expense or plant accounts and allocating each account directly to the customer classes, the FPL COS model effectively skips the functionalization step. This is problematic for common costs such as administrative and general expenses, general plant, and other shared costs. By not functionalizing those shared costs to the individual major functions, the FPL approach in its COS limits analyses for the for testing the validity of the COS results.

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[40] Exh. TMG-5 at page 3 of 10 (NARUC Electric Utility Cost Allocation Manual).

Q. IS FAILURE TO FUNCTIONALIZE COST DATA IMPORTANT?

A. Yes. Without the functionalization step, one cannot calculate or analyze the cost to FPL of providing fully embedded production service to customers. Functionalized costs inform rate design and valuation of certain services or products to specific customer classes. For example, the lack of a functionalized revenue requirement does not allow one to identify the production or transmission related revenue requirement portions of the full class COSS for the GSD-1 or CILC customer classes.

B. Failure to Reflect Cost Causation Based on Net Peak Demands

Q. HOW DID THE FPL COSS DERIVE CUSTOMER CLASS CONTRIBUTIONS TO THE FPL MONTHLY PEAK DEMANDS?

A. FPL used historical monthly system peaking data and each customer class's contribution to those historical peaks to develop the 12CP allocation factor.[41] The results of FPL's 12CP analysis are summarized in MFR E-11. These system peaks and the customer contributions to these monthly peaks were not updated to reflect the known and measurable changes expected by FPL in the Test Years of 2026 through 2029.[42] Most notably, FPL's COSS does not reflect the shifting of the net monthly peak demand to later in the evening in the summer months and each customer class's expected contributions to that shifted peak demand.[43]

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[41] *See e.g.*, FPL MFR Schedule E-11, Attachment No. 2 of 3, page 1 of 40; Exh. TMG-3, page 9 of 29 (FPL's Response to FRF's Int. No. 1, Att. 1).

[42] Exh. TMG-3, page 16 of 29 (FPL's Response to FRF Int. No. 13).

[43] *Id.*

Q. PLEASE DESCRIBE FPL'S ERROR IN NOT UPDATING THE TEST YEAR SYSTEM PEAK AND CUSTOMER CLASS CONTRIBUTIONS TO THE MONTHLY PEAK DEMANDS.

A. The NARUC Electric Utility Cost Allocation Manual defines this Test Year tenet stating, "the test year or test period . . . normally includes cost and sales data which are expected to be representative of those that will be experienced during the time the rates are likely to remain in effect."[44] FPL did not update the system load profiles, monthly peak demands, and each class's expected contribution to the new monthly peaks for the 12CP allocation factor.[45] This violates the matching principle of aligning the costs expected over the Test Year period with the system and customer consumption characteristics so both impacts on the system by customers and the costs imposed on the system are aligned. Specifically, the monthly coincident peaks and the customer class's contributions to those shifting peaks were not adjusted to reflect the expected conditions described by FPL witness Whitley.[46] FPL did not update or adjust the historical monthly coincident peak demands on the system and each class's contribution to those peaks to reflect the new, later peak system demands occurring later in the day at 8 pm versus the historical 5pm.[47]

FPL's approach creates a mismatch between the costs and customer characteristics and use of the system that is causing those costs. Aligning the Test Year period costs with

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[44] Exh. TMG-5, page 6 of 10 (NARUC Electric Utility Cost Allocation Manual).

[45] Exh. TMG-3, page 16 of 29 (FPL's Response to FRF Int. No. 13).

[46] *Id.*

[47] Whitley Direct at 32:4-7.

the customer class's use or impacts to the system over that same period is a fundamental element and industry standard to a COSS. By failing to update the class coincident peaks where material changes in system conditions are expected, FPL's COSS does not align Test Year costs with expected Test Year conditions and cost causation.

Q. WHY IS UPDATING THE CUSTOMER CLASS CONTRIBUTIONS TO THE EXPECTED SYSTEM CONDITIONS IN THE TEST YEAR IMPORTANT?

A. FPL has stated that this known and expected shift in system net peaking time is driving its resource planning decisions, capital investments, and elements of reliability operations.[48] By not updating the class CPs associated with this shift to reflect the expected operations during the test year and peaking later in the evening, FPL is not aligning the test year costs and expected generation resource investments to meet this new ramping and firm capacity issue quantified by the LOLP analysis with the same expected time period. As FPL has not aligned test year system conditions and customer classes' use of the system that are driving the costs, it is not accurately reflecting how each customer class is imposing costs on FPL for electric service. The COSS results for each class reflect the historical costs imposed on the system, not the known and expected costs imposed on the system during the test year. This inconsistency is a flaw in the accuracy and defensibility of the results as historical, rather than expected, conditions are used to allocate costs.[49]

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[48] *Id.* at 15.

[49] *See* FPL MFR Schedule E-11, Atts. 2 & 3 (showing Load Research Studies from 2022 and 2023); Exh. TMG-3, page 9 of 29 (FPL's Response to FRF's Int. No. 1, Att. 1).

Q. WHAT WOULD BE THE LIKELY IMPACT OF UPDATING THE CLASS COINCIDENT PEAKS TO ALIGN WITH NEW NET PEAK DEMANDS LATER IN THE EVENING?

A. While no data was available or provided by FPL,[50] I would expect adjusted CPs for each month to show a reduced allocation to commercial customer classes and an increase in the contribution of the residential class to the later net peak monthly demands. This is due to the typical consumption profiles of commercial and residential classes. Residential customer loads typically peak later in the evening, which is consistent with the shifting net peak load trend that FPL is expecting. Commercial customer loads, on the other hand, typically begin reducing consumption and their contribution to peak demands by 5pm, several hours before the now-shifted net peak demand. What is undisputed is that FPL, while asserting that its costs are caused in the test years by the shift to net peak demand, has entirely failed to reflect those costs in its COSS.[51]

Q. WHAT DO YOU RECOMMEND TO CORRECT THIS ERROR?

A. I recommend FPL correct their COS study and provide updated load research data aligned with the expected and known net peaking times for the test year period. This provides updated class contributions to the shifted peaks and accurate cost causation for production related investments. Based on the updated class contributions to the shifted peaks, FPL should develop a new 4CP allocation factor for the allocation of production and transmission related costs to the customer classes. If FPL does not

[50] Exh. TMG-3, page 16 of 29 (FPL's Response to FRF Int. No. 13).

[51] *Id.*

provide new load research and updated allocation factors, it should shift to using a 4CP allocation factor with the data currently available as discussed later in this section of my testimony.

C. Incorrect Classification of Production and Battery Storage Expenses

Q. PLEASE DESCRIBE THE ERROR IN FPL'S COS MODEL AND RESULTS RELATED TO CLASSIFICATION OF COSTS.

A. FPL's classification of costs for most of the production and battery storage operating expense accounts must be corrected because the FPL COSS allocates fixed costs to energy that are demand related based on their proposed allocation methodology.[52] By incorrectly classifying costs, FPL has incorrectly allocated costs among the customer classes.

D. O&M Expenses Misclassification

Q. HOW DOES FPL ALLOCATE AND CLASSIFY PRODUCTION O&M EXPENSES AS DEMAND- OR ENERGY-RELATED?

A. FPL classifies many FERC production expense accounts as a combination of energy- and demand-related costs. Other than production fuel expenses, most production O&M expenses are considered to be fixed (i.e., typically do not vary with the amount of electricity consumed by customers). Consequently, the classification of most non-fuel production operating expenses as fixed or demand-related aligns with the NARUC Electric Utility Cost Allocation Manual.[53]

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[52] FPL MFR Schedule E-4b, page 2 of 6.

[53] Exh. TMG-5, page 8 of 10 (NARUC Electric Utility Cost Allocation Manual).

FPL's proposed classification of costs for the production O&M expense accounts results in 48% of the total production O&M expenses classified as demand-related and 52% classified as energy-related.[54] As I explain, FPL's treatment of the production O&M expense accounts and each supervisory and engineering account is inconsistent with industry practice and cost-causation.

Q. PLEASE PROVIDE AN EXAMPLE OF FPL'S ERROR IN CLASSIFYING PRODUCTION O&M EXPENSES.

A. FPL allocates each production O&M supervisory and engineering expense account (e.g., FERC Account 500 or 510) to demand and energy-related costs based on the portion of labor costs in all other O&M expense accounts within the production account grouping and divided by the total O&M expenses in that grouping.[55] Thus, if the production-steam related total operating expenses are $100 million in FERC accounts 501 through 509, and the labor costs in these same accounts are $30 million of that total, FPL allocates 30% of the FERC account 500 production supervision and engineering costs to demand-related costs and the remaining 70% of the account to energy-related costs.

This is an incomplete and incorrect classification of costs as the costs associated with supervisory and engineering expenses are related to supervising and managing the activities or other staff / labor within the steam grouping of accounts. First, assuming all non-labor costs are variable is an incorrect assumption and contradicts other FPL

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[54] *See* FPL MFR Schedule E-4b, pages 1-2 of 6 (48% represents the sum of all production O&M expense accounts).

[55] *See, e.g.*, FPL MFR Schedule E-10, page 9 of 21.

cost classifications in the steam group of accounts. In addition, the activities and costs included in FERC Account 500 are rarely variable or vary with the amount of energy generated by steam production equipment. These costs are required for the steam operations regardless of the amount of energy generated, thus, industry practice is to classify these costs as fixed, or demand-related.

Q. HOW DOES FPL ALLOCATE PRODUCTION O&M EXPENSES?

A. FPL's COSS allocates the production supervision and engineering operating expense accounts, such as FERC account 500, according to the proportions of labor costs contained in other accounts in that account grouping.[56] It calculates the labor costs within each account in the account grouping and divides that by the total costs in all of the accounts. That ratio is then applied to the full supervisory and engineering account costs. Table 1 summarizes this calculation from their COSS.

Table 1 **Steam Production Supervision and Engineering Cost Classification**		
FERC Account	**Labor Costs**	**Total Costs**
501 Fuel	$550,317	$4,978,800
502 Steam	$2,138,168	$5,787,708
505 Electric Expenses	$1,318,691	$3,631,973
506 Misc. Steam Power Expenses	$6,363,039	$19,735,235
Subtotal	$10,370,214	$34,133,716
Percentage of Total	30.4%	69.6%
Classification of FERC Account 500		
	Demand	Energy
500 Supervisory and Engineering Total Operating Expenses $4,062,944 (Percentage of Total)	$1,234,369 (30.4%)	$2,828,575 (69.6%)

[56] *Id.*

Q. DOES FPL'S TREATMENT AND ALLOCATION OF PRODUCTION O&M SUPERVISION AND ENGINEERING EXPENSES PROPERLY FOLLOW THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL RECOMMENDATION?

A. No. FPL's treatment is not correctly allocating costs based on the NARUC recommendations for the production supervisory and engineering accounts.

Q. PLEASE EXPLAIN.

A. These varied accounts include labor costs to supervise or provide engineering within the FERC account grouping, such as supervision and engineering for steam or nuclear production operating activities. NARUC's cost allocation manual recommends allocating the costs in supervision and engineering FERC accounts, such as steam operating expense Account 500, based on the proportions of labor costs within the other steam production operating expense accounts and then allocating the supervision and engineering costs according to the ratio of labor costs classified as demand versus energy in those other accounts. Table 2 illustrates the proper application of the NARUC recommendation.

Table 2 Corrected Labor Cost Classification for Allocation of Supervisory and Engineering Costs		
FERC Account (Labor Costs Only)	**Demand**	**Energy**
501 Fuel	$550,317	$0
502 Steam	$2,138,168	$0
505 Electric Expenses	$1,318,691	$0
506 Misc. Steam Power Expenses	$6,363,039	$0
Subtotal Labor	$10,370,214	$0
Percentage of Total	100%	0%
Classification of FERC Account 500		
500 Supervisory and Engineering (Apply Subtotal Portions of Labor Costs) (Percentage of Total)	$4,062,994 (100%)	$0 (0%)

Q. WHAT IS THE DIFFERENCE BETWEEN FPL'S PROPOSED ALLOCATION AND THE CORRECTED ALLOCATION CONSISTENT WITH THE NARUC COST MANUAL?

A. FPL's incorrect calculations result in 30.4% ($1,234,369) of the $4,062,994 total FERC Account 500 Steam Operating Expense Supervision and Engineering costs classified as demand, and 69.6% ($2,828,575) classified as energy. The correct application of the NARUC methodology results in 100% or $4,062,994 of FERC Account 500 Supervision and Engineering costs classified as demand related as seen in Table 2. That is a difference of $2,828,575 moving from energy to demand related costs.[57]

[57] $4,062,994 - $1,234,369 = $2,828,575

Q. IS FERC ACCOUNT 500 PRODUCTION OPERATING SUPERVISION AND ENGINEERING THE ONLY O&M EXPENSE ACCOUNT FPL INCORRECTLY CLASSIFIED IN THE COSS?

A. No. This is merely one example of a mistake repeated throughout each supervisory and engineering expense account within the production function and costs, which includes nuclear, solar, production other, and battery storage FPL accounts.

Q. ARE THERE OTHER EXAMPLES OF FPL'S CLASSIFICATION OF PRODUCTION COSTS CONTRADICTING ITS TREATMENT OF THE SUPERVISORY AND ENGINEERING COST CLASSIFICATION?

A. Yes. For example, FERC Account 506, miscellaneous steam expenses, is classified as 100% demand-related costs in its COSS.[58] However, when FPL evaluates all the FERC steam operating expense accounts to derive a demand- and energy-related portion of FERC account 500, production operation supervisory and engineering costs, it allocates only $6,363,039, or 32% of the total miscellaneous steam expenses to demand as seen in Table 1, while the remaining 68% is classified as energy-related or variable. In short, FPL's treatment of these costs is internally inconsistent within the COSS. This treatment of 32% of the FERC Account 506 miscellaneous steam expenses to derive an allocation for the FERC Account 500 supervisory and engineering expenses as demand-related contradicts FPL's assigning 100% of those same costs to demand-related when allocating the FERC Account 506 miscellaneous steam expenses to the customer classes.

[58] *See* FPL MFR Schedule E-4b page 1 of 6, line 5.

Q. WHAT IS THE INDUSTRY PRACTICE FOR CLASSIFYING LABOR COSTS?

A. Labor costs are considered a fixed cost and rarely vary with the amount of electricity or kWh's generated or consumed. Thus, industry practice and NARUC recommendations are to classify labor costs as fixed and demand-related for the production function and operations.[59]

Q. WHAT IS YOUR RECOMMENDATION FOR THE CLASSIFICATION OF THE PRODUCTION O&M ACCOUNT EXPENSES?

A. I recommend that the production O&M expense accounts be corrected and adjusted to accurately reflect NARUC recommendations and the fixed cost nature of the expenses similar to the example provided in Table 3. Correcting these O&M expense account classifications shifts $169 million from energy-related to demand related costs in production as shown in Table 3.

[59] Exh. TMG-5, page 8 of 10 (NARUC Electric Utility Cost Allocation Manual).

Table 3 Summary of Corrected Production Expense Account Classification				
FERC Account	**FPL Proposed**		**Corrected**	
	Demand	**Energy**	**Demand**	**Energy**
Prod. Steam	$28,148,092	$36,193,162	$40,454,600	$23,886,653
Prod. Nuclear	$142,635,744	$137,708,222	$260,876,763	$19,467,203
Prod. Solar	$14,674,670	$21,222,450	$26,575,353	$9,321,768
Prod. Other Renewables.	$12,571	$1,910,297	$12,571	$1,910,297
Prod. Other	$75,657,534	$84,692,926	$102,129,919	$58,220,540
Total	**$261,128,611**	**$281,727,057**	**$430,049,206**	**$112,806,461**
	48%	**52%**	**79%**	**21%**
Difference from Proposed			**$168,920,595**	**($168,920,596)**
			65%	**-60%**
Notes: 1. COSS model provided in FIPUG 1st Int No. 11 Att. No. 1. NOI Classification Tab. 2. COSS Model WP and Adjusted NOI Classification Tab.				

E. Production Cost Allocation Errors

Q. PLEASE EXPLAIN HOW FPL PROPOSES TO ALLOCATE PRODUCTION COSTS TO THE CUSTOMER CLASSES IN THIS PROCEEDING.

A. FPL proposes in this case to apply a 12CP and 25% AD (average demand) method to allocate production costs in its COSS.[60] This method effectively splits each production related expense or rate base item into 75% demand-related and 25% energy-related.[61] From there, the 75% of the production related expense or rate base item classified as demand-related is allocated to the customer classes based on the class's 12CP or 12

[60] Dubose Direct at 20:19-22.

[61] Whitley Direct at 5:7-10.

months of contribution to the FPL system coincident gross peak demand. The 25% of the production costs related to average demand is effectively the same as energy consumption. Thus, the 25% of production costs are then allocated to the customer classes based on their annual energy consumption. This is a change from FPL's currently approved production allocation method, which uses a 12CP and 1/13 AD allocator.[62]

Q. HOW DOES FPL JUSTIFY THE USE OF THE 12CP AND 25% AD FOR ALLOCATING PRODUCTION COSTS TO CUSTOMER CLASSES?

A. FPL witness Tara Dubose points to FPL's increasing installation of large scale solar PV projects as the primary reason for proposing adoption of the 12CP and 25% AD method.[63] FPL cites solar PV's lack of fuel costs that has reduced fuel costs for all customers, and the fact that solar PV primarily provides energy and not capacity benefits to FPL as key reasons for inclusion of the 25% AD component to allocating production costs.[64]

Q. DO YOU AGREE WITH FPL'S RATIONALE?

A. No. FPL production cost allocation should focus on the growing system peak demands that are actually driving FPL's resource needs.

Q. PLEASE EXPLAIN THE ISSUES WITH FPL'S SELECTION OF THE 12CP AND 25% AD ALLOCATION FOR PRODUCTION COSTS.

A. The 12CP and 25% AD allocation approach is not appropriate for how FPL's system is planned and will operate during the Test Years. The 12CP and 25% AD method is

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[62] DuBose Direct at 20:19-22.

[63] *Id.* at 21:1-22:16.

[64] *Id.* at 22:1-5.

also inconsistent with its resource planning criteria, LOLP analysis, and basic cost causation principles.

Q. PLEASE EXPLAIN.

A. Based on the historic system data provided, and used for COSS allocators, FPL's system is a summer peaking system with the four highest peaks in June, July, August, and September.[65] In addition, FPL witness Whitley and the E3 LOLP analysis appended to his testimony further detail summer operational constraints and a continued shift of the net system peak demands in the Test Year summer months.[66] FPL witness Whitley also explains how FPL's generation investment and operational decisions are focusing more on summer reliability and net peaking issues.[67] These peaks are driving FPL's resource and generation related infrastructure decisions during the 2026 and 2027 Test Years. As discussed above, FPL is significantly reducing near-term solar additions because those additions have become an impediment to reliable and efficient operation in the near term.[68] The allocation of production costs in the COSS needs to match up with this system condition.

Also, as I noted above, FPL's current and test year solar PV output accounts for a relatively small amount of FPL's generation in the test years and does not provide a reasoned basis for allocating all production costs based on the limited solar output, and

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[65] *See, e.g.*, FPL MFR Schedule E-11, Attachment No. 2 of 3, Page 1 of 40.

[66] Whitley Direct at 31:14-22.

[67] *Id.*

[68] *Id.* at 20:10-15.

particularly when solar production limitations are causing the operational and capacity issues discussed above.

Q. HAS FPL PROVIDED ADDITIONAL INFORMATION TO SUPPORT THE SELECTION OF THE 12CP ALLOCATOR?

A. Yes. In a response to an interrogatory, FPL provided a 2021 historical 12CP FERC Test analysis.[69] This response showed FPL's system typically met the FERC Three Peaks Test and a 12 CP could be considered indicative of the system. However, this analysis is premised on outdated historical FPL system characteristics and is not adjusted to the expected conditions in the Test Year.

Q. IS THERE AN ISSUE APPLYING THE FERC THREE PEAKS TEST WITHOUT CONSIDERING OTHER FACTORS SUCH AS FPL'S EXPECTED NET PEAKS AND SYSTEM OPERATING CHARACTERISTICS DURING THE TEST YEAR?

A. Yes. While the Three Peaks Test provides insight into the gross system peak of FPL historically, it does not consider how FPL is and will be operating and investing in the system in the Test Years, which serve as the effective basis for the revenue requirement and eventual rates for customers. Thus, the Three Peaks Test is less applicable and tells an incomplete story of FPL's Test Year conditions and cost drivers. FPL's decisions regarding generation investments, reliability, and system operations are less guided by gross peak and more driven by the net peak in the Test Years. As noted above, compared to the resource plan in its 2024 TYSP, FPL now plans to reduce solar additions and accelerate battery storage installations in the test Years. This changed

[69] Exh. TMG-3, pages 12-15 of 29 (FPL's Response to FRF Int. No. 12 & POD No. 6).

dynamic is now driving generation, resource planning, and operational costs and decisions as noted by FPL witness Whitley and discussed further in my testimony.[70]

Q. HOW DOES THE STOCHASTIC LOLP ANALYSIS AFFECT FPL'S OPERATIONAL AND INVESTMENT DECISIONS AND THE PROPER ALLOCATION OF PRODUCTION COSTS TO CUSTOMER CLASSES?

A. Ignoring for the moment the substantial questions associated with the stochastic LOLP exhibit attached to FPL witness Whitley's testimony, the LOLP analysis confirms the FPL system is a summer peaking system with increasing reliability concerns in the summer months that is driving generation related investment and operational decision, thus costs. This was noted in FPL witness Whitley's testimony, which detailed summer operational constraints, shifting of net peak demands, and highest probability of reliability issues is mostly concentrated in summer evenings.[71] In fact, when planned or scheduled maintenance outages during the spring or fall are removed from the LOLP results, the highest probability of reliability issues is almost solely concentrated in the four summer months. There were no probable outages identified in the winter months of November through March.[72]

Q. HOW DOES THE SHIFTING NET PEAK DEMAND IMPACT COST ALLOCATION FOR PRODUCTION COSTS TO CUSTOMER CLASSES?

A. As discussed above, the FPL system remains distinctly summer peaking, with system peaks most likely to occur in the four summer months of June through September.[73]

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[70] Whitley Direct at 15:1-12.

[71] Exh. AWW-1, page 30 of 30.

[72] *Id.*

[73] FPL MFR Schedule E-11, Attachment No. 2 of 3, Page 1 of 40.

FPL's accelerated battery storage investment targets the need for reliable capacity for short periods during peak summer evenings. Also, the substantial organic growth in customer accounts that FPL is projecting are primarily residential accounts that are weather sensitive and will add to the summer peaks.[74] These circumstances do not seem to change whether FPL uses the stochastic LOLP model or its traditional approach.

A 4CP allocation method much better reflects the system conditions that are dictating how FPL, by its own admission, is investing in and managing the system at least through the year 2030. In short, that method is much more aligned with cost-causation than the proposed 12CP and 25% AD method. In addition, as discussed previously in my testimony, FPL's current monthly CP's utilized in the COSS were not updated to reflect the net peak moving later in the evening during the Test Year period.

Q. HOW DO YOU PROPOSE ADJUSTING THE COSS TO REFLECT THESE EXPECTED AND KNOWN CONDITIONS ON THE FPL SYSTEM RELATED TO THE NET PEAK DEMANDS?

A. I recommend applying a new 4CP allocation factor adjusted to reflect the customer class's contribution to the expected later peak demand times for the summer months. The new 4CP allocation factor should be applied to production and transmission demand costs in the COSS to allocate costs to the customer classes. The 4CP is a more accurate representation of system and how FPL is planning for and constructing resources based on the LOLP analysis and FPL witness Whitley's testimony. 4CP allocator used for demand allocations for generation and transmission related operating

[74] *See generally* Exh. TCC-4 (FPL's Load Forecasting Process for 2026-2029).

expenses, depreciation expenses, and rate base results in adjusted revenue requirement allocations.

Q. WHY DO YOU ALSO RECOMMEND A NEW 4CP ALLOCATION FACTOR BE APPLIED TO TRANSMISSION-RELATED COSTS?

A. Transmission systems are constructed in the same manner as generation assets and infrastructure to meet system peak demands. Thus, the cost-causation for transmission costs aligns with and matches the generation system. Thus, I recommend changing the FPL proposed 12CP allocation factor for transmission related costs to the 4CP allocation factor.

F. <u>CILC Rate and CDR Credit Value COSS Misalignment</u>

Q. HOW DOES FPL ALLOCATE GENERATION COSTS TO THE CILC AND CDR CUSTOMER-RELATED CLASSES?

A. FPL allocates demand costs associated with generation plant to the CILC and CDR-eligible customer classes based 75% on their metered demand coincident with the 12 monthly peaks on the FPL system as well as 25% on average demand.[75] In effect, all metered load is considered firm load in the COSS.[76]

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[75] *See* DuBose Direct at 20:19-22.

[76] Exh. TMG-3, page 18 of 29 (FPL's Response to FRF's Int. No. 16).

Q. IS THERE ANY REDUCTION OR ADJUSTMENT IN THIS DEMAND ALLOCATOR AT THE SYSTEM COINCIDENT PEAKS TO RECOGNIZE INTERRUPTIBLE (NON-FIRM) CUSTOMER LOAD?

A. No, FPL does not adjust the customer class demand allocations to account for non-firm demand.[77] CILC and CDR customers and related customer classes are treated as firm capacity customers, even though more than 1,000 MW of that coincident peak demand included in the cost allocations is interruptible and FPL does not design or construct firm capacity to serve that load.[78] This is an expedient way to perform a COSS, but it systematically over-allocates production costs to FPL's non-firm interruptible customers.

Q. FPL'S COSS ADDS BACK INTERRUPTIBLE REBATES TO THE INTERRUPTIBLE CLASS SALES REVENUES IN THE FORM OF A "CILC INCENTIVE OFFSET." DOES THIS CORRECT THE BASIC PRODUCTION COST OVER-ALLOCATION ERROR IN THE COSS?

A. No. The COSS allocates FPL's embedded costs, and the CILC/CDR credit, while a negotiated level in recent years, is based on FPL's avoided costs. The CILC incentive offset on MFR Schedule E-5 reflects the rebate level and not the embedded cost benefits of the interruptible service. From a rate-setting standpoint, it is always hazardous to mix embedded and avoided costs concepts. This misaligns embedded costs and marginal avoided costs concepts in an embedded COSS by FPL.

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[77] *Id.*

[78] *Id.*

Q. PLEASE EXPLAIN.

A. The FPL analysis is an embedded cost of service study. To properly correct the systematic production cost allocation error, it is necessary to assess FPL's historic embedded production and transmission costs. As I explain below, that embedded value is approximately $33.64/kW-month, or well more than triple the current rebate level of $8.76/kW-month that FPL applies on MFR Schedule E-5.[79] Consequently, the study still significantly over-allocates production costs to the service classes with interruptible service participants because the revenue offset that FPL employs does not approach the embedded value. This materially understates the interruptible customer class rates of return shown in the COSS as I explain further below.

Q. WHAT IS THE EFFECT OF FPL'S ALLOCATION OF CAPACITY COSTS TO CILC AND CDR CUSTOMER CLASSES ON THE ACTUAL METERED DEMAND RATHER THAN THE FIRM CAPACITY AMOUNTS?

A. The essential purpose of a COSS is to assign and allocate a utility's embedded costs to match cost causation or how customer classes impose costs on the utility system. For example, customers served at transmission voltages are not allocated distribution costs because they do not use the distribution system and thus do not cause distribution plant to be constructed. Similarly, the need for FPL's production plant is driven by net firm demand and excludes non-firm load, which receives a lesser quality of service.[80] By allocating its production costs based on customer class metered demand, and not the

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[79] *See* Exh. TMG-2 at page 1 of 1.

[80] *See infra* Section VII (CILC/CDR Credit Value).

lower firm capacity amount reduced for interruptible capacity, FPL over-allocates costs to the interruptible customer classes.

Q. PLEASE EXPLAIN FURTHER.

A. FPL's non-firm CILC/CDR service option has allowed FPL to avoid planning and constructing generating capacity to serve that load for decades. By allocating the full embedded generation costs to the CILC and CDR customer classes at the measured demand and not adjusting to reflect the non-firm amount of that peak demand in the allocation of costs, FPL's COSS misaligns cost causation with cost recovery. FPL should correct the COSS by crediting the full embedded cost value of the interruptible capacity back to the participating CDR and CILC customer classes.

Embedded costs evaluated in FPL's COSS represent the accumulated historical and recent costs for FPL's generation and transmission system. To properly match FPL's embedded costs to those classes, such production costs should only be allocated to CILC and CDR firm loads, and not the interruptible component. This would properly align cost allocation with cost causation.

Q. WHAT ARE THE EMBEDDED COSTS FPL HAS INCURRED FOR GENERATION AND TRANSMISSION SERVICE AND THE RELATED UNIT COSTS FOR THOSE SERVICES?

A. Exhibit TMG-2 details the system-level total costs for generation and transmission services in 2026 from FPL's MFR E-6 and translates those total costs to unit costs (i.e., per kW) based on the FPL system coincident peak billing determinants. I used FPL's coincident peak demand billing units to reflect the unit cost values during peak demand periods on the system because that best aligns with periods when the CILC and CDR services would most likely be activated by FPL.

This shows that generation unit costs, based on the coincident peaks, are $21.92 per kW, and the transmission costs are $6.11 per kW. The total unit cost for generation and transmission is $28.30/kW. Applying the 20% reserve margin to this total yields an embedded cost value of $33.64/kW. This amount reflects the full embedded cost of firm capacity that CILC/CDR participants allow FPL to avoid and represents the on-going embedded cost value of the CILC/CDR programs.

G. Recommendations

Q. WHAT ARE YOUR RECOMMENDATIONS FOR CORRECTING FPL'S COSS AND PROPOSED REVENUE ALLOCATION?

A. There are four significant errors in the COSS that erode its applicability and defensibility for the proposed rates:

1. FPL did not adjust historical class contributions to monthly peaks to reflect the expected changes on the system and shifting net peak issues driven by the increased amounts of solar PV on the system. This is a clear misalignment with the Test Year costs and cost causation concepts.
2. Specific to the CDR/CILC credit valuation, the erroneous allocation of production costs to non-firm load indicate that FPL's proposed allocation of above system average increases to its commercial and industrial service classes is not supportable.

3. There are fundamental errors in FPL's classification of costs for production and battery energy storage O&M expenses which total a $169 million shift from energy to demand-related costs.

4. The 12CP and 25% AD allocation for production costs does not accurately reflect FPL's resource planning decisions, generation investments, and shifting net peak demands on the system. A 4CP allocation is more appropriate and aligned with how FPL will be managing, investing, and operating the system during the Test Year period.

Q. WHAT IS THE RESULT OF THE COMBINED CORRECTIONS TO THE FPL COSS?

A. Each of the corrections results in a substantial shift toward parity of all the customer classes, and particularly the C&I classes. As I discussed, I did not have updated peak load data but expect that it would further reduce the allocation of production costs to commercial classes. Also, correcting the embedded COSS to reflect production cost allocation to non-firm service classes at the embedded cost value rather than the revenue offset approach adopted by FPL would dramatically improve the observed rates of return for those classes (i.e., bring CILC and applicable commercial classes closer to rate of return parity).

VI. REVENUE ALLOCATION

Q. FOR PURPOSES OF THIS CASE, HOW DO YOU RECOMMEND THAT FPL ALLOCATE ANY APPROVED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. As I discuss above, there are serious deficiencies in the COSS submitted by FPL. Also, FPL misapplies the gradualism principle in its proposed allocation of increased revenues. Apart from the cost allocation and other errors noted above, any COSS is built upon numerous judgements and assumptions, as is readily apparent from the testimonies of FPL witnesses DuBose and Tiffany Cohen regarding both revenue and expense estimates for the test years.[81] Consequently, the COSS results expressed in the form of an indexed rate of return relative to the system average is a rough approximation and not a precise value. To maintain stability in rate levels for gradualism purposes, a first step in the revenue allocation process should be to establish a tolerance zone within which a customer class should expect to receive no more or less than the system average increase. FPL did not perform that step at all, and I recommend that FPL establish a band of +/- 15% for that purpose. Finally, the basic function of the gradualism principle is to avoid rate shock caused by the decision in this base rate case. FPL uses total revenues to calculate its maximum increase of 150% of the system average rate increase.[82] Total revenues includes costs of adjustment

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[81] *See, e.g.*, DuBose Direct at 7:8-12:14 (describing the Load Research Study); Direct Testimony of Tiffany C. Cohen on Behalf of Florida Power & Light Company at 7:16-12:4 (describing the economic and load forecasting processes) ("Cohen Direct").

[82] Cohen Direct at 17:10-14.

clauses that are not being addressed in this case and should not factor into the assignment of base rate increases to customer classes.

In sum, rather than attempting to re-build the COSS from the ground up with data that may not be available, create a tolerance band based on the revised COSS results, and apply gradualism based on the change in base rate revenues, I recommend that FPL apply an equal percentage increase to all customer classes for any base rate revenue increase that the Commission may authorize.

VII. CILC/CDG CREDIT VALUE

Q. PLEASE DESCRIBE FPL'S CURRENT CILC/CDR PROGRAMS.

A. The Commercial/Industrial Load Control ("CILC") rate, and the successor Commercial Industrial Demand Reduction ("CDR") rider, are the largest and most successful FPL DSM programs for its commercial and industrial customers. They historically have been among the most cost-effective of all DSM programs implemented by FPL.[83] Combined, they currently provide approximately 1,004 MW of callable load reduction controlled by FPL, which provides exceptionally reliable capacity value to FPL and all of its other customers. [84]

The CILC rate incorporates an interruptible credit into the design of the rates and was the operative large customer interruptible rate for many years. This rate was closed to

[83] *See, e.g.*, Docket No. 20250048-EG, *Petition for Approval cf Forida Power & Light Company's Demand-Side Management Plan and request to Mod.fy Residential and Business On Call Tar.jf Sheets*, Att. 1, App'x B (Program-Level Cost-Effectiveness Analysis at PSC Form CE1 for the CDR program).

[84] Exh. TMG-3, page 17 of 29 (FPL's Response to FRF Int. No. 15, 2025 C/I Load Management Total).

new customers in the year 1996.[85] Customers participating in the commercial and industrial interruptible service program in subsequent years take service under an otherwise applicable rate schedule, typically GSLD or GSLDT, and receive the CDR credit to their demand charge. The participating CILC and CDR customers receive a reduction in their monthly bills through a direct percent reduction of the base CILC bill (currently 22%), or a bill credit of $8.76 per kW for the portion of their CILC or CDR that is interruptible.[86]

Q. HOW DOES THE OPERATION AND DEPLOYMENT OF THE CILC AND CDR PROGRAMS WORK?

A. Operationally, the CILC and CDR are identical in that both are interruptible by FPL on one hour notice for reliability purposes for up to six hours when needed to forestall a system emergency, capacity shortages (generation or transmission) or whenever, in FPL's sole judgement, actual or projected system load could require FPL to operate its generating units above their rated output (i.e., "peaking operation").[87] Moreover, in the event of an actual system emergency, the tariffs allow FPL to interrupt service to CILC/CDR participants on shorter notice (as little as 15 minutes, or even less if service to firm customers is threatened), and the interruption period may be longer than 6 hours.[88] Service interruptions under the programs by FPL can occur at any time of the year. FPL has complete control over the service interruption to participating customers

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[85] FPL CILC Tariff, FPL Eighth Revised Sheet No. 8.650, *available at* https://www.fpl.com/rates/retail-tariffs.html.

[86] Whitley Direct at 35:1-6.

[87] *See* FPL CILC Tariff, FPL Fifth Revised Sheet No. 8.652, *available at* https://www.fpl.com/rates/retail-tariffs.html.

[88] *See id.*

and there is no opportunity for a participating customer to avoid, or "buy through," any service interruption that FPL elects to implement. In fact, there are significant penalties under the tariff and CDR rider for energy consumption above a customer's contracted level of firm demand during an interruption event, and FPL can terminate a customer's participation for such non-compliance.[89] The result of these rigorously defined tariff conditions is an extremely reliable emergency resource that may be available faster than any FPL peaking supply resource. This resource is also dispersed throughout FPL's territory, so its availability is not limited by transmission constraints or other physical impediments.

In contrast, for peaking assets, FPL needs to acquire or encumber land, construct and operate the generation facilities, recover a return on the assets, pay property taxes on the land and assets, pay salaries and benefits to the staff required for those facilities, build or upgrade substations and other equipment to interconnect with the grid, maintain spare parts inventory, make regulatory filings for air permits and other licenses, incur fuel and other operating costs, and contend with all issues affecting unit start up and delivery of output to load centers (e.g., generator availability, location and transmission limits). As discussed previously in my testimony, FPL is now turning to battery storage investments in this Base Rate Case to supply reliable capacity during the emerging evening ramping and net peak periods, but the planned batteries are duration-limited at four hours, and the existing battery installations' discharge times

[89] *See, e.g.,* FPL CILC Tariff, FPL Sixteenth Revised Sheet No. 8.654, *available at* https://www.fpl.com/rates/retail-tariffs.html. (detailing the penalty provisions for exceeding usage above a Customer's Firm Demand).

are even shorter in duration.[90] For the interruptible resources participating in the CILC and CDR programs, FPL incurs none of those costs, emissions or system impediments.

Q. DOES FPL BUILD CAPACITY TO SERVE THE NON-FIRM PORTION OF CILC/CDR LOADS?

A. No. For resource planning purposes, FPL does not, and has not in the past, undertaken any obligation to reflect in its generation planning and construction, service to the non-firm CILC and CDR loads. This is routinely reflected in the FPL TYSP filings, which deduct commercial/industrial load management capacity values from the determination of Net Firm Demand upon which the utility calculates its capacity reserve margins and generation need determinations.[91] In short, CILC/CDR participants have, over several decades, provided a continuous stream of system reliability benefits and cost savings to FPL and all firm service customers.

Q. DO YOU AGREE WITH FPL'S PROPOSAL TO REDUCE THE INTERRUPTIBLE SERVICE CREDIT APPLICABLE TO NON-FIRM CUSTOMERS TAKING SERVICE UNDER CILC/CDR PROGRAMS BY ROUGHLY 29%?

A. No. The credits applied for this interruptible service should be *increased*, not decreased. FPL recognizes the continuing reliability value provided by its CILC/CDR interruptible customers and wants to retain all of the 1,004 MW of capacity value that current participants provide. FPL fails in this case to acknowledge the growing importance of these programs to the FPL system and all of its customers while FPL grapples with the

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[90] Exh. TMG-3 at page 11 of 29 (FPL's Response to FRF Int. No. 3); Oliver Direct at 8:20-9:15 (discussing FPL's currently in service and in construction storage facilities, which have a 2.2 hour to 3.0 hour duration range).

[91] *See, e.g.*, Exh. TMG-4, page 23-24, 27 of 40 (FPL 2025 TYSP, Schedules 3.1 and 7.1).

capacity needs created by intermittent solar production amid rising sales and peak demand. Capacity costs are not declining, and the reliability value of this interruptible load will only increase as FPL begins to place greater reliance on intermittent supply resources.

Q. PLEASE CONTINUE.

A. The CILC and CDR programs have allowed FPL to avoid or defer additional transmission and generation investments over the decades in which the programs have been in place and customers have been participating. FPL's generation and transmission systems are designed and constructed to meet expected net firm peak demands on the utility system, plus a reserve margin. In Florida, the accepted capacity additional reserve margin is 20%.[92] Thus, the capacity benefit that CILC and CDR participants provide includes the promised customer load reduction plus the applicable reduction in reserve margin. For example, if 100 MW were available for CILC and CDR, the actual benefit to FPL would be 120 MW in their resource plan. FPL admits that current CILC/CDR participation will allow it to avoid hundred of megawatts of capacity storage investment over the next five years.[93]

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE CURRENT CILC AND CDR VALUATION PROPOSED BY FPL.

A. FPL does not propose any changes to how the CILC/CDR programs work that would make them less valuable to the network as a resource. It simply proposes to pay participants less for providing those benefits. FPL witness Whitely proposes to reduce

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[92] Exh. TMG-4, page 11of 40 (FPL 2025 TYSP).

[93] Exh. TMG-3, page 6 of 29 (FPL's Response to FIPUG Int. No. 43).

the CDR incentive credit from \$8.76 per kW-month to \$6.22 per kW-month, a reduction of 29%, and to reflect a corresponding reduction in the credit incorporated in the CILC rate.[94]

Q. COULD YOU FURTHER DESCRIBE FPL'S STATED REASONS FOR REDUCING THE CDR CREDIT?

A. FPL arbitrarily proposes to reduce the CILC/CDR credit to a level that is expected to result in a RIM test of 1.49, which is higher than any currently approved FPL demand side management ("DSM") measure. [95] I describe the flaws in FPL's assessment below.

Q. WHAT WOULD THE CDR CREDIT BE IF A RIM TEST OF 1.0 WAS APPLIED SIMILAR TO THE PERFORMANCE OF FPL'S OTHER DSM PROGRAMS?

A. If the CDR credit were aligned with the other DSM measures with a RIM test of 1.0, the credit would be increased to \$9.33/kW, which is 6.5% higher than the current value.[96]

Q. WHAT IS THE EMBEDDED COSTS VALUE ASSOCIATED WITH CILC/CDR SERVICE?

A. As explained above, Exhibit TMG-2 demonstrates that the embedded cost benefit of the CILC/CDR programs is approximately \$33.64/kW. This amount reflects the full embedded cost of firm capacity that CILC/CDR participants allow FPL to avoid and represents the on-going embedded cost value of the CILC/CDR programs.

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[94] Whitley Direct at 40:14-16.

[95] Docket No. 20250048-EG, *Petition for Approval cf Forida Power & Light Company's Demand-Side Management Plan and request to Modify Residential and Business On Call Tar.jf Sheets*, Att. 1, App'x B (Program-Level Cost-Effectiveness Analysis).

[96] Exh. TMG-3, pages 19-21 of 29 (FPL's Response to FRF Int. No. 17).

Q. DOES FPL'S PROPOSED VALUATION FOR THE CILC/CDR CREDIT ALIGN WITH THE CURRENT STATE OF THE VALUE OF CAPACITY TO FPL OR IN THE BROADER ELECTRIC MARKET?

A. No; FPL's proposed valuation for the CILC/CDR program has not kept pace and has indeed lagged their own embedded cost increases for transmission and generation as well as current capacity market trends. Currently, there is significantly increasing demand for the development of new generation resources and capacity across the county and in the Southeastern United States. Much of this demand is being driven to serve the construction of data centers; however, organic system growth is also contributing to the increased need for capacity, as seen with FPL's TYSP and adding generation plant.

Q. IS THIS EMBEDDED UNIT COST MORE REFLECTIVE OF THE BENEFIT AND VALUE THE CURRENT CILC AND CDR CUSTOMERS PROVIDE FPL THAN FPL'S PROPOSED RATE?

A. Yes. If the forward-looking marginal new resource basis proposed by FPL witness Whitley is used to value the CDR incentive, it will not match the historical and on-going benefits these customers have provided FPL for more than two decades. Adopting FPL's proposed reduced incentive for the CILC and CDR interruptible customer loads substantially under-states the value provided by those customers to FPL and firm service.

Q. WHAT IS THE CURRENT STATE FOR CAPACITY IN THE ELECTRIC MARKET?

A. Currently, there is significant increasing demand for the development of new generation resources and capacity across the county and in the Southeastern United States. Much of this demand is being driven to serve the construction of data centers; however, organic system growth is also contributing to the increased need for capacity, as seen with FPL's TYSP and the addition of generation plant. The value of firm and dispatchable capacity resources remains stable and is increasing from current levels.

Further supporting the value of capacity and the upward pressure on prices and generation plant construction is the fact that FPL's strategy for addressing reliability issues is adding one new gas-fired combustion turbine each year. However, FPL has stated that it cannot get the combustion turbines in time as there is increased demand in the market and delays from the manufacturer.[97] The following figures show the near-term projected costs for firm capacity across the Southern United States which highlight the upward pressure on capacity costs.

[97] Exh. TMG-3, page 28 of 29 (FPL Corrected Supplemental Response to Staff Int. No. 44, Att. 1, page 1 of 5).

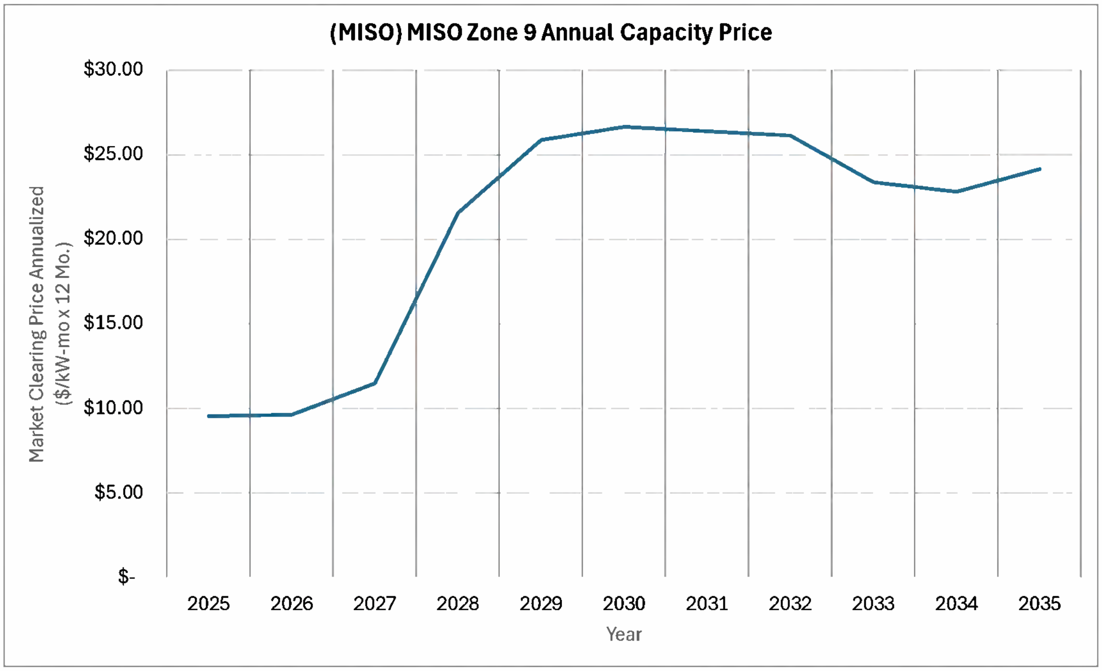

Figure 1: MISO Zone 9 & 10 Capacity Price Forecast Source; S&P Global Intelligence

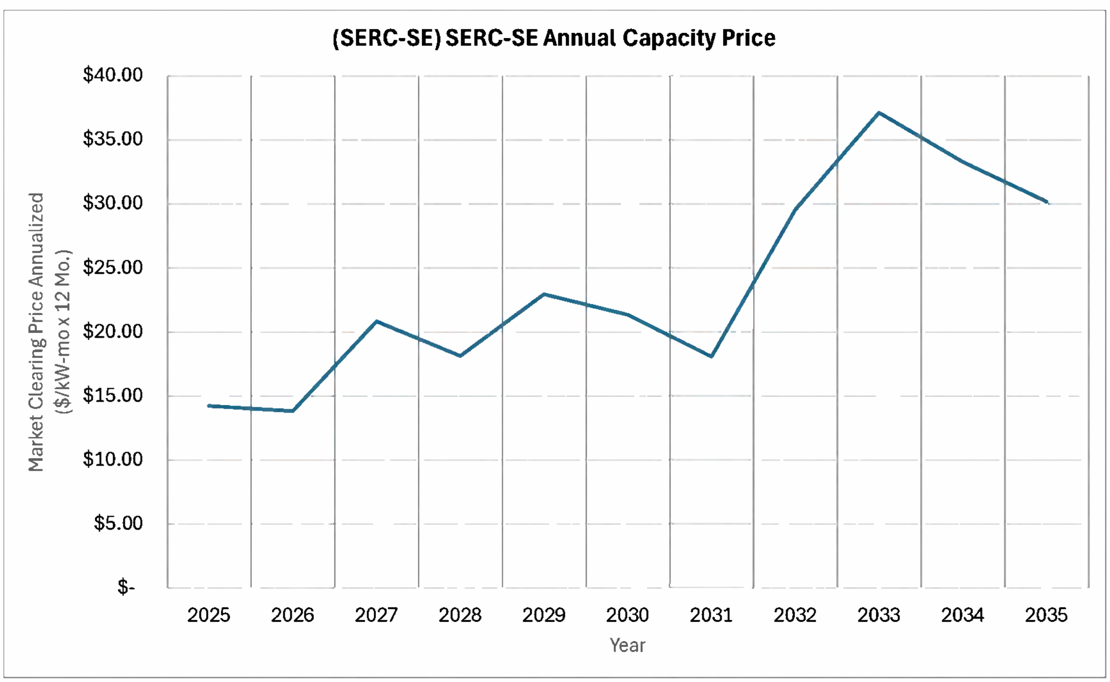

Figure 2: SERC-SE Capacity Price Forecast; S&P Global Intelligence

Q. WHAT ARE THE PROJECTED COMPOUNDED ANNUAL GROWTH RATES FOR 2026 THROUGH 2035 IN EACH OF THESE MARKET PROJECTIONS?

A. The compounded average annual growth rates for the years shown are 9.7% for MISO Zone 9 and 10, and 7.8% for SERC-SE. In each case, these projected costs for firm capacity are not decreasing, but are increasing substantially. In SERC-SE, the SERC reliability subregion that includes Florida, the capacity costs are projected to increase by 13.5% per year from 2026 through 2029, the same years as FPL's test year. In the MISO market forecast, the capacity costs are forecasted to increase at 28.0% per year from 2026 through 2029.

Q. COULD THESE ANNUAL GROWTH RATES BE USED AS AN ALTERNATIVE TO PROJECT THE VALUE OF CDR/CILC INTERRUPTIBLE CAPACITY?

A. Yes; the escalation rates seen in the above examples could be applied to the current CILC/CDR credit value to calculate a new value applicable during the period covered by the proposed FPL rate plan of 2026 through 2029.

Q. WHAT IS THE RESULT OF APPLYING THE ESCALATION RATES FOR CAPACITY TO THE CILC/CDR CREDIT?

A. Table 6 shows the annual CDR credit value when the average annual growth rate of 13.5% in SERC-SE is applied for 2026 through 2029.

Table 6
CDR Credit Projection with SERC-SE Capacity Increases ($/kW)

Current	2026	2027	2028	2029	Average (2026–2029)
$8.76	$9.94	$11.29	$12.82	$14.55	$11.47

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO INCREASE THE CILC/CDR CREDIT.

A. As noted, it is essential to consider historic and on-going system benefit that CILC/CDR participation provides, and that the continued participation, or expansion of participation, is especially crucial over the next five years given the limited capacity resource options available to FPL during that period. At a minimum, the credits should be increased based on a RIM measurement of 1.0, which as noted above would yield a credit increase to $9.33/ kW-month, or 6.5%.[98] However, it is also significant to note that FPL attributed a total resource cost ("TRC") score for the program was 40.06 in its latest DSM plan filing, which is indicative of the substantial system benefits of the tariff program.[99] I recommend that the CILC/CDR credit be increased by 10% to $10.07/kW through the year 2030, or until such later time as FPL is able to add 1,000 MW of reliable capacity capable of performing for at least 6 continuous hours. This level appropriately balances all of the factors described above.

VIII. TAX ADJUSTMENT MECHANISM (TAM)

Q. DO YOU SUPPORT APPROVAL OF FPL'S PROPOSED RESERVE TAX ADJUSTMENT MECHANISM ("TAM") IN THIS CASE?

A. No. The proposed TAM is not in the public interest and should not be approved.

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[98] Exh. TMG-3, pages 19-21 of 29 (FPL Response to FRF Int. No. 17).

[99] Docket No. 20250048-EG, *Petition for Approval of Forida Power & Light Company's Demand-Side Management Plan and request to Modify Residential and Business On Call Tariff Sheets*, Att. 1, App'x B (Program-Level Cost-Effectiveness Analysis at PSC Form CE1 for the CDR program).

Q. PLEASE EXPLAIN.

A. First, the TAM vehicle is only warranted, if at all, in the context of a four year base rate commitment by FPL. As noted above, it seems unlikely that FPL will garner approval of all the features that it claims are necessary to make a four year commitment. More important, even if FPL were willing to make that commitment, there seems to be far too much uncertainty for the Commission to authorize a base rate term that extends beyond the period covered by the test year MFRs. Continued strong sales and revenue growth, the emergence (or not) of new very large loads, continued investment in solar PV beyond what is approved for the test years, and the continued availability of federal clean energy incentives that are a driving force behind FPL's present resource planning choices are but a few of the significant areas of serious uncertainty beyond the test year horizon. All of those factors argue for the Commission to exercise caution.

Second, the dollars at issue with this mechanism involve the timing of recovery of tax expense from utility ratepayers.[100] In very general terms, rate-making typically assumes a straight-line amortization of capital assets when utilities may be applying accelerated depreciation methods for tax purposes. This tax-timing variance (i.e., under-stating depreciation and related tax benefits in earlier years) results in a deferred tax liability owed to ratepayers in later years. FPL's proposed TAM would allow FPL to manipulate how certain deferred tax liabilities to manage its reported regulatory earnings.[101] Hence, in a period in which high revenues might produce earnings above

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[100] Bores Direct at 56:6-13.

[101] *Id.*

the established range, FPL could accelerate the treatment of the deferred liabilities (increase its apparent costs) to keep its reported earnings within the range (i.e., avoid claims of excess regulated earnings). Presumably, the inverse would apply during periods of weak sales or higher costs. Since the accumulated deferred income tax ("ADIT") liability represents historic over-recoveries from utility customers, the initial question is why FPL investors should be permitted to effectively benefit twice from that tax-timing issue through operation of the TAM.

In sum, I recommend that the Commission reject the TAM proposal as unwarranted and not in the public interest. Relatedly, I recommend that the Commission deny the proposed solar and battery SOBRA's for 2028 and 2029 and confine its order in this docket to base rates for the two test years of 2026 and 2027. If the Commission approves the TAM, the Commission should direct that the TAM expire at the end of proposed term of the rate plan (i.e., year-end 2027).

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

Tony Georgis

Managing Director – Energy Practice

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EDUCATION

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Bachelor of Science in Mechanical Engineering, Texas A&M University

PROFESSIONAL REGISTRATIONS/ CERTIFICATIONS/COMMITTEES

Registered Professional Engineer (PE) Mechanical, Colorado

Registered Professional Engineer (PE) Mechanical, Louisiana

KEY EXPERTISE

Cost of Service and Rate Design

Expert Witness and Litigation Support

Financial / Economic Analysis

Strategic Planning

Sustainability

Mr. Tony Georgis has spent more than 25 years consulting in the energy and public utility markets and was a founding partner of NewGen. Mr. Georgis is currently the Managing Partner for NewGen's Energy Practice. His consulting career has focused on developing utility organizational and financial strategies with defensible, data-driven support. Tony's experience blends strategic planning, stakeholder engagement, expert witness, sustainability, and analytical expertise to deliver a unique, more integrated perspective of the market and utility financial performance. Like other leaders at NewGen, Tony applies his experience and expertise to generate insights and a roadmap to address the utility market's most complex issues and opportunities. His work includes leading strategic planning studies, expert witness testimony, financial and economic analyses, cost of service and rate studies, and market research.

RELEVANT EXPERIENCE

Sustainability, Energy Strategy, and Strategic Planning

Mr. Georgis leads and manages the development of strategic plans and Roadmaps for utilities, energy agencies, and municipal governments to guide decision-making in increasingly complex business environments. His strategic planning experience includes energy, water, wastewater, solid waste utilities, and local government entities. In support of strategic planning engagements, Mr. Georgis often facilitates internal planning teams and external stakeholder engagement activities to promote broad and/or targeted stakeholder input to the plans. A strategic plan or Roadmap development typically includes overarching strategic elements such as the organization's vision/mission, tactical components like projects and activities supporting and ensuring implementation, and tracking/reporting tools for the organization's measurement of progress to the plan.

Mr. Georgis has also led the development of clean energy and sustainability (or CSR) plans for cities, counties, and utilities to improve the triple bottom line (economic, environmental, and social) and energy performance. Mr. Georgis utilizes an enterprise-wide approach to sustainability to manage regulatory, customer, and financial demands while improving the triple bottom line. He has facilitated the development of city-wide sustainability plans and served as a sustainability subject matter expert. In his role, Mr. Georgis collaborated among internal and external stakeholders, including city/utility staff, key department managers, community representatives, utility customers, and non-profit or non-governmental organizations (NGOs). To support sustainability planning efforts, Mr. Georgis has developed optimization models to prioritize and identify the "next best dollar spent" to pursue sustainability goals while estimating total costs to implement. He has also implemented sustainability auditing/reporting tools such as greenhouse gas (GHG) inventories/reporting and the development of a utility-tailored version of the Global Reporting Initiative (GRI).

NewGen Strategies & Solutions

TONY GEORGIS

Managing Director – Energy Practice

Sustainability, Energy Strategy, and Strategic Planning (cont.)

Mr. Georgis' clients for sustainability, energy strategy, and strategic planning include:

- Alameda Municipal Power, CA
- City of Colorado Springs, CO
- City of El Paso, TX
- City of Fort Collins, CO
- City of Longmont, CO
- City of Palo Alto Utilities, CA
- Fort Collins Utilities, CO
- Lakeland Electric, FL
- Loudoun County, VA
- Tampa Bay Water, FL
- State of Vermont Department of Public Service, VT
- Western Area Power Administration, CO

Cost of Service and Rate Design

Mr. Georgis leads numerous utility financial planning, cost of service, and rate design projects. Specific tasks typically include:

- The development of the revenue requirement.
- Functionalization of costs.
- Allocation of costs to customer classes.
- Review of existing customer class criteria.
- Evaluation of line extension and facilities charges.
- Rate design.
- Transitioning of models for the client's future use.

He has also led the development of financial forecasting models to support long-term capital, expense, revenue budgeting, and decision-making. Mr. Georgis routinely facilitates workshops to develop utility rate strategies or rate studies and presents the study and financial recommendations to governing bodies, boards, and city councils. Mr. Georgis' clients for cost of service and rate design include:

- Alameda Municipal Power, CA
- American Samoa Power Authority
- Anaheim Public Utilities, CA
- Arizona Public Service, AZ
- Austin Energy, TX
- Benton Public Utility District, WA
- Burbank Water and Power, CA
- Central Cost Community Energy, CA
- City of Cleveland Electric Utility, OH
- City of Garland, TX
- City of Gonzales, CA
- City of Weatherford, TX
- City Utilities, Springfield, MO
- Clean Power Alliance, CA
- Cleveland Public Power, OH
- Colorado Springs Utilities, CO
- Farmington Electric Utility, NM
- Glendale Water and Power, CA
- Imperial Irrigation District, CA
- Lafayette Utilities System, LA
- La Plata Electric Association, CO
- Lincoln Electric System, NE
- Lubbock Power and Light, TX
- Merced Irrigation District, CA
- New Braunfels Utilities, TX
- Pasadena Water and Power, CA
- San Diego County Water Authority, CA
- San Jose Clean Energy, CA
- U.S. Army; Huntsville, AL
- Vernon Public Utilities, CA
- Victorville Gas Utility, CA

TONY GEORGIS

Managing Director – Energy Practice

Economic, Financial or Market Analyses

Mr. Georgis often provides technical, financial, and advisory support services for various energy and utility-related projects. He is an expert in developing financial pro formas, bond financings, performing scenario analyses, and evaluating market conditions to support project financing or feasibility decision-making. He has analyzed technical assumptions, optimized project financing, performed scenario/sensitivity analyses, and assisted clients in bidding processes. He has provided economic analyses of utility-scale renewable energy projects, power plant fuel conversions, LNG terminals, conventional/renewable distributed energy resources, and DSM/demand response program benefits. Mr. Georgis' clients for economic, financial, or market analyses include:

- Arizona Power Authority, AZ
- Austin Energy, TX
- CalRecycle, CA
- CPS Energy, TX
- Ember Infrastructure, NY
- Fayetteville Public Works Commission, NC
- Florida Municipal Power Agency, FL
- Fort Collins Utilities, CO
- Freeport Container Port, Grand Bahama
- Hawaii Gas Company, HI
- ISO-New England, MA
- Kings River Conservation District, CA
- Niobrara Energy Development, CO
- Solid Waste Authority of Central Ohio, OH
- Terrebonne Parrish, LA
- U.S. Army; Huntsville, AL
- Water and Power Authority, US Virgin Islands

Expert Witness and Litigation Support

Mr. Georgis has provided expert testimony since 2014 regarding electric utility revenue requirements, cost of service, rate design, and ratemaking issues before state and local regulatory bodies and courts. He has national experience providing litigation support regarding ratemaking matters at wholesale and retail levels in California, Florida, Indiana, and Texas.

Mr. Georgis' expert witness and litigation support experience include:

Public Utility Commission of Texas

- Centerpoint Energy Houston Electric, LLC; SOAH Docket No. 473-14-3897 and PUC Docket No. 42560
- City of Lubbock, Lubbock Power & Light; PUC Docket No. 52390
- City of Lubbock, Lubbock Power & Light; SOAH Docket No. 473-24-04313; PUC Docket No. 54657
- City of Lubbock, Lubbock Power & Light; SOAH Docket No. 473-21-0043 and PUC Docket No. 51100
- Oncor Electric Delivery Company; SOAH Docket No. 473-22-2695 and PUC Docket 53601
- Southwestern Electric Power Company (SWEPCO); SOAH Docket No. 473-21-0538 and PUC Docket No. 51415

Indiana Utility Regulatory Commission

- Indiana Michigan Power Company, Cause No. 45993
- Northern Indiana Public Service Company LLC (NIPSCO); Cause No. 45159

Northern Indiana Public Service Company LLC (NIPSCO); Cause No. 45772

TONY GEORGIS

Managing Director – Energy Practice

Florida Public Service Commission

- Duke Energy, Florida; Docket No. 20210016-EI
- Florida Power & Light Company; Docket No. 20210015-EI

Superior Court of the State of California for the County of Los Angeles

- City of Pasadena – Pasadena Water and Power; No. BC 677632

California Public Utility Commission

- Pacific Gas and Electric Company CPUC Application No. 21-06-021
- Southern California Edison Company CPUC Application No. 23-05-010
- San Diego Gas and Electric Company CPUC Application No. 22-05-016

PRESENTATIONS AND PUBLICATIONS

Mr. Georgis has presented at numerous industry associations and conferences, provided training for utility staff, and published several trade journal articles. These efforts have focused on utility finance, strategic planning, market trends/opportunities, and sustainability. Mr. Georgis' presentations and publications are detailed below.

Presentations

APPA Legislative Rally Preconference Seminar, 2020

- *Demystifying Distributed Energy Resources*

APPA Business and Finance Conference Preconference Seminar, 2019

- *Distributed Energy Resources: Risks and Opportunities*

APPA National Conference – Preconference Seminars, 2017/2018/2019

- *Distributed Energy Resources: Risks and Opportunities*

Washington PUD Association Finance Officers, 2016

- *Balancing Aging Infrastructure, Rates, and Residential Demand*

Harvard University Zofnass Program for Sustainable Infrastructure, 2011

- *Tools and Frameworks to Drive the Business Case for Sustainability*

Association of Climate Change Officers, 2010

- *SEC Climate Change Disclosure Guidance*

Platts Energy Markets Webinar, 2010

- *SEC Guidance on Climate Change Disclosures*

Global Commerce Conference, 2010

- *Leadership in Sustainability – Sustainability Decision Making, Implementation and Reporting*

University of Colorado Denver Managing for Sustainability, 2012

- *Regulatory Drivers for Sustainability*

Inter-American Development Bank, 2010

- *Transportation Sustainability and Climate Change Seminar*

Tire Industry Association Scrap to Profit, 2010

- *Evolution of the Carbon Markets and Opportunities for the Scrap Tire Industry*

Energy Utility and Environmental Conference, 2010

- *Evolution and Optimization of Energy Efficiency and Smart Grid Measures*

Tire Industry Association Recycling Conference, 2009

- *Carbon Credits and Recycling Products*

Tire Industry Association Recycling Conference, 2008

- *Selling Tire-derived Products to the Architectural and Construction Markets*

Articles

- *Growing Role for Demand Response in ISO Operations. Utility Automation and Engineering T&D*, November 2008
- *Recycling and Climate Change: A Primer. Resource Recycling*, August 2009
- *Recycling and Climate Change: Opportunities for Recycling as a Climate Change Strategy. Resource Recycling*, September 2009

Florida Public Service Commission
Florida Power and Light Company
Docket No. 2025011-E1
CILC and CDR Embedded Cost Basis Value

Line No.	Item	Amount ($000)	Amount ($000)	Comment or Source
	(1)	(2)	(3)	(4)
		Functional Estimate	Total Amounts	Tab / Source
1	**Production**			
2	Revenue Credits	$ (121,375,799)	(267,315,754)	MFR E-5
3				
4	OpEx	$ 550,208,004	$ 1,322,364,462	MFR E-4 E4b; including battery storage
5	Depreciation	$ 1,449,575,929	$ 3,081,921,683	MFR E-4 E4b; including battery storage
6	Taxes other than income	$ 417,272,597	$ 918,993,241	MFR E-4 E4b and prorated OpEx and Depr share of total to Production
7				
8	Income tax	$ (8,269,837)	$ (18,213,331)	MFR E-4 E4b and prorated OpEx and Depr share of total to Production
9	Total OpEx	$ 2,408,786,694	$ 5,305,066,054	Sum of Row 2, 4, 5, 6, and 8
10				
11	Rate Base	$ 45,358,429,191	$ 72,824,220,717	MFR E-4a
12	Return	$ 3,460,572,781	$ 5,556,045,933	ROR from E-1 multiplied by net plant
13	Total Production	$ 5,747,983,676	$ 10,593,796,233	
14			-5%	*Check to MFR E-1; expected to be lower as not all OpEx could be Functionalized in MFRs.*
15				
16				
17	**Transmission**			
18	Revenue Credits	NA	$ (267,315,754)	Row 2
19				
20	OpEx	$ 38,536,056	$ 1,322,364,462	MFR E-4 E4b and Row 4
21	Depreciation	$ 323,062,450	$ 3,081,921,683	MFR E-4 E4b and Row 5
22	Taxes other than income	$ 75,450,725	$ 918,993,241	MFR E-4 E4b and Row 6
23				
24	Income tax	$ (1,495,342)	$ (18,213,331)	MFR E-4 E4b and Row 8
25	Total OpEx	$ 435,553,889	$ 5,305,066,054	Row 9
26				
27	Rate Base	$ 15,297,110,527	$ 72,824,220,717	Row 11
28	Return	$ 1,167,076,666	$ 5,556,045,933	Row 12
29	Total Transmission	$ 1,602,630,555	$ 10,593,796,233	
30				
31				
32	12CP total system (kW)	21,852,220		MFR E-11
33	12CP - Months (kW-Mo)	262,226,641		Row 32 x 12 months
34				
35	**Unit Costs**			
36	Production Demand Revenue Requirement	$ 21.92	per kW	Row 13/Row 33
37	Transmission Capacity Demand Revenue Requirement	$ 6.11	per kW	Row 29/Row 33
38	Total	$ 28.03	per kW	Row36 + Row 37
39				
40	**Unit Costs with 20% Planning Reserve Applied**			
41	Production Demand Revenue Requirement	$ 26.30	per kW	1.2xRow 36
42	Transmission Capacity Demand Revenue Requirement	$ 7.33	per kW	1.2xRow 37
43	Total	$ 33.64	per kW	Row 42 + 41

<u>QUESTION</u>:
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.

<u>RESPONSE</u>:
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
Docket No. 20250011-EI
FIPUG's First Set of Interrogatories
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

QUESTION:
Please provide access to FP&L's class cost-of-service study models for the projected 2026 and 2027 test years that will allow FIPUG to run alternative production/transmission plant allocation methodologies (and potentially other changes) as directed by FIPUG's consultants.

RESPONSE:
In response to OPC's First Request for Production of Documents No. 14, FPL provided an Excel version of a COSS Roadmap for the 2026 Project Test Year, which is available in FPL's electronic data for OPC's First Request for Production of Documents No. 14 in the Cost of Service folder. The COSS Roadmap provided in response to OPC's First Request for Production of Documents, No. 14 provides a walk from the data starting point through the results of FPL's proposed Cost of Service Study.

Attachments Nos. 1 and 2 to this response provide live Excel versions of FPL's COSS Roadmap for the 2026 Projected Test Year and 2027 Projected Test Year, respectively, with two extra tabs that have inputs that can be changed for modeling purposes. The only changes from the COSS Roadmap produced in response to OPC's First Request for Production of Documents No. 14 are a few clean up items on the Table of Contents (including an indicator of the tabs that can be changed for modeling purposes) and the addition of dynamic MFR E-1 Attachment 1 and Attachment 2 worksheets.

DECLARATION

I, Tara Dubose, sponsor the answers to **Interrogatory Nos. 11, 12, 16** and co-sponsor the answers to **Interrogatory Nos. 10 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.

Tara DuBose

Tara Dubose

Date: 4/7/2025

Florida Power & Light Company
Docket No. 20250011-EI
FIPUG's Third Set of Interrogatories
Interrogatory No. 43
Page 1 of 1

QUESTION:
Please state the amount of capacity additions and related investment that FPL has avoided by continuing to offer interruptible service under the CDR Rider and CILC rate schedules.

RESPONSE:
Exhibit AWW-7 to FPL witness Whitley's direct testimony shows that the current CDR and CILC MW avoids future capacity of 100 MW of batteries in 2026, 224 MW of batteries in 2033, and 2,382 MW of batteries in 2034. The CDR and CILC megawatts also avoid and/or defer future generic capacity additions through the life of the analysis (through 2071). The associated CPVRR benefit of this avoided capacity is also shown in Exhibit AWW-7.

DECLARATION

I, Andrew Whitley, sponsor the answers to **Interrogatory Nos. 42 and 43** and co-sponsor the answers to **Interrogatory Nos. 40, 41 and 49** from FIPUG'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: 04/28/2025

QUESTION:
Please refer to FPL Witness Whitley's Direct Testimony:

a. Please provide FPL actual peak demands, by month, for the years 2019-2024.

b. Please provide FPL forecasts of its peak demand and net peak, by month, for the years 2025-2030

RESPONSE:
a. Please see Attachment No. 1 for the requested information.

b. Please see Attachment No. 2 for the requested information.

Florida Power & Light Company
Docket No. 20250011-EI
FRF's First Set of Interrogatories
Interrogatory No. 1
Attachment No. 1 of 2
Tab 1 of 1

FPL System Peak Demand

	January MW	February MW	March MW	April MW	May MW	June MW	July MW	August MW	September MW	October MW	November MW	December MW
2019	16,795	18,660	18,963	20,106	22,580	24,241	23,578	22,861	23,653	21,776	19,855	17,249
2020	17,514	18,429	20,602	21,594	21,932	24,499	24,483	24,166	24,493	22,214	19,496	15,773
2021	17,486	19,803	21,615	22,732	24,289	24,463	26,095	26,248	24,410	23,867	18,020	19,127
2022	21,027	19,011	20,778	22,411	24,256	26,415	26,011	26,429	26,413	23,580	22,997	20,609
2023	19,271	20,489	22,599	22,935	24,063	26,988	27,504	28,461	26,250	24,554	21,176	19,977
2024	18,595	18,147	20,596	21,148	26,889	27,296	27,722	28,266	26,477	26,287	19,524	18,408

Florida Power & Light Company
Docket No. 20250011-EI
FRF's First Set of Interrogatories
Interrogatory No. 1
Attachment No. 2 of 2
Tab 1 of 1

FPL System Peak Demand

	January MW	February MW	March MW	April MW	May MW	June MW	July MW	August MW	September MW	October MW	November MW	December MW
2025	23,042	21,421	21,414	22,918	25,189	27,189	27,656	28,312	27,191	25,394	22,162	20,935
2026	23,323	21,702	21,691	23,211	25,503	27,523	28,006	28,664	27,531	25,711	22,447	21,211
2027	23,648	21,892	21,883	23,419	25,733	27,772	28,258	28,925	27,782	25,946	22,651	21,401
2028	24,136	22,155	22,194	23,752	26,097	28,165	28,656	29,333	28,175	26,313	22,973	21,706
2029	24,603	22,464	22,455	24,033	26,409	28,507	28,996	29,687	28,515	26,632	23,246	21,958
2030	25,011	22,680	22,671	24,267	26,668	28,794	29,278	29,982	28,800	26,898	23,474	22,166

FPL System Net Peak Demand

	January MW	February MW	March MW	April MW	May MW	June MW	July MW	August MW	September MW	October MW	November MW	December MW
2025	22,478	20,943	17,425	18,929	21,200	23,200	23,667	24,324	23,203	21,056	17,652	19,903
2026	22,219	20,703	17,124	18,794	21,065	23,085	23,568	23,809	22,676	20,856	16,915	18,758
2027	21,091	19,473	15,805	17,681	19,995	22,034	22,318	22,985	21,842	19,991	15,713	18,130
2028	20,425	18,618	14,942	17,621	19,966	22,034	22,357	23,034	21,875	19,994	15,373	17,839
2029	20,253	18,331	14,536	17,554	19,930	22,028	22,371	23,062	21,890	19,983	14,968	17,495
2030	20,307	18,249	14,361	17,446	19,847	21,973	22,308	23,012	21,829	19,900	14,495	17,107

QUESTION:
Please describe and quantify the expected process to charge FPL's batteries that are paired with solar PV, including:

a. The typical charging time(s) of day,

b. Expected time (duration) to charge,

c. Expected discharge periods during the day, and

d. Length of discharge time (duration).

RESPONSE:
Note that even if batteries are "paired" with solar by being co-located at the same site, those batteries can still be charged by the grid during non-solar generating hours. The existing batteries on FPL's system are required to charge from the on-site solar through 2026.

a. As more solar is added to a system, marginal costs become lower during the daylight hours and charging may shift to the daytime. Batteries are projected to be charged during the lowest period of marginal costs throughout the day. This is typically either during the middle of the night or early in the morning but may shift to the daytime during winter months.

b. The expected time to charge batteries depends on the duration rating for the battery and if the battery is charged from the grid or from solar. FPL's projected batteries have a range of two to four hour durations, which indicates they can be charged in as little as four hours. However; charging a battery exclusively from solar may take longer, depending on the overall duration of the battery and amount of solar energy available.

c. Batteries are projected to be discharged during the highest period of marginal costs throughout the day. This time period varies based on seasonal load and generation patterns but is typically the early evening hours from 4PM to 9PM during the summer and during the 6AM to 9AM hours during the winter.

d. The expected time to discharge batteries also depends on the duration rating for the battery. FPL's projected batteries have a range of two to four hour durations, which indicates they can be discharged in as little as four hours.

QUESTION:
Has FPL performed the FERC Three Peak Ratios Test or an analysis of monthly peak demands? If so, please provide the results. If not, please explain why not.

RESPONSE:
Yes. FPL performed the FERC Three Peak Ratios Test in its 2021 retail base rate case and provided the results as an exhibit in rebuttal testimony for FPL witness DuBose. A copy of the exhibit is provided in responses to FRF's First POD, No. 6.

QUESTION:
Please provide any documents and/or workpapers supporting your answers provided to FRF's First Set of Interrogatories, No. 12.

RESPONSE:
See the responsive document provided.

Florida Power & Light Company
FERC Three Peak Ratios
Test Results
FPL Historical and FPL Consolidated Projected

(1)		(2)	(3)	(4)
Line No.	Year	Test 1: Peak - Off-Peak % Difference	Test 2: Low/Annual Peak Ratio	Test 3: Avg/Annual Peak Ratio
		≤ 19.0%	≥ 66.0%	≥ 81.0%
1	2023	17%	75%	86%
2	2022	17%	75%	86%
3	2021	16%	76%	87%
4	2020	19%	64%	87%
5	2019	17%	69%	86%
6	2018	16%	75%	88%
7	2017	18%	71%	87%
8	2016	18%	71%	84%
9	2015	14%	69%	89%

(1) Years 2015 - 2021 are FPL only; Projected Years 2022 - 2023 are for Consolidated FPL.

(2) Test No. 1 - On- and Off-Peak Test - This test first compares the average of the coincident peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincident peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

(3) Test No. 2 - Low-to-Annual Peak Test - Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

4) Test No. 3 - Average to Annual Peak Test – Compares the average of the twelve monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.

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Florida Power & Light Company
FERC Three Peak Ratios
Test Data
FPL Historical and FPL Consolidated Projected

	1	2	3	4	5	6	7	8	9	10	11	12		Jun-Sep	Jan-May and Oct-Dec			
Peak Day MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave.	Ave. Peak/Peak	Ave. Off-Peak/Peak	[1]	[2]	[3]
2023	22,826	20,841	20,867	22,337	24,899	26,698	27,132	27,661	26,541	24,610	21,582	20,611	23,884	98%	81%	17%	75%	86%
2022	22,436	20,503	20,527	21,970	24,487	26,258	26,686	27,205	26,102	24,205	21,224	20,270	23,489	98%	81%	17%	75%	86%
2021	20,061	19,140	19,111	20,466	22,323	23,727	24,200	24,620	23,658	22,204	19,618	18,694	21,485	98%	82%	16%	76%	87%
2020	17,514	18,429	20,602	21,594	21,932	24,499	24,483	24,166	24,493	22,214	19,496	15,773	21,266	100%	80%	19%	64%	87%
2019	16,795	18,660	18,963	20,106	22,580	24,241	23,578	22,861	23,653	21,776	19,855	17,249	20,860	97%	80%	17%	69%	86%
2018	19,109	17,492	17,887	19,348	19,595	22,254	22,528	23,217	23,187	21,781	19,649	18,088	20,345	98%	82%	16%	75%	88%
2017	16,535	17,172	18,029	20,474	22,311	22,176	23,109	23,373	23,243	21,276	18,126	17,091	20,243	98%	81%	18%	71%	87%
2016	16,934	17,031	19,190	20,061	20,392	22,528	23,858	23,645	21,574	20,809	17,240	17,815	20,090	96%	78%	18%	71%	84%
2015	15,747	19,718	17,979	21,242	21,016	22,959	22,153	22,717	22,563	20,990	20,541	18,129	20,480	98%	85%	14%	69%	89%

% of Peak Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	83%	75%	75%	81%	90%	97%	98%	100%	96%	89%	78%	75%
2022	82%	75%	75%	81%	90%	97%	98%	100%	96%	89%	78%	75%
2021	81%	78%	78%	83%	91%	96%	98%	100%	96%	90%	80%	76%
2020	71%	75%	84%	88%	90%	100%	100%	99%	100%	91%	80%	64%
2019	69%	77%	78%	83%	93%	100%	97%	94%	98%	90%	82%	71%
2018	82%	75%	77%	83%	84%	96%	97%	100%	100%	94%	85%	78%
2017	71%	73%	77%	88%	95%	95%	99%	100%	99%	91%	78%	73%
2016	71%	71%	80%	84%	85%	94%	100%	99%	90%	87%	72%	75%
2015	69%	86%	78%	93%	92%	100%	96%	99%	98%	91%	89%	79%

(1) Years 2015 - 2021 are FPL only; Projected Years 2022 - 2023 are for Consolidated FPL.

Florida Power & Light Company
Docket No. 20250011-EI
FRF's First Set of Interrogatories
Interrogatory No. 13
Page 1 of 1

QUESTION:
Referring to FPL Witness DuBose's Direct Testimony, page 21, lines 16-19: the testimony explains that the net system peak is shifting to later in the evening due to the installation of solar generation. And referring to Witness DuBose, page 5, lines 20-22 describing the load research used as the basis for cost allocations:

a. Does FPL's load research used in the Test Years account for the shifting of net system peak to later in the evening?

b. Does the calculation of the CP, GNCP, and NCP account for the shifting of net system peak to later in the evening?

c. What time(s) or hours does FPL expect the peak monthly demand to shift to with the addition of solar generation for 2026 – 2029?

RESPONSE:
a. No. The net system peak is determined by subtracting generation provided by solar resources from the total system peak. It is relevant for resource planning but is not used for allocating customer costs and thus not measured in FPL's load research analysis. When the net system peak shifts to later in the evening, it means that resource planners must use more traditional generation sources to meet customer demand as the solar generation rolls off during evening hours. For cost allocations however, total system costs, including the cost of solar resources, must be recovered from customers. Thus, the net system peak would not be an appropriate way to allocate total system costs.

b. No. As explained in part a., while the net system peak may be shifting to later in the evening, this does not indicate a change in the total system peak which is a measure of customer demand. However, the later net system peak indicates that energy consumption is being spread across a longer period, particularly through the day and into the evening, which supports FPL's proposal to allocate more costs based on energy consumption than peak demand. Prolonged peak periods like those reflected on FPL's system, reflect higher sustained usage rather than short term spikes. Therefore, the cost to maintain and operate the generation system can be more closely tied to overall energy use.

c. The addition of solar generation to FPL's system does not have an impact on total system peak demand which is based on customer demand.

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Interrogatory No. 15
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QUESTION:
Please provide the total amount (kW) of curtailment and/or interruptible power by customer class for the years 2015-2024 and forecast for years 2025-2027.

RESPONSE:

History and Forecast of Summer Load Management (MW)

Year	Residential Load Management[1]	C/I Load Management[2]
2021	830	882
2022	827	871
2023	797	946
2024	863	961
2025	932	1,004
2026	920	1,010
2027	909	1,016

(1) represents FPL's Residential On Call program

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

History and Forecast of Winter Load Management (MW)

Year	Residential Load Management[1]	C/I Load Management[2]
2021	689	619
2022	681	628
2023	670	631
2024	743	657
2025	771	698
2026	759	704
2027	747	709

(1) represents FPL's Residential On Call program

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

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FRF's First Set of Interrogatories
Interrogatory No. 16
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QUESTION:
Are monthly coincident peak demands adjusted for curtailable or interruptible service in each applicable customer class? If not, why not? Please explain.

RESPONSE:
No. The monthly coincident peak demands in MFR E-11, Attachment 1 were not adjusted for curtailable or interruptible service in each applicable customer class because production and transmission load assigned to the CILC and CDR rate classes is treated as firm load in FPL's COSS. Instead of adjusting these customers' load, FPL treats the CILC and CDR incentive payments as additional base revenues (or revenue credits), directly offsetting the revenue requirements of customer classes that participate in these programs. Providing a revenue credit in the COSS is a more direct method of crediting the CILC and CDR rate classes for these incentive payments than adjusting demand allocators. Furthermore, removing the curtailable load associated with CILC and CDR customers from COSS allocators, while also giving these customers revenue credits, would double count the credits and inappropriately shift costs to other customers. For these reasons, it is appropriate for the load assigned to CILC and CDR to be treated as firm load in the COSS rather than being removed from demand allocators as non-firm customer load.

Florida Power & Light Company
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FRF's First Set of Interrogatories
Interrogatory No. 17
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QUESTION:
Please refer to FPL Witness Whitley's Direct Testimony, page 40, lines 7-18. The testimony proposes a revised CDR credit of $6.22/kw-mo. with a calculated RIM cost- benefit ratio of 1.49.

a. What is the calculated credit at a RIM of 1.0?

b. Why was a 1.49 RIM chosen?

c. Why wasn't the RIM of 1.06 used to determine the CDR?

d. Please provide a table of all RIM calculations for all programs for the last five years.

RESPONSE:
a. A CDR credit of $9.33/kW-mo would result in a RIM ratio of 1.0. Note that FPL sets the minimum RIM ratio to at least 1.01 and potentially higher. Please see the response to subpart (b).

b. Please see the direct testimony of FPL witness Whitley, starting at line 16 of page 38 going through line 17 of page 39, for discussion of the factors that are incorporated in FPL setting the RIM ratio of the CDR and CILC programs. A 1.49 RIM score was chosen based on these factors.

c. Please see the response to subpart (b).

d. FPL interprets this question to be requesting the cost-effectiveness calculations of the CDR program for the last five years. That information is provided in Attachment No. 1. Note that the CILC program is closed to new participants, so there have been no calculations of the cost-effectiveness for incremental new participants to this program.

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Interrogatory No. 17
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Tab 1 of 1

		RIM Cost-Effe		
Program Evaluated:	Incentive Level Evaluated:	2020 DSM Plan	2021 Rate Case	2022 Integrated DSM Plan
Incremental CDR	As-Current Incentive:	0.97	---	0.242
Existing And Incremental CDR+CILC	As-Current Incentive:	---	0.97	---
	Proposed Incentive:	---	1.45	---

CILC is closed to new participants; therefore incremental cost-effectiveness evaluations are not perfc

ctiveness Evaluations			
2023	2024 DSM Goals	2025 DSM Plan	2025 Rate Case
0.404	0.725	0.792	---
---	---	---	1.06
---	---	---	1.49

rmed on it.

DECLARATION

I, Thomas Broad, co-sponsor the answer to **Interrogatory No. 3** from FRF's First 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.

Thomas Broad

Thomas Broad

Date: 5/6/25

DECLARATION

I, Tiffany Cohen, sponsor the answers to **Interrogatory Nos. 7, 8 and 10** and co-sponsor the answers to **Interrogatory Nos. 1, 4, 6 and 9** from FRF'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.

Tiffany Cohen
____
Tiffany Cohen

Date: 05/07/2025

DECLARATION

I, Tara DuBose, sponsor the answers to **Interrogatory Nos. 12, 13, 14 and 16** and co-sponsor the answers to **Interrogatory Nos. 9 and 18** from FRF'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.

Tara DuBose

____

Tara DuBose

Date: 05/06/2025

DECLARATION

I, Dawn Nichols, sponsor the answer to **Interrogatory No. 15** from FRF's First 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.

Dawn Nichols

Date: 5/6/25

DECLARATION

I, Andrew Whitley, sponsor the answers to **Interrogatory Nos. 2, 5, 11 and 17** and co-sponsor the answers to **Interrogatory Nos. 1, 3 and 18** from FRF'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: 05/06/2025

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

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.

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

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Staff's 3rd Set of Interrogatories, No. 44 - Correceted Supplemental
Page 1 of 5

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

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

FPL®

Ten Year Power Plant Site Plan

2025-2034

Submitted To:

Florida Public Service Commission

April 2025

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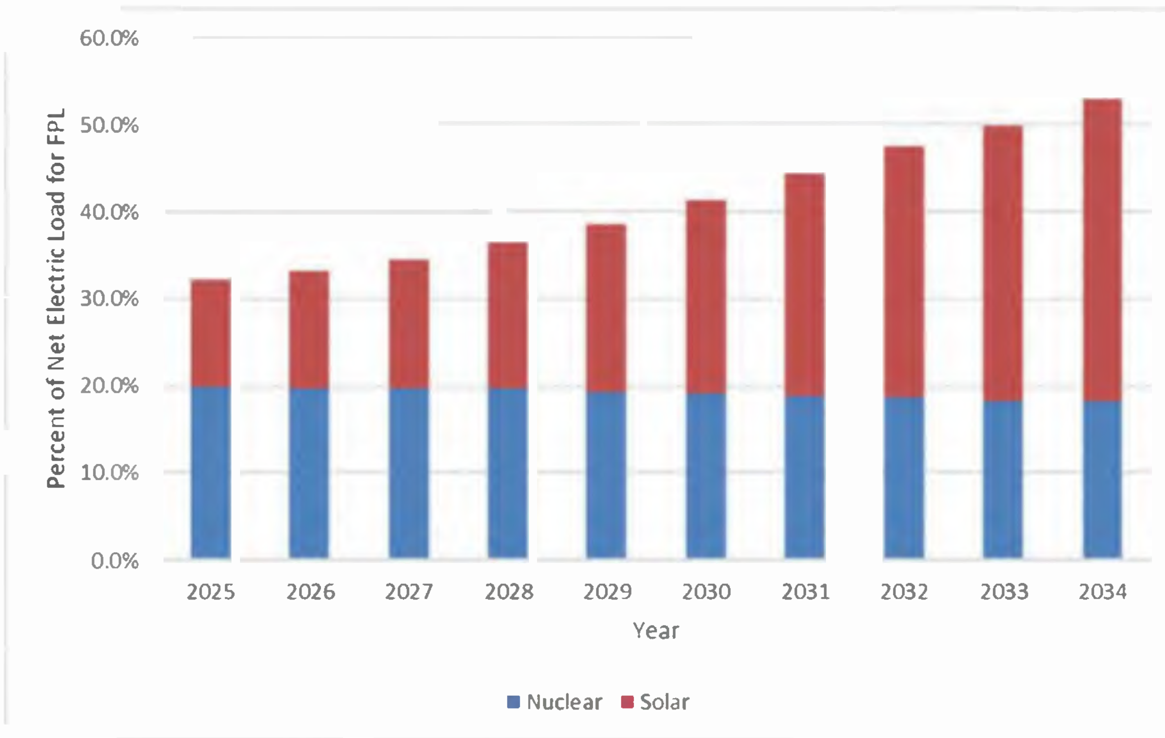
probability (LOLP) analysis designed so that FPL's proposed system additions optimally address system needs for each hour of the year. This enhancement of an existing reliability criterion factors in variations in system load, generating unit outages, and solar performance results in a resource plan that provides reliability for customers throughout the year in a variety of system conditions.

Regarding FPL's fuel mix, FPL delivered approximately 28% of its energy from nuclear and solar generation during 2024. Nearly all the remainder of FPL's energy generation in 2024 came from natural gas. By 2034, the last year of the ten-year reporting period addressed in this document, the percentage of the total energy delivered to all customers on FPL's system from nuclear and solar generation is projected to be approximately 53%. New cost-effective solar will also provide fuel diversity and energy independence by reducing the amount of natural gas FPL will use to generate electricity compared to the present day and adding battery storage will provide cost-effective capacity to help maintain system reliability. This diversity will also help to act as a hedge against swings in natural gas price volatility, providing additional savings to FPL customers during these periods. The graph below in Figure ES-1 represents a ten-year projection for the years 2025 through 2034 of the percentage of FPL's total generation (GWh) consisting of nuclear and solar, a result of FPL's commitment to building the lowest cost generation for customers. Further details regarding projections of energy by fuel/generation type are presented in Schedules 6.1 and 6.2 in Chapter III.

Figure ES-1: Nuclear and Solar Energy as a Percentage of Net Electric Load



By design, the primary focus of this document is on projected supply side additions, *i.e.*, electric generation capability and the sites for these additions. The supply side additions discussed herein are resources projected to be needed after accounting for existing and projected demand-side management (DSM) resources (including demand response and energy efficiency). In April of 2024, FPL filed its DSM Goals for the period of 2025 through 2034, and these Goals were approved by the FPSC on December 3, 2024. These DSM Goals address demand-side activities that reduce system peak loads and annual energy usage, along with consideration of the impacts of DSM on electric rates under which all customers are served. DSM is discussed in more detail in Chapters I, II, and III.

Additionally, FPL's load forecast accounts for a very large amount of energy efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these energy efficiency codes and standards are discussed later in this Executive Summary and in Chapters II and III. The updated load forecast presented in this Site Plan also accounts for the projected impact of both private rooftop photovoltaic (PV) solar and electric vehicle (EV) adoption.

FPL's projected resource additions and retirements over the ten-year reporting period are summarized below in Section II of this Executive Summary. In addition, there are several factors that either have influenced, or may influence, ongoing resource planning efforts. These factors could result in different

Broward counties). This balance has both reliability and economic implications for FPL's system and customers, and it is a key reason that FPL has expanded generation and transmission in specific areas in the past. The battery storage units that FPL is adding throughout the ten-year period will aid in addressing these balance concerns.

Factor # 3: The desire to maintain/enhance fuel diversity in the FPL system while considering system economics and reliability. Diversity is sought in terms of the types of fuel that FPL utilizes and how these fuels are transported to the locations of FPL's generation units. These fuel diversity objectives are considered in light of economic impacts to FPL's customers. For example, FPL is projecting the addition of significant amounts of cost-effective PV generation throughout the ten-year reporting period of this document. These PV additions enhance fuel diversity while at the same time allowing for the lowest cost generation resource to be constructed and operated. To enhance the reliability of these PV solar additions, FPL is planning to add cost-effective battery storage to maintain adequate generation and reserves at the time of the net system peak (FPL's peak after accounting for solar generation). At the same time, FPL is continuing to retire generating units that are no longer cost-effective for FPL customers. In addition, FPL also seeks to: 1) further enhance the efficiency with which it uses natural gas to generate electricity, 2) maintain the ability to use backup distillate oil that is stored on-site at many of FPL's gas-fueled generating units for purposes of system reliability, and 3) examine the ability of existing units to run on alternative clean fuels, such as hydrogen and renewable natural gas. All of the aforementioned additions enhance the overall fuel diversity of FPL's system which increases the energy independence of FPL's customers in the State of Florida.

Factor # 4: The need to maintain an appropriate balance of DSM and supply resources from the perspectives of both system reliability and operations. FPL addresses this through the use of a 10% generation-only reserve margin (GRM) reliability criterion to complement its other two reliability criteria: a 20%[4] total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year LOLP criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability and operations in a comprehensive manner.

Factor # 5: The significant impact of federal and state energy efficiency codes and standards. The incremental impacts of these energy efficiency codes and standards are projected to have significant impacts by reducing forecasted Summer and Winter peak loads, and by reducing annual net energy for

[4] The 20% reserve margin requirement is a minimum requirement – FPL's projected reserve margin may be higher than 20% during some years as additional resources are added for resource needs and meeting other reliability criteria.

Table I.A.3.1: FPL's Purchased Power Resources by Contract (as of December 31, 2024)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchase from QF's: Cogeneration/Small Power Production Facilities			
Broward South Landfill (firm)	Broward	Solid Waste	3.5
		Total:	3.5
II. Purchases from Utilities & IPP			
Santa Rosa, Southern Company Services		Natural Gas	230
Palm Beach SWA - REF 1	Palm Beach	Solid Waste	40
Palm Beach SWA - REF 2	Palm Beach	Solid Waste	70
MSCG - Kingfisher I	Oklahoma	Wind	53
MSCG - Kingfisher II	Oklahoma	Wind	28
		Total:	421
	Total Net Firm Generating Capability:		**425**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2024
Miami Dade Resource Recovery 1/	Dade	Solid Waste	-
Broward South Landfill (as-available) 1/	Broward	Solid Waste	45,118
Lee County Solid Waste 1/	Lee	Solid Waste	19,532
Next Era energy Resources - Brevard Landfill 1/	Brevard	Landfill Gas	36,260
Florida Crystals - Okeelanta 1/	Palm Beach	Bagasse/Wood	38,508
Waste Management Renewable Energy - Collier Landfill 1/	Collier	Landfill Gas	345
Next Era Energy Resources - Seminole Landfill 1/	Seminole	Landfill Gas	12,602
Tropicana - Bradenton	Manatee	Natural Gas	10,899
Georgia Pacific Palatka Mill	Putnam	Paper by-product	7,376
Aria Energy - Sarasota Landfill 1/	Sarasota	Landfill Gas	1,788
Waste Management Renewable Energy - Broward Landfill 1/	Broward	Landfill Gas	2,186
Fortistar - Charlotte Landfill 1/	Charlotte	Landfill Gas	102
Customer Owned PV & Wind 1/	Various	PV/Wind	770,381
International Paper Company 1/	Escambia	Biomass	968
Ascend Performance Materials	Escambia	Gas	31,356
Gulf Coast Solar Center I , II, III 1/	Various	Sun	226,722
Total Energy from Renewable Non-Firm Purchases Delivered to FPL in 2024 1/:			**1,161,888**
Total Energy from All Non-Firm Purchases Delivered to FPL in 2024:			**1,204,143**

1/ These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, row 9, column 6.

Table I.A.3.2: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Broward South Landfill	01/01/93	12/31/26	1.4	1.4	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/95	12/31/26	1.5	1.5	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/97	12/31/26	0.6	0.6	0	0	0	0	0	0	0	0
		QF Purchases Subtotal:	**3.5**	**3.5**	**0.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
None	-	-	-	-	-	-	-	-	-	-	-	-
		Utility Purchases Subtotal:	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total of QF and Utility Purchases =	**3.5**	**3.5**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Palm Beach SWA - REF1 1/	01/01/12	04/01/32	40	40	40	40	40	40	40	0	0	0
Palm Beach SWA - REF2	01/01/15	06/01/34	70	70	70	70	70	70	70	70	70	0
MSCG - Kingfisher I 2/	01/01/17	12/31/35	53	53	53	53	53	53	53	53	53	53
MSCG - Kingfisher II 2/	01/01/17	12/31/35	28	28	28	28	28	28	28	28	28	28
Gulf Solar PPAs 3/	11/17/14	12/31/42	41	40	40	40	40	40	40	40	40	40
		Other Purchases Subtotal:	**232**	**231**	**231**	**231**	**231**	**231**	**231**	**191**	**191**	**121**

Total "Non-QF" Purchases =	**232**	**231**	**231**	**231**	**231**	**231**	**231**	**191**	**191**	**121**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer Firm Capacity Purchases Total MW:	**235**	**235**	**231**	**231**	**231**	**231**	**231**	**191**	**191**	**121**

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and these became accounted for under "Other Purchases".
2/ These PPAs are from a variable wind source; however, the PPA supplier has committed to a certain amount of minimum MW per hour which FPL and Gulf treat as firm capacity for resource planning purposes.
3/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermittent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

Table I.A.3.3: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Broward South Landfill	01/01/93	12/31/26	1.4	1.4	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/95	12/31/26	1.5	1.5	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/97	12/31/26	0.6	0.6	0	0	0	0	0	0	0	0
QF Purchases Subtotal:			**3.5**	**3.5**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
None	-	-	-	-	-	-	-	-	-	-	-	-
Utility Purchases Subtotal:			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total of QF and Utility Purchases =	**3.5**	**3.5**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Santa Rosa, SCS	06/01/24	04/30/25	230	0	0	0	0	0	0	0	0	0
Palm Beach SWA - REF1 1/	01/01/12	04/01/32	40	40	40	40	40	40	40	40	0	0
Palm Beach SWA - REF2	01/01/15	06/01/34	70	70	70	70	70	70	70	70	70	70
MSCG - Kingfisher I 2/	01/01/17	12/31/35	71	71	71	71	71	71	71	71	71	71
MSCG - Kingfisher II 2/	01/01/17	12/31/35	38	38	38	38	38	38	38	38	38	38
Gulf Solar PPAs 3/	11/17/14	12/31/42	0	0	0	0	0	0	0	0	0	0
Other Purchases Subtotal:			**449**	**219**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total "Non-QF" Purchases =	**449**	**219**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Winter Firm Capacity Purchases Total MW:	**453**	**223**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and these became accounted for under "Other Purchases".

2/ These PPAs are from a variable wind source; however, the PPA supplier has committed to a certain amount of minimum MW per hour which FPL and Gulf treat as firm capacity for resource planning purposes.

3/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermittent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

Schedule 1: FPL Existing Generating Facilities as of December 31, 2024

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
									Alt.		Actual/					
							Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/		Firm Capability 2/	
	Unit			Unit	Fuel		Transport.		Days	In-Service	Retirement	Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Anhinga Solar 2/		FPL	Clay County													
			29.88213,-81.67618									74,500	74.5	74.5	1.86	28.46
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.86	28.46
Apalachee Solar 2/		FPL NWFL	Jackson County													
			30.76055,-85.06952									74,500	74.5	74.5	0.00	36.04
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	36.04
Babcock Preserve Solar 2/		FPL	Charlotte County													
			32,33/41S/26E : 4/42S/26E									74,500	74.5	74.5	0.00	37.24
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	37.24
Babcock Ranch Solar 2/		FPL	Charlotte County													
			29,31,32/41S/26E									74,500	74.5	74.5	0.00	37.38
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	37.38
Barefoot Bay Solar 2/		FPL	Brevard County													
			1, 10, 15,16/30S/38E									74,500	74.5	74.5	0.00	41.42
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	41.42
Beautyberry Solar 2/		FPL	Hendry County													
			26.373000, -81.026000									74,500	74.5	74.5	2.55	30.08
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.55	30.08
Big Juniper Solar 2/		FPL NWFL	Santa Rosa County													
			30.639000, -86.925000									74,500	74.5	74.5	0.00	36.76
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	36.76
Blackwater Solar 2/		FPL NWFL	Santa Rosa County													
			30.64691,-86.93821									74,500	74.5	74.5	0.00	27.88
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	27.88
Blue Cypress Solar 2/		FPL	Indian River County													
			16/33S/38E									74,500	74.5	74.5	0.00	39.77
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	39.77
Blue Heron Solar 2/		FPL	Hendry County													
			28,33/43S/32E									74,500	74.5	74.5	0.00	37.55
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	37.55
Blue Indigo Solar 2/		FPL NWFL	Jackson County													
			2/5N/12W : 35,36/6N/12W									74,500	74.5	74.5	0.00	49.96
	1			PV	Solar	Solar	N/A	N/A	--	Mar-20	Unknown	74,500	74.5	74.5	0.00	49.96
Blue Springs Solar 2/		FPL NWFL	Jackson County													
			36/5N/9W									74,500	74.5	74.5	0.02	41.01
	1			PV	Solar	Solar	N/A	N/A	--	Dec-21	Unknown	74,500	74.5	74.5	0.02	41.01
Bluefield Preserve Solar 2/		FPL	St. Lucie County													
			27.24354,-80.67097									74,500	74.5	74.5	1.94	21.96
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.94	21.96
Buttonwood Solar 2/		FPL	St. Lucie County													
			27.548000, -80.672000									74,500	74.5	74.5	2.21	33.66
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.21	33.66
Caloosahatchee Solar 2/		FPL	Hendry County													
			26.752000, -81.180000									74,500	74.5	74.5	1.93	29.66
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.93	29.66

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Schedule 1

FPL Existing Generating Facilities
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(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel		Alt. Fuel		Actual/		Net Capability 1/		Firm Capability 2/	
Plant Name	Unit No.	Area	Location	Unit Type	Fuel Pri.	Alt.	Transport. Pri.	Alt.	Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Canoe Solar 2/		FPL NWFL	Okaloosa County													
			30.680000, -86.782000									74,500	74.5	74.5	0.00	37.13
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.00	37.13
Cape Canaveral		FPL	Brevard County													
			19/23S/36E									1,418,000	1,418	1,290	1,418	1,290
	3			CC	NG	FO_2	PL	TK	Unknown	Apr-13	Unknown	1,418,000	1,418	1,290	1,418	1,290
Cattle Ranch Solar 2/		FPL	Desoto County													
			19,24,25/36S/26E									74,500	74.5	74.5	1.50	28.68
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	1.50	28.68
Cavendish Solar 2/		FPL	Okeechobee County													
			27.628,-80.80317									74,500	74.5	74.5	4.28	29.75
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	4.28	29.75
Cedar Trail Solar 2/		FPL NWFL	Baker County													
			30.322000, -82.192000									74,500	74.5	74.5	0.29	5.64
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.29	5.64
Chautauqua Solar 2/		FPL NWFL	Walton County													
			30.87576,-86.20813									74,500	74.5	74.5	0.00	40.13
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.00	40.13
Chipola Solar 2/		FPL NWFL	Calhoun County													
			30.45643,-85.27719									74,500	74.5	74.5	0.00	33.81
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	33.81
Citrus Solar 2/		FPL	DeSoto County													
			35/36S/25E : 2/37S/25E									74,500	74.5	74.5	0.00	38.80
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	38.80
Coral Farms Solar 2/		FPL	Putnam County													
			27,28,33,34/8S/24E									74,500	74.5	74.5	11.03	46.58
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	11.03	46.58
Cotton Creek Solar 2/		FPL NWFL	Jackson County													
			7/4N/8W									74,500	74.5	74.5	0.04	41.10
	1			PV	Solar	Solar	N/A	N/A	--	Dec-21	Unknown	74,500	74.5	74.5	0.04	41.10
Cypress Pond Solar 2/		FPL NWFL	Washington County													
			30.59444, -85.83008									74,500	74.5	74.5	0.00	37.17
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	37.17
Dania Beach Clean Energy Center		FPL	Broward County													
			30/50S/42E									1,252,000	1,252	1,246	1,252	1246
	7			CC	NG	FO_2	PL	TK	Unknown	Jan-22	Unknown	1,252,000	1,252	1,246	1,252	1,246
DeSoto Solar 2/		FPL	DeSoto County													
			27/36S/25E									22,950	25	25	0.71	10.27
	1			PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	22,950	25	25	0.71	10.27
Discovery Solar 2/		FPL	Brevard County													
			25,35,36/22S/36E									74,500	74.5	74.5	0.99	36.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	0.99	36.94
Echo River Battery Storage		FPL	Suwannee County													
			24,25,19/2S/14E : 30/2S/15E									30,000	30.0	30.0	30.0	30.0
	1			BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	30,000	30.0	30.0	30.0	30.0

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(1) Plant Name	(2) Unit No.	Area	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen. Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW	(15) Firm Capability [2/] Winter MW	(16) Firm Capability [2/] Summer MW
Echo River Solar [2/]		FPL	Suwannee County													
			24,25,19/2S/14E : 30/2S/15E									74,500	74.5	74.5	0.00	42.60
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	42.60
Egret Solar [2/]		FPL	Baker County													
			26,27/2S/21E									74,500	74.5	74.5	0.28	38.16
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	0.28	38.16
Elder Branch Solar [2/]		FPL	Manatee County													
			18, 33S, 21E									74,500	74.5	74.5	0.51	32.19
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	0.51	32.19
Etonia Creek Solar [2/]		FPL	Putnam County													
			29.76723,-81.77749									74,500	74.5	74.5	1.39	34.34
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.39	34.34
Everglades Solar [2/]		FPL	Miami-Dade County													
			25.54255,-80.55434									74,500	74.5	74.5	3.14	23.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	3.14	23.94
First City Solar [2/]		FPL NWFL	Escambia County													
			30.91993,-87.34002									74,500	74.5	74.5	0.00	28.69
	1									Jan-23	Unknown	74,500	74.5	74.5	0.00	28.69
				PV	Solar	Solar	N/A	N/A	Unknown							
Flowers Creek Solar [2/]		FPL NWFL	Calhoun County													
			30.57013,-85.03932									74,500	74.5	74.5	0.00	34.22
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	34.22
Fort Drum Solar [2/]		FPL	Okeechobee County													
			2,11,13/33S/35E									74,500	74.5	74.5	0.99	34.80
	1			PV	Solar	Solar	N/A	N/A	Unknown	Aug-21	Unknown	74,500	74.5	74.5	0.99	34.80
Fort Myers		FPL	Lee County													
			35/43S/25E									2,911,000	2,911	2,776	2,911	2,776
	2			CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,920,000	1,920	1,822	1,920	1,822
	3			CT	NG	FO_2	TK	TK	Unknown	Jun-03	Unknown	868,000	868	852	868	852
	1, 9			GT	FO_2	No	WA	No	Unknown	May-74	Unknown	123,000	123	102	123	102
Fourmile Creek Solar [2/]		FPL NWFL	Calhoun County													
			30.441000, -85.276000									74,500	74.5	74.5	0.00	38.53
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	38.53
Georges Lake Solar [2/]		FPL	Putnam County													
			29.760000, -81.765000									74,500	74.5	74.5	0.63	5.00
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	0.63	5.00
Ghost Orchid Solar [2/]		FPL	Hendry County													
			4,5 47S, 33E									74,500	74.5	74.5	1.95	22.08
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.95	22.08
Grove Solar [2/]		FPL	Indian River County													
			29, 33S, 37E									74,500	74.5	74.5	1.88	24.21
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.88	24.21
Gulf Clean Energy Center		FPL NWFL	Escambia County													
			25/1N/30W									1,901,000	1,901	1,887	1,901	1,887
	4			ST	NG	--	PL	--	--	Jul-59	4th Q 2029	75,000	75	75	75	75
	5			ST	NG	--	PL	--	--	Jun-61	4th Q 2029	75,000	75	75	75	75
	6			ST	NG	--	PL	--	--	May-70	Unknown	315,000	315	315	315	315
	7			ST	NG	--	PL	--	--	Aug-73	Unknown	496,000	496	496	496	496
	8			CT	NG	--	PL	--	--	Dec-21	Unknown	940,000	940	926	940	926

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(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Plant Name	Unit No.	Area	Location	Unit Type	Fuel Pri.	Alt.	Fuel Transport. Pri.	Fuel Transport. Alt.	Alt. Fuel Days Use	Commercial In-Service Month/Year	Actual/ Expected Retirement Month/Year	Gen.Max. Nameplate KW	Net Capability [1/] Winter MW	Net Capability [1/] Summer MW	Firm Capability [2/] Winter MW	Firm Capability [2/] Summer MW
Hammock Solar [2/]		FPL	Hendry County													
			34/43S/30E : 3,4,9,10/44S/30E									74,500	74.5	74.5	0.00	38.90
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	38.90
Hawthorne Creek Solar [2/]		FPL	Desoto County													
			27.086000, -81.836000									74,500	74.5	74.5	1.18	31.49
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	1.18	31.49
Hendry Isles Solar [2/]		FPL	Hendry County													
			26.749000, -81.192000									74,500	74.5	74.5	2.34	22.11
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.34	22.11
Hibiscus Solar [2/]		FPL	Palm Beach County													
			2/43S/40E									74,500	74.5	74.5	0.00	36.71
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	36.71
Honeybell Solar [2/]		FPL	Okeechobee County													
			27.522000, -80.744000									74,500	74.5	74.5	2.20	32.88
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.20	32.88
Horizon Solar [2/]		FPL	Alachua County													
			25,35,36/9S/22E : 30, 31/9S/23E									74,500	74.5	74.5	1.10	39.29
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	1.10	39.29
Ibis Solar [2/]		FPL	Brevard County													
			27.853000, -80.682000									74,500	74.5	74.5	1.98	35.07
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.98	35.07
Immokalee Solar [2/]		FPL	Collier County													
			4, 9, 16, 46S, 29E									74,500	74.5	74.5	2.47	20.70
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	2.47	20.70
Indian River Solar [2/]		FPL	Indian River County													
			30/33S/38E									74,500	74.5	74.5	0.00	39.54
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	39.54
Interstate Solar [2/]		FPL	St. Lucie County													
			28,33/34S/39E									74,500	74.5	74.5	0.00	37.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	37.94
Kayak Solar [2/]		FPL NWFL	Okaloosa County													
			30.704000, -86.700000									74,500	74.5	74.5	0.00	10.97
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-24	Unknown	74,500	74.5	74.5	0.00	10.97
Lakeside Solar [2/]		FPL	Okeechobee County													
			28,29,32/37S/36E									74,500	74.5	74.5	1.18	36.08
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.18	36.08
Lansing Smith		FPL NWFL	Bay County													
			36/2S/15W									705,000	705	673	705	673
	3			CC	NG	--	PL	--	--	Apr-02	Unknown	665,000	665	641	665	641
	A			CT	LO	--	TK	--	--	May-71	4th Q 2027	40,000	40	32	40	32
Lauderdale		FPL	Broward County													
			30/50S/42E									1,228,400	1,218	1,224	1,218	1,224
	6			CT	NG	FO_2	PL	TK	Unknown	Dec-16	Unknown	1,155,000	1,145	1,155	1,145	1,155
	3, 5			GT	NG	FO_2	PL	TK	Unknown	Aug-70	Unknown	73,400	73	69	73	69
Loggerhead Solar [2/]		FPL	St. Lucie County													
			21/37S/38E									74,500	74.5	74.5	0.58	26.38
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.58	26.38

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FPL Existing Generating Facilities
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(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel		Alt.		Actual/		Net Capability [1/]		Firm Capability [2/]	
	Unit			Unit	Fuel		Transport		Fuel Days	Commercial In-Service	Expected Retirement	Gen.Max. Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Magnolia Springs Solar [2/]		FPL	Clay County													
			15,16,21,22/7S/26E									74,500	74.5	74.5	1.03	39.11
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-21	Unknown	74,500	74.5	74.5	1.03	39.11
Manatee Battery Storage		FPL	Manatee County													
			1,12,13,24/33S/19E : 18,19/33S/20E									409,000	409	409	409	409
	1			BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	409,000	409	409	409	409
Manatee Solar [2/]		FPL	Manatee County													
			1,12,13,24/33S/19E : 18,19/33S/20E									74,500	74.5	74.5	0.00	38.70
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	38.70
Manatee		FPL	Manatee County													
			18/33S/20E									2,986,000	1,348	1,246	1,348	1,246
	1 [3/]			ST	NG	FO_6	PL	WA	Unknown	Oct-76	4/	819,000	0	0	0	0
	2 [3/]			ST	NG	FO_6	PL	WA	Unknown	Dec-77	4/	819,000	0	0	0	0
	3			CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,348,000	1,348	1,246	1,348	1,246
Martin		FPL	Martin County													
			30/39S/38E									2,385,000	2,394	2,223	2,394	2,223
	3			CC	NG	No	PL	No	Unknown	Feb-94	Unknown	538,000	538	487	538	487
	4			CC	NG	No	PL	No	Unknown	Apr-94	Unknown	520,000	529	487	529	487
	8			CC	NG	FO_2	PL	TK	Unknown	Jun-05	Unknown	1,327,000	1,327	1,249	1,327	1,249
Miami Dade Solar [2/]		FPL	Miami-Dade County													
			13/55S/38E									74,500	74.5	74.5	0.00	36.14
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	36.14
Mitchell Creek Solar [2/]		FPL NWFL	Escambia County													
			30.928510, -87.364140									74,500	74.5	74.5	0.00	29.19
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	0.00	29.19
Monarch Solar [2/]		FPL	Martin County													
			27.030740, -80.524800									74,500	74.5	74.5	1.52	30.37
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.52	30.37
Nassau Solar [2/]		FPL	Nassau County													
			2/1N/24E									74,500	74.5	74.5	1.02	37.03
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.02	37.03
Nature Trail Solar [2/]		FPL	Baker County													
			30.313000, -82.177000									74,500	74.5	74.5	0.36	37.61
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.36	37.61
Northern Preserve Solar [2/]		FPL	Baker County													
			13,18/3S/20E : 24/3S/21E									74,500	74.5	74.5	0.00	33.61
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	33.61
Norton Creek Solar [2/]		FPL	Madison County													
			30.383000, -83.327000									74,500	74.5	74.5	0.03	24.27
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-24	Unknown	74,500	74.5	74.5	0.03	24.27
Okeechobee [4/]		FPL	Okeechobee													
			2/33S/35E									1,720,000	1,672	1,720	1,672	1,720
	1			CC	NG	FO_2	PL	TK	Unknown	Mar-19	Unknown	1,720,000	1,672	1,720	1,672	1,720
Okeechobee Solar [2/]		FPL	Okeechobee County													
			1,12,13/33S/35E									74,500	74.5	74.5	0.00	36.21
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	36.21

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
3/ 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.
4/ 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

Schedule 1

FPL Existing Generating Facilities
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(1) Plant Name	(2) Unit No.	Area	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW	(15) Firm Capability 2/ Winter MW	(16) Firm Capability 2/ Summer MW
Orange Blossom Solar 2/		FPL	Indian River County													
			19/33S/38E									74,500	74.5	74.5	1.21	37.83
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.21	37.83
Orchard Solar 2/		FPL	Indian River/St. Lucie County													
			27.556000, -80.570000									74,500	74.5	74.5	2.92	35.99
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.92	35.99
Palm Bay Solar 2/		FPL	Brevard County													
			19,30/30S/37E									74,500	74.5	74.5	0.83	39.78
	1			FV	Solar	Solar	N/A	N/A	Unknown	May-21	Unknown	74,500	74.5	74.5	0.83	39.78
Pea Ridge		FPL NWFL	Santa Rosa County													
			15/1N/29W									15,000	15	12	15	12
	1			CT	NG	--	PL	--	--	May-98	4th Q 2024	5,000	5	4	5	4
	2			CT	NG	--	PL	--	--	May-98	4th Q 2024	5,000	5	4	5	4
	3			CT	NG	--	PL	--	--	May-98	4th Q 2024	5,000	5	4	5	4
Pecan Tree Solar 2/		FPL NWFL	Walton County													
			30.933000, -86.246000									74,500	74.5	74.5	0.00	40.07
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	40.07
Pelican Solar 2/		FPL	St. Lucie County													
			6,7/34S/38E									74,500	74.5	74.5	1.85	37.61
	1			FV	Solar	Solar	N/A	N/A	Unknown	Apr-21	Unknown	74,500	74.5	74.5	1.85	37.61
Perdido LFG		FPL NWFL	Escambia County													
												3,000	3	3	3	3
	1			IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,500	1.5	1.5	1.5	1.5
	2			IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,500	1.5	1.5	1.5	1.5
Pineapple Solar 2/		FPL	St. Lucie County													
			27.255000, -80.571000									74,500	74.5	74.5	2.19	32.64
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.19	32.64
Pink Trail Solar 2/		FPL	St. Lucie County													
			27.29783,-80.54214									74,500	74.5	74.5	2.58	21.84
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	2.58	21.84
Pioneer Trail Solar 2/		FPL	Volusia County													
			21/17S/32E									74,500	74.5	74.5	0.00	35.63
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	35.63
Port Everglades		FPL	City of Hollywood													
			23/50S/42E									1,333,000	1,333	1,237	1,333	1,237
	5			CC	NG	FO_2	PL	TK	Unknown	Apr-16	Unknown	1,333,000	1,333	1,237	1,333	1,237
Prairie Creek Solar 2/		FPL	Desoto County													
			27.045000, -81.809000									74,500	74.5	74.5	1.37	32.07
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.37	32.07
Riviera Beach		FPL	City of Riviera Beach													
			33/42S/432E									1,406,000	1,406	1,290	1,406	1,290
	5			CC	NG	FO_2	PL	TK	Unknown	Apr-14	Unknown	1,406,000	1,406	1,290	1,406	1,290
Rodeo Solar 2/		FPL	DeSoto County													
			23,24,25,26,27/36S/25E									74,500	74.5	74.5	1.50	36.68
	1			FV	Solar	Solar	N/A	N/A	Unknown	May-21	Unknown	74,500	74.5	74.5	1.50	36.68
Sabal Palm Solar 2/		FPL	Palm Beach County													
			33/42S/40E									74,500	74.5	74.5	1.53	38.21
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jun-21	Unknown	74,500	74.5	74.5	1.53	38.21

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel		Alt. Fuel	Commercial	Actual/ Expected	Gen. Max.	Net Capability 1/		Firm Capability 2/	
Plant Name	Unit No.	Area	Location	Unit Type	Fuel Pri.	Alt.	Transport Pri.	Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW	Winter MW	Summer MW
Sambucus Solar 2/		FPL	Manatee County													
			27.449000, -82.064000									74,500	74.5	74.5	0.93	30.74
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.93	30.74
Sanford		FPL	Volusia County													
			16/19S/30E									2,530,000	2,530	2,418	2,530	2,418
	4			CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,278,000	1,278	1,209	1,278	1,209
	5			CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,252,000	1,252	1,209	1,252	1,209
Saw Palmetto Solar 2/		FPL NWFL	Bay County													
			30.4213,-85.44103									74,500	74.5	74.5	0.00	39.70
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	39.70
Sawgrass Solar 2/		FPL	Hendry County													
			20, 21, 28, 29, 47S, 33E									74,500	74.5	74.5	1.93	21.86
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.93	21.86
Scherer 5/		FPL NWFL	Monroe, GA													
												215,000	215	215	215	215
	3			ST	C	--	RR	--	--	Jan-87	4th Q 2034	215,000	215	215	215	215
Shirer Branch Solar 2/		FPL NWFL	Calhoun County													
			30.39891,-85.27975									74,500	74.5	74.5	0.00	39.47
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.00	39.47
Silver Palm Solar 2/		FPL	Palm Beach County													
			26.788000, -80.352000									74,500	74.5	74.5	2.64	30.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.64	30.94
Southfork Solar 2/		FPL	Manatee County													
			26/33S/21E									74,500	74.5	74.5	0.00	43.15
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	43.15
Space Coast Solar 2/		FPL	Brevard County													
			13/23S/36E									10,000	10	10	0.13	3.76
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10	0.13	3.76
Sparkleberry Solar 2/		FPL NWFL	Escambia County													
			30.763000, -87.433000									74,500	74.5	74.5	0.00	37.92
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	37.92
St. Lucie 6/		FPL	St. Lucie County													
			16/36S/41E									1,863,000	1,863	1,821	1,863	1,821
	1			ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,003,000	1,003	981	1,003	981
	2			ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	860,000	860	840	860	840
Sundew Solar 2/		FPL	St. Lucie County													
			17, 37S, 38E									74,500	74.5	74.5	1.91	26.32
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.91	26.32
Sunshine Gateway Battery Storage		FPL	Columbia County													
			25,26,35,36/2S/15E : 31,32/5S/16E									30,000	30.0	30.0	30.0	30.0
	1			BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	30,000	30.0	30.0	30.0	30.0
Sunshine Gateway Solar 2/		FPL	Columbia County													
			25,26,35,36/2S/15E : 31,32/5S/16E									74,500	74.5	74.5	0.00	40.31
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	40.31
Sweetbay Solar 2/		FPL	Martin County													
			17,19/39S/39E									74,500	74.5	74.5	0.00	31.15
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	31.15

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
5/ Unit capabilities shown represent FPL NWFL's portion of Scherer Unit 3 (25%) located in Georgia
6/ 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, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and excludes the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1) Plant Name	(2) Unit No.	Area	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW	(15) Firm Capability 2/ Winter MW	(16) Firm Capability 2/ Summer MW
Terrill Creek Solar 2/		FPL	Clay County													
			29.884000, -81.767000									74,500	74.5	74.5	0.66	34.21
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.66	34.21
Three Creeks Solar 2/		FPL	Manatee County													
			27.581000, -82.260000									74,500	74.5	74.5	0.96	32.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.96	32.94
Trailside Solar 2/		FPL	St. Johns County													
			25,36/8S/28E									74,500	74.5	74.5	1.02	39.55
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.02	39.55
Turkey Point		FPL	Miami Dade County													
			27/57S/40E									3,083,000	3,083	2,973	3,083	2,973
	3			ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	859,000	859	837	859	837
	4			ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	866,000	866	844	866	844
	5			CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,358,000	1,358	1,292	1,358	1,292
Turnpike Solar 2/		FPL	Indian River County													
			27.568000, -80.645000									74,500	74.5	74.5	2.84	34.60
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.84	34.60
Twin Lakes Solar 2/		FPL	Putnam County													
			19,20,25/10S/24E : 30/10S/25E									74,500	74.5	74.5	0.96	38.32
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.96	38.32
Union Springs Solar 2/		FPL	Union County													
			3,4,9,10/6S/20E : 33/5S/20E									74,500	74.5	74.5	0.83	38.91
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	0.83	38.91
West County		FPL	Palm Beach County													
			29/43S/40E									4,047,000	4,047	3,771	4,047	3,771
	1			CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,349,000	1,349	1,257	1,349	1,257
	2			CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,349,000	1,349	1,257	1,349	1,257
	3			CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,349,000	1,349	1,257	1,349	1,257
White Tail Solar 2/		FPL	Martin County													
			27.080000, -80.379000									74,500	74.5	74.5	3.12	36.32
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.12	36.32
Wild Azalea Solar 2/		FPL NWFL	Gadsden County													
			30.6758,-84.74033									74,500	74.5	74.5	0.00	40.92
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.00	40.92
Wild Quail Solar 2/		FPL NWFL	Walton County													
			30.898050, -86.250070									74,500	74.5	74.5	0.00	41.34
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	41.34
Wildflower Solar 2/		FPL	Desoto County													
			25,26,/36S/25E									74,500	74.5	74.5	0.00	38.67
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	38.67
Willow Solar 2/		FPL	Manatee County													
			2,3,10,11/35S/22E									74,500	74.5	74.5	1.30	35.83
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.30	35.83
Woodyard Solar 2/		FPL	Hendry County													
			26.420000, -81.051000									74,500	74.5	74.5	2.17	28.98
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	2.17	28.98
Total Nameplate System Generating Capacity as of December 31, 2024 7/ =													36,821	35,531	-	-
Total Firm System Generating Capacity as of December 31, 2024 8/ =													-	-	29,878	31,691

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
7/ The Total Nameplate System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
8/ The System Firm Generating Capacity value shown includes only firm generating capacity.

Schedule 3.1
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	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 6.2 Actual
Energy Sources % by Fuel Type

	Energy Source	Units	Actual [1/] FPL 2023	Actual [1/] FPL 2024
(1)	Annual Energy Interchange [2/]	%	0.0	0.0
(2)	Nuclear	%	20.0	19.2
(3)	Coal	%	0.3	0.4
(4)	Residual (FO_6) -Total	%	0.0	0.0
(5)	Steam	%	0.0	0.0
(6)	Distillate (FO_2) -Total	%	0.2	0.1
(7)	Steam	%	0.0	0.0
(8)	CC	%	0.1	0.0
(9)	CT	%	0.1	0.0
(10)	Natural Gas -Total	%	73.6	71.4
(11)	Steam	%	1.3	1.4
(12)	CC	%	70.7	68.8
(13)	CC PPAs - Gas [3/]	%	1.0	0.0
(14)	CT	%	0.7	1.2
(15)	Solar [4/]	%	6.6	8.5
(16)	PV	%	4.3	4.7
(17)	Solar Together [5/]	%	2.1	3.6
(18)	Solar PPAs	%	0.1	0.1
(19)	Wind PPAs	%	0.7	0.7
(20)	Hydrogen Gas [6/]	%	0.0	0.0
(21)	Other [7/]	%	(1.4)	(0.2)
			100	100

1/ Sources: Actuals for FPL and FPL NWFL: A Schedules and Actual Data for Next Generation Solar Centers Report.

2/ Represents interchange between FPL/FPL NWFL and other utilities. For FPL NW, this number represents the net energy exchange with Southern Co.

3/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.

4/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.

5/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.

6/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program

7/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the LFG generation from the Perdido unit.

Schedule 6.2 Forecasted
Energy Sources % by Fuel Type

		FPL									
Energy Source	**Units**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
(1) Annual Energy Interchange [1/]	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	19.9	19.7	19.6	19.7	19.2	19.0	18.8	18.6	18.3	18.2
(3) Coal	%	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.5
(4) Residual (FO_6) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6) Distillate (FO_2) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	65.5	64.7	63.5	61.6	59.6	56.8	53.7	50.9	48.4	45.8
(11) Steam	%	1.3	1.3	1.0	1.0	0.9	0.9	0.8	0.7	0.8	0.7
(12) CC	%	63.7	62.9	62.1	60.3	58.5	55.6	52.6	50.0	47.4	44.8
(13) CC PPAs - Gas [2/]	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14) CT	%	0.5	0.5	0.4	0.3	0.2	0.3	0.2	0.3	0.3	0.2
(15) Solar [3/]	%	12.2	13.6	14.9	16.9	19.3	22.4	25.7	28.9	31.7	34.8
(16) PV	%	7.0	8.4	9.8	11.9	14.4	17.6	21.0	24.2	27.1	30.3
(17) Solar Together [4/]	%	5.0	5.0	5.0	4.9	4.8	4.7	4.6	4.5	4.4	4.4
(18) Solar PPAs	%	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(19) Wind PPAs	%	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6
(20) Hydrogen Gas [5/]	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(21) Other [6/]	%	1.4	1.0	0.9	0.8	0.7	0.7	0.8	0.5	0.5	0.2
		100	100	100	100	100	100	100	100	100	100

1/ Represents interchange between FPL and other utilities.
2/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.
3/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.
5/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
6/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the Perdido Unit projected generation.

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 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.A.3.1, and I.A.3.2

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, I.A.3.1, and I.A.3.2

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.A.3.1, and I.A.3.2

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.

FPL®

Ten Year Power Plant Site Plan

2024-2033

Submitted To:

***Florida Public
Service Commission***

April 2024

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Factor # 9: Ensuring system reliability during extreme weather events. Over the past several years, extreme weather events have caused significant outages and disruptions to electric grids across the country. These events include widespread hot weather in California in the summer of 2020, historic cold weather in February 2021 in Texas, and extreme cold conditions throughout the Mid-Atlantic and Southeast around Christmas of 2022. In addition to these events that occurred around the country, FPL's service area regularly experiences periods of hotter than average weather throughout the year and hurricanes that can potentially affect the output of its generation fleet. While FPL does not plan its system around extreme events, it continues to believe it is prudent to consider and prepare for the possibility of extreme weather events and the ability to reliably serve customers under those circumstances. To that end, FPL has reviewed the lessons learned from the outages and service disruptions experienced in other jurisdictions and enhanced its own system to ensure it is adequately prepared. This includes winterizing FPL's nuclear and fossil-fueled generation units, enhancing cooperation and preparation between FPL and suppliers of natural gas and fuel oil, and keeping several generation units as "extreme winter only" units that will provide the lowest cost backup capacity in the event of extreme winter weather in FPL's service area. The battery storage units that FPL is adding throughout the ten-year period will also provide additional reliability during extreme weather events.

FPL will continue to work with regulatory authorities, such as the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), to follow their guidance regarding proper planning procedures for extreme weather events.

Each of these factors described above will continue to be examined in FPL's ongoing resource planning work in 2024 and future years.

IV. FPL's Projected Resource Plan:

FPL's projected resource plan for the 2024 Site Plan is shown below. Regarding the resources projected in the Site Plan, no final decisions are needed at this time, nor have any decisions been made regarding many of the resource additions shown in the resource plan presented in this 2024 Site Plan. This is particularly relevant to resource additions shown for the years 2026 through 2033. Consequently, resource additions shown for these later years are more prone to change in the future.

Table ES-1: Resource Additions/Subtractions in FPL's Resource Plan

Year	Changes to Existing Generation	Subtractions	New Generation Additions	Summer RM%
2024	+43 MW CC Upgrades	Daniel 1&2 (502 MW)	894 MW SOBRA* 745 MW SolarTogether Extension*	22.7
2025	+26 MW CC Upgrades	Pea Ridge (12 MW)	894 MW SOBRA* 596 MW SolarTogether Extension*	23.4
2026	+29 MW CC Upgrades		2,235 MW Solar 522 MW Battery Storage**	25.2
2027	+137 MW CC Upgrades	Broward South (4 MW)	2,235 MW Solar 300 MW Battery Storage	25.3
2028	+20 MW CC Upgrades	Lansing Smith 3A (32 MW)	2,235 MW Solar 300 MW Battery Storage	24.8
2029		Scherer 3 (215 MW)	2,235 MW Solar 300 MW Battery Storage	23.6
2030		Perdido 1&2 (3 MW)	2,235 MW Solar 300 MW Battery Storage	23.0
2031			2,235 MW Solar 300 MW Battery Storage	22.0
2032		Palm Beach SWA 1 (40 MW)	2,235 MW Solar 300 MW Battery Storage	20.0
2033			2,235 MW Solar 1,700 MW Battery Storage	20.0
		Nameplate Solar Additions (2024-2033):	21,009	
		Nameplate Storage Additions (2024-2033):	4,022	

All solar and battery storage additions are in nameplate MW.

* These solar facilities were approved in FPL's 2021 Rate Case Settlement. All other solar additions will be presented to the FPSC for approval of cost recovery at a later date once the specific sites and costs for these additions are finalized.

** These battery storage units are projected to have an in-service date of December, 2025.

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

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CONTENTS

CHAPTER 2

OVERVIEW OF COST OF SERVICE STUDIES AND COST ALLOCATION

This chapter presents an overview of cost of service studies and cost allocation theory. It first introduces the role of cost of service studies in the regulatory process. Next, it summarizes the theory and methodologies of cost studies, with a comparison of accounting-based (embedded) cost methodologies and marginal cost methodologies. Finally, it introduces and briefly discusses the three major steps in the cost allocation process: the "functionalization" of investments and expenses, cost "classification", and the "allocation" of costs among customer classes.

I. COST OF SERVICE STUDIES IN THE REGULATORY PROCESS

Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates.

The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.

- To separate costs between different regulatory jurisdictions.

Generically, the prime purpose of cost of service studies is to aid in the design of rates. The development of rates for a utility may be divided into four basic steps:

- Development of the test period total utility revenue requirement - The total revenue requirement is the level of revenue to be collected from all sources. This subject will be addressed in detail in Chapter 3.

- Calculation of the test period revenue requirement to be recovered through rates - This is simply the total revenue requirement of the utility from all sources less the amount from sources other than rates.

- The cost allocation procedure - The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer classes.

- Design of rates - Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance.

II. THEORY AND METHODOLOGIES

Historically, regulation concerned itself with the overall level of a company's revenues and earnings and left the design of rates to the discretion of the utility. To the extent that utility managements justified their rate structures on cost, rather than rationales of value of service or "what the market will bear", they defined cost in engineering and accounting terms. Utilities developed cost studies that were based on monies actually spent (embedded) for plant and operating expenses and divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the analyst was to allocate, among customers, the costs identified in the test year for which the revenue requirement had been calculated.

Through the years, the industry and its regulators have witnessed a gradual evolution of the concepts for allocation. Since generating units and transmission lines are sized according to the peak demand consumed, the individual contribution to peak demand came to be considered the appropriate factor for the allocation of the costs of those the cost causation criteria requires that they not be allocated the cost associated with the secondary distribution system.

4. The Customer Service and Facilities Function

The customer service and facilities function includes the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection, and customer information and services. These investments and expenses are generally considered to be made and incurred on a basis related to the number of customers (by class) and are, therefore, of a fixed overhead nature.

5. Administrative and General Function

The administrative and general function includes the management costs, administrative buildings, etc. that cannot be directly assigned to the other major cost functions. These costs may be functionalized by relating them to specific groups of costs or other characteristics of the major cost functions, and then allocated on the same basis as the other costs within the function.

B. Classification of Costs

The next step is to separate the functionalized costs into classifications based on the components of utility service being provided. The three principal cost classifications for an electric utility are demand costs (costs that vary with the KW demand imposed by the customer), energy costs (costs that vary with the energy or KWH that the utility provides), and customer costs (costs that are directly related to the number of customers served).

After costs are functionalized into the primary functions, some can be identified as logically incurred to serve a particular customer or customer class. For example, a radial distribution line that serves only a particular customer may be assigned directly to that customer. Similarly, all the investment and expenses associated with luminaires and poles installed for street and private area lights are directly assigned to the lighting class(es). Segregation of these costs in a sense reverses the classification and allocation steps, as the costs are first allocated to the customer and subsequently classified as demand, energy or customer to determine how the customer is to be charged.

CHAPTER 3

DEVELOPING TOTAL REVENUE REQUIREMENTS

A utility, in order to remain viable, must be given the opportunity to recover its prudently incurred total cost of providing electric service to its various classes of customers. Cost of service is usually defined to include all of a utility's operating expenses, plus a reasonable return on its investment devoted to the service of the ratepaying public. Accordingly, it is incumbent on the utility to ensure that the rates it charges for electric services are sufficient to recover its total costs. The total theoretical revenues a utility is authorized to collect through its rates for its various types of service is called the total revenue requirement, or the total cost of service.

The total revenue requirement of a utility is equal to the sum of the costs to serve all its various classes of customers. Since a utility's rates are generally regulated by two or more governmental agencies, revenue requirements under different jurisdictions are usually established on the basis of cost allocation studies; but the rates so established can and often do reflect differing cost bases among jurisdictions.

The derivation of revenue requirements for each jurisdiction's classes of service requires findings in the following areas: (1) The proper development of rate base and fair rate of return to determine return allowances on investment; (2) allowable levels of operating expenses; and (3) proper recognition of other operating revenues, including those for opportunity-type sales of electricity. This chapter, therefore, will first discuss test year concepts, then, the major elements used to determine revenue requirements will be presented.

I. TEST YEAR CONCEPTS

Regulatory agencies recognize that the rates they establish are likely to remain in effect for an indeterminate period into the future. Consequently, rates so established are usually developed using the most current actual or projected cost and sales information for a selected time period. The period used is normally 12 months in length -- referred to as the test year or test period -- and normally includes cost and sales data which are expected to be representative of those that will be experienced during the time the rates are likely to remain in effect.

III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

CLASSIFICATION OF RATE BASE[1]

Production Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	-
330-336	Hydraulic Production	x	x[2]
340-346	Other Production	x	-

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant

Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

Maintencance

528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x

Hydraulic Power Generation Operation

535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-

Maintenance

541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]

Other Power Generation Operation

FERC Uniform System of Account	Description	Demand Related	Energy Related
546, 548-554	All Accounts	x	-
547	Fuel	-	x

Other Power Supply Expenses

FERC Uniform System of Account	Description	Demand Related	Energy Related
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH),