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June 11, 2024

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

Re: Docket No. 20240025-EI – Petition for rate increase by Duke Energy Florida, LLC.

Dear Mr. Teitzman:

Please find enclosed for filing in the above-referenced docket the Direct Testimony and Exhibits of Tony Georgis on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs and Nucor Steel Florida, Inc. 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 11th day of June, 2024:

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/s/ Laura Wynn Baker
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	)))	**DOCKET NO. 20240025-EI**

DIRECT TESTIMONY OF TONY GEORGIS

ON BEHALF OF WHITE SPRINGS AGRICULTURAL CHEMICALS, INC. D/B/A PCS PHOSPHATE – WHITE SPRINGS AND NUCOR STEEL FLORIDA, INC.

JUNE 11, 2024

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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 Boulevard, 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 White Springs Agricultural Chemicals, Inc. doing business as PCS-Phosphate – White Springs and Nucor Steel Florida, Inc.

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 states of Colorado and Louisiana.

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 to the California Public Utilities Commission, the Public Utility Commission of Texas, the Florida Public Service Commission ("Commission"), and 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. WHAT IS THE PURPOSE AND SCOPE OF YOUR DIRECT TESTIMONY?

A. My testimony addresses several issues and concerns regarding cost of service, revenue allocation and rate design that are presented in the Duke Energy Florida, LLC ("Duke" or "DEF") April 2, 2024 petition to increase its base rates. The base rate revenue increases proposed amount to more than 20% in 2025 from current base rates, with subsequent increases of 2.75% and 3.6% in 2026 and 2027, respectively.[1] In total, DEF

[1] *See* DEF Exhibit MJC-2, Company-Proposed Allocation of the Target Revenue and Rate Increase/(Decrease) by Rate Class.

seeks to increase its base rates over this period by roughly $820 million (28%) over current base rates, with the cumulative increase in DEF revenues exceeding $2 billion.[2] While the DEF proposed system average rate increase is more than 20%, DEF proposes even larger increases to its commercial and industrial service classes, plus DEF proposes to slash the interruptible service credit by more than 40%.[3] The net result for customers on the interruptible service rates is a base rate increase in 2025 in excess of 50%.[4]

My testimony explains that DEF's cost of service study systematically over-allocates utility production and transmission costs to its non-firm interruptible service commercial and industrial customers. I address other errors and issues in the Duke Energy cost of service analysis. Finally, I explain that DEF's proposed reductions in the interruptible and curtailable service credits are not warranted. Specifically, my testimony explains:

- How DEF production and transmission costs should be allocated to DEF's non-firm loads for cost of service ("COS") purposes;
- The system benefits, importance, and value of DEF's interruptible service and why the Commission should reject the proposal to substantially reduce the prevailing credits;

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2 *Id.*

3 *See* DEF MFR Schedule A-3, p. 21 of 24.

4 *See id.*

- Why DEF's reliance on the 12 month coincident peak ("CP") and 25% average demand ("AD") method for allocating production costs in its cost of service analysis is misplaced;
- Why a four month CP method is more appropriate for allocating DEF production costs;
- Why a correction is required to DEF's allocation of the production tax credits ("PTC") related to the production of solar photovoltaic energy; and
- Why DEF's distribution costs should be allocated using a Minimum Distribution System ("MDS") approach.

Each of these adjustments to DEF's allocated cost of service study aim to correct systematic over-allocation of its embedded costs to large customers, and particularly the curtailable service ("CS") and interruptible service ("IS") customer classes. Overall, I conclude that, due to these material errors, DEF's COS results cannot be relied upon for imposing above system average increases on the general service demand, curtailable, and interruptible service classes. I accordingly recommend that any rate increases that the Commission approves for DEF be assigned among rate classes on an equal percentage basis tied to the approved system average increase. Finally, I demonstrate that an increase to the CS and IS credits is justified rather than the substantial decrease that DEF proposes in this case.

III. CURTAILABLE AND INTERRUPTIBLE SERVICE BACKGROUND AND DUKE'S VALUE MISALIGNMENT

Q. PLEASE DESCRIBE DUKE'S CURRENT CS AND IS PROGRAMS.

A. The CS and IS service programs are important and long-standing DEF demand response programs. They are electric system reliability programs, which means that for IS service, DEF can interrupt service to all of a participating customer's load any time there is a system emergency that threatens service to Duke's firm service customers.[5] The DEF CS and IS programs have been in place for decades and have benefited Duke and its firm service customers by helping the utility avoid or defer the construction of generation peaking units during that time.

IS customers must provide interruptible capacity with no limit on the number of interruptions initiated by Duke. These interruptions may occur with little or no effective warning and will last as long as DEF requires to ensure continued reliable service to its firm retail loads.[6] DEF has designed the IS tariff to ensure that it can count on the committed load reduction in its resource planning. IS customers must commit for five-year contractual periods and must give three years of advanced notice to exit the program. CS service contains the same requirements as IS with the exception of two-year contract commitments instead of five years. However, if the CS customer transfers from a curtailable to a firm service offering, they must provide at least 36

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[5] *See* DEF MFR Schedule E-14, Rate Schedule IST-2, DEF Tariff Section No. VI, Thirtieth Revised Sheet No. 6.265.

[6] *Id.*

months prior written notice to Duke, which effectively makes the CS commitment three years, not two. Integration of the CS and IS capacity in DEF's resource planning is documented in its Ten-Year Site Plan.[7]

It is important to note that DEF interruptions of IS participants are not limited under the tariff to the system peak hours, but could occur at any time that there is a system need.[8] This form of non-firm service constitutes a virtual peaking or black-start generation unit that could be quickly dispatched at any time period, including baseload or critical system peaking events. Duke controls the customer's electric disconnect switches; thus, the load reduction is effectively 100% reliable and available. CS service interruptions function nearly identically to the IS service except that the customer controls their load reduction when called by DEF.[9]

Q. PLEASE PROVIDE SOME BACKGROUND ON INDUSTRY PRACTICES FOR COST OF SERVICE AND ALIGNING COST ALLOCATION WITH COST CAUSATION.

A. The core principle in performing a fully allocated COS study and in designing rates is to align cost recovery with cost causation. On any electric system, different customer classes and consumption behaviors impose varying costs on the system. For example, a large manufacturing facility that takes service at high voltage does not use the local

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[7] *See* Exhibit TMG-6, Duke Energy Florida, LLC's 2024 Ten-Year Site Plan, at p. 33 of 135 (Schedule 3.1.1).

[8] DEF MFR Schedule E-14, Rate Schedule IS-2, DEF Tariff Section No. VI, Thirty-First Revised Sheet No. 6.255.

[9] *See, e.g.*, *id.*, Rate Schedule CS-2, DEF Tariff Section No. VI, Fourth Revised Sheet No. 6.237.

distribution network. Thus, distribution costs should not be allocated to, nor recovered from, those customers or customer class.

Q. WHAT TYPES OF PRODUCTION-RELATED COSTS DOES DUKE INCUR TO PROVIDE PRODUCTION SERVICE?

A. Duke incurs both demand and energy related costs to provide production services to retail customers. Demand costs are fixed costs related to constructing power generation facilities while energy costs vary with the amount of energy consumed. These variable or energy costs include items such as natural gas or fuel purchases to run generation plants.

Q. **HOW DOES DUKE ALLOCATE PRODUCTION AND TRANSMISSION DEMAND COSTS TO CUSTOMER-RELATED CLASSES?**

A. Duke allocates demand costs associated with production and transmission plant to all customer classes based on their metered demand coincident with the 12 monthly peaks on the Duke system.[10] All of a customer class's metered load is considered firm load even when a customer class does not receive firm service.[11] Duke witness Marcia Olivier explains that DEF's cost of service analysis:

> is based on the premise that all the [rate] groups' load requirements are firm. This is because the Company's various forms of non-firm service are elements of its demand side management ("DSM") program, and, therefore, the value of each rate group's load subject to interruption or curtailment is not a consideration in setting base rates….[12]

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[10] Direct Testimony of Marcia J. Olivier on behalf of Duke Energy Florida, LLC at p. 33 (DEF witness Olivier Testimony).

[11] *Id.* at pp. 40-41.

[12] *Id.*

Q. WHAT ALLOCATORS DOES DUKE USE TO ALLOCATE ALL PRODUCTION RELATED COSTS?

A. DEF witness Olivier explains that the utility relies on the 12CP (12 monthly peaks) and 25% average demand ("25AD") approach (collectively, the "12CP and 25AD" method) to allocate all production demand related costs, including those listed above. DEF bases its proposed allocation of revenue increases for each of the three test years on the cost of service results produced using the 12CP and 25AD method.[13]

Q. HOW DOES DUKE DESIGN AND CONSTRUCT ITS GENERATION AND TRANSMISSION SYSTEMS?

A. For resource planning purposes, Duke designs and constructs its generation and transmission systems to meet expected net firm peak demands on the utility system plus a reserve margin. DEF witness Benjamin Borsch explains that DEF has two basic planning criteria: satisfying a minimum Reserve Margin and a maximum Loss of Load Probability, but that it effectively plans based on reserve margin.[14] Duke has not in the past, and does not currently, treat the full measured system coincident demand of CS and IS customers as firm loads that Duke must design generation resources to serve. As is shown in its Ten-Year Site Plan, DEF deducts the CS and IS demands from the determination of Net Firm Demand upon which Duke calculates its capacity reserve margins and generation capacity requirements.[15] Hence, DEF does not build or acquire capacity to serve non-firm load.

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[13] *See id.* at pp. 35 & 40.

[14] Deposition of Duke Energy Florida, LLC witness Benjamin Borsch at p. 17 ("[W]e have found historically that planning to the 20% reserve margin gives you a portfolio which also satisfies the LOLP criteria.").

[15] Exhibit TMG-6 at page 33 of 135 (Schedule 3.1.1).

In its 2024 Revised Ten-Year Site Plan, DEF calculates 402 MWs of available interruptible load reductions that it subtracts from the Net Firm Demand requirements for 2024.[16] Adding a 20% reserve margin to that amount yields 482 MWs of current CS and IS generation resource benefit.[17] Similarly, Duke constructs its transmission system to serve its firm service peaking requirements on the system.[18]

Q. IS DUKE'S ALLOCATION OF PRODUCTION COSTS IN ITS COST OF SERVICE STUDY CONSISTENT WITH THE WAY IT DESIGNS AND CONSTRUCTS ITS GENERATION SYSTEM?

A. No. As Duke witness Olivier states, for its cost of service purposes, DEF considers all rate groups to be firm load.[19] As CS and IS receive a lower level of service than firm retail service, this constitutes a fundamental error in Duke's COS that mismatches cost assignment and cost causation. By allocating its production costs based on customer

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16 *Id.*

17 402MW x 20% reserve = 80MW of avoided reserves; 80MW + 402MW = 482MW.

18 Direct Testimony of Edward L. Scott on behalf of Duke Energy Florida, LLC at pp. 19-20 ("[A]pproximately two-thirds of DEF's transmission capital expenditure requirements for 2025-2027 are allocated to the Growth category. Growth and system expansion include new service accounts, new major construction projects, and increased electrical demand in an area, all of which affect planning and operations on the transmission system.").

19 DEF witness Olivier testimony at p. 40.

class metered demand, and not an amount reduced for interruptible capacity, Duke over-allocates costs to the CS and IS customer classes.

Q. DOES DEF INCORPORATE ANY CORRESPONDING ADJUSTMENT IN THE DEMAND ALLOCATORS IN ITS COS STUDY TO ACCOUNT FOR THIS MISALIGNMENT?

A. No, there is no adjustment in the COS. To ensure cost allocation is aligned with cost causation, Duke should adjust the customer class demand allocations to account for non-firm demand. By failing to do so, DEF's cost study systematically over-allocates production and transmission costs to Duke's non-firm, interruptible customer classes. Furthermore, National Association of Regulatory Utility Commissioners' ("NARUC") Electric Utility Cost Allocation Manual provides instructions how non-firm load is treated in COS studies by noting that non-firm customers are usually excluded from the demand allocation factor calculations in recognition of their level of service.[20] This lack of an adjustment unnecessarily depresses the reported CS and IS class returns reported in the COS results, which in turns leads to DEF's proposal to assign a higher than system average revenue increase to these non-firm customer classes.

Q. SHOULD DUKE MAKE ANY ADJUSTMENT TO THE COST OF SERVICE OR DEMAND ALLOCATORS TO MAINTAIN CONSISTENCY IN COST CAUSATION PRINCIPLES AND COS FUNDAMENTALS?

A. Yes. As Duke chose to allocate production and transmission costs under the assumption that all customer classes are firm load, to ensure consistency with cost

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[20] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at p. 76 (1992), *available at* https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD (NARUC Cost Allocation Manual).

causation principles, CS and IS credits should be incorporated in the COS based on embedded production and transmission costs. This adjustment would correct the COS for how Duke chose to allocate the production and transmission costs to CS and IS customers. This approach will produce an accurate COS result and cost causation approach in quantifying the benefits as well as the costs imposed on the DEF system by the CS and IS classes.

Q. HOW DOES DUKE EXPLAIN THE INCONSISTENCY IN ITS COST OF SERVICE STUDY?

A. Duke witness Olivier maintains that credits provided to non-firm loads through its demand side management programs corrects for the cost misallocation.[21]

Q. DO YOU AGREE?

A. No. The CS and IS credits contained in DEF's DSM plans do not take the on-going and embedded cost benefits of its existing program participants into account at all. Docket No. 20240013-EG, *In re: Commission review of numeric conservation goals (Duke Energy Florida, LLC)*, looks only to incremental participation based on assumed future marginal (avoided) costs. The COS study, however, examines actual embedded costs for a historic period (in this case the year 2023) adjusted for future Test Year forecast changes to those embedded costs (2025, 2026, and 2027). To maintain consistency in benefits and cost causation, the required adjustment to the COS allocations must look to the embedded cost benefits of the non-firm service, which I describe and quantify below, and not marginal benefits or costs.

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[21] DEF witness Olivier testimony at pp. 40-41.

Q. PLEASE EXPLAIN.

A. Embedded costs evaluated in the Duke COS study represent the accumulated historical and planned costs for Duke's generation and transmission system. Historically, Duke has not designed its system or constructed production assets to serve CS and IS customer interruptible loads, and thus the embedded costs are lower than they otherwise would be. Thus, there is an on-going CS and IS benefit (or reduction in costs) reflected in DEF's embedded costs but not in the COS for each customer class. This mismatch leads to over-allocation of costs to CS and IS customers.

Q. WHAT ARE THE EMBEDDED COST BENEFITS ATTRIBUTABLE TO CS AND IS SERVICE?

A. Instead of looking at a projected marginal unit at an assumed cost, the embedded cost benefits must consider historic and Test Year generation and transmission costs commensurate with 402 MWs of assured load reduction, plus an additional reserve margin. Exhibit TMG-2 details the system-level total costs for generation and transmission services and translates those total costs to unit costs (i.e., per kW) based on the Duke system coincident peak billing determinants. I used Duke's coincident peak demand billing units to reflect the unit cost values during peak demand periods on the system because that best aligns with how the CS and IS services are quantified and used by Duke in its Ten-Year Site Plan and generation resource plan (even though DEF has the ability to interrupt CS and IS loads whenever they are needed).

As shown in Exhibit TMG-2, based on Duke's Updated Fall of 2023 sales forecast and related cost of service MFRs, without any other adjustments, generation unit costs, based on the coincident peaks, are $15.36 per kW, and the transmission costs are $6.18 per kW for the 2025 Test Year. Thus, the total unit cost for generation and transmission for the Duke system based on coincident peak demands is $21.54 per kW. When the 20% reserve margin is applied to this total it becomes $25.84 per kW.[22] This amount fully reflects Duke's embedded cost of firm capacity and the on-going value to the system of the existing CS and IS interruptible load.

Q. HOW SHOULD THE EMBEDDED CS AND IS COST BENEFIT BE APPLIED IN THE COST OF SERVICE STUDY?

A. The short answer is that the COS study should be revised to develop distinct production and transmission demand allocation factors for firm and non-firm service. The COS should allocate production and transmission costs based on the actual firm service delivered and reduced for the CS and IS interruptible capacity. This would rectify the over-allocation of production and transmission costs to the CS and IS classes discussed previously. The alternative to revamping the cost study altogether is to calculate an allocation adjustment based on the above-noted embedded benefits attributable to existing CS and IS load participation to appropriately reduce the production and transmission costs allocated to these classes.

Q. HOW DOES DUKE'S PROPOSED CS AND IS CREDIT COMPARE TO THE EMBEDDED COST VALUE REALIZED IN THE COS?

A. DEF proposes a going-forward IS credit of $4.62 per kW.[23] As shown above, existing IS loads currently provide a fully realized, embedded cost-based benefit to DEF of

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[22] *See* Exhibit TMG-2 at p. 1 of 1.

[23] *See, e.g.*, MFR Schedule E-14, Rate Schedule IS-2, DEF Tariff Section No. VI, Thirty-First Revised Sheet No. 6.255.

$25.84 per kW. That is a difference of more than $20 per kW that is missing from DEF's approach.

IV. <u>OTHER PROPOSED CORRECTIONS TO DUKE'S COST OF SERVICE</u>

Q. WHAT ERRORS OR ISSUES DID YOU IDENTIFY IN DUKE'S COS MODEL AND THE MINIMUM FILING REQUIREMENTS ("MFR")?

A. In addition to the error and misalignment of the value for CS and IS interruptible capacity, I have identified issues and errors related to the production and transmission demand cost allocation method, the production tax credit ("PTC") allocation, and the allocation method for distribution costs.

A. <u>Production and Transmission Demand Cost Allocation</u>

Q. HOW DOES DUKE ALLOCATE PRODUCTION AND TRANSMISSION DEMAND COSTS TO THE CUSTOMER CLASSES?

A. As stated previously in my testimony, Duke allocates production demand revenue requirement to the customer classes using the 12CP and 25AD method.[24] Transmission demand costs are allocated on a 12CP methodology.[25]

Q. ARE DEF'S ASSUMPTIONS FOR ALLOCATING PRODUCTION DEMAND COSTS TO CUSTOMER CLASSES REASONABLE?

A. No. The 12CP and 25AD allocation approach is not appropriate for how DEF's system is planned and operates and is inconsistent with its resource planning criteria and basic

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[24] DEF witness Olivier testimony at p. 34.

[25] *Id.*

cost causation principles. Based on the system data provided for the Base Rate Case and used for COS allocators, Duke's system is a summer peaking system with the four highest peaks in June, July, August, and September.[26] These peaks drive Duke's required reserve margin for planning purposes and are materially higher than either DEF's average demands or peaks in other months.

Q. PLEASE FURTHER DESCRIBE DUKE'S SYSTEM PEAK DEMANDS AND RELATED CHARACTERISTICS.

A. The DEF system is more variable than the two other large investor owned utilities in Florida, Florida Power & Light Company ("FPL") and Tampa Electric Company ("TECO"). This variability is seen in Duke's system as it operates at a comparatively lower load factor, which means it has a greater disparity between its peak and average demands compared to FPL and TECO.[27] In practical terms, the lower DEF system load factor means that it is more reliant on peaking generation to follow load and meet less frequent peak demands than the other two large investor-owned utilities.

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26 *See* DEF MFR Schedules E-9 & E-17.

27 *Cf.* Exhibit TMG-6 at p. 39 of 135 (Schedule 3.3.1, History and Forecast of Annual Net Energy for Load (GWh)) (showing a load factor between 2014 and 2023 ranging between 48.9% and 53.1%); Florida Power & Light Company Ten Year Power Plan Site Plan 2024-2033 at Schedule 3.3, History of Annual Net Energy for Load (GWh), *available at* https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2024/Florida%20Power%20and%20Light%20Company.pdf (showing a load factor between 2014 and 2023 ranging between 57.7% and 60.9%); Tampa Electric Company 2024 Ten-Year Site Plan at Schedule 3.3, History and Forecast of Annual Net Energy for Load (GWh), *available at* https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2024/Tampa%20Electric%20Company%20-%20Revised.pdf (showing a load factor between 2014 and 2023 ranging between 53.2% and 58.1%).

Q. PLEASE GENERALLY DESCRIBE DUKE'S NEAR TERM GENERATION RESOURCE PLANS AND CONTRIBUTIONS TO SYSTEM PEAKING NEEDS.

A. Between 2024 and the Test Year ending December 2027, Duke's current generation resource program is centered on retiring 705 MWs of oil-fired combustion turbines that collectively carry a summer capacity rating of 460 MWs.[28] Aligned with this large peaking capacity retirement, Duke plans on adding more than a dozen large scale solar projects amounting to 1,348 MWs of added nameplate generating capacity.[29] These solar additions offer only 434 MWs of what DEF considers to be firm summer capability.[30] Duke expects that the solar summer capability (both existing and new) will drop to less than 25% of nameplate rating by 2027 as the summer peak time moves later in the day.[31] In winter months, Duke deems the added solar capacity to have zero peak capability or contribution. [32]

Q. PLEASE EXPLAIN YOUR RECOMMENDED APPROACH FOR ALLOCATING DEF'S PRODUCTION COSTS.

A. Considering the operating characteristics of Duke's system, it is apparent that Duke may be electing to add significant amounts of solar generation to its system, but the utility's need is mostly for fast ramping and peak load following generation. Moreover,

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28 *See* Exhibit TMG-6 at pp. 75-76 of 135 (Schedule 8).

29 *Id.*

30 *Id.*

31 *Id.* at p. 68 of 135 ("DEF recognizes that as solar penetration increases, including both DEF and customer owned PV, the relationship between the solar production and the coincident load peak will change. . . . DEF modeling derives an equivalent summer non-coincident, but on-peak-hour capacity value equal to 25% of the facility's nameplate rating for planned PV installations from 2025 to 2027 and 10% for 2028 and beyond.").

32 *Id.* at p. 16 of 135 (Schedule 1).

that need becomes increasingly more pronounced as DEF adds more intermittent, weather-sensitive solar power to its portfolio. Growth in sales will further drive the peak, while solar generation's contribution to the overall system will further erode the system load factor and lead to additional variability and increased ramping needs. This expected trendline requires a more realistic allocation of production costs based on peak demands.

Duke's monthly system peak demands suggest that allocating production costs based on the pronounced summer peak (4CP) would be most appropriate at this time as a reasonable transition from its historic 12CP and 1/13AD method and proposed 12CP and 25AD. Duke customers' contributions to these four monthly peaks more properly reflect the costs imposed on the system, as they drive the capacity investments to serve customers' firm loads. Furthermore, these months are all within 97% of the system peak in June.[33]

Q. PLEASE EXPLAIN YOUR RECOMMENDED APPROACH FOR ALLOCATING DEF'S TRANSMISSION DEMAND COSTS.

A. Transmission systems are constructed to serve the system loads, and the criteria to construct and operate the system are similar to that of the production function. As the transmission system is constructed to serve peaks, the transmission demand cost allocation should align with the production demand cost allocation. Furthermore, the NARUC cost allocation manual recommends aligning transmission and production

[33] *See* DEF MFR Schedules E-9 & E-17.

cost allocation as the transmission system is essentially an extension of the production system.[34] Thus, Duke should apply a 4CP allocation to the transmission demand costs.

Q. WHAT IS THE RESULT OF THE CLASS ALLOCATION AFTER APPLYING THE 4CP ALLOCATION METHOD TO DUKE'S PRODUCTION AND TRANSMISSION DEMAND COSTS?

A. Table 1 below summarizes the impact of adjusting the production and transmission demand cost allocations.

Table 1
Production and Transmission Demand Allocation Corrections

Customer Class	Proposed COS ($000)	Corrected COS ($000)	Difference ($000)
Total Retail Adjusted	$3,373,238.76	$3,373,238.76	$-
Residential	$2,155,768.04	$2,240,733.47	$84,965.43
Gen Service Non Demand	$193,589.97	$186,777.32	$(6,812.65)
Gen Service 100% L.F.	$11,668.07	$10,913.59	$(754.48)
Gen Service Demand	$775,775.97	$711,445.53	$(64,330.44)
Gen Service Curtailable	$2,917.99	$2,693.54	$(224.45)
Gen Service Interruptible	$104,675.98	$91,736.37	$(12,939.62)
Lighting Energy	$20,295.93	$18,042.75	$(2,253.18)
Lighting Facilities	$103,604.38	$105,921.84	$2,317.47
EV Solution	$4,942.42	$4,974.36	$31.93

B. Production Tax Credit Allocation Error

Q. WHAT IS THE FEDERAL PRODUCTION TAX CREDIT ("PTC")?

A. The PTC is a per kWh federal tax credit to businesses for electricity generated by a qualified renewable energy resource. The PTC can vary based on the type of renewable

[34] NARUC Cost Allocation Manual at p. 75.

technology and other factors such as certain labor requirements and content of the facility manufactured domestically in the U.S.[35]

Q. HOW DOES DUKE ALLOCATE THE INCOME TAX CREDIT FROM THE PTC IN THE COS TO THE CUSTOMER CLASSES?

A. Duke allocates the PTC benefit to the customer classes based on the total accumulated depreciation of all plant included in its rate base calculations.[36]

Q. IS THAT CORRECT?

A. No. The PTC is an energy production (i.e., kWh) based income tax credit to businesses. It provides a varying credit per kWh of energy generated from accepted renewable energy generation resources such as Duke's construction of solar photovoltaic plants. This credit varies from $0.0055 to $0.0275 per kWh depending on certain project construction and labor requirements.[37] Accumulated depreciation is a balance sheet, asset related item that quantifies the reduction in the book value of Duke's assets. It is not related to how much energy (i.e., kWh) is generated by renewable energy generation assets. It is therefore inconsistent to allocate the PTC benefit based on accumulated depreciation of plant.

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[35] U.S. Environmental Protection Agency, *Renewable Electricity Production Tax Credit Information*, https://www.epa.gov/lmop/renewable-electricity-production-tax-credit-information (last accessed June 11, 2024).

[36] *See, e.g.*, DEF MFR Schedule E-1, 12 CP and 25% AD Cost of Service Study for Test Year 2025. at p. 10 of 230 (Line Nos. 3 & 505).

[37] U.S. Department of Energy, *Federal Solar Tax Credits for Businesses*, https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses (last accessed June 11, 2024).

Q. HOW DO YOU RECOMMEND DUKE ALLOCATE THE INCOME TAX CREDIT FROM THE PTC IN THE COS TO THE CUSTOMER CLASSES?

A. Duke must change the PTC allocation from accumulated depreciation of assets by customer class to the energy generated at the source level to serve each class. Using the Production Energy – Solar allocator for the federal PTC properly allocates the tax credits to the customer classes using the energy generated at the source level to serve the classes. This aligns the benefits received by Duke in the energy PTC with the energy consumption of the customer classes.

Q. WHAT IMPACT DOES THIS HAVE?

A. I applied the production energy allocation factor to the PTC in Duke's COS model. Table 2 summarizes the impact on the class total COS by changing the PTC allocation and leaving all other components of the COS unchanged.

Table 2
PTC Allocation Correction

Customer Class	Proposed PTC Allocation ($000)	Corrected PTC Allocation ($000)	Difference ($000)
Total Retail Adjusted	$(64,562.86)	$(64,562.86)	$-
Residential	$(40,588.70)	$(34,801.29)	$5,787.41
Gen Service Non Demand	$(3,495.51)	$(3,528.75)	$(33.24)
Gen Service 100% L.F.	$(224.81)	$(334.68)	$(109.87)
Gen Service Demand	$(15,282.00)	$(21,164.95)	$(5,882.94)
Gen Service Curtailable	$(59.09)	$(103.65)	$(44.56)
Gen Service Interruptible	$(2,211.35)	$(4,097.30)	$(1,885.95)
Lighting Energy	$(352.00)	$(532.24)	$(180.24)
Lighting Facilities	$(2,317.47)	$-	$2,317.47
EV Solution	$(31.93)	$-	$31.93

C. Minimum Distribution System Methodology and Application

Q. PLEASE DESCRIBE THE MINIMUM DISTRIBUTION SYSTEM ("MDS") METHODOLOGY.

A. Distribution costs are driven by the utility's requirement to connect customers to the system no matter where they are located within its service area and the demand requirements those customers place on the system. The MDS method classifies costs as either customer-related or demand-related based on the concept of a minimum system. A minimum system simply represents that infrastructure cost required to connect a customer to the grid without further consideration of the customer's demand and energy requirements. This involves determining the minimum size of pole, conductor, transformer, and service drops required to simply connect to a customer premises. Once the minimum sizes of each of the distribution system components is determined, the value of the MDS plant is determined. This MDS portion of the total distribution plant is classified as customer-related and allocated to customer classes based on the number of customers. The remaining portion of the distribution plant is classified as demand-related and allocated to customers based on non-coincident peak demand allocation factors.

For example, if the total distribution plant value was $500 million and the MDS study calculated that $100 million was related to the minimum system, then 20% of the distribution plant would be classified as customer-related and allocated accordingly. The remaining 80% would remain classified as demand-related and allocated accordingly. The use of MDS represents a fair classification of distribution costs to customers because it recognizes that the physical location of the customer is an important driver of costs, and these costs should be properly classified as customer-related.

Q. IS THE MDS METHODOLOGY FOR CLASSIFYING COSTS AN ACCEPTED INDUSTRY PRACTICE AND CLASSIFICATION METHODOLOGY?

A. Yes. NARUC recognizes and details the use and application of the MDS methodology.[38]

Q. WHY SHOULD THE MDS METHODOLOGY BE APPLIED AND INCLUDED IN THE DUKE COST OF SERVICE AND BASE RATE CASE?

A. The MDS more accurately reflects the costs incurred by the utility to simply connect a customer to the system regardless of its size or load factor compared to Duke's current methodology. It calculates the minimum distribution component sizes for poles, transformers, and conductors to simply connect a customer's meter to the distribution substations to receive power. These distribution assets and infrastructure are required if the customer's peak demand is 10 kW or 0 kW. As there is a certain level or amount of distribution assets and infrastructure required whether or not the customer is using any power, a portion of the distribution system costs should be classified as customer related. This customer portion of the distribution costs does not vary with the demand levels; rather, it varies with the number of customers. Thus, it should be classified as customer-related.

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[38] NARUC Cost Allocation Manual at p. 90.

Q. SHOULD THE MDS METHODOLOGY BE APPLIED AND ADOPTED IN THIS RATE PROCEEDING?

A. Yes, it should be included in this and subsequent Duke rate proceedings. The MDS methodology should be included to better reflect the costs imposed on the system by each customer class. The MDS is a long-standing accepted methodology for classifying distribution costs as both customer and demand related. These costs are then allocated using customer and demand allocation factors to the customer classes.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS AND RECOMMENDATIONS CONCERNING DEF'S COST OF SERVICE AND PROPOSED REVENUE ALLOCATION?

A. Considering the magnitude of the base rate increases that DEF has proposed, it is crucial to allocate any approved rate increases properly. I have quantified the cost of service effects associated with adopting a 4CP production cost allocation method and correcting the PTC allocation, but I was not able to re-run DEF's cost of service model to correct for the over-allocation of production costs to its non-firm loads or for allocating distribution costs using the MDS approach. All of the above corrections adjust for systematic over-allocation of costs to Duke's large customers, and particularly those on non-firm rates. I conclude that these corrections are large enough that DEF cannot rely on its filed COS results to justify imposing rate increases of 150% of the system average increase on its large customers. I propose instead that any approved increases be implemented on an equal percentage basis for all customer classes. This would better allocate the rate increase among Dukes customer classes given the errors in Duke's cost of service and the uncertain impact of some of those errors. Additionally, I recommend that the Commission require Duke to file a cost of service study incorporating the changes I recommend in its next base rate proceeding.

V. INTERRUPTIBLE SERVICE CREDIT

Q. PLEASE EXPLAIN DEF'S PROPOSED CHANGES TO THE CURRENT CS AND IS CREDITS.

A. Duke does not propose any changes to how the CS and IS programs work that would make them less valuable to the network as a resource. Duke simply proposes to pay participants less for providing the same benefits. Duke proposes to reduce the IS incentive credit from $7.72 per kW-month to $4.62 per kW-month, a reduction of more than 40%. DEF proposes to reduce the current CS credit of $7.72/kW-month to $5.82/kW-month. [39]

Q. DO YOU AGREE WITH DUKE'S PROPOSAL TO REDUCE THE IS AND CS CREDITS?

A. No. The CS and IS credits should each be increased rather than reduced. As discussed above, the CS and IS programs have helped Duke 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. This on-going benefit provided by CS and IS participants includes the contracted and dedicated capacity reductions of 402 MWs as previously noted plus the associated reduction in DEF's required reserve margin.

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[39] *See* MFR Schedule E-14, Rate Schedule CST-2, DEF Tariff Section No. VI, Twenty-Ninth Revised Sheet No. 6.245.

Q. WHAT CS AND IS CREDIT DO YOU RECOMMEND BE ADOPTED?

A. I recommend a credit of $9.01 per kW per month for CS and IS customers. This credit is based on the estimated revenue requirement associated with more recent (e.g., the last ten years) generation constructed in Duke and other investor owned utilities territories in Florida. This represents the generation plant and costs that would have been built if the CS and IS customers were treated as firm customers over the last ten years. As Duke has had limited new generator construction during this ten year period, I also reviewed the other Florida investor owned utilities to gain a more accurate representation of generation costs DEF has avoided in the last ten years. This represents a balance between the full embedded costs DEF has avoided over multiple decades (almost $26 per kW) and evaluates a more recent period and the representative revenue requirement associated with those avoided generation plant investments.

Q. PLEASE EXPLAIN.

A. If the CS and IS customers were treated at firm customers in resource planning over the last ten years, DEF would have had more net firm load than it needed to plan to serve. Duke would have increased the amount of the generation required to meet firm load requirements and the planning reserve margin throughout that time. As shown in Exhibit TMG-5, I calculated the relationship between the current DEF functionalized production demand revenue requirement and historic initial installed plant costs and apply that relationship to costs of constructing new generation over the last ten years in Florida. This approximates the production revenue requirements avoided as a result of CS and IS loads' lower quality of service (by lowering the net firm load and system requirements) over the last ten years.

This aligns with the embedded cost value methodology previously discussed in my testimony as it looks at prior generation investments and revenues requirements. However, it evaluates a more recent period than the multiple decades the CS and IS customers have contributed to reducing DEF's embedded costs included in this COS study. Exhibit TMG-4 and TMG-5 summarize the development of this credit amount.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Tony Georgis

Managing Director – Energy Practice

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EDUCATION

Master of Business Administration, Finance Specialization, Texas A&M University

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).

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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

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

Record of Testimony: **Tony Georgis, P.E.**

	UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1.	Indiana Michigan Power Company	Cause No. 45993	Authority to Increase its Rates and Charges for Electric Utility Service Through a Phase in Rate Adjustment	Indiana Utility Regulatory Commission	City of Fort Wayne, the City of Marion, and Marion Municipal Utilities	2023
2.	San Diego Gas & Electric Company	CPUC Application No. 22-05-016	Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Application 22-05-016 Revenue Requirement and Base Rates Effective on January 1, 2024	California Public Utility Commission	Joint Community Choice Aggregators	2023
3.	City of Lubbock, Lubbock Power & Light	PUC Docket No. 54657	Application of the City of Lubbock for Authority to Change Rates for Wholesale Transmission Service	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2023
4.	Northern Indiana Public Service Company LLC (NIPSCO)	Cause No. 45772	Petition of Northern Indiana Public Service Company LLC (NIPSCO) Authority to 1) Modify Electric Utility Rates; 2) Approval of New Schedules of Rates and Changes, General Rules and Regulations and Riders; 3) Approval of a new Rider for VOM, and other requests.	Indiana Utility Regulatory Commission	Bose McKinney & Evans LLP, United States Steel Corporation	2023
5.	Pacific Gas and Electric Company	CPUC Application No. 21-06-021	Application for 2023 General Rate Case	California Public Utility Commission	Joint Community Choice Aggregators	2022
6.	City of Lubbock, Lubbock Power & Light	PUC Docket No. 52390	Application of the City of Lubbock for Authority for Interim Update of Wholesale Transmission Rates	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2021
7.	Florida Power & Light Company	Docket No. 20210015-EI	Petition for Rate Increase by Florida Power & Light Company	Florida Public Service Commission	Stone Mattheis Xenopoulos & Brew, PC; Florida Retail Federation	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
8. Southwestern Electric Power Company (SWEPCO)	SOAH Docket No. 473-21-0538 PUC Docket No. 51415	Application of Southwestern Electric Power Company for Authority to Change Rates	State Office of Administrative Hearings, Public Utility Commission of Texas	Office of Public Utility Counsel	2021
9. City of Pasadena – Pasadena Water and Power	BC 677632	Komesar vs. City of Pasadena; State of California Proposition 218, City General Fund Transfer from Utility	Superior Court of the State of California for the County of Los Angeles	Jarvis, Fay and Gibson, LLP; City of Pasadena	2020
10. City of Lubbock, Lubbock Power & Light	SOAH Docket No. 473-21-0043 PUC Docket No. 51100	Application of the City of Lubbock for Authority to Establish Initial Wholesale Transmission Rates and Tariffs	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2020
11. Northern Indiana Public Service Company LLC (NIPSCO)	Cause No. 45159	Petition of Northern Indiana Public Service Company LLC (NIPSCO) Authority to 1) Modify Electric Utility Rates; 2) Approval of New Schedules of Rates and Changes, General Rules and Regulations and Riders; 3) Approval of Revised Common and Electric Depreciation Rates; 4) Accounting Relief; and 5) Approval of New Service Structure for Industrial Rates	Indiana Utility Regulatory Commission	Bose McKinney & Evans LLP, United States Steel Corporation	2019
12. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-14-3897 PUC Docket No. 42560	Application of CenterPoint Energy Houston Electric, LLC for Approval of an Adjustment to its Energy Efficiency Cost Recovery Factor	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C., Gulf Coast Coalition of Cities	2014

Florida Public Service Commission
Duke Energy Florida
Docket No. 20240025-EI
TMG - 2 CS and IS Embedded Cost Value

Line No.	Item (1)		Amount ($000) (2)	Comment or Source (3)
1	**Functionalized Revenue Requirement**			
2	Production Capacity Demand			
3	Revenue Credits	$	201.38	Schedule 2B 2025
4				
5	Operations & Maintenance	$	97,221.42	Schedule 2B 2025
6	Depreciation	$	531,941.24	Schedule 2B 2025
7	Tax Other Than Income Tax	$	68,421.48	Schedule 2B 2025
8	Gain/Loss on Disposition	$	(481.88)	Schedule 2B 2025
9	Operating Expense before Tax	$	697,102.26	Schedule 2B 2025
10	Income Tax Expense	$	77,558.11	Schedule 2B 2025
11	Total Operating Expense	$	774,660.37	Schedule 2B 2025
12				
13	Return			
14	Net Operating Income Required	$	539,616.34	Schedule 2B 2025
15	Total Production Demand Revenue Requirement	$	1,314,075.33	Schedule 2B 2025
16	check	$	-	
17				
18	Transmission Capacity Demand			
19	Revenue Credits	$	10,329.23	Schedule 2B 2025
20				
21	Operations & Maintenance	$	34,935.13	Schedule 2B 2025
22	Depreciation	$	119,676.15	Schedule 2B 2025
23	Tax Other Than Income Tax	$	37,229.95	Schedule 2B 2025
24	Gain/Loss on Disposition	$	(268.09)	Schedule 2B 2025
25	Operating Expense before Tax	$	191,573.15	Schedule 2B 2025
26	Income Tax Expense	$	60,236.28	Schedule 2B 2025
27	Total Operating Expense	$	251,809.42	Schedule 2B 2025
28				
29	Return			
30	Net Operating Income Required	$	287,406.36	Schedule 2B 2025
31	Total Transmission Demand Revenue Requirement	$	528,886.55	Schedule 2B 2025
32	check	$	-	
33				
34				
35	12CP Avg		7,131,100	E-10 Class Alloc
36	12 months 12CP Avg		85,573,200	CP-months; Row 35 x 12 months
37				
38	Unit Costs			
39	Production Demand Revenue Requirement	$	15.36	per kW; (Row 15 x 1000)/ Row 36
40	Transmission Capacity Demand Revenue Requirement	$	6.18	per kW; (Row 16 x 1000)/ Row 36
41	Total	$	21.54	per kW; Row 39 + Row 40
42				
43	Add 20% Planning Reserve			
44	Production	$	3.07	per kW; Row 39 x 20%
45	Transmission	$	1.24	per kW; Row 40 x 20%
46	Subtotal	$	4.31	per kW; Row 44 + Row 45
47	Total Embedded Prod. & Trans. Cost	$	25.84	per kW; Row 46 + Row 41

Florida Public Service Commission
Duke Energy Florida
Docket No. 20240025-EI
TMG - 3 Cost of Service Corrections

PTC Adjustment

Line No.	($000)	Total Retail Adjusted	Residential	Gen Service Non Demand	Gen Service 100% L.F.	Gen Service Demand	Gen Service Curtailable	Gen Service Interruptible	Lighting Energy	Lighting Facilities	EV Solution	Comment or Source
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1												
2	Federal Income Tax (PTC)	$ (64,562.86)	$ (40,588.70)	$ (3,495.51)	$ (224.81)	$ (15,282.00)	$ (59.09)	$ (2,211.35)	$ (352.00)	$ (2,317.47)	$ (31.93)	Schedule 2A
3												
4	ACC Depr	$ (7,310,021.55)	$ (4,595,587.10)	$ (395,773.19)	$ (25,454.15)	$ (1,730,279.17)	$ (6,690.61)	$ (250,376.18)	$ (39,854.21)	$ (262,391.17)	$ (3,615.77)	Schedule 2A
5			62.9%	5.4%	0.3%	23.7%	0.1%	3.4%	0.5%	3.6%	0.0%	
6												
7	Energy Alloc		53.9%	5.5%	0.5%	32.8%	0.2%	6.3%	0.8%			Schedule 3 Alloc Factors
8												
9	Adjusted PTC to classes using Energy Alloc.	$ (64,562.86)	$ (34,801.29)	$ (3,528.75)	$ (334.68)	$ (21,164.95)	$ (103.65)	$ (4,097.30)	$ (532.24)	$ -	$ -	Row 8 x total PTC in Row 8, Column 2
10	Difference from proposed PTC	$ -	$ 5,787.41	$ (33.24)	$ (109.87)	$ (5,882.94)	$ (44.56)	$ (1,885.95)	$ (180.24)	$ 2,317.47	$ 31.93	Row 11 - Row 3
11												
12												
13												
14												
15												
16												
17												

18 **4CP Adjustment**

Line No.	($000)	Total Retail Adjusted	Residential	Gen Service Non Demand	Gen Service 100% L.F.	Gen Service Demand	Gen Service Curtailable	Gen Service Interruptible	Lighting Energy	Lighting Facilities	EV Solution	Comment or Source
19												
20	Proposed Cost of Service	$ 3,373,239	$ 2,155,768	$ 193,590	$ 11,668	$ 775,776	$ 2,918	$ 104,676	$ 20,296	$ 103,604	$ 4,942	Schedule 2A
21	Corrected Cost of Service	$ 3,373,239	$ 2,240,733	$ 186,777	$ 10,914	$ 711,446	$ 2,694	$ 91,736	$ 18,043	$ 105,922	$ 4,974	Updated Schedule 2A with 4CP allocations
22	Difference	$ -	$ 84,965	$ (6,813)	$ (754)	$ (64,330)	$ (224)	$ (12,940)	$ (2,253)	$ 2,317	$ 32	Row 22 - Row 21
23												
24												
25	Proposed COS Based Rate Increase	18.18%	15.58%	-2.09%	38.06%	26.03%	53.27%	51.72%	106.40%	22.39%	-23.95%	Schedule 2A
26	Adjusted COS Based Rate Increase	18.18%	21.06%	-6.48%	27.79%	13.61%	40.01%	30.46%	82.93%	25.90%	-23.24%	Updated Schedule 2A with 4CP allocations
27												

Florida Public Service Commission
Duke Energy Florida
Docket No. 20240025-EI
TMG - 4 Historical Generation Addition Total Installed Costs

Line No.	Plant Name (1)	Year in Service (2)	Investment ($) (3)	Net Capacity (kW) (4)	Installed Cost ($/kW) (5)
	Duke				
1	Osprey	2004	$ 414,015,669	611,000	$ 678
2	Bartow	2009	$ 763,413,352	1,259,000	$ 606
3	Citrus County	2018	$ 1,460,889,468	1,854,000	$ 788
4	Lake Placid (1)	2019	$ 24,328,650	18,000	$ 1,352
5	Solar Projects	Various	$ 1,821,870,000	1,186,400	$ 1,536
6	Total		$ 4,484,517,139	4,928,400	$ 910
7	Total Excluding Solar		$ 2,662,647,139	3,742,000	$ 712
8					
9	**FPL**				
10	Anhinga	2023	$ 79,833,371	74,500	$ 1,072
11	Apalachee	2023	$ 88,621,769	74,500	$ 1,190
12	Babcock Preserve Solar Er	2020	$ 78,993,857	74,500	$ 1,060
13	Babcock Solar Energy Cen	2016	$ 129,916,920	74,500	$ 1,744
14	Barefoot Bay Solar Energy	2018	$ 96,688,872	74,500	$ 1,298
15	Blackwater River	2023	$ 82,275,523	74,500	$ 1,104
16	Blue Cypress Solar Energy	2018	$ 93,732,991	74,500	$ 1,258
17	Blue Heron Solar Energy C	2020	$ 84,679,933	74,500	$ 1,137
18	Blue Indigo Solar Energy C	2020	$ 92,825,079	74,500	$ 1,246
19	Blue Springs Solar Energy	2021	$ 96,148,366	74,500	$ 1,291
20	Bluefield Preserve	2023	$ 78,242,078	74,500	$ 1,050
21	Cape Canaveral	2013	$ 986,388,176	1,305,000	$ 756
22	Cattle Ranch Solar Energy	2020	$ 77,068,857	74,500	$ 1,034
23	Cavendish	2023	$ 84,390,671	74,500	$ 1,133
24	Chautauqua	2023	$ 94,759,933	74,500	$ 1,272
25	Total		$ 2,244,566,396	2,348,000	$ 956
26	Total Excluding Solar		$ 986,388,176	1,305,000	$ 756
27					
28	**TECO**				
29	Big Bend CT 4	2009	$ 42,853,011	61,000	$ 703
30	Bayside Units 3 - 6	2009	$ 125,711,260	244,000	$ 515
31	Payne Creek Solar	2018	$ 86,958,440	70,000	$ 1,242
32	Balm Solar	2018	$ 105,392,300	74,000	$ 1,424
33	Lithia Solar	2019	$ 102,843,242	75,000	$ 1,371
34	Grange Hall Solar	2019	$ 80,949,643	61,000	$ 1,327
35	Peace Creek Solar	2019	$ 75,994,581	55,000	$ 1,382
36	Bonnie Mine Solar	2019	$ 53,262,074	38,000	$ 1,402
37	Lake Hancock	2019	$ 68,589,835	50,000	$ 1,372
38	Little Manatee Solar	2020	$ 103,791,607	75,000	$ 1,384
39	Wimauma Solar	2020	$ 105,669,018	75,000	$ 1,409
40	Durrance Solar	2021	$ 83,463,606	60,000	$ 1,391
41	Magnolia Solar	2021	$ 89,616,586	75,000	$ 1,195
42	Big Bend 1 CC	2022	$ 817,000,213	1,120,000	$ 729
43	Big Bend II Solar	2022	$ 65,858,301	46,000	$ 1,432
44	Total		$ 2,007,953,717	2,179,000	$ 922
45	Total Excluding Solar		$ 1,051,422,785	1,471,000	$ 715
46	**Grand Total**		**$ 8,737,037,252**	**$ 9,455,400**	**$ 924**
47	**Grand Total Excluding Solar**		**$ 4,700,458,100**	**$ 6,518,000**	**$ 721**
48					
49	Source: S&P Global IQ FERC Form 1 Data for Duke, FPL, and TECO				
50					
51	Notes:				
52	(1) https://www.duke-energy.com/Our-Company/Future/Solar-and-Renewables/Battery-Storage?jur=FL01#:~:text=An%2018%2Dmegawatt%20lithium%20battery,came%20online%20in%20December%202019.				

Florida Public Service Commission
Duke Energy Florida
Docket No. 20240025-EI
TMG - 5 CS and IS Proposed Credit Value Calculation

Line No.	Item (1)	Amount (2)	Unit (3)	Comment or Source (4)
1	Total Production Capacity Demand Revenue Requirement	$ 1,314,075	($000)	8-JSS & COS (12CP & 25AD) - 2025 Updated Fall 2023 Sales Forecast (2-Summary (rev at COS))
2	Total Original Production Plant Investment	$ 10,520,504	($000)	Schedule 2A
3				
4	Avg. Prod Revenue Requirement Divided by Plant Investment	12.5%		Line 1 / Line 2
5				
6	Avg. Total Installed Cost of Conventional Generation	$ 721	per kW	Exhibit TMG - 4, Average TIC of FPL, TECO and Duke for Recent Generation Additions
7				
8	Demand Revenue Requirement per kW Total Installed Cost	$ 90.08	per kW - Year	
9				
10	Reserve Margin for DEF	20%		DEF Ten-Year Site Plan p. 3-46
11				
12	Avg. Avoided Production Demand Revenue Requirement	$ 9.01	per kW-Month	(Line 8 x (1+ Line 10))/ 12 months

DUKE ENERGY FLORIDA

Stephanie A. Cuello
SENIOR COUNSEL

April 22, 2024

VIA ELECTRONIC DELIVERY

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

Re: Ten-Year Site Plan as of December 31, 2023; Undocketed

Dear Mr. Teitzman:

Pursuant to Rule 25-22.071, F.A.C., please find enclosed for filing Duke Energy Florida, LLC's, 2024 Amended Ten-Year Site Plan. DEF discovered an inadvertent error in the coal price forecast, which caused a change to Schedules 5, 6.1, 6.2 and a portion of 9.

Thank you for your assistance in this matter and if you have any questions, please feel free to contact me at (850) 521-1425.

Sincerely,

/s/ Stephanie A. Cuello

Stephanie A. Cuello

SAC/clg
Attachments

cc: Greg Davis, GDavis@psc.state.fl.us and Phillip Ellis, PEllis@psc.state.fl.us, Division of Engineering, FPSC

106 East College Avenue, Suite 800, Tallahassee, FL 32301 ▪ Phone: 850.521.1425
▪ Email: stephanie.cuello@duke-energy.com

Duke Energy Florida, LLC
Ten-Year Site Plan

April 2024

2024-2033

Submitted to:
Florida Public Service Commission

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CODE IDENTIFICATION SHEET

Generating Unit Type

BA - Battery Storage
CC - Combined Cycle
COG - Cogeneration Facility
CT - Combustion Turbine
GT - Gas Turbine
NP - Steam Power - Nuclear
PV – Photovoltaic
SPP - Small Power Producer
SPS – Solar (PV) Plus Storage
ST - Steam Turbine - Non-Nuclear

Fuel Type

BIO – Biomass
BIT - Bituminous Coal
DFO - No. 2 Distillate Fuel Oil
MSW - Municipal Solid Waste
NG - Natural Gas
NUC - Nuclear (Uranium)
RFO - No. 6 Residual Fuel Oil
SO – Solar PV
WH - Waste Heat

Fuel Transportation

PL - Pipeline
RR - Railroad
TK - Truck
UN - Unknown
WA - Water

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

EXECUTIVE SUMMARY

Duke Energy Florida's (DEF) 2024 Ten-Year Site Plan (TYSP) provides a description of the future electric generating unit additions and retirements selected to meet projected DEF customer resource needs for 2024 through 2033. DEF's plan continues the multi-year progress in the transition to a cleaner and more cost-effective generating fleet. In the near term, DEF anticipates the expiration of high-priced legacy contracts and retirement of numerous older simple cycle combustion turbine (CT) units offset by a planned investment in new solar, storage, and solar plus storage generation. Looking out beyond the ten-year horizon, DEF anticipates the retirement of the remaining two coal fired generating units and the potential to replace most of the energy supplied by those units with energy generated from future solar generating projects.

DEF's planned investments in renewable generation will enable fuel savings for customers, energy diversification, and will continue DEF's commitment towards a lower carbon future. Through this TYSP, DEF is planning to extend the successful deployment of utility scale solar projects approved by the Florida Public Service Commission (FPSC) in 2017 and 2021, which will bring over 1,400 MW of solar generating capacity to the DEF system through early 2024. Over the remainder of the ten-year planning period, DEF projects the addition of at least 450 MW per year of utility scale solar. By the end of the period, DEF expects to have more than 6,100 MW of utility scale solar generating capacity online.

DEF's measured and steady pace of projected solar generation adoption will combine with the increasingly clean gas fired generating fleet. DEF is beginning efficiency enhancements that will reduce fleet fuel consumption while adding close to 400 MW in highly efficient combined cycle generating capacity. Even with the additional CC upgrades, DEF anticipates a reduction in the fossil fuel fired generation of approximately 1,500 MW over the planning period.

In addition to improvements to the existing asset portfolio and the planned solar, DEF continues to build upon its pilot battery program approved in 2017. This program installed 50 MW of batteries from 2021 to 2023. These batteries provide a variety of services including solar energy storage and smoothing, grid support and voltage control, and deferral of potential new distribution investments. These assets also have the capability to enable islanding to support an amount of local load in the event of grid separation. A transmission-tied grid scale battery energy storage unit is planned to be placed in service in 2027. This unit combines over 200 MWh of energy storage and a 100 MW capacity to provide grid stabilization during periods of solar volatility and energy shifting to lower cost of energy based on time of day. In addition, DEF continues to plan batteries paired with solar units in 2028-2030 to further balance the system and provide reliability resources supporting the large amount of planned solar generation.

DEF will accelerate the addition of four combustion turbines between years 2032 and 2033 that will replace some of the generation from Crystal River North that is planned to be retired in year 2034.

DEF plans to meet the power needs of its customers cost-effectively while adding an increasing portfolio of non-carbon emitting assets. The future solar and storage in this expansion plan along with increased efficiency in conventional generation provides energy diversity by reducing natural gas consumption while maintaining reliable and dispatchable capacity.

INTRODUCTION

Section 186.801 of the Florida Statutes (F.S.) requires electric generating utilities to submit a TYSP to the FPSC. The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. DEF's TYSP is compiled in accordance with FPSC Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.).

DEF's TYSP is based on the projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning DEF's planning assumptions and projections and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

This TYSP document contains four chapters as indicated below:

- **CHAPTER 1 - DESCRIPTION OF EXISTING FACILITIES**
  This chapter provides an overview of DEF's generating resources as well as the transmission and distribution system.

- **CHAPTER 2 - FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION**
  Chapter 2 presents the history and forecast for load and peak demand as well as the forecast methodology used. Demand-Side Management (DSM) savings and fuel requirement projections are also included.

- **CHAPTER 3 - FORECAST OF FACILITIES REQUIREMENTS**
  The resource planning forecast, transmission planning forecast as well as the proposed generating facilities and bulk transmission line additions status are discussed in Chapter 3.

- **CHAPTER 4 - ENVIRONMENTAL AND LAND USE INFORMATION**

Preferred and potential site locations along with any environmental and land use information are presented in this chapter.

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1
DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Duke Energy Florida, LLC (DEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

AREA OF SERVICE

DEF has an obligation to serve approximately 1.9 million customers in Florida. Its service area covers approximately 20,000 square miles in west central Florida and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. DEF is interconnected with 21 municipal and nine rural electric cooperative systems who serve additional customers in Florida. DEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the FPSC. DEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The DEF transmission system includes approximately 5,300 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 14,000 circuit miles of underground distribution cable.

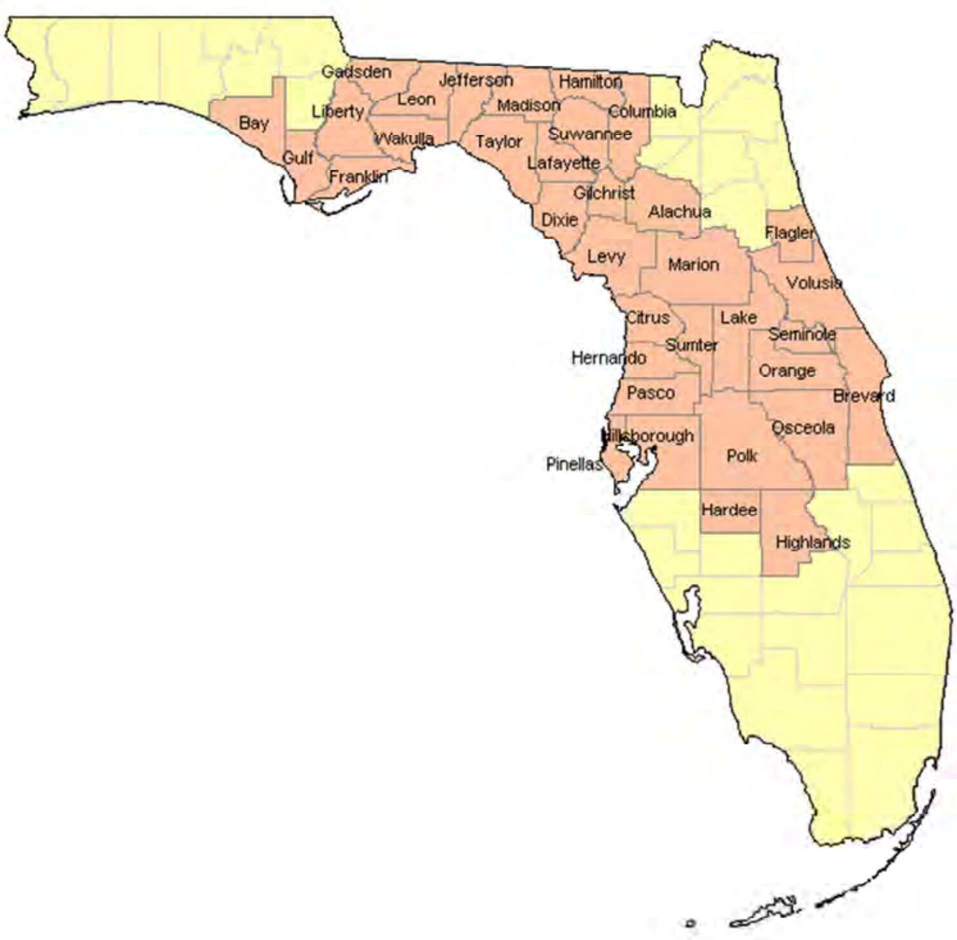
ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response (DR) type of program where participating customers help manage future load growth and costs. Approximately 433,000 customers participated in the residential Energy Management program during 2023, contributing about 638 MW of winter peak-shaving capacity for use during high load periods. DEF's currently approved DSM portfolio of programs consist of five residential programs (four energy efficiency and one demand response), six commercial and industrial programs (three energy efficiency and three demand response) and one research and development program.

TOTAL CAPACITY RESOURCE

As of December 31, 2023, DEF had total summer firm capacity resources of 11,750 MW consisting of installed capacity of 10,290 MW and 1,460 MW of firm purchased power. Additional information on DEF's existing generating resources can be found in Schedule 1 and Table 3.1 (Chapter 3).

FIGURE 1.1
DUKE ENERGY FLORIDA
County Service Area Map



DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	NG		PL			10/74		556,200	508	521
ANCLOTE	2	PASCO	ST	NG		PL			10/78		556,200	505	514
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	712	721
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	698	721
											Steam Total	**2,423**	**2,477**
COMBINED-CYCLE													
P L BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	*	6/09		1,254,200	1,112	1,259
CITRUS COUNTY COMBINED CYCLE	PB1	CITRUS	CC	NG		PL			10/18		985,150	807	925
CITRUS COUNTY COMBINED CYCLE	PB2	CITRUS	CC	NG		PL			11/18		985,150	803	929
HINES ENERGY COMPLEX	1	POLK	CC	NG		PL			4/99		546,500	501	521
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	*	12/03		548,250	532	549
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	*	11/05		561,000	523	535
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	*	12/07		610,500	525	544
OSPREY ENERGY CENTER POWER PLANT	1	POLK	CC	NG		PL			5/04		644,300	245	245
TIGER BAY	1	POLK	CC	NG		PL			8/97		278,100	199	230
											CC Total	**5,247**	**5,737**
COMBUSTION TURBINE													
BARTOW	P1	PINELLAS	CT	DFO		WA		*	5/72	6/2027 **	55,400	41	50
BARTOW	P2	PINELLAS	CT	NG	DFO	PL	WA	*	6/72		55,400	41	53
BARTOW	P3	PINELLAS	CT	DFO		WA		*	6/72	6/2027 **	55,400	41	51
BARTOW	P4	PINELLAS	CT	NG	DFO	PL	WA	*	6/72		55,400	45	58
BAYBORO	P1	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	44	58
BAYBORO	P2	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	21	27
BAYBORO	P3	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	43	57
BAYBORO	P4	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	43	56
DEBARY	P2	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	45	57
DEBARY	P3	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	45	59
DEBARY	P4	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	46	59
DEBARY	P5	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	45	58
DEBARY	P6	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	46	59
DEBARY	P7	VOLUSIA	CT	NG	DFO	PL	TK	*	10/92		103,500	74	93
DEBARY	P8	VOLUSIA	CT	NG	DFO	PL	TK	*	10/92		103,500	75	94
DEBARY	P9	VOLUSIA	CT	NG	DFO	PL	TK	*	10/92		103,500	76	94
DEBARY	P10	VOLUSIA	CT	DFO		TK		*	10/92		103,500	72	88
INTERCESSION CITY	P1	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	45	61
INTERCESSION CITY	P2	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	46	60
INTERCESSION CITY	P3	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	46	61
INTERCESSION CITY	P4	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	46	62
INTERCESSION CITY	P5	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	45	59
INTERCESSION CITY	P6	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	47	60
INTERCESSION CITY	P7	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	78	90
INTERCESSION CITY	P8	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	77	88
INTERCESSION CITY	P9	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	77	88
INTERCESSION CITY	P10	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	74	86
INTERCESSION CITY	P11	OSCEOLA	CT	DFO		PL,TK		*	1/97		148,500	140	161
INTERCESSION CITY	P12	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	89
INTERCESSION CITY	P13	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	91
INTERCESSION CITY	P14	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	90
SUWANNEE RIVER	P1	SUWANNEE	CT	NG	DFO	PL	TK	*	10/80		65,999	48	65
SUWANNEE RIVER	P2	SUWANNEE	CT	NG	DFO	PL	TK	*	10/80		65,999	48	64
SUWANNEE RIVER	P3	SUWANNEE	CT	NG	DFO	PL	TK	*	11/80		65,999	49	65
UNIVERSITY OF FLORIDA	P1	ALACHUA	GT	NG		PL			1/94		43,000	44	50
											CT Total	**1,972**	**2,461**

* APPROXIMATELY 2 TO 3 DAYS OF OIL USE TYPICALLY TARGETED FOR ENTIRE PLANT.
** DATES FOR RETIREMENT ARE APPROXIMATE AND SUBJECT TO CHANGE

DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
SOLAR													
OSCEOLA SOLAR FACILITY	PV1	OSCEOLA	PV	SO					5/16		3,800	2	0
PERRY SOLAR FACILITY	PV1	TAYLOR	PV	SO					8/16		5,100	2	0
SUWANNEE RIVER SOLAR FACILITY	PV1	SUWANNEE	PV	SO					11/17		8,800	4	0
HAMILTON SOLAR POWER PLANT	PV1	HAMILTON	PV	SO					12/18		74,900	42	0
TRENTON SOLAR POWER PLANT	PV1	GILCHRIST	PV	SO					12/19		74,900	42	0
LAKE PLACID SOLAR POWER PLANT	PV1	HIGHLANDS	PV	SO					12/19		45,000	25	0
ST PETERSBURG PIER	PV1	PINELLAS	PV	SO					12/19		350	0	0
COLUMBIA SOLAR POWER PLANT	PV1	COLUMBIA	PV	SO					3/20		74,900	42	0
DEBARY SOLAR POWER PLANT	PV1	VOLUSIA	PV	SO					5/20		74,500	33	0
SANTA FE SOLAR POWER PLANT	PV1	COLUMBIA	PV	SO					3/21		74,900	42	0
TWIN RIVERS SOLAR POWER PLANT	PV1	HAMILTON	PV	SO					3/21		74,900	42	0
DUETTE SOLAR POWER PLANT	PV1	MANATEE	PV	SO					10/21		74,500	42	0
SANDY CREEK SOLAR POWER PLANT	PV1	BAY	PV	SO					5/22		74,900	42	0
FORT GREEN SOLAR POWER PLANT	PV1	HARDEE	PV	SO					6/22		74,900	33	0
CHARLIE CREEK SOLAR POWER PLANT	PV1	HARDEE	PV	SO					8/22		74,900	42	0
BAY TRAIL SOLAR POWER PLANT	PV1	CITRUS	PV	SO					9/22		74,900	42	0
HILDRETH SOLAR POWER PLANT	PV1	SUWANNEE	PV	SO					4/23		74,900	42	0
HIGH SPRINGS SOLAR POWER PLANT	PV1	ALACHUA	PV	SO					4/23		74,900	42	0
HARDEETOWN SOLAR POWER PLANT	PV1	LEVY	PV	SO					4/23		74,900	42	0
BAY RANCH SOLAR POWER PLANT	PV1	BAY	PV	SO					4/23		74,900	42	0
											Solar Total	**648**	**0**
											TOTAL RESOURCES (MW)	**10,290**	**10,675**

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

DUKE ENERGY.
FLORIDA

CHAPTER 2
FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). In general, this discussion refers to DEF's base forecast.

The DEF forecast utilized economic data from July 2023. From a macro perspective, the U.S. economy was characterized by several significant trends and changes. The labor market was at full employment. The Federal Reserve had actively increased interest rates since early 2022 in an effort to control inflation (3.6% as of July 2023). Additionally, the central bank had been reducing its holdings of financial assets. Interest rates on ten-year Treasury bonds were near their expected long-term levels, and fiscal policy, despite a temporary suspension of the debt limit, was projected to be somewhat expansionary with the passage of the Inflation Reduction Act. The U.S. dollar remained strong due to monetary policy and global uncertainties. From a low in Q2 2020 to a peak in Q2 2021, inflation adjusted corporate profits remained above pre-pandemic levels. Global oil prices were expected to stay below $100 per barrel. The pandemic's impact was waning, and the ongoing Russian war's influence on global markets was predicted to decrease.

In mid-2023, Florida's economy held its position as one of the top performers in the region. Job growth had slowed slightly over the past quarter, but Florida had outperformed nearly all states in the region during the past six- and 12-month periods. Every major industry had been performing well throughout the year, with tourism, the state's core driver, leading in job creation. Healthcare and utilities also stood out. Net hiring in finance had slowed due to market instability. The unemployment rate had remained steady below its previous cyclical low, despite a 5% growth in the labor force since its pre-pandemic level. While the housing market had cooled, there were signs of optimism, including a monthly increase in house prices in February. Single-family permit issuance had decreased from the previous year's pace, but the multifamily market was on track for its strongest year in decades. Florida was expected to continue performing well, but the impact of higher prices and elevated interest rates would likely slow job creation and put pressure on the housing market. The vital tourism industry would provide less support as well. In the long term, Florida's advantageous factors such as low costs, favorable weather, and an improving industrial composition would drive above-average job and income growth.

Historical 29 county service area household, population, and people per household data were used for the Base Case, High Case, and Low Case service area population projections. The DEF service area population was estimated to have grown at an average ten-year compound annual growth rate (CAGR) of 1.56% from 2014-2023 (Schedule 2.1.1 Column 2). The projected DEF service area population growth weakened to a level of 1.20% over the 2024-2033 period due to higher mortality rates among aging baby-boomers. The rate of residential customer growth, which averaged 1.72% per year over the historical ten-year period, is expected to continue at an average of 1.72%. The total number of DEF customers grew from 1.69 million in 2014 to 1.96 million in 2023, an increase of 269,130 or 1.65% annual growth rate. The projected number of additional total customers between 2024 and 2033 is projected to be 320,423 for a 1.67% annual growth rate.

Responses to the pandemic, which changed the patterns of class energy consumption, have reverted to pre-COVID usage characteristics. Remote work in the DEF service area still exists but at a much smaller level than that reached early in the pandemic. These changes imply a decrease in residential energy consumption which can be seen in the projected annual growth rate for average kWh consumption per customer (Schedule 2.1.1 Column 6). The projected ten-year annual growth rate for average kWh consumption per customer is -0.37% vs. a historical rate of -0.21%. Residential use per customer continues to decline due to higher energy prices/inflation, energy efficiency and rooftop solar adoption. In terms of annual residential sales growth, measured in GWh (1.34% projected vs. 1.51% historical), sustained residential customer growth (1.72% projected vs. 1.72% historical) is working to offset the declining use per customer. Labor shortages and the low cost of living in Florida relative to other parts of the U.S. also continue to attract people to the state as per capita income adjusted for cost of living is more favorable in Florida than other parts of the U.S. Florida continues to be a tourist attraction and retirement haven. Given the increase in the retirement population in the U.S. over the near term as the “Baby Boomer” generation reaches 65 and older, the retirement cohort in Florida should increase significantly over the next five to ten years. Increases in commercial and industrial class energy requirements have returned as well. Commercial sales growth (1.57% projected vs. 0.61% historical) is projected to be driven by the return to normal operating hours, population growth, and consumer spending/tourism. Sales to the industrial class (0.20% projected vs. 0.43% historical) were helped in 2023 by the Nucor Steel plant startup, Mosaic's operations growth, and Trulieve's startup. On the other hand, in November 2023, GP Cellulose shut down its Perry, FL manufacturing site. In February 2024, another major customer announced that they will be installing 6 MW of customer-owned CHP. These two customers accounted for nearly 5% of 2023 Industrial sales. In 2033, several major mining customers will deplete their resources through their operations. This is discussed in further detail under "General Assumptions" page 2-33. Over a nine-year period from 2024-2032, the industrial GWh growth rate was 1.08%. Long-term, total retail sales continue to increase (1.30% projected vs. 1.03% historical) but remain subject to uncertain economic conditions such as increasing rates, unemployment, and energy prices.

From 2014 to 2023, net energy for load (NEL) increased by 0.81% per year (Schedule 2.3.1 Column 4). The average projected ten-year CAGR for NEL is 0.91%. While Sales for Resale experienced an average annual decrease of -26.45% during the forecast period, sustained retail load growth offsets the loss of these contracts. Long term, DEF Sales for Resale energy sales are projected to essentially disappear.

During the 2014 to 2023 historical period the DEF summer net firm demand (Schedule 3.1.1 Column 10) increased from 8,523 MW to 9,352 MW, an average annual ten-year increase of 1.04%. This increase was driven by the ten-year average customer growth of 1.65% per year. The Wholesale summer peak remained relatively flat with a ten-year CAGR of 0.18%. Wholesale load was offset by higher conservation levels and additional residential demand response capability (Schedule 3.1.1). Going forward, the projected total DEF summer net firm demand, 2024 – 2033, grows at a slightly lower average annual rate of 0.96% due to declining Sales for Resale. The historical DEF firm winter peak ten-year CAGR was 1.00% per year driven by customer growth. Projected total DEF winter net firm demand remained positive with an average annual rate of 0.42% between 2024 and 2033 due to a reduction in the projected Sales for Resale peak demand

(-8.03% annual average decline), offset by expected ten-year growth in Retail winter peak of 1.06%. Both summer and winter Sales for Resale peak demand are expected to decline significantly towards the end of the ten-year projection.

DEF continues to provide alternate “high” and “low” forecasts for customers, energy, and peak demand, recognizing that the economic future is uncertain due to the tightening of monetary policy or other unknown events. The Fed’s goal has been a “soft landing” where inflation is reigned in to 2% without sending the economy into a recession. Moody’s S1 and S3 (high & low) Florida economic scenarios were used to provide a range of economic variables around the Base Case scenario. These were combined with high and low peak weather scenarios for each season and high and low population growth scenarios from Moody’s.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided to represent DEF's expectations for a Base Case as well as reasonable High and Low forecast scenarios for resource planning purposes. (Base-B, High-H and Low-L):

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class (B, H and L)
3.1	History and Forecast of Base Summer Peak Demand (MW) (B, H and L)
3.2	History and Forecast of Base Winter Peak Demand (MW) (B, H and L)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh) (B, H and L)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month (B, H and L)

DUKE ENERGY FLORIDA

SCHEDULE 2.1.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,037,435	2.483	20,775	1,626,117	12,776	12,198	178,036	68,514
2020	4,089,498	2.471	21,459	1,655,304	12,964	11,522	179,666	64,129
2021	4,130,929	2.448	21,192	1,687,471	12,558	11,785	182,195	64,686
2022	4,253,325	2.473	21,508	1,719,905	12,505	12,220	184,453	66,248
2023	4,308,553	2.457	21,750	1,753,583	12,403	12,450	186,524	66,749
FORECAST:								
2024	4,338,254	2.439	21,660	1,778,702	12,177	12,031	189,760	63,400
2025	4,383,772	2.420	21,850	1,811,476	12,062	12,232	192,439	63,564
2026	4,431,461	2.403	21,583	1,844,137	11,704	12,268	195,108	62,879
2027	4,481,068	2.388	21,717	1,876,494	11,573	12,383	197,753	62,617
2028	4,534,352	2.375	21,981	1,909,201	11,513	12,599	200,426	62,859
2029	4,591,824	2.364	22,446	1,942,396	11,556	12,849	203,140	63,252
2030	4,651,193	2.354	22,949	1,975,868	11,614	13,097	205,875	63,617
2031	4,711,426	2.345	23,390	2,009,137	11,642	13,322	208,595	63,865
2032	4,772,194	2.337	23,646	2,042,017	11,580	13,568	211,282	64,217
2033	4,830,765	2.329	24,422	2,074,180	11,774	13,847	213,911	64,734

DUKE ENERGY FLORIDA

SCHEDULE 2.1.2

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,037,435	2.483	20,775	1,626,117	12,776	12,198	178,036	68,514
2020	4,089,498	2.471	21,459	1,655,304	12,964	11,522	179,666	64,129
2021	4,130,929	2.448	21,192	1,687,471	12,558	11,785	182,195	64,686
2022	4,253,325	2.473	21,508	1,719,905	12,505	12,220	184,453	66,248
2023	4,308,553	2.457	21,750	1,753,583	12,403	12,450	186,524	66,749
FORECAST:								
2024	4,352,608	2.439	24,377	1,784,587	13,660	12,719	190,241	66,858
2025	4,413,787	2.420	24,708	1,823,879	13,547	12,977	193,453	67,080
2026	4,469,921	2.403	24,607	1,860,142	13,228	13,052	196,417	66,452
2027	4,526,156	2.388	24,808	1,895,375	13,088	13,213	199,296	66,301
2028	4,586,538	2.375	25,175	1,931,174	13,036	13,444	202,222	66,484
2029	4,651,704	2.364	25,613	1,967,726	13,017	13,650	205,210	66,516
2030	4,719,116	2.354	26,146	2,004,722	13,042	13,880	208,234	66,658
2031	4,786,708	2.345	26,627	2,041,240	13,045	14,107	211,218	66,790
2032	4,853,400	2.337	26,977	2,076,765	12,990	14,351	214,122	67,024
2033	4,916,610	2.329	27,723	2,111,039	13,133	14,617	216,923	67,382

DUKE ENERGY FLORIDA

SCHEDULE 2.1.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,037,435	2.483	20,775	1,626,117	12,776	12,198	178,036	68,514
2020	4,089,498	2.471	21,459	1,655,304	12,964	11,522	179,666	64,129
2021	4,130,929	2.448	21,192	1,687,471	12,558	11,785	182,195	64,686
2022	4,253,325	2.473	21,508	1,719,905	12,505	12,220	184,453	66,248
2023	4,308,553	2.457	21,750	1,753,583	12,403	12,450	186,524	66,749
FORECAST:								
2024	4,336,457	2.439	19,369	1,777,965	10,894	11,583	189,700	61,060
2025	4,377,461	2.420	19,473	1,808,868	10,765	11,679	192,226	60,757
2026	4,415,587	2.403	19,370	1,837,531	10,541	11,828	194,569	60,792
2027	4,453,353	2.388	19,550	1,864,888	10,483	12,021	196,805	61,082
2028	4,496,433	2.375	19,840	1,893,235	10,479	12,251	199,121	61,527
2029	4,546,275	2.364	20,183	1,923,128	10,495	12,459	201,565	61,811
2030	4,600,010	2.354	20,572	1,954,125	10,528	12,693	204,098	62,191
2031	4,655,643	2.345	20,909	1,985,349	10,532	12,908	206,650	62,464
2032	4,711,960	2.337	21,129	2,016,243	10,479	13,139	209,175	62,812
2033	4,767,593	2.329	21,739	2,047,056	10,620	13,388	211,694	63,242

DUKE ENERGY FLORIDA

SCHEDULE 2.2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
FORECAST:							
2024	3,230	1,786	1,808,343	0	31	3,111	40,063
2025	3,360	1,765	1,903,655	0	31	3,185	40,658
2026	3,423	1,758	1,946,910	0	30	3,185	40,489
2027	3,453	1,756	1,966,388	0	29	3,196	40,777
2028	3,507	1,759	1,993,696	0	29	3,220	41,336
2029	3,500	1,762	1,986,265	0	28	3,234	42,057
2030	3,509	1,764	1,989,180	0	28	3,249	42,832
2031	3,515	1,767	1,989,291	0	27	3,239	43,493
2032	3,523	1,772	1,987,977	0	26	3,232	43,995
2033	3,288	1,776	1,851,436	0	26	3,231	44,815

DUKE ENERGY FLORIDA

SCHEDULE 2.2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
					STREET &	OTHER SALES	TOTAL SALES
		AVERAGE	AVERAGE KWh	RAILROADS	HIGHWAY	TO PUBLIC	TO ULTIMATE
		NO. OF	CONSUMPTION	AND RAILWAYS	LIGHTING	AUTHORITIES	CONSUMERS
YEAR	GWh	CUSTOMERS	PER CUSTOMER	GWh	GWh	GWh	GWh
HISTORY:							
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
FORECAST:							
2024	3,266	1,786	1,828,571	0	31	3,177	43,570
2025	3,398	1,765	1,924,953	0	31	3,251	44,363
2026	3,460	1,758	1,967,978	0	30	3,249	44,398
2027	3,489	1,756	1,986,894	0	29	3,254	44,794
2028	3,543	1,759	2,014,133	0	29	3,275	45,465
2029	3,536	1,762	2,006,629	0	28	3,277	46,104
2030	3,545	1,764	2,009,498	0	28	3,284	46,883
2031	3,551	1,767	2,009,524	0	27	3,268	47,580
2032	3,558	1,772	2,008,105	0	26	3,254	48,168
2033	3,324	1,776	1,871,458	0	26	3,246	48,936

DUKE ENERGY FLORIDA

SCHEDULE 2.2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
FORECAST:							
2024	3,202	1,786	1,792,981	0	31	3,030	37,216
2025	3,334	1,765	1,888,814	0	31	3,098	37,615
2026	3,400	1,758	1,934,233	0	30	3,086	37,715
2027	3,432	1,756	1,954,492	0	29	3,089	38,122
2028	3,487	1,759	1,982,346	0	29	3,106	38,712
2029	3,480	1,762	1,974,753	0	28	3,118	39,268
2030	3,488	1,764	1,977,382	0	28	3,134	39,914
2031	3,494	1,767	1,977,407	0	27	3,116	40,454
2032	3,502	1,772	1,976,094	0	26	3,102	40,898
2033	3,267	1,776	1,839,499	0	26	3,094	41,515

DUKE ENERGY FLORIDA

SCHEDULE 2.3.1

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,304	2,776	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
2020	2,887	2,697	44,814	26,845	1,863,814
2021	3,302	2,311	45,064	27,082	1,898,726
2022	3,673	1,956	46,141	26,834	1,933,060
2023	1,396	1,821	44,049	26,343	1,968,222
FORECAST:					
2024	1,119	2,237	43,418	26,304	1,996,552
2025	904	1,956	43,519	26,402	2,032,082
2026	904	2,190	43,584	26,501	2,067,504
2027	900	2,098	43,775	26,586	2,102,589
2028	889	2,279	44,504	26,680	2,138,066
2029	887	2,177	45,121	26,765	2,174,063
2030	887	2,258	45,977	26,847	2,210,354
2031	70	2,260	45,824	26,926	2,246,425
2032	71	2,536	46,602	27,014	2,282,085
2033	70	2,209	47,094	27,110	2,316,977

DUKE ENERGY FLORIDA

SCHEDULE 2.3.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,304	2,776	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
2020	2,887	2,697	44,814	26,845	1,863,814
2021	3,302	2,311	45,064	27,082	1,898,726
2022	3,673	1,956	46,141	26,834	1,933,060
2023	1,396	1,821	44,049	26,343	1,968,222
FORECAST:					
2024	1,119	2,799	47,488	26,108	2,002,722
2025	904	2,584	47,852	26,148	2,045,245
2026	904	2,775	48,077	26,243	2,084,560
2027	900	2,731	48,425	26,321	2,122,748
2028	889	2,894	49,248	26,401	2,161,556
2029	887	2,823	49,814	26,432	2,201,130
2030	887	2,902	50,671	26,474	2,241,194
2031	70	2,922	50,572	26,524	2,280,749
2032	71	3,136	51,375	26,570	2,319,229
2033	70	2,905	51,911	26,626	2,356,364

DUKE ENERGY FLORIDA

SCHEDULE 2.3.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,304	2,776	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
2020	2,887	2,697	44,814	26,845	1,863,814
2021	3,302	2,311	45,064	27,082	1,898,726
2022	3,673	1,956	46,141	26,834	1,933,060
2023	1,396	1,821	44,049	26,343	1,968,222
FORECAST:					
2024	1,119	1,760	40,094	26,056	1,995,507
2025	904	1,512	40,031	26,062	2,028,921
2026	904	1,688	40,308	26,038	2,059,896
2027	900	1,640	40,662	26,071	2,089,520
2028	889	1,782	41,383	26,118	2,120,233
2029	887	1,701	41,856	26,217	2,152,672
2030	887	1,762	42,564	26,318	2,186,305
2031	70	1,770	42,294	26,364	2,220,130
2032	71	1,961	42,929	26,405	2,253,595
2033	70	1,732	43,317	26,471	2,286,997

DUKE ENERGY FLORIDA

SCHEDULE 3.1.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
FORECAST:										
2024	10,958	730	10,228	402	358	566	91	461	80	9,000
2025	10,824	451	10,372	402	364	581	94	467	80	8,836
2026	10,805	451	10,354	402	370	593	97	473	80	8,790
2027	10,822	451	10,371	402	376	605	100	477	80	8,781
2028	10,969	451	10,518	402	377	618	103	480	80	8,908
2029	11,174	451	10,723	402	378	630	107	484	80	9,093
2030	11,361	451	10,910	402	379	642	110	488	80	9,260
2031	11,493	401	11,093	402	380	653	113	492	80	9,374
2032	11,733	401	11,332	402	381	663	116	496	80	9,595
2033	11,967	401	11,566	402	382	674	119	499	80	9,811

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.1.2

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1,021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
FORECAST:										
2024	11,456	730	10,726	402	358	566	91	461	80	9,498
2025	11,362	451	10,911	402	364	581	94	467	80	9,375
2026	11,371	451	10,920	402	370	593	97	473	80	9,356
2027	11,415	451	10,964	402	376	605	100	477	80	9,375
2028	11,575	451	11,124	402	377	618	103	480	80	9,514
2029	11,751	451	11,300	402	378	630	107	484	80	9,670
2030	11,947	451	11,496	402	379	642	110	488	80	9,847
2031	12,461	401	12,060	402	380	653	113	492	80	10,341
2032	12,314	401	11,913	402	381	663	116	496	80	10,176
2033	12,555	401	12,154	402	382	674	119	499	80	10,399

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.1.3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1,021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
FORECAST:										
2024	10,505	730	9,776	402	358	566	91	461	80	8,547
2025	10,360	451	9,909	402	364	581	94	467	80	8,373
2026	10,391	451	9,940	402	370	593	97	473	80	8,376
2027	10,444	451	9,992	402	376	605	100	477	80	8,403
2028	10,592	451	10,141	402	377	618	103	480	80	8,532
2029	10,774	451	10,323	402	378	630	107	484	80	8,693
2030	10,926	451	10,475	402	379	642	110	488	80	8,825
2031	11,407	401	11,006	402	380	653	113	492	80	9,287
2032	11,621	401	11,220	402	381	663	116	496	80	9,483
2033	11,476	401	11,075	402	382	674	119	499	80	9,320

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.1

HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)

BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
FORECAST:										
2023/24	11,506	852	10,654	388	646	1,055	87	263	195	8,872
2024/25	11,787	1,052	10,735	388	654	1,081	90	266	196	9,112
2025/26	11,833	1,052	10,781	388	662	1,101	93	268	196	9,124
2026/27	11,908	1,052	10,855	388	670	1,120	96	270	197	9,165
2027/28	11,452	451	11,001	388	671	1,141	100	273	198	8,682
2028/29	11,594	451	11,143	388	672	1,161	103	276	200	8,795
2029/30	11,784	451	11,333	388	673	1,180	106	278	202	8,957
2030/31	11,870	401	11,469	388	674	1,197	109	280	204	9,017
2031/32	12,002	401	11,601	388	675	1,215	112	282	205	9,125
2032/33	12,112	401	11,711	388	676	1,232	115	284	206	9,210

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
FORECAST:										
2023/24	13,301	852	12,449	388	646	1,055	87	263	195	10,667
2024/25	13,680	1,052	12,628	388	654	1,081	90	266	196	11,005
2025/26	13,779	1,052	12,727	388	662	1,101	93	268	196	11,070
2026/27	13,899	1,052	12,847	388	670	1,120	96	270	197	11,157
2027/28	13,491	451	13,039	388	671	1,141	100	273	198	10,720
2028/29	13,641	451	13,190	388	672	1,161	103	276	200	10,842
2029/30	13,836	451	13,385	388	673	1,180	106	278	202	11,009
2030/31	13,938	401	13,538	388	674	1,197	109	280	204	11,086
2031/32	14,083	401	13,682	388	675	1,215	112	282	205	11,205
2032/33	14,209	401	13,808	388	676	1,232	115	284	206	11,307

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.3

HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
FORECAST:										
2023/24	9,330	852	8,478	388	646	1,055	87	263	195	6,696
2024/25	9,493	1,052	8,441	388	654	1,081	90	266	196	6,818
2025/26	9,559	1,052	8,507	388	662	1,101	93	268	196	6,850
2026/27	9,655	1,052	8,603	388	670	1,120	96	270	197	6,913
2027/28	9,187	451	8,736	388	671	1,141	100	273	198	6,416
2028/29	9,291	451	8,840	388	672	1,161	103	276	200	6,492
2029/30	9,423	451	8,972	388	673	1,180	106	278	202	6,596
2030/31	9,472	401	9,071	388	674	1,197	109	280	204	6,619
2031/32	9,567	401	9,166	388	675	1,215	112	282	205	6,689
2032/33	9,645	401	9,245	388	676	1,232	115	284	206	6,744

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.3.1

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)

BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,304	2,775	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
2020	47,476	1,050	1,016	596	39,230	2,887	2,697	44,814	52.9
2021	47,786	1,100	1,027	595	39,451	3,302	2,311	45,064	53.1
2022	48,842	1,120	986	595	40,512	3,673	1,956	46,141	52.8
2023	46,805	1,168	996	595	40,832	1,392	1,821	44,046	49.0
FORECAST:									
2024	46,240	1,223	1,004	595	40,063	1,119	2,237	43,418	55.1
2025	46,392	1,259	1,018	596	40,658	904	1,956	43,519	54.4
2026	46,503	1,297	1,028	595	40,489	904	2,190	43,584	54.5
2027	46,743	1,337	1,036	595	40,777	900	2,098	43,775	54.5
2028	47,519	1,376	1,044	595	41,336	889	2,279	44,504	57.0
2029	48,183	1,413	1,053	596	42,057	887	2,177	45,121	56.5
2030	49,081	1,447	1,062	595	42,832	887	2,258	45,977	56.7
2031	48,970	1,481	1,070	595	43,493	70	2,260	45,824	55.8
2032	49,789	1,515	1,077	595	43,995	71	2,536	46,602	55.4
2033	50,322	1,547	1,085	596	44,815	70	2,209	47,094	54.6

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 3.3.2

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)

HIGH CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,304	2,775	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
2020	47,476	1,050	1,016	596	39,230	2,887	2,697	44,814	52.9
2021	47,786	1,100	1,027	595	39,451	3,302	2,311	45,064	53.1
2022	48,842	1,120	986	595	40,512	3,673	1,956	46,141	52.8
2023	46,805	1,168	996	595	40,832	1,392	1,821	44,046	49.0
FORECAST:									
2024	50,309	1,223	1,004	595	43,570	1,119	2,799	47,488	50.8
2025	50,724	1,259	1,018	595	44,363	904	2,584	47,852	49.6
2026	50,998	1,297	1,028	596	44,398	904	2,775	48,077	49.4
2027	51,392	1,337	1,036	595	44,794	900	2,731	48,425	49.5
2028	52,263	1,376	1,044	595	45,465	889	2,894	49,248	52.4
2029	52,876	1,413	1,053	596	46,104	887	2,823	49,814	52.3
2030	53,776	1,447	1,062	595	46,883	887	2,902	50,671	52.5
2031	53,719	1,481	1,070	595	47,580	70	2,922	50,572	52.1
2032	54,562	1,515	1,077	595	48,168	71	3,136	51,375	52.3
2033	55,139	1,547	1,085	596	48,936	70	2,905	51,911	52.3

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 3.3.3

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) *
HISTORY:									
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,304	2,775	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
2020	47,476	1,050	1,016	596	39,230	2,887	2,697	44,814	52.9
2021	47,786	1,100	1,027	595	39,451	3,302	2,311	45,064	53.1
2022	48,842	1,120	986	595	40,512	3,673	1,956	46,141	52.8
2023	46,805	1,168	996	595	40,832	1,392	1,821	44,046	49.0
FORECAST:									
2024	42,916	1,223	1,004	595	37,216	1,119	1,760	40,094	53.5
2025	42,904	1,259	1,018	596	37,615	904	1,512	40,031	54.4
2026	43,227	1,297	1,028	595	37,715	904	1,688	40,308	54.9
2027	43,629	1,337	1,036	595	38,122	900	1,640	40,662	55.2
2028	44,398	1,376	1,044	595	38,712	889	1,782	41,383	55.4
2029	44,918	1,413	1,053	596	39,268	887	1,701	41,856	54.8
2030	45,668	1,447	1,062	595	39,914	887	1,762	42,564	55.1
2031	45,441	1,481	1,070	595	40,454	70	1,770	42,294	52.0
2032	46,116	1,515	1,077	595	40,898	71	1,961	42,929	51.7
2033	46,544	1,547	1,085	596	41,515	70	1,732	43,317	52.9

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 4.1

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2023		2024		2025	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,840	3,128	**10,109**	3,205	**10,360**	3,239
FEBRUARY	6,657	2,797	7,984	2,772	8,190	2,784
MARCH	7,608	3,320	7,559	3,170	7,694	3,180
APRIL	7,845	3,457	7,963	3,342	7,685	3,360
MAY	8,354	3,781	8,773	3,832	8,532	3,863
JUNE	9,322	4,188	9,099	4,171	8,769	4,138
JULY	9,725	4,767	9,758	4,345	9,448	4,304
AUGUST	**10,268**	4,978	**9,851**	4,453	**9,696**	4,469
SEPTEMBER	9,281	4,152	8,897	3,988	8,685	4,013
OCTOBER	7,859	3,455	8,492	3,715	8,277	3,723
NOVEMBER	6,799	3,010	6,905	3,111	6,735	3,136
DECEMBER	5,936	3,014	7,965	3,314	8,210	3,310
TOTAL		44,046		43,418		43,519

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.
December 2022 is the 2023 winter peak 8110 MW.

DUKE ENERGY FLORIDA

SCHEDULE 4.2

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2023		2024		2025	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,840	3,128	**11,904**	3,648	**12,253**	3,713
FEBRUARY	6,657	2,797	9,231	3,210	9,507	3,250
MARCH	7,608	3,320	8,617	3,668	8,806	3,702
APRIL	7,845	3,457	8,545	3,668	8,369	3,707
MAY	8,354	3,781	9,276	4,055	9,078	4,107
JUNE	9,322	4,188	9,625	4,394	9,338	4,382
JULY	9,725	4,767	10,277	4,544	10,014	4,524
AUGUST	10,268	4,978	**10,349**	4,643	**10,235**	4,678
SEPTEMBER	9,281	4,152	9,356	4,171	9,180	4,213
OCTOBER	7,859	3,455	9,141	4,049	8,962	4,076
NOVEMBER	6,799	3,010	7,664	3,517	7,569	3,560
DECEMBER	5,936	3,014	9,795	3,921	10,090	3,939
TOTAL		44,046		47,488		47,852

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.
December 2022 is the 2023 winter peak 8110 MW.

SCHEDULE 4.3

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND AND NET ENERGY FOR LOAD BY MONTH

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2023		2024		2025	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,840	3,128	**7,933**	2,860	**8,066**	2,852
FEBRUARY	6,657	2,797	6,902	2,390	7,046	2,374
MARCH	7,608	3,320	6,761	2,809	6,836	2,790
APRIL	7,845	3,457	7,558	3,119	7,239	3,114
MAY	8,354	3,781	8,402	3,673	8,120	3,684
JUNE	9,322	4,188	8,659	3,977	8,315	3,928
JULY	9,725	4,767	9,307	4,162	8,976	4,111
AUGUST	**10,268**	4,978	**9,398**	4,265	**9,233**	4,277
SEPTEMBER	9,281	4,152	8,469	3,799	8,255	3,824
OCTOBER	7,859	3,455	7,973	3,451	7,761	3,461
NOVEMBER	6,799	3,010	6,321	2,776	6,128	2,802
DECEMBER	5,936	3,014	6,423	2,816	6,706	2,812
TOTAL		44,046		40,094		40,031

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.
December 2022 is the 2023 winter peak 8110 MW.

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. Although DEF's fuel mix continues to rely on an increasing amount of natural gas to meet its generation needs, DEF continues to maintain alternate fuel supplies including long term operation of some coal fired facilities, adequate supplies of oil for dual fuel back up and increasing amounts of renewable generation particularly from solar generation. Projections shown in Schedules 5 and 6 reflect the Base Load and Energy Forecasts.

DUKE ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	2,117	1,825	1,045	927	815	768	702	695	789	814	768	927
(3)	RESIDUAL	TOTAL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	312	124	26	19	16	27	47	36	29	33	36	37
(9)		STEAM	1,000 BBL	48	54	11	9	12	14	10	12	13	9	11	14
(10)		CC	1,000 BBL	123	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	141	70	15	10	4	14	37	24	16	24	24	24
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	271,484	265,288	252,983	255,245	253,111	248,403	247,856	244,586	238,530	229,462	228,043	223,608
(14)		STEAM	1,000 MCF	25,066	21,181	15,119	13,755	10,865	8,764	11,038	13,379	10,949	11,540	12,064	11,894
(15)		CC	1,000 MCF	238,711	234,659	233,195	236,804	237,822	234,218	231,497	225,655	222,892	211,949	209,562	204,652
(16)		CT	1,000 MCF	7,708	9,448	4,670	4,686	4,425	5,421	5,321	5,552	4,689	5,973	6,418	7,062
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	N/A	N/A	2,420	2,650	1,639	601	0	0	0	0	0	0
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	N/A	N/A	0	0	0	0	0	0	0	0	0	0

DUKE ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,203	60	237	260	161	60	18	3	6	15	7	2
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	4,375	3,829	2,157	1,920	1,639	1,539	1,370	1,395	1,569	1,617	1,519	1,873
(4)	RESIDUAL	TOTAL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	146	29	7	5	2	6	17	11	7	10	11	10
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	91	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	55	29	7	5	2	6	17	11	7	10	11	10
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	36,423	35,526	36,389	37,056	37,034	36,479	36,197	35,521	34,714	33,083	32,668	31,801
(15)		STEAM	GWh	2,249	1,737	1,337	1,205	948	749	942	1,137	916	992	1,032	1,004
(16)		CC	GWh	33,607	32,996	34,577	35,374	35,631	35,193	34,722	33,831	33,331	31,509	31,014	30,123
(17)		CT	GWh	567	792	475	477	456	537	533	553	467	582	622	674
(18)	OTHER 2/														
	QF PURCHASES		GWh	1,769	1,814	818	493	0	0	0	0	0	0	0	0
	RENEWABLES OTHER		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES MSW		GWh	645	624	556	71	73	73	73	73	72	73	73	71
	RENEWABLES BIOMASS		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES SOLAR		GWh	1,581	2,165	3,255	3,714	4,674	5,630	6,852	8,161	9,670	11,097	12,401	13,415
	BATTERIES		GWh	0	0	0	0	0	-11	-22	-43	-61	-72	-76	-78
	IMPORT FROM OUT OF STATE		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	EXPORT TO OUT OF STATE		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	46,141	44,046	43,418	43,519	43,584	43,775	44,504	45,121	45,977	45,824	46,602	47,094

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

DUKE ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	ANNUAL FIRM INTERCHANGE 1/		%	2.6%	0.1%	0.5%	0.6%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	9.5%	8.7%	5.0%	4.4%	3.8%	3.5%	3.1%	3.1%	3.4%	3.5%	3.3%	4.0%
(4)	RESIDUAL	TOTAL	%	0.0%	0.0%	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%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	78.9%	80.7%	83.8%	85.1%	85.0%	83.3%	81.3%	78.7%	75.5%	72.2%	70.1%	67.5%
(15)		STEAM	%	4.9%	3.9%	3.1%	2.8%	2.2%	1.7%	2.1%	2.5%	2.0%	2.2%	2.2%	2.1%
(16)		CC	%	72.8%	74.9%	79.6%	81.3%	81.8%	80.4%	78.0%	75.0%	72.5%	68.8%	66.6%	64.0%
(17)		CT	%	1.2%	1.8%	1.1%	1.1%	1.0%	1.2%	1.2%	1.2%	1.0%	1.3%	1.3%	1.4%
(18)	OTHER 2/														
	QF PURCHASES		%	3.8%	4.1%	1.9%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES OTHER		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES MSW		%	1.4%	1.4%	1.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
	RENEWABLES BIOMASS		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES SOLAR		%	3.4%	4.9%	7.5%	8.5%	10.7%	12.9%	15.4%	18.1%	21.0%	24.2%	26.6%	28.5%
	BATTERIES		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.2%	-0.2%	-0.2%
	IMPORT FROM OUT OF STATE		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric consumption over the planning horizon. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use (SAE) approach to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how DSM impacts the forecast and a review of DEF's DSM programs.

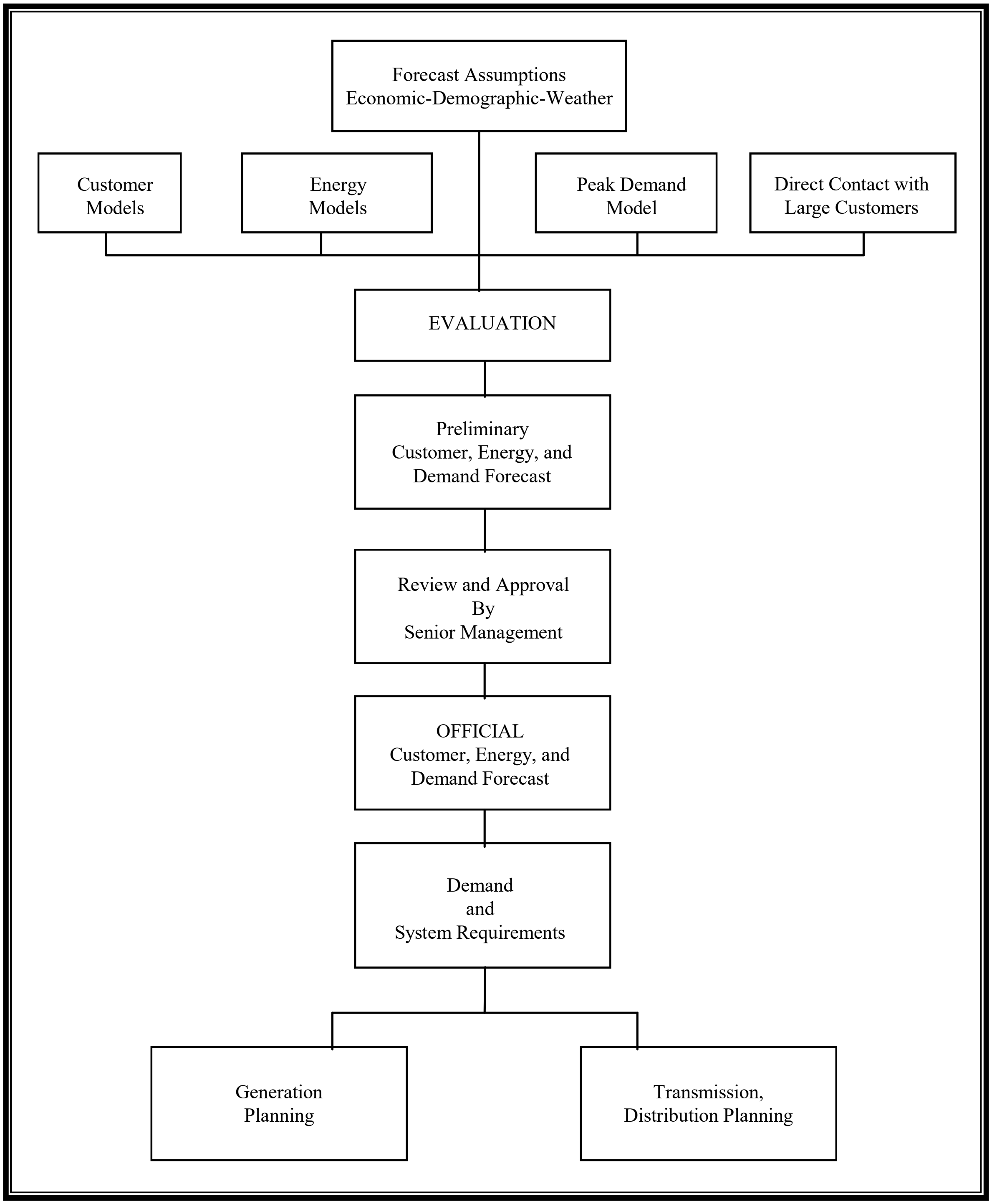
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of several external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 30-year average of conditions at the St. Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 30-year average of calendar and billing cycle weighted monthly heating and cooling degree-days (HDD and CDD). The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the 30-year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day (DD) values begin to accumulate. Seasonal and monthly peak demand projections are based on a 30-year historical average of system-weighted degree days using the "Itron Rank-Sort Normal" approach which takes annual weather extremes into account as well as the date and hour of occurrence.

2. The DEF customer forecast is based upon Moody's historical and forecasted population estimates of the 29 counties served by DEF. National and Florida economic projections produced by Moody's Analytics in their July 2023 forecast, along with Energy Information Administration (EIA) 2023 surveys of residential appliance saturation and average appliance efficiency levels provided the basis for development of the DEF energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Two major customers accounted for approximately 39% of the industrial class MWh sales in 2023. These energy-intensive "crop nutrient" producers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, international trade pacts and U.S. environmental regulations. The market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations. Going forward, global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. Any increase in self-service generation will act to reduce energy

requirements from DEF. An upside risk to this projection lies in the price of energy, especially low natural gas price, which is a major cost in mining and producing phosphoric fertilizers. DEF has begun to assume a decline in Phosphate sector energy consumption late in the planning horizon as mining product becomes scarce in the areas currently mined.

4. DEF has supplied capacity and energy service to wholesale customers on a “full” and “partial” requirement basis for many years. Many Sales for Resale Customers have moved to other suppliers for their needs or have begun to self-generate. What remains are Partial Requirements (PR) contracted loads with the Reedy Creek Improvement District (RCID) and Seminole Electric Cooperative, Inc. (SECI). The forecast reflects the current contractual obligations based on the nature of the stratified load being requested, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. All contracts are projected to expire in the specific year designated in the respective contracts.

5. This forecast assumes that DEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions expected to be realized through currently FPSC approved DSM goals as stated in Docket No. 20190018-EG.

7. This forecast reflects impacts from both Plug-in Hybrid Electric Vehicle (PHEV) and behind the meter customer-owned renewable generation which is mostly solar photovoltaic (PV) installations on energy and peak demand. PHEV customer penetration levels, which are expected to be a small share of the total DEF service area vehicle stock over the planning horizon, incorporates an EPRI Model view that includes gasoline price expectations. DEF customer PV penetration levels are expected to continue to grow over the planning horizon and the forecast incorporates a view on equipment and electric price impacts on customer use.

8. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. DEF will supply the supplemental load of self-service

cogeneration customers. While DEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place.

ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2023.As mentioned in the overview, in mid-2023 the U.S. continued to experience strong job growth, rising wages, and low unemployment. Inflation was receding in response to the Federal Reserve's rate increases. The funds rate was considered sufficient to slow the economy's growth and succeed in bringing inflation back to the Fed's target by the fall of 2024. It is with this background that the DEF Customer, Energy and Peak Demand forecast was developed and the environment in which the Moody's Analytics July 2023 U.S. forecast and Florida forecast was applied. Major assumptions are as follows:

- In Moody's July 2023 outlook, an additional 25-basis point rate hike to the federal funds rate was incorporated at the July FOMC meeting. This brought the policy rate's range to 5.25% to 5.5%. The first-rate cut was also pushed back from March to June 2024. The assumption was that the reduction in the Federal Reserve's balance sheet would remain on autopilot.

- Recent U.S. bank failures were disconcerting to watch, but they were not symptomatic of a serious broader problem in the financial system. Policymakers' aggressive response ensured the failures did not weaken the system or more than modestly undermine already-weak economic growth.

- Moody's did not make any adjustments in light of the Supreme Court striking down President Biden's student loan forgiveness plan. Moreover, the implications of the ruling for near-term growth were minimal. If the Supreme Court had upheld it, debt cancellation would have only boosted the level of real personal consumption expenditures by 0.1%.

- The ten-year U.S. Treasury peaked in the second quarter of 2024 just shy of 4%, as in the prior baseline.

- Moody's expected strong oil demand growth—headlined by emerging economies and namely China—coupled with OPEC production cuts pushed up oil prices in the second half of the year.

- A full-employment economy is one with an unemployment rate around 3.5%, a 62.5% labor force participation rate, and a prime-age employment-to-population ratio in the range of 80%. The economy was at that level then.

Throughout the ten-year forecast horizon, risks and uncertainties are always recognized and handled on a "highest probability of outcome" basis. General rules of economic theory, namely supply and demand equilibrium, are maintained in the long run. This notion is applied to energy/commodity prices, currency levels, the housing market, wage rates, birth rates, inflation and interest rates. Uncertainty surrounding specific weather anomalies (hurricanes or earthquakes), international crises such as wars or terrorist acts, or future pandemic events, are not explicitly designed into this projection. Thus, any situations of this variety will result in a deviation from this forecast.

FORECAST METHODOLOGY

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's SAE approach while other classes use customer-class specific econometric models. These models are expressly designed to capture class-specific variation over time. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, demand response, interruptible service, and changes in self-service generation capacity.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. Internal company forecasts are used for projections of electricity price, weather conditions, the length of the billing month and rates of customer owned renewable and electric vehicle adoption. The external sources of data include Moody's Analytics forecasts of changes in population, demographics and economic conditions. The incorporation of residential and commercial "end-use" energy has been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company's Market Research department and the EIA, along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an explanation of usage levels and changes in weather-sensitivity over time. The "bundling" of 19 residential appliances into "heating", "cooling" and "other" end uses form the basis of equipment-oriented drivers that interact with typical exogenous factors such as real median household income, average household size, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating monthly residential customers with county level population projections, provided by Moody's, for counties in which DEF serves residential customers.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month, and the heating and cooling degree-day values. As in the residential sector, these variables interact with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating
- Cooling
- Ventilation
- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the EIA's Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A large portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment, energy prices, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to anticipated market conditions. Since this sub-sector is comprised of only three customers, the forecast is dependent upon information received from direct customer contact. DEF Large Account Management employees provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out and start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon. These Florida mining companies compete globally into a global market where farming conditions dictate the need for “crop nutrients”.

The projection of industrial accounts was not expected to decline as rapidly as it has in the previous ten years. The pace of “off-shoring” manufacturing jobs was expected to decline from past levels. Both the Trump and Biden administrations have favored the rebuilding of the American manufacturing sector, with the Biden administration adding a focus on carbon reduction. Also, the rapid increase in Florida population may recalibrate Florida’s competitiveness in “location analysis” studies performed by industry when determining site selection for new operations.

Street Lighting

Electricity sales to the street and highway lighting class are projected to decrease over the forecast period due to increased energy efficiency. The number of accounts has increased due to rate changes from the Public Authority class. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised of federal, state and local government operated services, are projected to increase within the DEF's service area. This is a result of a growing economy and population representing a larger tax base. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e., public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with cooling degree-days, energy prices and the sales month billing days, explains most of the variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use throughout the year. The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

SECI is a wholesale, or Sales for Resale, customer of DEF that contracts for both seasonal and stratified loads over the forecast horizon. The municipal Sales for Resale class includes a number of customers, divergent not only in scope of service (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. DEF serves partial requirement service (PR) to load serving customers such as Reedy Creek Improvement District. In each case, these customers contract with DEF for a specific level and type of stratified capacity (MW) needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using information provided by the purchaser who better understands their needs. Electric energy growth and competitive market prices will dictate the amount of wholesale demand and energy throughout the forecast horizon.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, DEF's coincident system peak is separated into five major components. These components consist of total retail load, interruptible and curtailable tariff non-firm load, conservation and demand response program capability, wholesale demand, and company use demand.

Total retail load refers to projections of DEF retail monthly net peak demand before any activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of DEF's retail net peak demand assuming no utility activated load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels and coincident weather conditions at the time of the peak and the amounts of Base-Heating-Cooling load estimated by the monthly Itron models without the impacts of year-to-year variation in utility-sponsored DR programs. Monthly peaks are projected using the Itron SAE generated use patterns for both weather sensitive (cooling & heating) appliances and base load appliances calculated by class in the energy models. Daily and hourly models of applying DEF class-of-business load research survey data lead to class and total retail hourly load profiles when a 30-year normal weather template replaces actual weather. The projections of retail peak are the result of a monthly model driven by the summation of class base, heating and cooling energy interpolated 30-year normal weather pattern-driven load profile. The projection for the months of January (winter) and August (summer) are typically when the seasonal peaks occur. Energy conservation and direct load control estimates consistent with DEF's DSM goals that have been established by the FPSC are applied to the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of firm retail monthly peak demand figures. The Interruptible and Curtailable service (IS and CS) tariff load projection is developed from historic monthly trends, as well as the incorporation of specific projected information obtained from DEF's large industrial accounts on these tariffs by account executives. Developing this piece of the demand forecast allows for appropriate firm retail demand results in the total retail coincident peak demand projection.

Sales for Resale demand projections represent load supplied by DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. For Partial Requirement demand projections, contracted MW levels dictate the level of seasonal demands.

DEF "company use" at the time of system peak is estimated using load research metering studies similar to potential firm retail. It is assumed to remain stable over the forecast horizon as it has historically.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW SCENARIOS

DEF has developed high and low scenarios around the base case energy sales and peak demand projections. Both scenarios incorporate historical variation in weather and economic conditions as well as service area population and household growth. Historical variation for economic driver variables selected in the base case energy sales models using the Moody's S1 & S3 (High/Low) scenarios. High and low weather variables were determined for the energy and peak weather variables (HDDs, CDDs, and monthly peak DDs) using actual 30-year weather conditions. Each weather variable used in the modeling process is ranked monthly from "high-to-low" degree days. The high (hottest or coldest) one-fourth of each variable is averaged and becomes a normal "High Case" weather condition. Similarly, the "mildest" one-fourth of each weather variable's 30 observations are averaged and become the normal "Low Case" weather condition. A review of twenty-year historical variation of DEF 29-county population growth based on Moody's high and low customer projections out ten years resulted in the final area of variability around the Load Forecast.

This procedure captures the most influential variables around energy sales and peak demand by estimating high and low cases for economics, demographics, and weather conditions. DEF has evaluated the load projections generated through this process against projected loads based on extreme temperature events over the last 40 years and concluded that the range of load represented in these cases encompasses the probable outcome of such extreme weather recurrence.

DEMAND SIDE MANAGEMENT

Pursuant to the provisions of Florida Statutes Section 366.82 (the "FEECA Statute"), which requires the FPSC to adopt goals for the FEECA utilities to increase energy efficiency and increase the development of demand-side renewable energy systems and directs the FPSC to review those goals every five years, in 2019, the FPSC conducted its statutorily required review and determined that it was in the public interest to continue with the goals for the 2020-2024 time period established in the 2014 Goals setting proceeding and directed the utilities to file Program Plans designed to achieve these goals (Order No. PSC-2019-0509-FOF-EG). In February 2020, DEF submitted a Plan designed to achieve the 2020-2024 goals which was approved by the Commission (Order No. PSC-2020-0274-PAA-EG) in August of that year. The programs included in this Plan are subject to periodic monitoring and evaluation to ensure that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable. Tables 2.1 and 2.2 reflect the annual Program achievements for the residential and commercial sector compared to the Commission established goals for the 2020-2024 time period.

RESIDENTIAL DEMAND SIDE MANAGEMENT PROGRAMS

TABLE 2.1

Residential DSM MW and GWH Savings

RESIDENTIAL									
	WINTER PEAK MW REDUCTION			SUMMER PEAK MW REDUCTION			GWH ENERGY REDUCTION		
YEAR	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE
2020	31	32	-5%	18	16	13%	35	9	277%
2021	16	28	-42%	10	14	-26%	25	6	311%
2022	25	25	1%	16	12	30%	49	4	1205%
2023	30	22	36%	19	11	70%	50	2	2244%
2024		21			11			1	

The following provides a list of DEF's Residential DSM programs as of December 31, 2023, along with a brief overview of each program:

Home Energy Check – This is DEF's home energy audit program as required by Rule 25-17.003(3)(b), F.A.C. DEF offers a variety of options to customers for home energy audits including walk-through audits, phone assisted audits, and on-line audits. At the completion of the audit, DEF also provides kits that contain energy saving measures that may be easily installed by the customer.

Residential Incentive Program – This program provides incentives on a variety of cost-effective measures designed to provide energy savings. DEF expects to provide incentives to customers for the installation of approximately 75,000 energy saving measures over the 2020 to 2024 time period. These measures primarily include heating and cooling, duct repair, insulation, and energy efficient windows and home energy management systems. The measures and incentive levels included in this program have been updated to reflect the impacts of new codes and standards.

Neighborhood Energy Saver – This program is designed to provide energy saving education and assistance to low-income customers. This program targets neighborhoods that meet certain income eligibility requirements. DEF plans to install energy saving measures in approximately 5,250 homes annually over the 2020 to 2024 time period. Additionally, DEF increased its targeted homes by 5% or 250 homes above the annual projected homes for the calendar years 2022-2024. These measures will be installed at no cost to the customer and include air infiltration measures, water heating measures, lighting, insulation, duct repair, and heat pump and air conditioning tune-ups.

Low Income Weatherization Assistance Program – DEF partners with local agencies to provide funding for energy efficiency and weatherization measures to low-income customers through this program. DEF expects to provide assistance to approximately 500 customers annually through this program.

Residential Load Management a/k/a EnergyWise – This is a voluntary residential demand response program that provides monthly bill credits to customers who allow DEF to reduce peak demand by controlling service to selected electric equipment through various devices and communication options installed on the customer's premises. These interruptions are at DEF's option, during specified time periods, and coincident with hours of peak demand. Customers must have a minimum average monthly usage of 600 kWh to be eligible to participate in this program.

The Company is actively replacing 3G load control devices at customer premises and it remains on track for that work to be completed in 2025, as noted in the 2023 Ten-Year Site Plan. DEF will file its plan for incremental capability in the DSM goal setting docket this year and reflect the Commission approved increases in the 2025 Ten-Year Site Plan.

COMMERCIAL/INDUSTRIAL DEMAND SIDE MANAGEMENT PROGRAMS

TABLE 2.2

Commercial/Industrial DSM MW and GWH Savings

COMMERCIAL / INDUSTRIAL									
	WINTER PEAK MW REDUCTION			SUMMER PEAK MW REDUCTION			GWH ENERGY REDUCTION		
YEAR	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE
2020	24	5	354%	46	8	460%	40	6	582%
2021	11	5	124%	24	7	248%	22	4	454%
2022	5	5	1%	5	6	-17%	3	2	25%
2023	30	5	510%	27	6	377%	10	1	654%
2024		5			5			1	

The following provides a list of DEF's Commercial DSM programs as of December 31, 2023, along with a brief overview of each program:

Business Energy Check – This is a commercial energy audit program that provides commercial customers with an analysis of their energy usage and information about energy-saving practices specific to their business and operations and cost-effective measures that they can implement at their facilities.

Smart $aver Business f/k/a Better Business – This program provides incentives to commercial customers on a variety of cost-effective energy efficiency measures. These measures are primarily comprised of measures that reduce cooling and heating load.

Smart $aver Custom Incentive f/k/a Florida Custom Incentive – The objective of this program is to encourage customers to make capital investments for the installation of energy efficiency measures which reduce energy and peak demand. This program provides incentives for customized energy efficiency projects and measures that are cost effective but are not otherwise included in DEF's prescriptive commercial programs.

Interruptible Service – This program is available to commercial customers with a minimum billing demand of 500 KW or more who are willing to have their power interrupted at times of capacity shortage during peak or emergency conditions. DEF has remote control access to the switch providing power to the customer's equipment. Customers participating in the Interruptible Service program receive a monthly interruptible demand credit based on their bills.

Curtailable Service - This program is an indirect load control program that reduces DEF's energy demand at times of capacity shortage during peak or emergency conditions. The program is available to commercial customers with a minimum of 500KW or more who are willing to curtail their load.

Standby Generation - This program is a demand control program that reduces DEF's demand based upon the control of the customer's back-up generator. The program is a voluntary program available to all commercial and industrial customers who have on-site stand-by generation capacity of at least 50 KW and are willing to allow remote activation of their on-site generation capability in emergencies.

OTHER DSM PROGRAMS

The following provides an overview of other DSM programs:

Technology Development – This program is used to fund research, testing and development of new energy efficiency and demand response technologies. This program provides the opportunity to investigate and test new technologies and determine their usefulness and feasibility in the support of energy efficiency and demand response programs.

Qualifying Facilities – This program analyzes, forecasts, facilitates, and administers the potential and actual power purchases from Qualifying Facilities (QFs) and the state jurisdictional QF or distributed generator interconnections. The program supports meetings with interested parties or potential QFs, including cogeneration and small power production facilities including renewables interested in providing renewable capacity or energy deliveries within our service territory. Project, interconnection, and avoided cost discussions with renewable and combined heat and power developers who are also exploring distributed generation options continue to remain steady. Most of the interest is coming from companies utilizing solar photovoltaic technology as the price of photovoltaic panels has decreased over time. The cost of this technology continues to decrease, and subsidies remain in place. As of December 31st, 2023, DEF had 69 active solar projects totaling approximately 5,100 MW in its FERC jurisdictional interconnection queue and 19 of those projects included DEF as the project developer. As the technologies advance and the market evolves, the Company's policies will continue to be refined and remain compliant.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2023, DEF had a summer total firm capacity resource of 11,750 MW (see Table 3.1). This capacity resource includes fossil steam generators (2,423 MW), combined cycle plants (5,247 MW), combustion turbines (1,972 MW), solar power plants (648 MW), independent power purchases (1,163 MW), and non-utility purchased power (297 MW). Table 3.2 presents DEF's firm capacity contracts with renewable and cogeneration Facilities.

Demand-Side Programs

In August 2020, the FPSC approved demand-side management programs designed to meet the DSM goals established by the Commission in Order PSC-2019-0509-FOF-EG. Total DSM resources are presented in Schedules 3.1 and 3.2 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources.

Capacity and Demand Forecast

DEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. Demand forecasts shown in these schedules are based on Schedules 3.1.1 and 3.2.1, the base summer and winter forecasts. DEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with DEF. In its planning process, DEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base.

Base Expansion Plan

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes a net addition of over 4,700 MW of solar PV generation with an expected equivalent summer firm capacity contribution of approximately 880 MW, 90 MW of firm storage added in 2027 and 430 MW of combustion turbine firm capacity added in years 2032 and 2033. The incorporation of the full firm capacity of the Osprey Energy Center takes place at the end of 2025. Between 2022 and 2027, DEF will add close to 400 MW of combined cycle capacity that results from projects focusing on increasing the fuel efficiency of the combined cycle generating units. DEF continues to consider market supply-side resource alternatives to enhance DEF's resource plan.

DEF recognizes that as solar penetration increases, including both DEF and customer owned PV, the relationship between the solar production and the coincident load peak will change. In this plan, DEF has assigned this DEF owned solar PV generation an equivalent summer capacity value equal to 57% of the nameplate capacity of the planned installations from 2021 to 2024. DEF modeling derives an equivalent summer non-coincident, but on-peak-hour capacity value equal to 25% of the facility's nameplate rating for planned PV installations from 2025 to 2027 and 10% for 2028 and beyond. An annual performance degradation factor of 0.5% has been assigned to the PV installations. DEF will continue to evaluate these assignments over time and may revise these values in future Site Plans based on changes in project designs and the data received from actual operation of these facilities once they are installed. In addition, DEF recognizes that higher penetration of PV resources on the system will result in a need for additional balancing of generation intermittency. The declining capacity value for PV installations late in this decade and beyond could be improved substantially if battery technology advances support economic pairing of PV with energy storage, which could also help to address the need for balancing generation intermittency. DEF's strategy of steady and carefully paced additions of PV to the system will allow continued evaluation of these impacts and the need for additional resources in the future to meet these needs.

In their ongoing efforts to regulate greenhouse gas emissions, on June 19, 2019 the Environmental Protection Agency (EPA) issued the Affordable Clean Energy (ACE) Rule to replace the 2015 Clean Power Plan. However, on January 19, 2021, the U.S. Court of Appeals for the District of

Columbia issued its opinion vacating the ACE Rule and remanding the rule to the EPA. On October 29, 2021, the Supreme Court agreed to hear the appeal of the ACE vacatur. The case was heard at the Supreme Court in February 2022, and on June 30, 2022, the Court issued a decision reversing and remanding the January 19, 2021 D.C. Circuit Court decision. Currently, neither the CPP nor the ACE rule are in effect, as the EPA is working on a replacement rule. On May 23, 2023, EPA proposed five separate actions, which include establishing GHG performance standards for fossil fuel fired EGUs and combustion turbines as well as repealing the ACE rule. The EPA proposal aims to implement more protective GHG emission standards, which are potentially applicable to several DEF coal and natural gas combustion turbine units. DEF will continue to monitor the proposed rule, which is expected to be finalized by May 2024, and the potentially applicable requirements to the DEF emission units.

Duke Energy has set a goal at the enterprise level of achieving at least a 50% reduction in CO_2 emissions from a 2005 baseline by 2030 and net-zero emissions by 2050. DEF has incorporated anticipated tax savings from the 2022 IRA into our resource plan optimization and production cost models. These savings have increased the cost effectiveness of clean energy resources, particularly solar and batteries, enabling further cost-effective progress toward achievement of Duke Energy's enterprise level target.

DEF continues to modernize its generation resources with the retirement and projected retirements of several of the older units in the fleet, particularly combustion turbines at Bayboro, DeBary P2 - P6, and Bartow P1 & P3. Continued operations of the peaking units at Bayboro are planned through the year 2026. The DeBary units P2 - P6 and Bartow units P1 & P3 are projected to retire in 2027. There are many factors which may impact these retirements including environmental regulations and permitting, unit age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs. In addition to retirements, DEF anticipates the expiration of several contracts with Qualifying Facilities (QFs) and Independent Power Producers (IPPs) over the plan period. Although the Base Expansion Plan projects expiration of all these contracts, DEF continues to consider options for renewing these contracts in a manner that provides system reliability and cost-effective capacity and energy for our customers.

DEF continues to improve the performance of its generation fleet. Starting in mid-2023 and through the end of 2027, DEF will perform upgrades to the combustion turbines associated with several of the fleet combined cycle units. The goal of these upgrades is to reduce the unit heat rates, improve the fleet fuel efficiency, and reduce DEF CO2 emissions. These upgrades will also result in the addition of close to 400 MWs of combined cycle capacity.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2024 through 2033. The planned capacity additions, together with purchases from QFs, Investor-Owned Utilities (IOUs), and IPPs enable the DEF system to meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power, cogeneration and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan.

DEF has examined the high and low load scenarios presented in Schedules 3.1 and 3.2. As discussed in Chapter 2, these scenarios were developed to present and test a range of likely outcomes in peak load and energy demand. DEF found that the Base Expansion Plan was robust under the range of conditions examined. Current planned capacity is sufficient to meet the demand including reserve margin in these cases through 2028 allowing DEF sufficient time to plan additional generation capacity either through power purchase or new generation construction as needed if higher than baseline conditions emerge. If lower than baseline conditions emerge, DEF can defer future generation additions.

Status reports and specifications for the planned new generation facilities are included in Schedule 9. Planned transmission lines associated with the DEF Bulk Electric System (BES) are shown in Schedule 10.

TABLE 3.1

DUKE ENERGY FLORIDA

**TOTAL CAPACITY RESOURCES OF
POWER PLANTS AND PURCHASED POWER CONTRACTS**

AS OF DECEMBER 31, 2023

PLANTS	SUMMER NET DEPENDABLE CAPABILITY (MW)
Fossil Steam	2,423
Combined Cycle	5,247
Combustion Turbine	1,972
Solar	648
Total Net Dependable Generating Capability	**10,290**
Dependable Purchased Power	1,460
Firm Qualifying Facility Contracts (297 MW)	
Investor Owned Utilities (0 MW)	
Independent Power Producers (1,163 MW)	
TOTAL DEPENDABLE CAPACITY RESOURCES	**11,750**

TABLE 3.2

DUKE ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS

AS OF DECEMBER 31, 2023

Facility Name	Firm Capacity (MW)
Mulberry	115
Orange Cogen (CFR-Biogen)	104
Pasco County Resource Recovery	23
Pinellas County Resource Recovery	54.8
TOTAL	**296.8**

DUKE ENERGY FLORIDA

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)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2024	10,418	874	0	78	11,369	9,000	2,369	26%	0	2,369	26%
2025	10,681	759	0	0	11,440	8,836	2,603	29%	0	2,603	29%
2026	11,319	655	0	0	11,974	8,790	3,184	36%	0	3,184	36%
2027	11,038	0	0	0	11,038	8,781	2,257	26%	0	2,257	26%
2028	11,155	0	0	0	11,155	8,908	2,247	25%	0	2,247	25%
2029	11,242	0	0	0	11,242	9,093	2,149	24%	0	2,149	24%
2030	11,336	0	0	0	11,336	9,260	2,076	22%	0	2,076	22%
2031	11,390	0	0	0	11,390	9,374	2,016	22%	0	2,016	22%
2032	11,873	0	0	0	11,873	9,595	2,279	24%	0	2,279	24%
2033	12,356	0	0	0	12,356	9,811	2,545	26%	0	2,545	26%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2023/24	10,675	1,442	0	78	12,195	8,872	3,323	37%	0	3,323	37%
2024/25	10,774	803	0	0	11,577	9,112	2,465	27%	0	2,465	27%
2025/26	11,272	699	0	0	11,971	9,124	2,847	31%	0	2,847	31%
2026/27	11,205	699	0	0	11,904	9,165	2,739	30%	0	2,739	30%
2027/28	10,902	0	0	0	10,902	8,682	2,220	26%	0	2,220	26%
2028/29	10,974	0	0	0	10,974	8,795	2,179	25%	0	2,179	25%
2029/30	11,046	0	0	0	11,046	8,957	2,089	23%	0	2,089	23%
2030/31	11,118	0	0	0	11,118	9,017	2,100	23%	0	2,100	23%
2031/32	11,118	0	0	0	11,118	9,125	1,993	22%	0	1,993	22%
2032/33	11,587	0	0	0	11,587	9,210	2,377	26%	0	2,377	26%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2024 THROUGH DECEMBER 31, 2033

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	FIRM NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
MULE CREEK	1	BAY	PV	SO				04/2023	03/2024		74,900	43	0	P	(1)
WINQUEPIN	1	MADISON	PV	SO				04/2023	03/2024		74,900	43	0	P	(1)
FALMOUTH	1	SUWANNEE	PV	SO				06/2023	08/2024		74,900	43	0	P	(1)
COUNTY LINE	1	GILCHRIST	PV	SO				12/2023	10/2024		74,900	43	0		(1)
P L BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	09/2024	11/2024			141	99	P	(1) and (5)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(3)			(2)
SUNDANCE	1	MADISON	PV	SO				04/2024	03/2025		74,900	19	0		(1)
HINES	2	POLK	CC	NG	DFO	PL	TK	03/2025	05/2025			65	65	P	(1) and (5)
OSPREY CC	1	POLK	CC	NG	DFO	PL	TK		10/2025			347	381	P	(3)
HINES	4	POLK	CC	NG	DFO	PL	TK	10/2025	11/2025			52	52	P	(1) and (5)
BAILEY MILL	1	JEFFERSON	PV	SO				04/2025	12/2025		74,900	19	0		(1)
HALF MOON	1	SUMTER	PV	SO				04/2025	12/2025		74,900	19	0		(1)
RATTLER	1	HERNANDO	PV	SO				04/2025	12/2025		74,900	19	0		(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)
TIGER BAY	1	POLK	CC	NG	DFO	PL	TK	02/2026	03/2026			22	22	P	(1) and (5)
HINES	3	POLK	CC	NG	DFO	PL	TK	02/2026	04/2026			65	65	P	(1) and (5)
CITRUS	PB1	CITRUS	CC	NG				02/2026	05/2026			22	22	P	(1) and (5)
CITRUS	PB2	CITRUS	CC	NG				02/2026	05/2026			22	22	P	(1) and (5)
UNKNOWN		UNKNOWN	PV	SO				09/2025	06/2026		224,700	56			(1) and (4)
UNKNOWN		UNKNOWN	PV	SO				03/2026	12/2026		149,800	37	0	P	(1) and (4)
BAYBORO	P1 - P4	PINELLAS	CT	DFO		WA				10/2026		(151)	(198)		
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)
UNKNOWN		UNKNOWN	BA	N/A		N/A		01/2026	01/2027		100,000	90	90	P	(1)
DEBARY	P2 - P6	VOLUSIA	CT	DFO		TK				06/2027		(227)	(292)		
BARTOW	P1, P3	PINELLAS	CT	DFO		WA				06/2027		(82)	(101)		
UNKNOWN		UNKNOWN	PV	SO				09/2026	06/2027		224,700	56			(1) and (4)
UNKNOWN		UNKNOWN	PV	SO				04/2027	12/2027		149,800	37	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(5)			(2)

a. See page v. for Code Identification of Future Generating Unit Status.

b. NOTES

(1) Planned, Prospective, or Committed project.

(2) Solar capacity degrades by 0.5% every year

(3) Osprey CC Acquisition total capacity is available once Transmission Upgrades are in service, total Summer capacity goes up to 592MW and total Winter capacity goes up to 626MW

(4) Multiple 74.9 MWs units at different sites. For SPS, 40 MW of storage for 74.9 MW of Solar PV.

(5) Combustion Turbines Heat Rate upgrades for Combined Cycles

DUKE ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2024 THROUGH DECEMBER 31, 2033

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	FIRM NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
UNKNOWN		UNKNOWN	PV	SO				09/2027	07/2028		299,600	30	0	P	(1) and (4)
UNKNOWN		UNKNOWN	SPS	SO				09/2027	07/2028		149,800	55	72	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN		UNKNOWN	PV	SO				09/2028	07/2029		374,500	37	0	P	(1) and (4)
UNKNOWN		UNKNOWN	SPS	SO				09/2028	07/2029		149,800	55	72	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN		UNKNOWN	PV	SO				09/2029	07/2030		449,400	45	0	P	(1) and (4)
UNKNOWN		UNKNOWN	SPS	SO				09/2029	07/2030		149,800	55	72	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN		UNKNOWN	PV	SO				09/2030	07/2031		599,200	60	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN	P1 - P2	UNKNOWN	CT	NG	DFO	FL	TK	07/2029	06/2032		455,000	430	466	P	(1)
UNKNOWN		UNKNOWN	PV	SO				09/2032	07/2033		599,200	60	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(7)			(2)
UNKNOWN	P3 - P4	UNKNOWN	CT	NG	DFO	FL	TK	07/2030	06/2033		455,000	430	466	P	(1)
UNKNOWN		UNKNOWN	PV	SO				09/2032	07/2033		599,200	60	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(7)			(2)

a. See page v. for Code Identification of Future Generating Unit Status.
b. NOTES
(1) Planned, Prospective, or Committed project.
(2) Solar capacity degrades by 0.5% every year
(3) Osprey CC Acquisition total capacity is available once Transmission Upgrades are in service, total Summer capacity goes up to 592MW and total Winter capacity goes up to 626MW
(4) Multiple 74.9 MWs units at different sites. For SPS, 40 MW of storage for 74.9 MW of Solar PV.
(5) Combustion Turbines Heat Rate upgrades for Combined Cycles

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**Mule Creek**	
(2)	Capacity		
	a. Nameplate (MWac):	74.9	
	b. Summer Firm (MWac):	42.7	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2023	
	b. Commercial in-service date:	3/2024	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~28 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/Kwh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,221.86	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**Winquepin**		
(2)	Capacity			
	a. Nameplate (MWac):	74.9		
	b. Summer Firm (MWac):	42.7		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	4/2023		
	b. Commercial in-service date:	3/2024	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~28	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,221.86	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)		17.17	
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Falmouth**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		6/2023	
	b. Commercial in-service date:		8/2024	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~28	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,221.86	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**County Line**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		12/2023	
	b. Commercial in-service date:		10/2024	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~28	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,221.86	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Sundance**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2024	
	b. Commercial in-service date:		3/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,415.40	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**Bailey Mill**	
(2)	Capacity		
	a. Nameplate (MWac):	74.9	
	b. Summer Firm (MWac):	18.7	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2025	
	b. Commercial in-service date:	12/2025	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A	%
	b. Forced Outage Factor (FOF):	N/A	%
	c. Equivalent Availability Factor (EAF):	N/A	%
	d. Resulting Capacity Factor (%):	~27	%
	e. Average Net Operating Heat Rate (ANOHR):	N/A	BTU/Kwh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,415.40	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Half Moon**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2025	
	b. Commercial in-service date:		12/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,428.31	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Rattler**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2025	
	b. Commercial in-service date:		12/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,428.31	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	224.7		
	b. Summer Firm (MWac):	56.2		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2025		
	b. Commercial in-service date:	6/2026	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,428.34	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)		17.17	
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	149.8	
	b. Summer Firm (MWac):	37.5	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2026	
	b. Commercial in-service date:	12/2026	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A	%
	b. Forced Outage Factor (FOF):	N/A	%
	c. Equivalent Availability Factor (EAF):	N/A	%
	d. Resulting Capacity Factor (%):	~27	%
	e. Average Net Operating Heat Rate (ANOHR):	N/A	BTU/Kwh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,419.08	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		100.0	
	b. Summer Firm (MWac):		90.0	
	c. Winter Firm (MWac):		90.0	
(3)	Technology Type:		BATTERY STORAGE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		7/2026	
	b. Commercial in-service date:		3/2027	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		N/A	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~1 ACRE / 5 MW	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~10 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			15
	b. Total Installed Cost (In-service year $/Kw):			1,650.00
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		30.00
	g. Variable O&M ($/MWh):	($2024)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	224.7	
	b. Summer Firm (MWac):	56.2	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	9/2026	
	b. Commercial in-service date:	6/2027	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A	%
	b. Forced Outage Factor (FOF):	N/A	%
	c. Equivalent Availability Factor (EAF):	N/A	%
	d. Resulting Capacity Factor (%):	~27	%
	e. Average Net Operating Heat Rate (ANOHR):	N/A	BTU/Kwh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,409.96	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	149.8	
	b. Summer Firm (MWac):	37.5	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2027	
	b. Commercial in-service date:	12/2027	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A	%
	b. Forced Outage Factor (FOF):	N/A	%
	c. Equivalent Availability Factor (EAF):	N/A	%
	d. Resulting Capacity Factor (%):	~27	%
	e. Average Net Operating Heat Rate (ANOHR):	N/A	BTU/Kwh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,409.96	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		299.6	
	b. Summer Firm (MWac):		30.0	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2027	
	b. Commercial in-service date:		7/2028	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,648.99	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	149.8		
	b. Summer Firm (MWac):	55.0		
	c. Winter Firm (MWac):	72.0		
(3)	Technology Type:	PHOTOVOLTAIC WITH BATTERY STORAGE		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2027		
	b. Commercial in-service date:	7/2028	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~34	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		2,470.83	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)			
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	374.5	
	b. Summer Firm (MWac):	37.5	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	9/2028	
	b. Commercial in-service date:	7/2029	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~27 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/Kwh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,632.89	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)		
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	149.8		
	b. Summer Firm (MWac):	55.0		
	c. Winter Firm (MWac):	72.0		
(3)	Technology Type:	PHOTOVOLTAIC WITH BATTERY STORAGE		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2028		
	b. Commercial in-service date:	7/2029	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~34	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		2,444.11	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)			
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		449.4	
	b. Summer Firm (MWac):		44.9	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2029	
	b. Commercial in-service date:		7/2030	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,617.30	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	149.8	
	b. Summer Firm (MWac):	55.0	
	c. Winter Firm (MWac):	72.0	
(3)	Technology Type:	PHOTOVOLTAIC WITH BATTERY STORAGE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	9/2029	
	b. Commercial in-service date:	7/2030	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):		N/A %
	b. Forced Outage Factor (FOF):		N/A %
	c. Equivalent Availability Factor (EAF):		N/A %
	d. Resulting Capacity Factor (%):		~34 %
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/Kwh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):		30
	b. Total Installed Cost (In-service year $/Kw):		2,418.04
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)		
	g. Variable O&M ($/MWh): ($2024)		0.00
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	599.2	
	b. Summer Firm (MWac):	59.9	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	9/2030	
	b. Commercial in-service date:	7/2031	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~27 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/Kwh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,602.23	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)		
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Undesignated CTs P1-P2**	
(2)	Capacity			
	a. Summer (MWs):		215	
	b. Winter (MWs):		235	
(3)	Technology Type:		COMBUSTION TURBINE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		7/2029	
	b. Commercial in-service date:		6/2032	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low Nox Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		UNKNOWN	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.00	%
	b. Forced Outage Factor (FOF):		2.00	%
	c. Equivalent Availability Factor (EAF):		95.06	
	d. Resulting Capacity Factor (%):		1.9	%
	e. Average Net Operating Heat Rate (ANOHR):		10,487	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		1,421.8	
	c. Direct Construction Cost ($/kW):	($2024)	1,239.7	
	d. AFUDC Amount ($/kW):		180.9	
	e. Escalation ($/kW):		1.2	
	f. Fixed O&M ($/kW-yr):	($2024)	2.86	
	g. Variable O&M ($/MWh):	($2024)	9.03	
	h. K Factor:		NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnection and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		599.2	
	b. Summer Firm (MWac):		59.9	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2031	
	b. Commercial in-service date:		7/2032	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~27 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,587.67	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Undesignated CTs P3-P4**	
(2)	Capacity			
	a. Summer (MWs):		215	
	b. Winter (MWs):		235	
(3)	Technology Type:		COMBUSTION TURBINE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		7/2030	
	b. Commercial in-service date:		6/2033	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low Nox Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		UNKNOWN	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.00	%
	b. Forced Outage Factor (FOF):		2.00	%
	c. Equivalent Availability Factor (EAF):		95.06	
	d. Resulting Capacity Factor (%):		1.9	%
	e. Average Net Operating Heat Rate (ANOHR):		10,487	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		1,428.6	
	c. Direct Construction Cost ($/kW):	($2024)	1,245.5	
	d. AFUDC Amount ($/kW):		181.7	
	e. Escalation ($/kW):		1.4	
	f. Fixed O&M ($/kW-yr):	($2024)	2.86	
	g. Variable O&M ($/MWh):	($2024)	9.03	
	h. K Factor:		NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnection and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	599.2	
	b. Summer Firm (MWac):	59.9	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	9/2032	
	b. Commercial in-service date:	7/2033	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A	%
	b. Forced Outage Factor (FOF):	N/A	%
	c. Equivalent Availability Factor (EAF):	N/A	%
	d. Resulting Capacity Factor (%):	~27	%
	e. Average Net Operating Heat Rate (ANOHR):	N/A	BTU/Kwh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,518.91	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)		
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

MULE CREEK SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Ladybug Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	1/1/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,536,000
(8) SUBSTATIONS:	Ladybug Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

WINQUEPIN SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Birch Switching Station
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	4/26/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$16,018,213
(8) SUBSTATIONS:	Birch Switching Station
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

FALMOUTH SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Suwannee Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.2 miles
(5) VOLTAGE:	115 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	4/26/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,190,000
(8) SUBSTATIONS:	Suwannee Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

COUNTY LINE SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Ginnie Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	12/31/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$3,532,625
(8) SUBSTATIONS:	Ginnie Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

SUNDANCE SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Birch Switching Station
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.5 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	3/1/2025
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,540,000
(8) SUBSTATIONS:	Birch Switching Station
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BAILEY MILL SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Waukeenah Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	115 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	7/3/2026
(7) ANTICIPATED CAPITAL INVESTMENT:	$11,060,000
(8) SUBSTATIONS:	Waukeenah Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HALF MOON SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	A new 230 kV Switching Station on the Central Florida to Holder 230 kV line, approximately 18 miles from Holder substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	12/1/2025
(7) ANTICIPATED CAPITAL INVESTMENT:	$28,167,740
(8) SUBSTATIONS:	A new 230 kV Switching Station on the Central Florida to Holder 230 kV line, approximately 18 miles from Holder substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

RATTLER SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	A greenfield four (4) position ring bus substation along the DEF Brooksville to Inverness 69 kV transmission line, proximate to the existing Nobleton Tap
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	1 mile
(5) VOLTAGE:	69 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	11/1/2025
(7) ANTICIPATED CAPITAL INVESTMENT:	$22,337,000
(8) SUBSTATIONS:	A greenfield four (4) position ring bus substation along the DEF Brooksville to Inverness 69 kV transmission line, proximate to the existing Nobleton Tap
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

OSPREY

(1) POINT OF ORIGIN AND TERMINATION:	Kathleen - Osprey
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	26.5 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	11/1/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$150,000,000
(8) SUBSTATIONS:	Kathleen, Osprey
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

INTEGRATED RESOURCE PLANNING OVERVIEW

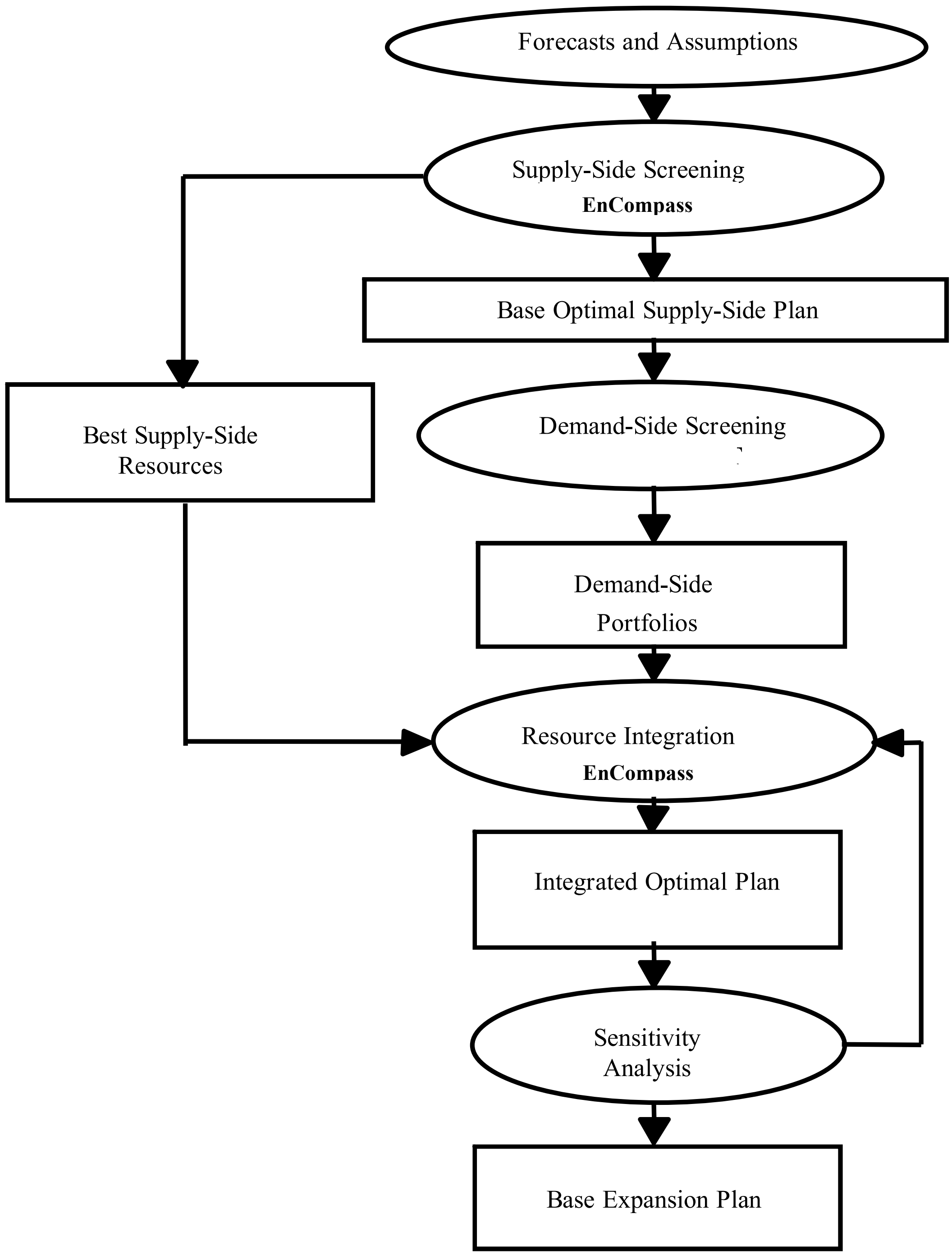
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of DEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified, and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for DEF to pursue over the next ten years that meets the reliability criteria for our customers. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The Integrated Resource Planning (IRP) Process".

The IRP provides DEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g., plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

Integrated Resource Planning (IRP) Process Overview



THE INTEGRATED RESOURCE PLANNING (IRP) PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect DEF's view of the most likely future scenario are developed. Additional future scenarios along with high and low forecasts may also be developed. Computer models used in the process are brought up to date to reflect this data, along with the latest operating parameters and maintenance schedules for DEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

DEF plans its resources in a manner consistent with utility industry planning practices and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of DEF's ability to meet its forecasted seasonal peak load with firm capacity. DEF plans its resources to satisfy a minimum 20% Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin considers the peak load and amount of installed resources, LOLP considers generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability.

DEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. DEF's resource portfolio is designed to satisfy the 20% Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. DEF has found that resource additions are typically triggered to meet the 20% Reserve Margin thresholds before LOLP becomes a factor.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and DEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters (e.g., emissions, possible climate impact), and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the Capacity Expansion module of the EnCompass Power Planning Software licensed from Anchor Power Solutions. This optimization tool evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. Capacity expansion models are used to identify cost-effective system resources. However, additional modeling in a detailed production cost model is necessary to verify the resource selections with respect to cost, reliability, and environmental compliance as well as to conduct an overall assessment of the performance of the portfolio.

Demand-Side Screening

Like supply-side resources, the impacts of potential demand-side resources are also factored into the integrated resource plan. The projected MW and MWH impacts for demand-side management resources are based on the energy efficiency measures and energy management programs included in DEF's 2015 DSM Plan and meet the goals established by the FPSC in December 2019 (Docket 20190018-EG).

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives can then be optimized together with the demand-side portfolios developed in the screening process to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the Company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and reasonable revenue requirements (rates) for DEF's customers. Candidate base plans are then evaluated using the production cost module of EnCompass. Production cost models maintain full chronology and load requirements in all hours simulating the hour-to-hour operation of the system. This provides hourly modeling of the portfolio dispatch and provides insights into the detailed energy production cost of a given portfolio, the emissions profile and helps to identify potential issues with unit operation and reliability.

Developing the Base Expansion Plan

The integrated optimized plan that provides the lowest revenue requirements may then be further tested using sensitivity analysis, including High and Low Demand and Energy Forecasts (see Schedules 2 and 3). The economics of the plan may be evaluated under high and low forecast scenarios for fuel, load and financial assumptions, or any other sensitivities which the planner deems relevant. From the sensitivity assessment, the plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it would then be considered the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast are described in Chapter 2 of this TYSP. The High and Low forecasts of load and energy were provided to Resource Planning to test the robustness of the base plan.

Fuel Price Forecast

The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between DEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates.

Financial Forecast

The key financial assumptions used in DEF's most recent planning studies were 47% debt and 53% equity capital structure, projected cost of debt of 6.0%, and an equity return of 10.1%. The assumptions resulted in a weighted average cost of capital of 8.17% and an after-tax discount rate of 7.45%.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes a net addition of over 4,700 MW of solar PV generation with an expected equivalent summer firm capacity contribution of approximately 880 MW, 90 MW of firm storage added in 2027 and 430 MW of combustion turbine firm capacity added in years 2032 and 2033. The incorporation of the full firm capacity of the Osprey Energy Center takes place at the end of 2025. Between 2022 and 2027, DEF will add close to 400 MW of combined cycle capacity that results from projects focusing on increasing the fuel efficiency of the combined cycle generating units. DEF continues to consider market supply-side resource alternatives to enhance DEF's resource plan.

The incorporation of the IRA tax credits has helped offset projected cost increases for solar, batteries, and solar plus storage units. In DEF's most recent approved rate settlement (FPSC Docket No. 20210016-EI), DEF anticipates the retirement of the two remaining coal units at Crystal River (Crystal River units 4 and 5) in 2034. Solar PV and a mix of batteries and CTs will be the cost-effective generation to replace most of that energy in the 2034 timeframe. DEF's plan to construct Solar Plants continues following a steady path, including a total of 1350 MW in the years 2024 through 2027. From 2028 through 2030 two Solar plus Storage units will be added per year. A more aggressive addition of Solar resources will continue from 2028 through 2033, totaling an additional 2,925 MW over those 6 years. This provides a path to meeting this goal through a measured and paced approach to bringing the solar onto the system which recognizes the challenges of building and interconnecting solar projects, helps maintain reliability as solar penetration increases and maintains affordability in customer rates. As with other elements of the plan, DEF will update these projections as decision dates approach. DEF also continues to consider market supply-side resource alternatives to enhance DEF's resource plan.

DEF recognizes that, as solar penetration increases, including both DEF and customer-owned PV, the total dependable solar resource capability is influencing or shifting DEF's reserve planning focus later beyond the on-peak period. DEF is accounting for this planning shift by deriving reduced summer capacity values of planned PV installations starting in 2025. Refer to Page 3-2 for additional solar resource capacity values that are accounting for this change.

DEF's Base Expansion Plan projects the need for additional capacity with estimated in-service dates during the ten-year period from 2024 through 2033. The planned capacity additions, together with purchases from QFs, IOUs, and IPPs help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan.

Through its ongoing planning process, DEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, lead times in the construction marketplace, project development timelines for new fuels and technologies, and environmental compliance considerations. The

Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

RENEWABLE ENERGY

DEF continues to secure renewable energy from the following facilities listed by fuel type:

Purchases from Municipal Solid Waste Facilities:

- Pasco County Resource Recovery (23 MW)
- Pinellas County Resource Recovery (54.8 MW)
- Dade County Resource Recovery (As Available)
- Lake County Resource Recovery (As Available)
- Lee County Resource Recovery (As Available)

Purchases from Waste Heat from Exothermic Processes:

- PCS Phosphate (As Available)
- Citrus World (As Available)

Solar Photovoltaic Facilities

- DEF-owned Solar Generation (1185.75 MW)
  - Osceola Solar Facility 3.8 MW
  - Perry Solar Facility 5.1 MW
  - Suwannee Solar Facility 8.8 MW
  - Hamilton Solar Power Plant 74.9 MW
  - Trenton Solar Power Plant 74.9 MW
  - Lake Placid Solar Power Plant 45.0 MW
  - St. Petersburg Pier Solar Power Plant 0.35 MW
  - DeBary Solar Power Plant 74.5 MW
  - Columbia Solar Power Plant 74.9 MW

Twin Rivers Solar Power Plant 74.9 MW
Santa Fe Solar Power Plant 74.9 MW
Duette Solar Power Plant 74.5 MW
Sandy Creek Solar Power Plant 74.9 MW
Fort Green Solar Power Plant 74.9 MW
Charlie Creek Solar Power Plant 74.9 MW
Bay Trail Solar Power Plant 74.9 MW
Bay Ranch Solar Power Plant 74.9 MW
Hardeetown Solar Power Plant 74.9 MW
High Springs Solar Power Plant 74.9 MW
Hildreth Solar Power Plant 74.9 MW

Customer-owned renewable generation under DEF's Net Metering Tariff (about 775 MW as of 12/31/23)

At this time, DEF is reviewing the potential for as-available purchased power contracts with third-party solar companies. In-service dates, however, are generally projected to be beyond 2025. As of December 31, 2023, DEF had over 5,100 MW of FERC jurisdictional solar projects in the DEF grid interconnection queue, representing over 69 active projects and 19 of those projects included DEF as the noted developer. DEF anticipates that additional projects developed by DEF as well as third parties will be added through the decade. Project ownership proportions may change over time based on specific project economics, development details, renewable energy incentives and other factors.

DEF continues to field inquiries from potential renewable suppliers and explore whether these potential QFs can provide project commitments and reliable capacity or energy consistent with FERC Rules and the FPSC Rules, 25-17.080 through 25-17.310. DEF will continue to submit renewable contracts in compliance with all policies as appropriate.

The development, construction, commissioning and initial operation of the solar projects at Perry, Osceola, Suwannee, Hamilton, Lake Placid, Trenton, DeBary, Columbia, Twin Rivers, Santa Fe, Duette, Bay Trail, Sandy Creek, Fort Green, Charlie Creek, the now commercial Bay Ranch, Hildreth, Hardeetown, and High Springs plants and under construction Mule Creek, Winquepin, Falmouth and County Line have provided DEF with valuable experience in siting, community engagement, contracting, constructing, operating, and integrating solar photovoltaic technology facilities on the power grid. DEF has worked with our communities on renewable and solar energy technology education, and our contractors to establish necessary standards for the construction and upkeep of utility grade facilities and to develop standards necessary to ensure the reliability of local distribution systems.

DEF is integrating voltage control in the transmission connected solar projects to enhance operational reliability and local transmission resiliency. In addition, DEF is incorporating the ability to place the solar facilities on Automatic Generation Control (AGC). This capability is preparing DEF for future scenarios where there is an excess of generation on the system and a need to utilize the solar resources to balance generation with demand. DEF is utilizing its operational experience and historic data from these solar resources to optimize the daily economic system dispatch, to quantify additional system flexibility needs to counteract the variability of solar generation and investigate potential fuel diversity contributions. The arrays for the solar plants that went in-service in 2023, Bay Ranch, Hardeetown, High Springs, and Hildreth, are shown in Figures 3.2, 3.3, 3.4, and 3.5 below.

FIGURE 3.2
Bay Ranch Solar Power Plant

FIGURE 3.3
Hardeetown Solar Power Plant

FIGURE 3.4
High Springs Solar Power Plant

FIGURE 3.5
Hildreth Power Plant

DEF's current forecast, supporting the Base Expansion Plan includes over 1,340 MW of DEF-owned solar PV to be under development over the next four years and approximately 4,700 MW over the ten-year planning horizon. As with all forecasts included here, the forecast relies heavily on the forward-looking price for this technology, the value rendered by this technology, and considerations to other emerging and conventional cost-effective alternatives, including the use of emerging battery storage technology.

BATTERY ENERGY STORAGE SYSTEMS

The final energy storage systems from DEF's 50 MW battery storage pilot program (Battery Storage Pilot) were placed in-service in 2023. This portfolio of projects may serve a variety of purposes including, but not limited to substation upgrade deferral, distribution line reconducting deferral, power reliability improvement, frequency regulation, Volt/VAR support, backup power, energy capture, and peak load shaving. The projects, max power output, and guaranteed energy storage for a minimum of ten years are provided in Table 3.3. Going forward, DEF will use the data gathered from the operation of these Pilot Program sites to evaluate the opportunities and uses of future DEF battery development. Integration and information sharing with the Duke Energy enterprise Emerging Technology Office will also allow real-world comparison with alternative technologies that may be available for commercial use in coming years.

Table 3.3
DEF Battery Energy Storage Pilot Program Projects Summary

Name	Max Power Output (MW)	Guaranteed Energy Storage (MWh)
Cape San Blas	5.5	14.3
Trenton	11.0	10.1
Micanopy	8.25	11.7
Jennings	5.5	5.5
John Hopkins Middle School	2.475	18.0
Lake Placid	17.275	34.0

DEF is currently developing a 100 MW / 200 MWH Battery Energy Storage System with a planned in-service date in 2027. The project will utilize lithium-ion energy storage and be located to maximize the Standalone Storage Investment Tax Credit (ITC) passed into law by the current administration. The expected increase of solar energy generation on the system provides a unique opportunity for energy storage assets to assist system integration of these intermittent resources and shift energy from lower system value periods to times with higher system value. This energy arbitrage will allow the cost of energy to be more predictably levelized and potentially partially reduces the need for peaking generation. New technologies and changing economics may allow acceleration of energy storage deployment in the future.

TECHNOLOGY AND INNOVATION

Duke Energy continues to evaluate new technology and innovations for potential application both in and beyond the ten-year plan window. Technologies under evaluation, but not yet included in the base expansion plan may be commercially or economically unproven, but Duke Energy and DEF are active in investigation and development of these technologies. At the Duke Energy enterprise level, engineers and specialists are involved in cooperative work with vendors and industry groups on supply-side technologies including wind generation, advanced battery development, hydrogen generation and combustion, and advanced nuclear. On the demand side, technologies including advanced demand response technologies such as commercial building pre-cooling, two-way water heater control, and smart appliance applications are being explored and evaluated. In addition, the company continues to explore intersections of grid and system operations with alternative generating technologies including distributed solar and storage and microgrid applications.

PLAN CONSIDERATIONS

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize. A specific discussion of DEF's review of load growth forecasts higher and lower than the base forecast can be found in the previous sections.

TRANSMISSION PLANNING

DEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form No. 715 filing, and to assure the system meets DEF, Florida Reliability Coordinating Council, Inc. (FRCC), and North American Electric Reliability Corporation (NERC) criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and in determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. DEF runs this analysis for contingencies that may occur at system peak and off-peak load levels, under both summer and winter conditions. Additional studies are performed to determine the system response to credible, but less probable criteria. These studies include the loss of multiple generators, transmission lines, or combinations of each (some load loss is permissible under the more severe disturbances). These credible, but less probable scenarios are also evaluated at various load levels since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs. As noted in the DEF reliability criteria, some remedial actions are allowed to reduce system loadings; in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

DEF presently uses the following reference documents to calculate and manage Available Transfer Capability (ATC), Total Transfer Capability (TTC) and Transmission Reliability Margin (TRM) for required transmission path postings on the Florida Open Access Same Time Information System (OASIS):

- http://www.oatioasis.com/FPC/FPCdocs/ATCID_Posted_Rev4.pdf
- http://www.oatioasis.com/FPC/FPCdocs/TRMID_4.pdf

DEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID_rev3.pdf

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

DEF's 2024 TYSP Preferred Sites include eight solar generations sites: the Mule Creek Solar Site, the Winquepin Solar Site, the Falmouth Solar Site, the County Line Solar Site, the Sundance Solar Site, the Bailey Mill Solar Site, the Half Moon Solar Site, and the Rattler Solar Site. These Preferred Sites are discussed below.

MULE CREEK SOLAR SITE

DEF has identified the Mule Creek Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Bay County, Florida. Mule Creek is the third project constructed in Bay County. The site was used for pasture lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection is a new 230 kV breaker in DEF's existing Ladybug Switching Station and is connected via a short generation tie-line. All environmental surveys are complete. Solar is a now a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are no longer required. However, a Development Order (Final Site Plan approval) was required from Bay County. An Environmental Resource Permit (ERP) from the Florida Department of Environmental Protection (FDEP) was received in November 2022. There were no wetland impacts on site and there are no impacts to listed species. The project started construction in the spring of 2023. Construction is substantially complete, and the expected in-service date is March 2024.

FIGURE 4.1

Mule Creek Solar Project

Mule Creek	2500 Sandy Creek Rd
	Panama City, FL 32404

WINQUEPIN SOLAR SITE

DEF has identified the Winquepin Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Madison County, Florida. The site is located on former agricultural and timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection is a new 230 kV, three terminal, three breaker switching station and is connected via a short generation tie-line. All environmental surveys are complete. Madison County approved the Final Site Plan and an ERP from FDEP was secured. There were no wetland impacts on site. State listed gopher tortoises were present onsite. The appropriate permit (Conservation/Relocation Permit) from the Florida Fish and Wildlife Conservation Commission (FWC) was secured. Tortoises have been relocated from the site. No additional listed species of concern were present. Construction began in the spring of 2023. Construction activities are substantially complete, and the expected in-service date is March 2024.

FIGURE 4.2

Winquepin Solar Project

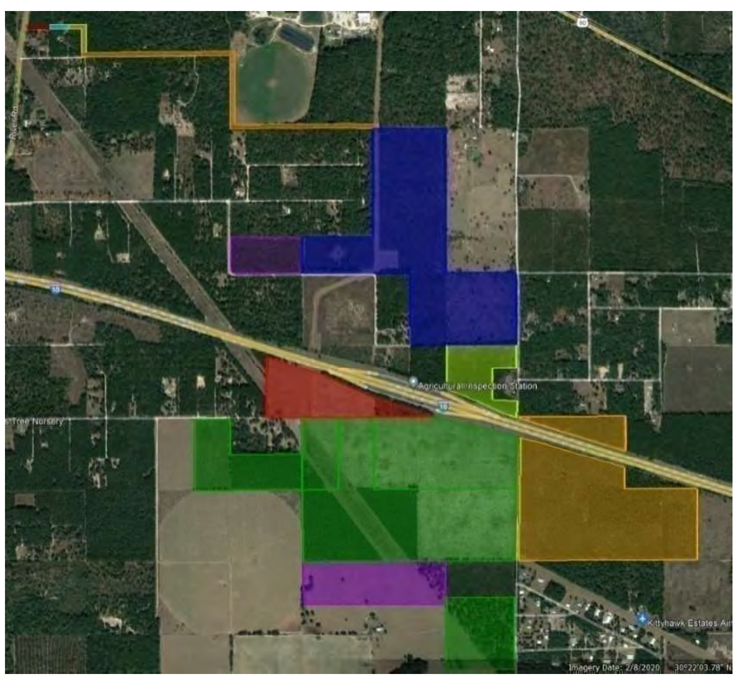
Winquepin	N. County Rd 53
	Madison, FL 32059

FALMOUTH SOLAR SITE

DEF has identified the Falmouth Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Suwanee County, Florida. Falmouth will be the third project constructed in Suwannee County. The site was historically used as pasture and timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 115 kV breaker in DEF's existing Suwanee Switching Station and will be connected via a 1.5-mile generation tie-line. All environmental surveys are complete. Suwannee County has provided Final Site Plan approval. The ERP was issued by FDEP on June 12, 2023. The two small wetlands on site, less than .5 acres total, were avoided thus there were no wetland impacts. The habitat assessment survey and subsequent species-specific surveys confirmed presence for the state-listed Southeastern American kestrel. Gopher tortoises were also present. FWC issued an Incidental Take Permit (ITP) for impacts to Southeastern American kestrel habitat and a Conservation/Relocation permit for gopher tortoises. Construction began in June of 2023. Construction is expected to complete by Q3 2024, with an expected in-service date of August 2024.

FIGURE 4.3

Falmouth Solar Project



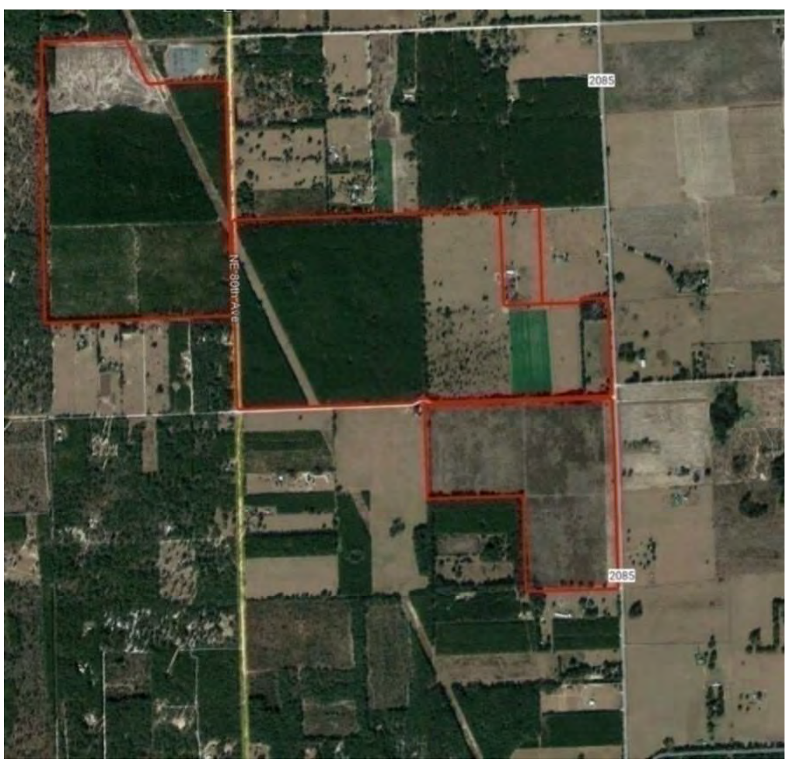
Falmouth	4431 River Rd
	Live Oak FL 32060

COUNTY LINE SOLAR SITE

DEF has identified the County Line Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Gilchrist County, Florida. The site was used for timber and pasture land and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 230 kV breaker in DEF's existing Ginnie Substation and will be connected via a short generation tie-line. Environmental surveys have been completed and confirmed the presence of state-listed Southeastern American kestrel and state-listed gopher tortoise. There are no wetlands onsite. Final Site Plan approval from Gilchrist County was received on November 14, 2023. FDEP issued the final ERP on July 25, 2023. There are no wetland impacts proposed. FWC issued an ITP for impacts to Southeastern American kestrel habitat and a Conservation/Relocation permit for gopher tortoises. All gopher tortoises have been relocated. Construction began in December 2023. The expected in-service date is October 2024.

FIGURE 4.4

County Line Solar Project



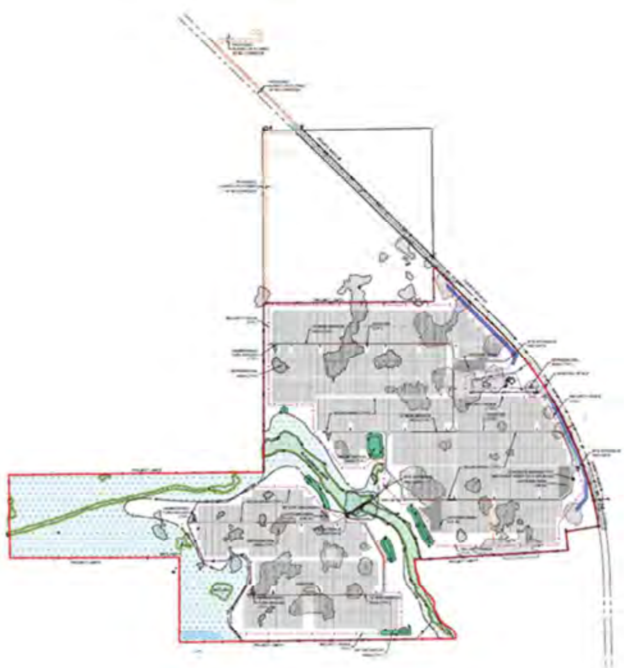
County Line	4960 NE 80th Blvd High Springs, FL 32643

SUNDANCE SOLAR SITE

DEF has identified the Sundance Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Madison County, Florida. The site is located on former agricultural lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new breakered terminal in the 230 kV, three Birch switching station and will be connected via a mile generation tie-line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Madison County. An ERP from FDEP will also be required. DEF has applied for the ERP and expects to receive it early in spring 2024. There are several wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate Relocation Permit from the FWC will be secured prior to construction. No additional listed species of concern were present. The project is expected to start construction in the spring of 2024, with an expected in-service date of early 2025.

FIGURE 4.5

Sundance Solar Project



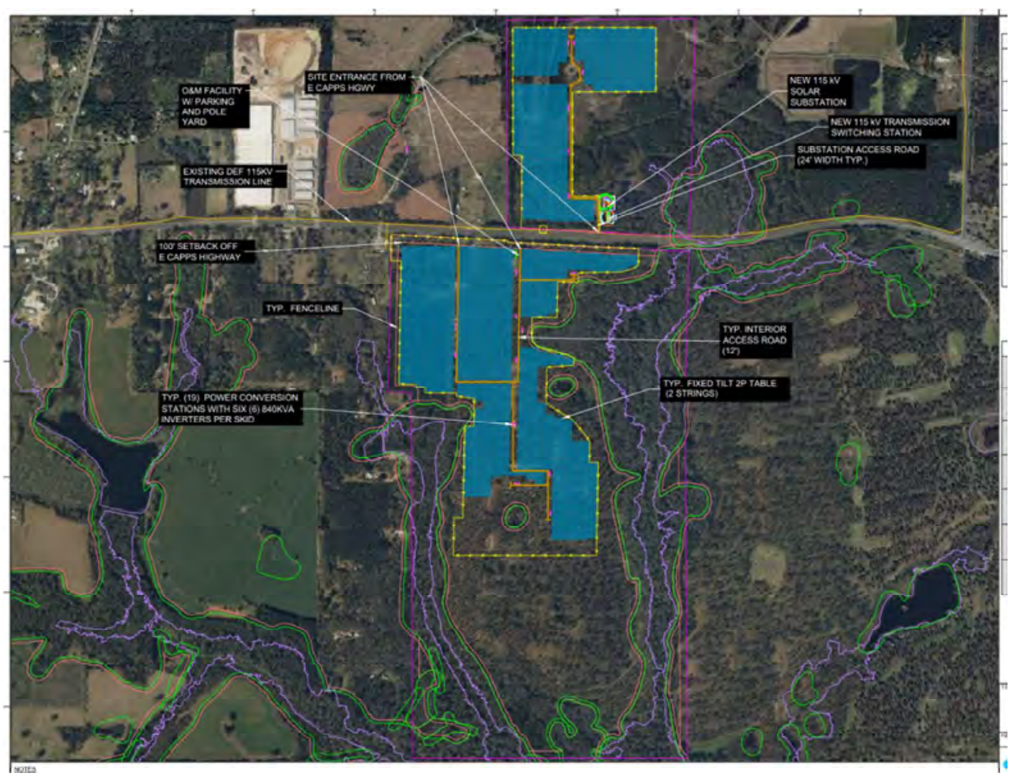
Sundance	16606 County Rd. 53
	Madison, FL 32059

BAILEY MILL SOLAR SITE

DEF has identified the Bailey Mill Renewable Energy Center, a 74.9 MWac solar Fixed tilt PV project located in Jefferson County, Florida. The site is located on timber and agricultural lands with some sloping that limits the use of a tracking system. The point of interconnection will be a new line tap on the Drifton to Waukeenah 115 kV line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Jefferson County. An ERP from FDEP will also be required. DEF intends to submit the ERP summer of 2024 and expects to receive it in late 2024. There are limited wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate Relocation Permit from the FWC will be secured prior to construction. No additional listed species of concern were present. The project is expected to start construction in the spring of 2025, with an expected in-service date of December 2025.

FIGURE 4.6

Bailey Mill Solar Project



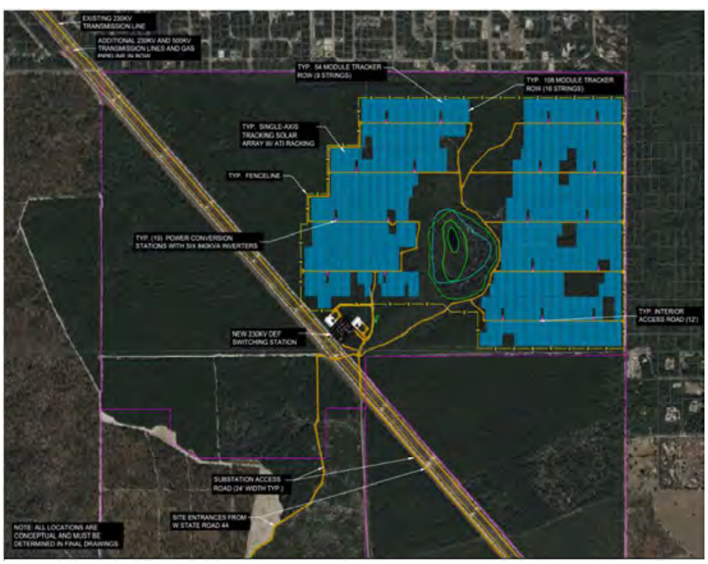
Bailey Mill	Jefferson County
	Zip Code 32344

<u>HALF MOON SOLAR SITE</u>

DEF has identified the Half Moon Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Sumter County, Florida. The site is located on merchantable timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 230 kV, three terminal, three breaker switching station and is connected via a short generation tie-line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Sumter County. An ERP from FDEP will also be required. DEF intends to submit the ERP summer of 2024 and expects to receive it in late 2024. There are limited wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate Relocation Permit from the FWC will be secured prior to construction. The Florida Scrub Jay was shown in the area, but not present on site. Consultation with the FWC will be completed prior to the start of construction. The project is expected to start construction in the spring of 2025, with an expected in-service date of December 2025.

FIGURE 4.7

Half Moon Solar Project



<u>Half Moon</u>	County:	Sumter	Latitude:	28.955619	Longitude:	-82.159585

RATTLER SOLAR SITE

DEF has identified the Rattler Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Hernando County, Florida. The site is located on agricultural lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 69 kV, four breaker switching station and is connected via a ~2-mile generation tie-line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Hernando County. An ERP from FDEP will also be required. DEF intends to submit the ERP summer of 2024 and expects to receive it in late 2024. There are limited wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate permit Relocation Permit from the FWC will be secured prior to construction. The project is expected to start construction in the spring of 2025, with an expected in-service date of December 2025.

FIGURE 4.8

Rattler Solar Project